ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

RECEIVED
2014 MAY 28 AM 10: 33
IDAHO PUBLIC
UTILITIES COMMISSION

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

May 28, 2014

VIA OVERNIGHT DELIVERY

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

Attention: Jean D. Jewell
Commission Secretary

RE: FERC Form 1

PacifiCorp (d.b.a. Rocky Mountain Power) submits for filing one copy of PacifiCorp's annual FERC Form 1 report for the year ended December 31, 2013.

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

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

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

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

Sincerely,

Jeffrey K. Larsen /wcs

Jeffrey K. Larsen
Vice President, Regulation & Government Affairs

Enclosure

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 2013/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 2013/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 Jennifer N. Kahl	06 Title of Contact Person External Reporting Director
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) 813-5958	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	03 Signature Douglas K. Stuver	04 Date Signed *(Mo, Da, Yr)* 04/11/2014
02 Title Senior VP & Chief Financial Officer		

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	N/A
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	N/A
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	N/A
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

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	

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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.

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 9.2% and Gregory E. Abel owns 1.0% of MEHC's common stock.

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	Trapper Mining Inc.	Mining	21.40	
9	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, an inactive wholly owned subsidiary of PacifiCorp, were sold to TransAlta. In December 2013, Centralia Mining Company was dissolved.

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

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.: 9 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 2013/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, 2013:		
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	246,495
5	President and Chief Executive Officer,		
6	Rocky Mountain Power	A. Richard Walje	372,000
7	President and Chief Executive Officer, Pacific Power	R. Patrick Reiten	310,000
8	President and Chief Executive Officer, PacifiCorp Energy	Micheal G. Dunn	310,000
9			
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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, 2013, 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, 2013 (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 2013/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, 2013:	
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	1111 South 103rd Street, Omaha, Nebraska 68124
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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Schedule Page: 105 Line No.: 13 Column: a

Mark C. Moench retired as a director and employee of PacifiCorp effective February 2014.

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 2013/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. The settlement agreement includes modifications to the formula used to determine transmission rates. The FERC approved interim rates for real power loss factors and certain ancillary services to be effective March 1, 2013 and for a new reactive power service rate to be effective May 1, 2013. In May 2013, the FERC approved PacifiCorp's settlement agreement resolving all issues for the transmission rate case. 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 2013/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	20130401-5001	04/01/2013	ER13-1207		
2	20130515-5178	05/15/2013	ER11-3643		
3	20131231-5176	12/31/2013	ER14-918		
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Schedule Page: 1061 Line No.: 1 Column: d

PacifiCorp submits tariff filing per 35.13(a)(2)(iii: OATT Revised Attachment H-1 (Depreciation Rates) to be effective 6/1/2013 under ER13-1207

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

PacifiCorp's Volume No. 11 Open Access Transmission Tariff

Schedule Page: 1061 Line No.: 2 Column: d

Transmission Formula Rate Annual Update Informational Filing of PacifiCorp under ER11-3643

Schedule Page: 1061 Line No.: 2 Column: e

PacifiCorp's Volume No. 11 Open Access Transmission Tariff

Schedule Page: 1061 Line No.: 3 Column: d

PacifiCorp submits tariff filing per 35.13(a)(2)(iii: OATT Revised Attachment H-1 (Revised Depreciation Rates) to be effective 1/1/2014 under ER14-918

Schedule Page: 1061 Line No.: 3 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 2013/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 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)			
Iona	07/25/2013	07/25/2028	3.0%
Oregon (3)			
Astoria	01/17/2013	01/17/2023	3.5%
Hermiston	02/21/2013	02/21/2043	$2,500 annual
Waterloo	04/03/2013	04/03/2033	7.0%
Jacksonville	04/23/2013	04/23/2033	6.0%
Coburg	07/26/2013	07/26/2023	7.5%
Klamath Falls	12/10/2013	12/10/2014	7.0%
Pilot Rock	12/19/2013	12/19/2033	8.0%
Utah (2)			
Garland	01/09/2013	01/09/2023	4.0%
Joseph	01/09/2013	01/09/2038	-
Kane County	03/27/2013	03/27/2038	-
Sigurd	03/27/2013	03/27/2038	-
Elmo	04/05/2013	04/05/2038	6.0%
American Fork	04/24/2013	04/24/2023	6.0%
Syracuse	07/25/2013	07/25/2023	6.0%
Mapleton	08/12/2013	08/12/2023	6.0%
Annabella	08/14/2013	08/14/2038	-
Cedar City	08/19/2013	08/19/2023	6.0%
Lehi	08/28/2013	08/28/2018	6.0%
Provo	09/03/2013	09/03/2018	6.0%
Salina	11/15/2013	11/15/2038	-
Washington (2)			
Pomeroy	07/11/2013	07/11/2033	6.0%
Garfield County	12/12/2013	12/12/2038	-
Selah	12/24/2013	12/24/2038	6.0%
Wyoming (4)			
Sublette County	07/09/2013	07/09/2038	-
Cokeville	10/22/2013	10/22/2033	1.0%
Rawlins	11/01/2013	11/01/2038	5.0%
Manderson	12/20/2013	12/20/2038	2.0%

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

(2) In Idaho, Utah and Washington, PacifiCorp collects franchise agreement fees 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. The 3.5% franchise agreement fee does not apply to Hermiston and is not embedded in rates. This $2,500 annual fee is an expense to PacifiCorp.

(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 March 2013, the Federal Energy Regulatory Commission ("FERC") in Docket No. AC-13-18-000 approved the journal entries required by the Uniform System of Accounts ("USofA") for the acquisition from Brigham City Corporation of certain electric transmission facilities as approved in Docket No. EC12-136-000. Accordingly, PacifiCorp cleared account 102, Electric plant purchased or sold, and recorded the purchase to the appropriate accounts. For further discussion, refer to Important Changes During the Quarter/Year, Item 3, in PacifiCorp's Form No. 1 for the year ended December 31, 2012.

In September 2013, PacifiCorp sold the St. Anthony hydroelectric generating facility to St. Anthony Hydro LLC and recorded the sale in account 102, Electric plant purchased or sold. The sale was approved by the FERC in Docket No. P-2381-063, the Idaho Public Utilities Commission ("IPUC") in Case No. PAC-E-13-06 and Order No. 32864 and the Wyoming Public Service Commission ("WPSC") in Docket No. 20000-433-EA-13. In October and November 2013, PacifiCorp filed for approval with the FERC the journal entries required by the USofA. In December 2013, the FERC in Docket No. AC14-1-000 approved the journal entries for the sale. Accordingly, PacifiCorp cleared account 102, Electric plant purchased or sold, and recorded the sale to the appropriate accounts. PacifiCorp also received approval from the IPUC in Case No. PAC-E-13-07 and Order No. 32865 and from the WPSC in Docket No. 20000-434-EK-13 to enter into a power purchase agreement with St. Anthony Hydro LLC for all of the net output of the St. Anthony hydroelectric generating facility, which became effective after the closing of the sale. For further discussion, refer to Important Changes During the Quarter/Year, Item 3, in PacifiCorp's Form No. 1 for the year ended December 31, 2012.

In December 2013, PacifiCorp entered into an agreement for the sale of certain facilities to the Navajo Tribal Utility Authority ("NTUA"). These facilities, substantially consisting of distribution facilities, provide service to approximately 1,500 customers on the Navajo Nation Reservation. The sale is subject to approval by the Public Service Commission of Utah, the WPSC, the Oregon Public Utility Commission ("OPUC"), the California Public Utilities Commission and the Navajo Nation Council and President of the Navajo Nation. Incorporated as part of the agreement for the sale of facilities is a power supply agreement with the NTUA for PacifiCorp to sell power to the NTUA, which is to become effective after the closing of the sale of the facilities.

ITEM 4.

None.

ITEM 5.

In May 2013, PacifiCorp placed into service the 100-mile high-voltage Mona-Oquirrh transmission line. Refer to pages 424-425 in this Form No. 1 for additional information regarding transmission lines added or removed during the year ended December 31, 2013.

For the year ended December 31, 2013, PacifiCorp did not significantly increase or decrease its distribution territory.

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, 2013. For further discussion, refer to Note 6 of Notes to Financial Statements in this Form No. 1.

Long-term Debt

In March 2014, PacifiCorp issued $425 million of 3.60% First Mortgage Bonds due April 2024. The net proceeds are being used to fund capital expenditures and for general corporate purposes, including retirement of short-term debt that was partially incurred to pay a $500 million common stock dividend to PPW Holdings LLC, a wholly owned subsidiary of MidAmerican Energy Holdings Company and PacifiCorp’s direct parent company ("PPW Holdings"), in March 2014.

In June 2013, PacifiCorp issued $300 million of 2.95% First Mortgage Bonds due June 2023. The net proceeds were used to fund capital expenditures and for general corporate purposes, including a portion of the common stock dividend paid to PPW Holdings in June 2013.

After the March 2014 issuance, PacifiCorp has regulatory authority from the OPUC and the IPUC to issue an additional $125 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.

As of December 31, 2013, PacifiCorp had $559 million of letters of credit providing credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $546 million plus interest. These letters of credit were fully available as of December 31, 2013 and expire periodically through March 2015. 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, 2013, PacifiCorp estimated it would be able to issue up to $8.8 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.

ITEM 7.

None.

ITEM 8.

For the year ended December 31, 2013, PacifiCorp's bargaining unit wage scale changes were as follows:

Unions Represented	% Increase (1)	Effective Date(s)	Estimated Annual Financial Impact (2)
IBEW 125 (OR, WA)	1.86%	1/26/2013	$ 479,528
IBEW 57 Combustion Turbine (UT)	1.18%	1/26/2013	29,427
IBEW 659 (OR, CA)	1.29%	4/26/2013	419,724
UWUA 197 (OR)	1.20%	5/26/2013	18,146
IBEW 57 Laramie (WY)	1.03%	6/26/2013	4,803
IBEW 57 Power Delivery (UT, ID & WY)	0.83%	6/26/2013	691,751
IBEW 57 Power Supply (UT, ID & WY)	0.85%	6/26/2013	335,000
UWUA 127 (WY)	0.53%	9/26/2013	233,143
Total			$ 2,211,522

(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.

Refer to Note 13 of Notes to Financial Statements in this Form No. 1 for information regarding certain legal proceedings affecting PacifiCorp.

ITEM 10.

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, 2013 other than the redemption of preferred stock shares as discussed in Note 14 of Notes to Financial Statements in this Form No. 1 and common and preferred stock dividends declared and paid.

ITEM 11.

(Reserved)

ITEM 12.

None.

ITEM 13.

Mark C. Moench retired as a director and employee of PacifiCorp effective February 2014.

ITEM 14.

Not applicable.

Deloitte.

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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, 2013, 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 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 PacifiCorp as of December 31, 2013, 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

March 3, 2014 (April 11, 2014 as to Notes 7 and 15)

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	24,810,145,362	23,971,186,312
3	Construction Work in Progress (107)	200-201	1,321,622,138	1,250,513,185
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		26,131,767,500	25,221,699,497
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	8,511,018,083	8,018,360,420
6	Net Utility Plant (Enter Total of line 4 less 5)		17,620,749,417	17,203,339,077
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)		17,620,749,417	17,203,339,077
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		14,388,489	16,067,385
19	(Less) Accum. Prov. for Depr. and Amort. (122)		2,937,770	3,461,732
20	Investments in Associated Companies (123)		69,928	69,928
21	Investment in Subsidiary Companies (123.1)	224-225	210,924,059	239,062,484
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)		82,248,215	84,847,739
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		19,849,214	19,796,604
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		154,542	1,367,457
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		324,696,677	357,749,865
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		6,739,098	23,522,354
36	Special Deposits (132-134)		172,901	139,866
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		44,824,535	55,313,879
39	Notes Receivable (141)		72,137	102,892
40	Customer Accounts Receivable (142)		420,371,007	388,339,929
41	Other Accounts Receivable (143)		34,941,278	49,311,318
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		8,008,893	8,884,148
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		6,608,556	4,537,480
45	Fuel Stock (151)	227	240,980,677	265,591,187
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	212,544,115	202,524,644
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		48,954,180	45,371,059
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		14,382	16,988
60	Rents Receivable (172)		2,320,602	1,773,869
61	Accrued Utility Revenues (173)		258,009,000	250,650,000
62	Miscellaneous Current and Accrued Assets (174)		109,302	481,065
63	Derivative Instrument Assets (175)		10,279,567	9,253,434
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		154,542	1,367,457
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)		1,278,777,902	1,286,678,359
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		33,721,944	34,752,802
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	1,760,602	4,126,549
72	Other Regulatory Assets (182.3)	232	1,373,975,244	1,821,244,610
73	Prelim. Survey and Investigation Charges (Electric) (183)		3,615,224	4,377,278
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)		113,051	46,898
78	Miscellaneous Deferred Debits (186)	233	90,972,267	86,782,863
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)		8,089,941	9,502,793
82	Accumulated Deferred Income Taxes (190)	234	482,567,288	648,219,005
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,994,815,561	2,609,052,798
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		21,219,039,557	21,456,820,099

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	2,397,600	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	1,102,063,956	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	41,101,061	41,284,560
11	Retained Earnings (215, 215.1, 216)	118-119	3,187,664,983	2,979,135,293
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	127,661,628	157,299,053
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-9,091,505	-12,003,821
16	Total Proprietary Capital (lines 2 through 15)		7,787,541,497	7,644,054,942
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	6,842,300,000	6,820,029,000
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)		91,152	102,179
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		13,958,237	14,074,076
24	Total Long-Term Debt (lines 18 through 23)		6,828,432,915	6,806,057,103
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		45,935,961	48,633,502
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		59,307,721	41,118,850
29	Accumulated Provision for Pensions and Benefits (228.3)		205,063,178	621,638,182
30	Accumulated Miscellaneous Operating Provisions (228.4)		38,745,810	38,367,730
31	Accumulated Provision for Rate Refunds (229)		0	6,578,797
32	Long-Term Portion of Derivative Instrument Liabilities		26,001,569	26,416,841
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		137,818,818	127,418,688
35	Total Other Noncurrent Liabilities (lines 26 through 34)		512,873,057	910,172,590
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		472,746,697	440,465,394
39	Notes Payable to Associated Companies (233)		8,616,719	11,109,978
40	Accounts Payable to Associated Companies (234)		42,517,163	37,303,255
41	Customer Deposits (235)		36,794,115	34,640,410
42	Taxes Accrued (236)	262-263	53,535,702	87,443,808
43	Interest Accrued (237)		113,038,154	114,528,244
44	Dividends Declared (238)		40,476	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)		19,668,643	17,617,882
48	Miscellaneous Current and Accrued Liabilities (242)		81,535,728	74,650,810
49	Obligations Under Capital Leases-Current (243)		2,772,497	6,482,626
50	Derivative Instrument Liabilities (244)		52,849,128	74,922,884
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		26,001,569	26,416,841
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)		858,113,453	873,260,912
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		24,877,489	19,569,969
57	Accumulated Deferred Investment Tax Credits (255)	266-267	32,306,325	34,331,017
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	308,485,444	333,027,535
60	Other Regulatory Liabilities (254)	278	91,533,914	102,737,542
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	226,880,978	208,722,047
63	Accum. Deferred Income Taxes-Other Property (282)		3,991,613,412	3,796,825,280
64	Accum. Deferred Income Taxes-Other (283)		556,381,073	728,061,162
65	Total Deferred Credits (lines 56 through 64)		5,232,078,635	5,223,274,552
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		21,219,039,557	21,456,820,099

Schedule Page: 112 Line No.: 39 Column: c

Represents amounts due to Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp, pursuant to an umbrella loan agreement for which interest is determined daily and is equal to the lowest cost of borrowings PacifiCorp could otherwise incur externally. At December 31, 2013 and 2012, the interest rate on the outstanding borrowings was 0.25% and 0.35%, respectively.

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

As of December 31, 2013, Account 236, Taxes accrued, included $18,691,010 of income taxes payable to MidAmerican Energy Holdings Company, PacifiCorp's indirect parent company.

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

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 PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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	5,153,186,543	4,849,485,873		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,660,714,690	2,512,486,745		
5	Maintenance Expenses (402)	320-323	423,183,559	427,348,788		
6	Depreciation Expense (403)	336-337	600,829,680	571,953,425		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	45,434,666	44,350,044		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	5,211,112	5,523,970		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		2,365,947	507,060		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		294,983	337,452		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	169,647,183	160,882,952		
15	Income Taxes - Federal (409.1)	262-263	74,343,217	-106,857,967		
16	- Other (409.1)	262-263	15,767,344	-785,331		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	826,690,640	770,193,169		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	625,812,453	419,882,524		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,812,064	-1,851,300		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)		63,381			
22	(Less) Gains from Disposition of Allowances (411.8)		26,460	49,887		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)			7,758		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		4,196,895,425	3,964,164,354		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		956,291,118	885,321,519		

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 2013/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
5,153,186,543	4,849,485,873					2
						3
2,660,714,690	2,512,486,745					4
423,183,559	427,348,788					5
600,829,680	571,953,425					6
						7
45,434,666	44,350,044					8
5,211,112	5,523,970					9
2,365,947	507,060					10
						11
294,983	337,452					12
						13
169,647,183	160,882,952					14
74,343,217	-106,857,967					15
15,767,344	-785,331					16
826,690,640	770,193,169					17
625,812,453	419,882,524					18
-1,812,064	-1,851,300					19
						20
63,381						21
26,460	49,887					22
						23
	7,758					24
4,196,895,425	3,964,164,354					25
956,291,118	885,321,519					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		956,291,118	885,321,519		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,154,351	3,143,641		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,395,781	3,064,403		
33	Revenues From Nonutility Operations (417)		389,833	651,778		
34	(Less) Expenses of Nonutility Operations (417.1)		127,665	130,325		
35	Nonoperating Rental Income (418)		122,658	-9,703		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	13,397,403	11,211,230		
37	Interest and Dividend Income (419)		5,541,076	6,422,547		
38	Allowance for Other Funds Used During Construction (419.1)		57,244,026	58,494,261		
39	Miscellaneous Nonoperating Income (421)		1,000,254	602,865		
40	Gain on Disposition of Property (421.1)		306,494	896,553		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		77,632,649	78,218,444		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		342,145	71,235		
44	Miscellaneous Amortization (425)		1,298,969	1,292,207		
45	Donations (426.1)		2,516,950	2,491,665		
46	Life Insurance (426.2)		-4,817,326	-5,124,160		
47	Penalties (426.3)		2,337,066	719,036		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,763,417	1,497,850		
49	Other Deductions (426.5)		3,789,575	129,377,724		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		7,230,796	130,325,557		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	345,622	315,476		
53	Income Taxes-Federal (409.2)	262-263	-2,396,204	-1,654,653		
54	Income Taxes-Other (409.2)	262-263	-325,603	-224,840		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	70,283,900	84,103,300		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	67,854,963	129,629,658		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		928,426	1,827,951		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-875,674	-48,918,326		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		71,277,527	-3,188,787		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		355,945,454	355,713,688		
63	Amort. of Debt Disc. and Expense (428)		3,888,848	3,835,726		
64	Amortization of Loss on Reaquired Debt (428.1)		1,421,460	1,797,595		
65	(Less) Amort. of Premium on Debt-Credit (429)		11,027	8,949		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		24,397	-12,665		
68	Other Interest Expense (431)		13,394,876	12,226,166		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		29,258,693	28,756,114		
70	Net Interest Charges (Total of lines 62 thru 69)		345,405,315	344,795,447		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		682,163,330	537,337,285		
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)		682,163,330	537,337,285		

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, 2013 and 2012, depreciation expense associated with transportation equipment was $15,921,062 and $15,898,715, 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, 2013 and 2012, payroll taxes were $39,811,382 and $40,291,150, respectively.

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

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		2,974,333,637	2,645,655,455
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6	Write-off of 2010 gain on repurchase of preferred stock	211	166,025	
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		166,025	
10				
11	Call premiums and fees on preferred stock redemption		-1,943,279	
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-1,943,279	
16	Balance Transferred from Income (Account 433 less Account 418.1)		668,765,927	526,126,055
17	Appropriations of Retained Earnings (Acct. 436)			
18	Appropriation of excess earnings at certain hydroelectric generating facilities	215.1	-2,762,978	(1,225,845)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-2,762,978	(1,225,845)
23	Dividends Declared-Preferred Stock (Account 437)			
24	Preferred Stock, various series and rates	238	-1,493,811	(2,049,846)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-1,493,811	(2,049,846)
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock	238	-500,000,000	(200,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-500,000,000	(200,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings	216.1	43,034,828	5,827,818
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		3,180,100,349	2,974,333,637
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

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)		7,564,634	4,801,656
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		7,564,634	4,801,656
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		3,187,664,983	2,979,135,293
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		157,299,053	151,915,641
50	Equity in Earnings for Year (Credit) (Account 418.1)		13,397,403	11,211,230
51	(Less) Dividends Received (Debit)			
52	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		-43,034,828	(5,827,818)
53	Balance-End of Year (Total lines 49 thru 52)		127,661,628	157,299,053

Schedule Page: 118 Line No.: 11 Column: b

Account 131, Cash
Account 214, Capital stock expense
Account 930.2, Miscellaneous general expenses

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

Outstanding shares of preferred stock as of December 31, 2013 and dividends on preferred stock during the year ended December 31, 2013 were as follows:

		Shares	Dividend
4.52%	Serial Preferred	-	$ 7,062
4.56%	Serial Preferred	-	280,575
4.72%	Serial Preferred	-	235,099
5.00%	Serial Preferred	-	62,862
5.40%	Serial Preferred	-	269,113
6.00%	Serial Preferred	5,930	35,580
7.00%	Serial Preferred	18,046	126,322
5%	Preferred	-	477,198
		23,976	$ 1,493,811

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

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%	Preferred	126,243	631,215
		407,331	$2,049,846

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

In May 2013, Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp, declared and paid a dividend of $43 million to PacifiCorp. Also, in September 2013, Trapper Mining Inc., a subsidiary of PacifiCorp, paid a dividend of $34,828 to PacifiCorp.

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

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.

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

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

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 2013/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)	682,163,330	537,337,285
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	623,158,412	589,168,608
5	Amortization:	52,239,730	51,502,307
6			
7			
8	Deferred Income Taxes (Net)	203,307,124	304,784,287
9	Investment Tax Credit Adjustment (Net)	-2,740,490	-3,679,251
10	Net (Increase) Decrease in Receivables	-10,007,750	-14,624,273
11	Net (Increase) Decrease in Inventory	14,591,039	-34,659,850
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	30,795,829	57,856,504
14	Net (Increase) Decrease in Other Regulatory Assets	-23,882,915	17,169,240
15	Net Increase (Decrease) in Other Regulatory Liabilities	-8,253,088	-15,997,931
16	(Less) Allowance for Other Funds Used During Construction	57,244,026	58,494,261
17	(Less) Undistributed Earnings from Subsidiary Companies	-29,637,425	5,383,412
18	Amounts Due To/From Affiliates (Net)	-33,476,313	110,233,418
19	Derivative Collateral (Net)	42,900,000	68,250,000
20	Other Operating Activities:	21,056,199	25,993,723
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,564,244,506	1,629,456,394
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,119,674,872	-1,398,801,462
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	-57,244,026	-58,494,261
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,062,430,846	-1,340,307,201
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	277,539	739,512
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-1,499,000	
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 2013/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:	6,064,789	-13,553,729
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,057,587,518	-1,331,952,019
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	299,100,000	748,786,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		11,107,806
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	299,100,000	759,893,806
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-277,729,000	-101,026,000
74	Preferred Stock	-40,095,281	
75	Common Stock		
76	Other (provide details in footnote):	-6,831,840	-7,826,267
77	Repayment of Capital Lease Obligations	-6,407,670	-1,316,468
78	Net Decrease in Short-Term Debt (c)		-688,436,607
79			
80	Dividends on Preferred Stock	-1,965,797	-2,049,846
81	Dividends on Common Stock	-500,000,000	-200,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-533,929,588	-240,761,382
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-27,272,600	56,742,993
87			
88	Cash and Cash Equivalents at Beginning of Period	78,836,233	22,093,240
89			
90	Cash and Cash Equivalents at End of period	51,563,633	78,836,233

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

Includes depreciation expense associated with transportation equipment and capital lease assets of $22,328,732 and $17,215,183 during the years ended December 31, 2013 and 2012, respectively.

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

	Years Ended December 31, 2013	2012
Amortization of software development & other intangibles	$ 46,733,635	$ 45,642,251
Amortization of electric plant acquisition adjustments	5,211,112	5,523,970
Amortization of regulatory assets	294,983	336,086
	$ 52,239,730	$ 51,502,307

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

	Years Ended December 31, 2013	2012
Depreciation and depletion included in cost of fuel	$12,456,145	$12,461,354
Net (gain)/loss on sale of property	22,871	(1,063,591)
Write-off of assets under construction	10,483,484	10,606,163
Change in corporate owned life insurance cash surrender value	(4,880,695)	-
Amortization of debt issuance expenses and bond discount/premium	3,877,821	3,826,777
Other	(903,427)	163,020
	$21,056,199	$25,993,723

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

Represents proceeds from the disposal of fixed assets.

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

Represents proceeds from the disposal of fixed assets.

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

	Years Ended December 31, 2013	2012
Other investments/special funds	$ 5,949,345	$ (369,775)
Temporary facilities	(66,153)	20,007
Restricted cash	181,597	(13,203,961)
	$ 6,064,789	$(13,553,729)

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

Affiliate borrowing from subsidiary company, Pacific Minerals, Inc.

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

	Years Ended December 31, 2013	2012
Net repayments of affiliate borrowing from subsidiary company, Pacific Minerals, Inc.	$ (2,492,611)	$ -
Long-term debt issuance and other deferred financing costs	(4,339,229)	(7,826,267)
	$ (6,831,840)	$(7,826,267)

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 utility 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 other utilities, energy marketing companies, financial institutions and other market participants. 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." For GAAP, unrecognized tax benefits associated with temporary differences are reflected as other liabilities while for FERC the income tax impact of uncertain tax positions associated with temporary differences are reflected in accumulated deferred 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 will be 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 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):

	2013	2012
Cash (131)	$ 7	$ 24
Working funds (135)	—	—
Temporary cash investments (136)	45	55
Total cash and cash equivalents	$ 52	$ 79

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, 2013 and 2012, 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):

	2013	2012
Beginning balance	$ 9	$ 9
Charged to operating costs and expenses, net	13	14
Write-offs, net	(14)	(14)
Ending balance	$ 8	$ 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.

Debt and equity AFUDC, which represents the estimated costs of debt and equity funds necessary to finance the construction of utility plant, 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 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, 2013 and 2012, unbilled revenue was $258 million and $251 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 include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of sales among 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 and expense for certain property-related basis differences and other various differences that PacifiCorp is required to pass on to its customers are charged or credited directly to a regulatory asset or liability. These amounts were recognized as regulatory assets of $461 million and $456 million as of December 31, 2013 and 2012, respectively, and regulatory liabilities of $21 million as of December 31, 2013 and 2012, 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 or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more likely than not to be realized.

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 income 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 on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that 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 impact on PacifiCorp's financial results.

Segment Information

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

New Accounting Pronouncements

In February 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2013-04, which amends FASB Accounting Standards Codification ("ASC") Topic 405, "Liabilities." The amendments in this guidance require an entity to measure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date as the amount the reporting entity agreed to pay plus any additional amounts the reporting entity expects to pay on behalf of its co-obligor. Additionally, the guidance requires the entity to disclose the nature and amount of the obligation, as well as other information about those obligations. This guidance is effective for interim and annual reporting periods beginning after December 15, 2013. PacifiCorp adopted this guidance on January 1, 2014. The adoption of this guidance did not have a material impact on PacifiCorp's disclosures included within Notes to Financial Statements.

In December 2011, the FASB issued ASU No. 2011-11, which amends FASB 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. 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. PacifiCorp adopted the guidance on January 1, 2013. The adoption of the 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, 2013 and 2012.

In January 2013, PacifiCorp filed applications for depreciation rate changes with the Utah Public Service Commission ("UPSC"), the Oregon Public Utility Commission ("OPUC"), the Wyoming Public Service Commission ("WPSC"), the Washington Utilities and Transportation Commission ("WUTC") and the Idaho Public Utilities Commission ("IPUC") based on PacifiCorp's most recent depreciation study. PacifiCorp received approval from the state commissions to change the depreciation rates effective January 1, 2014. The approved depreciation rates will result in an estimated annual increase in depreciation expense of $40 million on a total company basis based on the depreciable plant balances as of December 31, 2013 included in the study.

(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, 2013 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4	67%	$ 1,121	$ 523	$ 19
Hunter No. 1	94	394	152	54
Hunter No. 2	60	293	85	—
Wyodak	80	450	163	1
Colstrip Nos. 3 and 4	10	227	126	4
Hermiston	50	173	62	1
Craig Nos. 1 and 2(1)	19	323	197	2
Hayden No. 1	25	55	26	6
Hayden No. 2	13	32	17	2
Foote Creek	79	37	21	—
Transmission and distribution facilities	Various	341	75	3
Total		$ 3,446	$ 1,447	$ 92

(1) Includes unallocated acquisition adjustments of $141 million related to Facility in Service and $102 million related to Accumulated Depreciation and Amortization.

(5) Regulatory Matters

PacifiCorp had regulatory assets not earning a return on investment of $1.244 billion and $1.618 billion as of December 31, 2013 and 2012, 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):

2013:	
Revolving credit facilities	$ 1,200
Less:	
Short-term debt	—
Letters of credit and tax-exempt bond support	(321)
Net revolving credit facilities	$ 879
2012:	
Revolving credit facilities	$ 1,230
Less:	
Short-term debt	—
Letters of credit	(602)
Net revolving credit facilities	$ 628

In March 2013, PacifiCorp replaced its $630 million unsecured revolving credit facility, which had been set to expire in July 2013, with a $600 million unsecured revolving credit facility expiring in March 2018. Additionally, PacifiCorp has a $600 million unsecured revolving credit facility expiring in June 2017. These credit facilities, which support PacifiCorp's commercial paper program, certain series of its tax-exempt bond obligations and provide for the issuance of letters of credit, 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. These 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. As of December 31, 2013, PacifiCorp was in compliance with the covenants of its credit facilities.

As of December 31, 2013 and 2012, PacifiCorp had $559 million and $602 million, respectively, of fully available letters of credit issued under committed arrangements, of which $270 million and $602 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 expire through March 2015.

As of December 31, 2013, PacifiCorp had approximately $16 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, 2013 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 generally includes provisions that allow PacifiCorp to redeem the first mortgage bonds 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 March 2014, PacifiCorp issued $425 million of 3.60% First Mortgage Bonds due April 2024. The net proceeds are being used to fund capital expenditures and for general corporate purposes, including retirement of short-term debt that was partially incurred to pay a $500 million common stock dividend to PPW Holdings LLC, a wholly owned subsidiary of MEHC and PacifiCorp’s direct parent company ("PPW Holdings"), in March 2014.

In June 2013, PacifiCorp issued $300 million of 2.95% First Mortgage Bonds due June 2023. The net proceeds were used to fund capital expenditures and for general corporate purposes, including a portion of the common stock dividend paid to PPW Holdings in June 2013.

After the March 2014 issuance, PacifiCorp has regulatory authority from the OPUC and the IPUC to issue an additional $125 million of long-term debt. PacifiCorp must make a notice filing with the WUTC 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 October 2016.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $24 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2013.

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 $49 million and $55 million as of December 31, 2013 and 2012, respectively, were included in net utility plant in the Comparative Balance Sheet.

As of December 31, 2013, the annual maturities of long-term debt and capital lease obligations, excluding unamortized discounts and including interest on capital lease obligations, for 2014 and thereafter are as follows (in millions):

	Long-term Debt	Capital Lease Obligations	Total
2014	$ 236	$ 8	$ 244
2015	122	7	129
2016	57	7	64
2017	52	11	63
2018	586	7	593
Thereafter	5,789	61	5,850
Total	6,842	101	6,943
Unamortized discount	(14)	—	(14)
Amounts representing interest	—	(52)	(52)
Total	$ 6,828	$ 49	$ 6,877

(8) Income Taxes

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

	2013	2012
Current:		
Federal	$ 72	$ (108)
State	16	(1)
Total	88	(109)
Deferred:		
Federal	177	273
State	26	32
Total	203	305
Investment tax credits	(3)	(4)
Total income tax expense	$ 288	$ 192

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:

	2013	2012
Federal statutory income tax rate	35 %	35 %
State income taxes, net of federal income tax benefit	3	3
Federal income tax credits(1)	(7)	(9)
Other	(1)	(3)
Effective income tax rate	30 %	26 %

(1) Primarily attributable to the impact of federal renewable electricity production tax credits for 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):

	2013	2012
Deferred income tax assets:		
Employee benefits	$ 99	$ 217
Derivative contracts and unamortized contract values	76	109
State carryforwards	68	69
Loss contingencies	67	61
Asset retirement obligations	48	46
Regulatory liabilities	36	40
Other	89	106
	483	648
Deferred income tax liabilities:		
Property, plant and equipment	(4,219)	(4,005)
Regulatory assets	(526)	(696)
Other	(30)	(32)
	(4,775)	(4,733)
Net deferred income tax liability	$ (4,292)	$ (4,085)

The following table provides PacifiCorp's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2013 (in millions):

	State
Net operating loss carryforwards	$ 1,451
Deferred income taxes on net operating loss carryforwards	$ 52
Expiration dates	2014 - 2032
Tax credit carryforwards	$ 16
Expiration dates	2014 - indefinite

The United States Internal Revenue Service has effectively settled its examination of PacifiCorp's income tax returns through December 31, 2009. State agencies have closed their examinations of PacifiCorp's income tax returns through March 31, 2003, except for the 1995 and 1997 tax years in Utah.

(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 continue to 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.

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	
	2013	2012	2013	2012
Service cost	$ 6	$ 7	$ 9	$ 7
Interest cost	54	61	25	28
Expected return on plan assets	(74)	(74)	(30)	(30)
Net amortization	48	34	8	4
Net periodic benefit cost	$ 34	$ 28	$ 12	$ 9

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	
	2013	2012	2013	2012
Plan assets at fair value, beginning of year	$ 1,012	$ 931	$ 424	$ 384
Employer contributions	63	49	8	9
Participant contributions	—	—	7	7
Actual return on plan assets	213	120	86	52
Benefits paid	(117)	(88)	(39)	(28)
Plan assets at fair value, end of year	$ 1,171	$ 1,012	$ 486	$ 424

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

	Pension		Other Postretirement	
	2013	2012	2013	2012
Benefit obligation, beginning of year	$ 1,391	$ 1,291	$ 632	$ 575
Service cost	6	7	9	7
Interest cost	54	61	25	28
Participant contributions	—	—	7	7
Actuarial (gain) loss	(104)	120	(36)	43
Benefits paid	(117)	(88)	(39)	(28)
Benefit obligation, end of year	$ 1,230	$ 1,391	$ 598	$ 632
Accumulated benefit obligation, end of year	$ 1,229	$ 1,390		

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	
	2013	2012	2013	2012
Plan assets at fair value, end of year	$ 1,171	$ 1,012	$ 486	$ 424
Less - Benefit obligation, end of year	1,230	1,391	598	632
Funded status	$ (59)	$ (379)	$ (112)	$ (208)

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 $48 million and $44 million as of December 31, 2013 and 2012, 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	
	2013	**2012**	**2013**	**2012**
Net loss	$ 361	$ 660	$ 108	$ 214
Prior service credit	(29)	(37)	(33)	(40)
Regulatory deferrals	(4)	(5)	2	3
Total	$ 328	$ 618	$ 77	$ 177

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2013 and 2012 is as follows (in millions):

	Regulatory Asset	**Accumulated Other Comprehensive Loss**	**Total**
Pension			
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
Net gain arising during the year	(239)	(3)	(242)
Net amortization	(47)	(1)	(48)
Total	(286)	(4)	(290)
Balance, December 31, 2013	$ 313	$ 15	$ 328

	Regulatory Asset
Other Postretirement	
Balance, December 31, 2011	$ 163
Net loss arising during the year	18
Net amortization	(4)
Total	14
Balance, December 31, 2012	177
Net gain arising during the year	(92)
Net amortization	(8)
Total	(100)
Balance, December 31, 2013	$ 77

The net loss, prior service credit and regulatory deferrals that will be amortized in 2014 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Regulatory Deferrals	Total
Pension	$ 38	$ (8)	$ (1)	$ 29
Other postretirement	9	(7)	—	2
Total	$ 47	$ (15)	$ (1)	$ 31

Plan Assumptions

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

	Pension		Other Postretirement	
	2013	2012	2013	2012
Benefit obligations as of December 31:				
Discount rate	4.80 %	4.05 %	4.90 %	4.10 %
Rate of compensation increase	3.00	3.00	N/A	N/A
Net periodic benefit cost for the years ended December 31:				
Discount rate	4.05 %	4.90 %	4.10 %	4.95 %
Expected return on plan assets	7.50	7.50	7.50	7.50
Rate of compensation increase	3.00	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 forward-looking views of the financial markets and historical performance.

	2013	2012
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	8.00%	8.00%
Rate that the cost trend rate gradually declines to	5.00%	5.00%
Year that the rate reaches the rate it is assumed to remain at	2019	2018

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	$ 4	$ (3)
Other postretirement benefit obligation	41	(33)

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $10 million and $4 million, respectively, during 2014. 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 generally contribute an amount equal to the net periodic benefit cost.

The expected benefit payments to participants in PacifiCorp's pension and other postretirement benefit plans for 2014 through 2018 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments		
		Other Postretirement	
	Pension	Gross	Medicare Subsidy
2014	$ 102	$ 38	$ —
2015	108	39	—
2016	109	39	—
2017	104	40	—
2018	104	42	—
2019 - 2023	470	210	(3)

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 target allocations (percentage of plan assets) for PacifiCorp's pension and other postretirement benefit plan assets are as follows as of December 31, 2013:

	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 are 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, 2013				
Cash equivalents	$ —	$ 18	$ —	$ 18
Debt securities:				
United States government obligations	13	—	—	13
International government obligations	—	1	—	1
Corporate obligations	—	48	—	48
Municipal obligations	—	8	—	8
Agency, asset and mortgage-backed obligations	—	50	—	50
Equity securities:				
United States companies	489	—	—	489
International companies	16	—	—	16
Investment funds[2]	215	227	—	442
Limited partnership interests[3]	—	—	86	86
Total	$ 733	$ 352	$ 86	$ 1,171
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

(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 50% and 50%, respectively, for 2013 and 60% and 40%, respectively, for 2012, and are invested in United States and international securities of approximately 42% and 58%, respectively, for 2013 and 2012.

(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, 2013				
Cash and cash equivalents	$ 3	$ 1	$ —	$ 4
Debt securities:				
United States government obligations	1	—	—	1
Corporate obligations	—	4	—	4
Municipal obligations	—	1	—	1
Agency, asset and mortgage-backed obligations	—	4	—	4
Equity securities:				
United States companies	167	—	—	167
International companies	6	—	—	6
Investment funds(2)	173	120	—	293
Limited partnership interests(3)	—	—	6	6
Total	$ 350	$ 130	$ 6	$ 486
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

(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 49% and 51%, respectively, for 2013 and 48% and 52%, respectively, for 2012, and are invested in United States and international securities of approximately 70% and 30%, respectively, for 2013 and 66% and 34%, respectively, for 2012.

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

For level 1 investments, 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. For level 2 investments, the fair value is determined using pricing models or unquoted net asset values based on observable market inputs. For level 3 investments, 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 pension and other postretirement benefit plans' proportionate shares 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, 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
Actual return on plan assets still held at December 31, 2013	16	1
Purchases, sales, distributions and settlements	(26)	(2)
Balance, December 31, 2013	$ 86	$ 6

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 although formed with the ability for other employers to participate in the plan, there are no other employers that participate in this 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):

		PPA zone status or plan funded status percentage for plan years beginning July 1,(1)				Contributions(2)		
Plan name	Employer Identification Number	2013	2012	Funding improvement plan	Surcharge imposed under PPA	2013	2012	Year contributions to plan exceeded more than 5% of total contributions(3)
UMWA Pension Plan	52-1050282	Seriously Endangered(4)	Seriously Endangered	Implemented	None	$ 3	$ 3	None
Local 57 Trust Fund	87-0640888	At least 80%	At least 80%	None	None	$ 9	$ 12	2012, 2011

(1) Among other factors, multiemployer plans in seriously endangered status are at least 65% but less than 80% funded and 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.

(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 agreements 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, 2011. Information for the plan years beginning July 1, 2013 and 2012 is not available. For the Local 57 Trust Fund, information is for plan years beginning July 1, 2012 and 2011. Information for the plan year beginning July 1, 2013 is not yet available.

(4) If PacifiCorp's subsidiary was to withdraw from the UMWA Pension Plan, a liability of up to an estimated $125 million could be triggered.

The current collective bargaining agreements governing the Local 57 Trust Fund expire in January 2016. Although the collective bargaining agreement governing the UMWA Pension Plan expired in January 2013 and a new agreement has not yet been reached, operations continue under the provisions of the expired agreement.

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 $35 million and $36 million for the years ended December 31, 2013 and 2012, 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 $843 million and $810 million as of December 31, 2013 and 2012, respectively.

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

	2013	2012
Beginning balance	$ 127	$ 123
Change in estimated costs	3	17
Additions	8	4
Retirements	(6)	(22)
Accretion	6	5
Ending balance	$ 138	$ 127

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 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, 2013					
Not designated as hedging contracts[1]:					
Commodity assets	$ 11	$ —	$ 2	$ 1	$ 14
Commodity liabilities	(1)	—	(29)	(39)	(69)
Total	10	—	(27)	(38)	(55)
Total derivatives	10	—	(27)	(38)	(55)
Cash collateral receivable	—	—	—	12	12
Total derivatives - net basis	$ 10	$ —	$ (27)	$ (26)	$ (43)
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)

(1) PacifiCorp's commodity derivatives are generally included in rates and as of December 31, 2013 and 2012, a regulatory asset of $55 million and $121 million, respectively, was recorded related to the net derivative liability of $55 million and $121 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):

	2013	2012
Beginning balance	$ 121	$ 264
Changes in fair value recognized in regulatory assets	15	45
Net gains reclassified to operating revenue	9	38
Net losses reclassified to energy costs	(90)	(226)
Ending balance	$ 55	$ 121

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	2013	2012
Electricity sales	Megawatt hours	(1)	(1)
Natural gas purchases	Decatherms	120	74
Fuel oil purchases	Gallons	15	16

Credit Risk

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

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

Collateral and Contingent Features

In accordance with industry practice, certain wholesale derivative contracts contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the three recognized credit rating agencies. 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, 2013, 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 $68 million and $153 million as of December 31, 2013 and 2012, respectively, for which PacifiCorp had posted collateral of $12 million and $56 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, 2013 and 2012, PacifiCorp would have been required to post $51 million and $73 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, 2013					
Assets:					
Commodity derivatives	$ —	$ 12	$ 2	$ (4)	$ 10
Money market mutual funds(2)	61	—	—	—	61
	$ 61	$ 12	$ 2	$ (4)	$ 71
Liabilities - Commodity derivatives	$ —	$ (69)	$ —	$ 16	$ (53)
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)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $12 million and $55 million as of December 31, 2013 and 2012, respectively.

(2) Amounts are included in 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 estimated 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 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):

	2013	2012
Beginning balance	$ —	$ 1
Changes in fair value recognized in regulatory assets	1	1
Purchases	4	—
Settlements	(3)	(2)
Ending balance	$ 2	$ —

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):

	2013		2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 6,828	$ 7,626	$ 6,806	$ 8,350

(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 the first quarter of 2013, PacifiCorp filed its responses to the Plaintiff's post-trial motions for exemplary damages, attorneys' fees and prejudgment interest. An initial judgment was entered in April 2013 in which 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. In May 2013, a final judgment was entered against PacifiCorp in the amount of $115 million, which includes the $113 million of aggregate damages previously awarded and amounts awarded for the Plaintiff's attorneys' fees. The final judgment also ordered that postjudgment interest accrue beginning as of the date of the April 2013 initial judgment. In May 2013, PacifiCorp posted a surety bond issued by a subsidiary of Berkshire Hathaway to secure its estimated obligation. PacifiCorp strongly disagrees with the jury's verdict and plans to vigorously pursue all appellate measures. Both PacifiCorp and the Plaintiff filed appeals with the Utah Supreme Court. The parties are briefing their positions before the Utah Supreme Court with briefing expected to be completed and oral arguments held by late 2014. As of December 31, 2013, PacifiCorp had accrued $117 million for the final judgment and postjudgment interest, 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 appeals process, which could take as long as several years.

Sanpete County, Utah Rangeland Fire

In June 2012, a major rangeland fire occurred in Sanpete County, Utah. Certain parties allege that contact between two of PacifiCorp’s transmission lines may have triggered a ground fault that led to the fire. PacifiCorp has engaged experts to review the cause and origin of the fire, as well as to assess the damages. PacifiCorp has accrued its best estimate of the potential loss and believes it is reasonably possible it may incur additional loss beyond the amount accrued. PacifiCorp does not believe the potential additional loss will have a material impact to its financial results, particularly with PacifiCorp's ability to seek insurance recovery if considered necessary.

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 among all parties. The plaintiff parties to the proceeding filed claims against multiple parties, including PacifiCorp. PacifiCorp entered into settlements with the plaintiff parties, and the resulting settlements were approved by the FERC. The outcome of such settlements did not have a material impact on PacifiCorp's financial results. The FERC, however, declined to dismiss PacifiCorp from the case entirely, noting that additional parties may, in the future, assert sequential claims against parties to the case, including PacifiCorp. PacifiCorp believes it is unlikely that the FERC will address sequential claims until after the primary cases have proceeded through the trial-type hearing. Due to the uncertainties associated with the sequential claims, PacifiCorp is unable to predict the outcome and the impact of any claims on its financial results.

Environmental Laws and Regulations

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, renewable portfolio standards, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact PacifiCorp's current and future operations. PacifiCorp believes it is in material compliance with all applicable laws and regulations.

Hydroelectric Relicensing

PacifiCorp's 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, 2013, PacifiCorp's assets included $103 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 and the CPUC to depreciate and amortize the Klamath hydroelectric system's mainstem dams and the associated relicensing and settlement costs through the December 2019 expected dam removal date. PacifiCorp also filed for consistent ratemaking treatment in the 2011 and 2013 Washington general rate cases and the treatment was uncontested in both cases. PacifiCorp has received approvals from the UPSC, the WPSC and the IPUC to depreciate and amortize 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 $189 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, 2013 are as follows (in millions):

	2014	2015	2016	2017	2018	2019 and Thereafter	Total
Contract type:							
Purchased electricity contracts	$ 119	$ 116	$ 100	$ 76	$ 72	$ 503	$ 986
Fuel contracts	765	570	514	516	451	1,776	4,592
Construction commitments	404	121	37	9	9	37	617
Transmission	115	105	98	87	79	656	1,140
Operating leases and easements	6	5	4	4	4	49	72
Maintenance, service and other contracts	52	28	16	16	12	79	203
Total commitments	$ 1,461	$ 945	$ 769	$ 708	$ 627	$ 3,100	$ 7,610

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 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 a lease. Rent expense related to those power purchase agreements that meet the definition of a lease totaled $24 million for 2013 and $19 million for 2012.

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 2013 and 2012 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 costs associated with investments in emissions control equipment and certain transmission projects.

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 $16 million for 2013 and $14 million for 2012.

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

In 2013, PacifiCorp redeemed and canceled all remaining outstanding shares of its redeemable preferred stock at stated redemption prices, which in aggregate totaled $40 million, plus accrued and unpaid dividends.

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 $- million and $1 million as of December 31, 2013 and 2012, respectively.

(15) Common Shareholder's Equity

In February 2014, PacifiCorp declared a dividend of $500 million, which was paid to PPW Holdings in March 2014.

Through PPW Holdings, 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, 2013, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings 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, 2013, PacifiCorp's actual common equity percentage, as calculated under this measure, was 54.1%, and PacifiCorp would have been permitted to dividend $2.6 billion under this commitment.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings or MEHC if PacifiCorp's senior 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, 2013, PacifiCorp met the minimum required senior unsecured debt ratings for making distributions.

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):

	2013	2012
Interest paid, net of amounts capitalized	$ 340	$ 330
Income taxes paid (received), net(1)	$ 124	$ (209)
Supplemental disclosure of non-cash investing and financing activities:		
Accounts payable related to utility plant additions	$ 157	$ 167

(1) PacifiCorp is party to a tax-sharing agreement and is part of the Berkshire Hathaway United States federal income tax return. Amounts substantially represent income taxes paid to (received from) MEHC.

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				(9,055,432)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				317,072
3	Preceding Quarter/Year to Date Changes in Fair Value				(3,265,461)
4	Total (lines 2 and 3)				(2,948,389)
5	Balance of Account 219 at End of Preceding Quarter/Year				(12,003,821)
6	Balance of Account 219 at Beginning of Current Year				(12,003,821)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				498,291
8	Current Quarter/Year to Date Changes in Fair Value				2,414,025
9	Total (lines 7 and 8)				2,912,316
10	Balance of Account 219 at End of Current Quarter/Year				(9,091,505)

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			(9,055,432)	[redacted]	
2			317,072		
3			(3,265,461)		
4			(2,948,389)	537,337,285	534,388,896
5			(12,003,821)	[redacted]	
6			(12,003,821)		
7			498,291		
8			2,414,025		
9			2,912,316	682,163,330	685,075,646
10			(9,091,505)	[redacted]	

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 2013/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)	24,483,414,682	24,483,414,682
4	Property Under Capital Leases	48,708,458	48,708,458
5	Plant Purchased or Sold		
6	Completed Construction not Classified	95,477,903	95,477,903
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	24,627,601,043	24,627,601,043
9	Leased to Others		
10	Held for Future Use	23,368,811	23,368,811
11	Construction Work in Progress	1,321,622,138	1,321,622,138
12	Acquisition Adjustments	159,175,508	159,175,508
13	Total Utility Plant (8 thru 12)	26,131,767,500	26,131,767,500
14	Accum Prov for Depr, Amort, & Depl	8,511,018,083	8,511,018,083
15	Net Utility Plant (13 less 14)	17,620,749,417	17,620,749,417
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	7,863,751,463	7,863,751,463
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	529,162,303	529,162,303
22	Total In Service (18 thru 21)	8,392,913,766	8,392,913,766
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	118,104,317	118,104,317
33	Total Accum Prov (equals 14) (22,26,30,31,32)	8,511,018,083	8,511,018,083

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
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					33

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	206,314,615	1,937,773
4	(303) Miscellaneous Intangible Plant	648,104,811	8,094,410
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	854,419,426	10,032,183
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	93,164,157	441,938
9	(311) Structures and Improvements	1,004,588,118	9,774,932
10	(312) Boiler Plant Equipment	4,091,983,619	42,030,125
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	966,966,274	39,953,518
13	(315) Accessory Electric Equipment	475,506,492	4,268,263
14	(316) Misc. Power Plant Equipment	34,367,481	138,263
15	(317) Asset Retirement Costs for Steam Production	53,698,542	10,962,817
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	6,720,274,683	107,569,856
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	31,389,764	
28	(331) Structures and Improvements	181,647,007	7,701,030
29	(332) Reservoirs, Dams, and Waterways	453,238,675	24,745,664
30	(333) Water Wheels, Turbines, and Generators	120,151,371	1,431,836
31	(334) Accessory Electric Equipment	74,757,801	2,201,133
32	(335) Misc. Power PLant Equipment	2,358,351	1,702
33	(336) Roads, Railroads, and Bridges	17,635,627	514,113
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	881,178,596	36,595,478
36	D. Other Production Plant		
37	(340) Land and Land Rights	29,096,571	
38	(341) Structures and Improvements	164,387,266	1,394,065
39	(342) Fuel Holders, Products, and Accessories	10,801,123	347,115
40	(343) Prime Movers	2,512,410,690	26,242,867
41	(344) Generators	353,390,092	2,150,465
42	(345) Accessory Electric Equipment	249,559,251	608,767
43	(346) Misc. Power Plant Equipment	12,476,182	8,309
44	(347) Asset Retirement Costs for Other Production	9,072,015	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	3,341,193,190	30,751,588
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	10,942,646,469	174,916,922

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
600,000			207,652,388		3
6,635,441		69,660	649,633,440		4
7,235,441		69,660	857,285,828		5
					6
					7
1,563			93,604,532		8
2,435,409		-643,167	1,011,284,474		9
17,417,180		-459,302	4,116,137,262		10
					11
17,842,817		-47,213	989,029,762		12
539,274		1,209,122	480,444,603		13
2,327,900		-1,044,592	31,133,252		14
	-6,180,122		58,481,237		15
40,564,143	-6,180,122	-985,152	6,780,115,122		16
					17
					18
					19
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					21
					22
					23
					24
					25
					26
3,329		-69,719	31,316,716		27
470,946		3,399,612	192,276,703		28
1,281,438		-5,413,120	471,289,781		29
816,511			120,766,696		30
639,020			76,319,914		31
600			2,359,453		32
280,206		2,012,668	19,882,202		33
					34
3,492,050		-70,559	914,211,465		35
					36
635			29,095,936		37
338,694		862	165,443,499		38
30,897			11,117,341		39
14,641,889		41,311,300	2,565,322,968		40
1,083,879		-41,314,067	313,142,611		41
487,335		-5,291	249,675,392		42
17,730		-328,178	12,138,583		43
			9,072,015		44
16,601,059		-335,374	3,355,008,345		45
60,657,252	-6,180,122	-1,391,085	11,049,334,932		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 2013/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	198,218,069	26,830,476
49	(352) Structures and Improvements	170,949,185	2,454,073
50	(353) Station Equipment	1,735,328,437	102,719,775
51	(354) Towers and Fixtures	992,008,798	226,035,308
52	(355) Poles and Fixtures	686,214,770	22,197,850
53	(356) Overhead Conductors and Devices	919,805,558	140,800,705
54	(357) Underground Conduit	3,312,843	27,261
55	(358) Underground Conductors and Devices	7,489,179	10,281
56	(359) Roads and Trails	11,586,681	336,114
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	4,724,913,520	521,411,843
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	59,625,027	1,953,555
61	(361) Structures and Improvements	89,144,237	2,823,009
62	(362) Station Equipment	884,422,143	34,439,329
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	1,015,605,530	41,474,798
65	(365) Overhead Conductors and Devices	679,910,311	16,227,790
66	(366) Underground Conduit	322,706,767	8,701,790
67	(367) Underground Conductors and Devices	759,050,565	18,756,758
68	(368) Line Transformers	1,165,115,776	42,891,258
69	(369) Services	628,986,472	25,907,953
70	(370) Meters	176,687,115	5,148,695
71	(371) Installations on Customer Premises	8,827,913	76,676
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	60,443,784	1,289,956
74	(374) Asset Retirement Costs for Distribution Plant	2,459,448	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	5,852,985,088	199,691,567
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	19,478,606	1,995,376
87	(390) Structures and Improvements	227,482,706	8,525,002
88	(391) Office Furniture and Equipment	89,904,683	12,843,359
89	(392) Transportation Equipment	103,227,297	3,808,692
90	(393) Stores Equipment	14,568,536	323,811
91	(394) Tools, Shop and Garage Equipment	62,887,623	1,897,471
92	(395) Laboratory Equipment	37,053,335	889,654
93	(396) Power Operated Equipment	155,194,085	6,930,033
94	(397) Communication Equipment	344,747,037	40,183,598
95	(398) Miscellaneous Equipment	7,929,038	274,366
96	SUBTOTAL (Enter Total of lines 86 thru 95)	1,062,472,946	77,671,362
97	(399) Other Tangible Property	296,636,099	14,112,209
98	(399.1) Asset Retirement Costs for General Plant	39,748	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	1,359,148,793	91,783,571
100	TOTAL (Accounts 101 and 106)	23,734,113,296	997,836,086
101	(102) Electric Plant Purchased (See Instr. 8)	124,000	
102	(Less) (102) Electric Plant Sold (See Instr. 8)		4,235
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	23,734,237,296	997,831,851

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
-42,168		540,691	225,631,404		48
337,828		11,108,939	184,174,369		49
10,370,235		-13,781,678	1,813,896,299		50
283,249		1,157,121	1,218,917,978		51
2,204,447		2,209	706,210,382		52
1,194,467		101,667	1,059,513,463		53
			3,340,104		54
			7,499,460		55
			11,922,795		56
					57
14,348,058		-871,051	5,231,106,254		58
					59
		450,001	62,028,583		60
163,979		5,573,747	97,377,014		61
6,298,413		-6,314,001	906,249,058		62
					63
4,082,719		-29,476	1,052,968,133		64
2,333,196		-490	693,804,415		65
1,214,416			330,194,141		66
1,234,781		29,966	776,602,508		67
7,256,962		68,471	1,200,818,543		68
732,840			654,161,585		69
3,870,794			177,965,016		70
81,842			8,822,747		71
					72
964,505			60,769,235		73
	-808,055		1,651,393		74
28,234,447	-808,055	-221,782	6,023,412,371		75
					76
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					84
					85
27		-1,570	21,472,385		86
2,694,054		381,097	233,694,751		87
15,852,325		251,723	87,147,440		88
2,012,986		-6,743	105,016,260		89
108,868		101,319	14,884,798		90
2,165,541		509,735	63,129,288		91
2,659,745		178,018	35,461,262		92
3,731,189			158,392,929		93
2,026,518		1,922,418	384,826,535		94
280,913		107,673	8,030,164		95
31,532,166		3,443,670	1,112,055,812		96
4,921,397	-104,703	-64,568	305,657,640		97
			39,748		98
36,453,563	-104,703	3,379,102	1,417,753,200		99
146,928,761	-7,092,880	964,844	24,578,892,585		100
		-124,000			101
		-4,235			102
					103
146,928,761	-7,092,880	845,079	24,578,892,585		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	40,344,676	3,929,050	49,700	-	(296,811)	43,927,215
39941	Surface-Plant Equipment	13,554,030	734,400	85,144	-	232,243	14,435,529
39944	Surface-Electric Power Facil	3,424,575	-	-	-	-	3,424,575
39945	Underground-Coal Mine Equip	73,363,902	4,977,654	3,355,546	-	-	74,986,010
39946	Longwall Shields	24,486,688	-	-	-	-	24,486,688
39947	Longwall Equipment	9,115,912	-	-	-	-	9,115,912
39948	Mainline Extension	19,968,210	305,947	-	-	-	20,274,157
39949	Section Extension	7,293,886	906,150	787,445	-	-	7,412,591
39951	Vehicles	1,235,651	136,486	50,707	-	-	1,321,430
39952	Heavy Construction Equip	6,158,245	-	-	-	-	6,158,245
39960	Miscellaneous General Equip	2,519,978	171,624	335,876	-	-	2,355,726
39961	Computers-Mainframe	398,573	128,483	56,060	-	-	470,996
39970	Mine Development and Road Ext	38,858,038	-	200,919	-	-	38,657,119
39915	Coal Mine ARO	728,172	2,822,415	-	(104,703)	-	3,445,884
		$296,636,099	$14,112,209	$ 4,921,397	$(104,703)	$(64,568)	$305,657,640

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: f

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

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

Refer to Important Changes During the Quarter/Year, Item 3, in 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 2013/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	2028	6,763,094
6	Twelve Mile Wind Plant	2007	2028	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	2017	396,020
11	Bend Service Center	2010	2021	3,507,838
12	Legacy Substation	2010	2025	562,276
13	Aeolus Substation	2011	2019	1,014,053
14	Anticline Substation	2011	2019	964,505
15	Populus Substation	2011	2021	254,753
16	Snyderville Substation	2011	2016	253,401
17	Lassen Substation	2012	2019	683,318
18	Old Mill Substation	2012	2020	1,838,281
19	Chimney Butte-Paradise 230-kV Transmission Line	2013	2017	598,457
20	Miscellaneous, each under $250,000:			960,657
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
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41				
42				
43				
44				
45				
46				
47	Total			23,368,811

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 2028, 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 2028, 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.

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 2013/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Intangible:	
2	EMS/SCADA Replacement / Upgrade	6,379,651
3	IT-Mobility Upgrade / Click Replacement	3,945,054
4	Call Center Automated Call Distribution Replacement Project	3,172,645
5	Wallowa Falls Hydro Relicensing	1,669,508
6	FastGate Replacement Project	1,640,548
7		
8	Production:	
9	Lake Side 2 Development	614,209,928
10	Lewis River System Relicensing Implementation	52,671,773
11	Hunter U1 Clean Air - Particulate Matter Emissions	46,150,540
12	Blundell Proofing Well Integration	20,557,817
13	Jim Bridger U3 Selective Catalytic Reduction System	7,127,067
14	Hayden U1 Selective Catalytic Reduction System	5,733,463
15	Jim Bridger U4 Selective Catalytic Reduction System	4,317,914
16	Soda Springs Hydro Fish Screen Upgrade	3,541,368
17	Hunter U1 Reheater Pendant Replacement	2,911,278
18	Huntington U1 and U2 Submerged Drag Chain Conveyor	2,147,715
19	Hunter U1 Finishing Superheat Replacement	2,105,610
20	Hayden U2 Selective Catalytic Reduction System	1,818,427
21	Colstrip 4 Generator Repair	1,393,943
22	Hunter U1 NOX LNB Clean Air (low NOx burners)	1,193,369
23	Dave Johnston U2 Secondary Superheater Pendant Replacement	1,150,546
24	Jim Bridger New Sewage Treatment Facility	1,102,463
25	Naughton Fire Pump Backup	1,057,878
26		
27	Transmission:	
28	Sigurd - Red Butte - Crystal 345kV Line	174,960,526
29	Energy Gateway Preliminary Engineering and Permitting	54,190,714
30	Aeolus Clover 500kV Line	49,711,487
31	Populus - Hemingway 500kV Line	34,443,886
32	Boardman - Hemingway 500kV Line	18,345,344
33	Standpipe Substation New 230kV Sub	15,350,782
34	Oquirrh - Terminal 345kV Line	9,194,279
35	Southwest WY Silver Creek Build 138kV Line	7,543,974
36	Carbon Plant Replacement - Transmission	6,765,795
37	Whetstone 230-115kV Substation Phase 1	6,393,911
38	Vantage - Pomona Heights 230kV Line	5,956,560
39	West Point - New 138kV Line & 40 MVA Substation	5,492,868
40	Lake Side 2 Transmission Interconnection	5,402,073
41	Cameron Milford 138kV Transmission 138-46 Transformer	4,496,676
42	Line 37 Convert to 115kV Build Nickel Mt Substation	4,462,667
43	TOTAL	1,321,622,138

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 2013/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	Goshen Substation Bus Rebuild - Kinsport Line Relocation	3,879,167
2	Union Gap Substation Add 230 - 115kV Capacity	2,994,234
3	Jim Bridger U2 GSU Transformer Replacement	2,592,977
4	Red Butte WY Increase Substation Capacity	2,398,388
5	Middleton - Toquerville Rebuild 69kV to 138kV	2,110,627
6	Huntington U2 Main GSU Transformer	1,816,880
7	Two Elks Intercon at Tri County Switchyard	1,751,357
8	Tooele Sub Connect to Oquirrh - Limber 345kV	1,452,170
9	Utah-NERC Line Rating Project - Low Priority Lines	1,195,558
10	Terminal - Tooele 138kV Reconductor	1,159,498
11	Fry Substation Install 115 kV Capacitor Bank	1,155,493
12		
13	Distribution:	
14	ODOT Highway Relocation OR 99 & Fern Valley Road	1,259,146
15	Wyoming Avian Protection	1,118,415
16		
17	General:	
18	Mobile Radio Replacement Project	8,195,396
19	EIM Energy Imbalance Market Project (CAISO)	3,732,249
20	Lloyd Center Tower EMC VMAX Storage	2,586,739
21	Deer Creek - 2 Section Terminal Groups	1,547,357
22		
23	Miscellaneous Projects each under $1,000,000	91,966,440
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	1,321,622,138

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 2013/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	7,404,667,421	7,404,667,421		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	600,829,680	600,829,680		
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):	34,064,727	34,064,727		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	634,894,407	634,894,407		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	138,724,384	138,724,384		
13	Cost of Removal	42,756,350	42,756,350		
14	Salvage (Credit)	7,019,825	7,019,825		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	174,460,909	174,460,909		
16	Other Debit or Cr. Items (Describe, details in footnote):	-1,349,456	-1,349,456		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	7,863,751,463	7,863,751,463		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	2,621,710,730	2,621,710,730		
21	Nuclear Production				
22	Hydraulic Production-Conventional	281,113,356	281,113,356		
23	Hydraulic Production-Pumped Storage				
24	Other Production	672,417,401	672,417,401		
25	Transmission	1,361,684,760	1,361,684,760		
26	Distribution	2,387,803,953	2,387,803,953		
27	Regional Transmission and Market Operation				
28	General	539,021,263	539,021,263		
29	TOTAL (Enter Total of lines 20 thru 28)	7,863,751,463	7,863,751,463		

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	$10,502,660
Account 143, Other accounts receivable, - depreciation expense billed to joint owners	236,958
Asset retirement obligation asset depreciation recorded as a regulatory asset or liability	6,120,540
Transportation depreciation charged to operations and maintenance expense and construction work in progress based on usage activity	15,921,062
Account 503, Steam from other sources, - Blundell depletion	185,368
Account 503, Steam from other sources, - Blundell depreciation	1,098,139
Total Other Accounts	$34,064,727

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.	$(12,902,183)
Other items include: - Recovery from third parties for asset relocations and damaged property - Insurance recoveries - Adjustments of reserve related to electric plant sold - Reclassifications from electric plant	11,552,727
Total Other Debit or Cr. Items	$ (1,349,456)

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 2013/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			151,388,983
5	SUBTOTAL			199,348,984
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			5,916,977
26	SUBTOTAL			11,954,977
27				
28	FOSSIL ROCK FUELS, LLC	2011		
29	Paid-in Capital			27,762,429
30	Undistributed Subsidiary Earnings			-6,907
31	SUBTOTAL			27,755,522
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 83,262,431		TOTAL	239,062,484

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
12,972,869		121,361,852		4
12,972,869		169,321,853		5
				6
				7
		1,000		8
		1,000		9
				10
				11
				12
				13
				14
				15
		1		16
		1		17
				18
				19
		1,000		20
		1,000		21
				22
				23
		6,038,000		24
427,962		6,310,111		25
427,962		12,348,111		26
				27
				28
		29,262,429		29
-3,428		-10,335		30
-3,428		29,252,094		31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
13,397,403		210,924,059		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.: 4 Column: g

In May 2013, Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp, declared and paid a dividend of $43 million to PacifiCorp.

Schedule Page: 224 Line No.: 11 Column: a

In December 2013, Centralia Mining Company, an inactive wholly owned subsidiary of PacifiCorp, was dissolved.

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

In September 2013, Trapper Mining Inc., a subsidiary of PacifiCorp, paid a dividend of $34,828 to PacifiCorp.

Schedule Page: 224 Line No.: 29 Column: g

In August 2013, PacifiCorp contributed $1.5 million to its wholly owned subsidiary Fossil Rock Fuels, LLC.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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)	265,591,187	240,980,677	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)	83,816,884	91,333,148	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	98,097,803	101,171,275	Electric
8	Transmission Plant (Estimated)	750,972	678,432	Electric
9	Distribution Plant (Estimated)	13,817,380	12,375,512	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	6,041,605	6,985,748	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	202,524,644	212,544,115	
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)	468,115,831	453,524,792	

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

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

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

Mining materials and supplies	$	6,914,497
General plant materials and supplies		71,251
	$	6,985,748

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 2013/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2014 No. (d)	2014 Amt. (e)
1	Balance-Beginning of Year	270,494.00		156,645.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Hermiston Generating Co.	25.00			
10					
11					
12					
13					
14					
15	Total	25.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	42,227.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	AES Warrior Run LP	2,500.00			
23	AES Beaver Valley, LLC	6,000.00			
24	Duke Energy Kentucky, Inc	29,000.00			
25					
26					
27					
28	Total	37,500.00			
29	Balance-End of Year	190,792.00		156,645.00	
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.

2015 No. (f)	2015 Amt. (g)	2016 No. (h)	2016 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	Line No.
136,466.00		149,627.00		4,062,626.00		4,775,858.00		1
								2
								3
				156,644.00		156,644.00		4
								5
								6
								7
								8
						25.00		9
								10
								11
								12
								13
								14
						25.00		15
								16
								17
						42,227.00		18
								19
								20
								21
						2,500.00		22
						6,000.00		23
						29,000.00		24
								25
								26
								27
						37,500.00		28
136,466.00		149,627.00		4,219,270.00		4,852,800.00		29
								30
								31
								32
								33
								34
								35
2,259.00		2,259.00		110,921.00		119,957.00		36
				4,528.00		4,528.00		37
								38
				2,269.00		4,528.00		39
2,259.00		2,259.00		113,180.00		119,957.00		40
								41
								42
								43
								44
								45
								46

Schedule Page: 228 Line No.: 9 Column: a

Hermiston Generating Company, L.P. operates the Hermiston Generating Plant, which is jointly owned. PacifiCorp owns 50% of the plant. Purchases represent PacifiCorp's share of allowances purchased by Hermiston Generating Company, L.P. for the Hermiston Generating Plant.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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	3,013,540		407	1,808,124	1,205,416
23	upgrades					
24	Plant located near Evanston, WY					
25	Date of Commission Authorization:					
26	09/19/2012					
27	Amortization Period: 10/12/2012					
28	through 08/31/2014					
29						
30	WY-Naughton Unit #3 environmental	1,113,009		407	557,823	555,186
31	upgrades					
32	Plant located near Evanston, WY					
33	Date of Commission Authorization:					
34	10/8/2012					
35	Amortization Period: 10/22/2012					
36	through 12/31/2014					
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	4,126,549			2,365,947	1,760,602

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 78003595	3,219	561.6	3,219	456
3	AREF 77762035	11,829	561.6		
4	AREF 77762000	11,316	561.6		
5	System Impact Study Agreement	1,179	561.6		
6	AREF 78351080	19,271	561.6		
7	AREF 788834184	335	561.6		
8	Integrated Resource Planning Agrmt	42,403	561.6		
9	AREF 77755718	3,827	107		
10	AREF 78764672	34	107		
11	AREF 78849614	34	107		
12	Customer Studies Accrual	158	561.6		
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0252	442	561.7	442	456
23	GIQ0255	5,051	561.7	5,051	456
24	GIQ0311	101	561.7	101	456
25	GIQ0316	1,031	561.7	1,031	456
26	GIQ0332	74	561.7	74	456
27	GIQ0335	1,179	561.7	1,179	456
28	GIQ0367	396	561.7	396	456
29	GIQ0377	147	561.7	147	456
30	GIQ0384	3,162	561.7	3,162	456
31	GIQ0393	2,795	561.7	2,795	456
32	GIQ0397	4,904	561.7	4,904	456
33	GIQ0403	6,445	561.7	6,445	456
34	GIQ0409	86,820	561.7	86,820	456
35	GIQ0411	1,620	561.7	1,620	456
36	GIQ0414	6,158	561.7	6,158	456
37	GIQ0420	20,827	561.7	20,827	456
38	GIQ0422	1,651	561.7	1,651	456
39	GIQ0425	9,778	561.7	9,778	456
40	GIQ0426	23,908	561.7	23,908	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**				
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21	**Generation Studies**				
22	GIQ0427	9,362	561.7	9,362	456
23	GIQ0429	24,141	561.7	24,141	456
24	GIQ0430	3,133	561.7	3,133	456
25	GIQ0431	3,444	561.7	3,444	456
26	GIQ0432	4,497	561.7	4,497	456
27	GIQ0436	1,446	561.7	1,446	456
28	GIQ0437	7,903	561.7	7,903	456
29	GIQ0438	20,622	561.7	20,622	456
30	GIQ0439	706	561.7	706	456
31	GIQ0440	2,145	561.7	2,145	456
32	GIQ0441	9,444	561.7	9,444	456
33	GIQ0442	11,365	561.7	11,365	456
34	GIQ0443	34,673	561.7	34,673	456
35	GIQ0445	15,848	561.7	15,848	456
36	GIQ0446	161	561.7	161	456
37	GIQ0447	1,516	561.7	1,516	456
38	GIQ0448	825	561.7	825	456
39	GIQ0449	3,632	561.7	3,632	456
40	GIQ0450	25,465	561.7	25,465	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**				
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21	**Generation Studies**				
22	GIQ0451	13,558	561.7	13,558	456
23	GIQ0453	18,808	561.7	18,808	456
24	GIQ0454	12,348	561.7	12,348	456
25	GIQ0455	7,905	561.7	7,905	456
26	GIQ0456	12,458	561.7	12,458	456
27	GIQ0457	9,206	561.7	9,206	456
28	GIQ0458	10,076	561.7	10,076	456
29	GIQ0459	7,530	561.7	7,530	456
30	GIQ0460	33,332	561.7	33,332	456
31	GIQ0461	1,891	561.7	1,891	456
32	GIQ0462	8,512	561.7	8,512	456
33	GIQ0463	10,283	561.7	10,283	456
34	GIQ0464	16,256	561.7	16,256	456
35	GIQ0465	4,229	561.7	4,229	456
36	GIQ0466	3,584	561.7	3,584	456
37	GIQ0467	886	561.7	886	456
38	GIQ0468	3,526	561.7	3,526	456
39	GIQ0469	7,122	561.7	7,122	456
40	GIQ0470	22,149	561.7	22,149	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**				
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21	**Generation Studies**				
22	GIQ0471	7,937	561.7	7,937	456
23	GIQ0472	6,543	561.7	6,543	456
24	GIQ0473	5,871	561.7	5,871	456
25	GIQ0474	4,566	561.7	4,566	456
26	GIQ0475	13,417	561.7	13,417	456
27	GIQ0476	2,022	561.7	2,022	456
28	GIQ0477	1,410	561.7	1,410	456
29	GIQ0478	731	561.7	731	456
30	GIQ0479	584	561.7	584	456
31	GIQ0480	530	561.7	530	456
32	GIQ0481	530	561.7	530	456
33	GIQ0482	530	561.7	530	456
34	GIQ0483	614	561.7	614	456
35	GIQ0484	772	561.7	772	456
36	GIQ0485	530	561.7	530	456
37	GIQ0486	530	561.7	530	456
38	GIQ0487	732	561.7	732	456
39	GIQ0488	12,769	561.7	12,769	456
40	GIQ0489	11,531	561.7	11,531	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**				
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21	**Generation Studies**				
22	GIQ0490	5,973	561.7	5,973	456
23	GIQ0491	7,992	561.7	7,992	456
24	GIQ0492	11,626	561.7	11,626	456
25	GIQ0493	9,437	561.7	9,437	456
26	GIQ0494	825	561.7	825	456
27	GIQ0495	3,672	561.7	3,672	456
28	GIQ0496	11,932	561.7	11,932	456
29	GIQ0497	2,796	561.7	2,796	456
30	GIQ0498	8,233	561.7	8,233	456
31	GIQ0499	6,456	561.7	6,456	456
32	GIQ0500	1,903	561.7	1,903	456
33	GIQ0501	10,027	561.7	10,027	456
34	GIQ0502	9,380	561.7	9,380	456
35	GIQ0503	7,835	561.7	7,835	456
36	GIQ0504	5,914	561.7	5,914	456
37	GIQ0505	3,380	561.7	3,380	456
38	GIQ0507	7,195	561.7	7,195	456
39	GIQ0509	47,491	561.7	47,491	456
40	GIQ0510	21,762	561.7	21,762	456

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 2013/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	GIQ0511	7,063	561.7	7,063	456
23	GIQ0512	9,586	561.7	9,586	456
24	GIQ0513	7,433	561.7	7,433	456
25	GIQ0514	2,017	561.7	2,017	456
26	GIQ0515	4,763	561.7	4,763	456
27	GIQ0516	3,897	561.7	3,897	456
28	GIQ0517	3,959	561.7	3,959	456
29	GIQ0522	1,514	561.7	1,514	456
30	GIQ0523	5,958	561.7	5,958	456
31	GIQ0524	6,599	561.7	6,599	456
32	GIQ0525	3,848	561.7	3,848	456
33	GIQ0526	6,493	561.7	6,493	456
34	GIQ0527	5,452	561.7	5,452	456
35	GIQ0528	4,578	561.7	4,578	456
36	GIQ0529	2,356	561.7	2,356	456
37	GIQ0530	1,965	561.7	1,965	456
38	GIQ0531	1,895	561.7	1,895	456
39	GIQ0532	1,909	561.7	1,909	456
40	GIQ0533	1,273	561.7	1,273	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**				
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20					
21	**Generation Studies**				
22	GIQ0534	686	561.7	686	456
23	GIQ0535	872	561.7	872	456
24	GIQ0536	462	561.7	462	456
25	GIQ0537	462	561.7	462	456
26	GIQ0539	451	561.7	451	456
27	GIQ1605	(20,254)	561.7		
28	GIQ1604	(16,038)	561.7		
29	Customer Studies Accrual	(4,261)	561.7		
30		4,427	107		
31					
32					
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Schedule Page: 231.6 Line No.: 30 Column: a

Large Generation Interconnect Agreement Modification

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 2013/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		1,001,435			1,001,435
2	DSM Regulatory Asset - ID	511,241	3,817,719	908,431	4,328,960	
3	DSM Regulatory Asset - WA	1,428,381	9,885,547	908	11,313,928	
4	DSM Regulatory Asset - WY	591,995	4,677,295	908,431	5,269,290	
5	Deferred Income Taxes Electric	455,760,491	5,694,040			461,454,531
6	Tax Revenue Requirement Adjustment - WY (4)	70,531			30,857	39,674
7	Deferred Excess Net Power Costs - CA (1)	2,690,515	2,977,788	555	876,977	4,791,326
8	Deferred Excess Net Power Costs - WY	35,999,609	13,466,699		11,106,414	38,359,894
9	Deferred Excess Net Power Costs - ID	23,109,560	13,936,067	555	12,551,661	24,493,966
10	Deferred Excess Net Power Costs - UT	73,121,161	25,100,839		27,003,375	71,218,625
11	Deferred Excess RECs in Rates - UT		16,140,769			16,140,769
12	Deferred Excess RECs/SO2 in Rates - WY (1)	1,415,596	5,318,852	456	1,328,559	5,405,889
13	Environmental Costs (10)	33,421,538	10,220,311	925,253	5,531,702	38,110,147
14	Environmental Costs - WA (10)	(905,335)	174,805	925	336,552	-1,067,082
15	Cholla Plant Transaction Costs (26)	4,302,064	183,792	557	1,122,424	3,363,432
16	Washington Colstrip Unit No. 3 (22)	421,883		456	52,188	369,695
17	Unamortized Contract Values	166,028,027		242	20,223,402	145,804,625
18	Derivative Net Regulatory Asset	120,369,451		175,244	65,999,890	54,369,561
19	Asset Retirement Obligations Regulatory Difference	55,451,404		230	4,425,764	51,025,640
20	Pension	599,085,779			286,214,827	312,870,952
21	Other Postretirement	176,879,947			100,067,651	76,812,296
22	Postemployment Costs	8,226,541	1,073,052		1,564,795	7,734,798
23	Deferred Independent Evaluator Fee - OR (1)	97,200	673	254	97,873	
24	Deferred Intervenor Funding Grants - CA	32,952	7,355			40,307
25	Deferred Intervenor Funding Grants - ID (2)	69,206	5,756	928	19,500	55,462
26	Deferred Intervenor Funding Grants - OR	585,536	217,390			802,926
27	BPA Balancing Account - ID	257,230			257,230	
28	Generating Plant Liquidated Damages - WY	1,395,997	114,152	930.2	48,581	1,461,568
29	Generating Plant Liquidated Damages - UT		700,000			700,000
30	Chehalis Generating Facility Deferral - WA (6)	9,000,000			3,000,000	6,000,000
31	Powerdale Decommissioning - ID (10)	193,631	13,785	407.3	24,838	182,578
32	Powerdale Decommissioning - WA (3)	354,912		407.3	283,930	70,982
33	Solar Feed-In Tariff Deferral - OR (1)	2,751,487	3,533,318		2,179,249	4,105,556
34	Tax Adj on Postretirement Benefits - CA (3)	127,813		410.1,283	127,811	2
35	Tax Adj on Postretirement Benefits - ID (4)	409,994		410.1,283	204,997	204,997
36	Tax Adj on Postretirement Benefits - OR (5)	4,471,643		410.1,283	894,330	3,577,313
37	Tax Adj on Postretirement Benefits - UT (4)	2,749,250		410.1,283	1,571,000	1,178,250
38	Tax Adj on Postretirement Benefits - WY (4)	1,118,269		410.1,283	559,134	559,135
39	Deferred Overburden Cost - ID	169,233	452,001	501	436,551	184,683
40	Deferred Overburden Cost - WY	466,888	1,205,219	501	1,178,554	493,553
41	Naughton Unit No. 3 Environmental Costs - CA	102,043				102,043
42	Naughton Unit No. 3 Environmental Costs - ID	478,988				478,988
43	Klamath Hydroelectric Relicensing Costs - UT (10)	34,709,389	1,788,167	404	4,483,442	32,014,114

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 2013/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	Greenhouse Gas Allowance Compliance Costs - CA		7,099,190			7,099,190
2	Renewable Portfolio Standards Compliance - OR		180,906			180,906
3	Schedule 94-Distribution Safety Surcharge - OR		118,130	588	111,185	6,945
4	Excess Gain on Sale of Assets in Rates - OR		275,610			275,610
5	Injuries & Damage Reserve - OR	614,814	520,227	925	248,471	886,570
6	Property Insurance Reserve - OR	3,107,756	2,169,593	924	5,277,349	
7	Property Insurance Reserve - WY		702,183			702,183
8	Misc. Regulatory Assets/Liabilities - OR		62,655			62,655
9	Renewable Energy Credit Sales Deferral - OR		248,555			248,555
10						
11						
12						
13						
14						
15						
16						
17						
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40						
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43						
44	**TOTAL :**	1,821,244,610	133,083,875		580,353,241	1,373,975,244

Schedule Page: 232 Line No.: 5 Column: a
Weighted average remaining life is 33 years. Amounts primarily represent income tax benefits related to certain property-related basis differences and other various items that PacifiCorp is required to pass on to its customers.

Schedule Page: 232 Line No.: 6 Column: d
Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

Schedule Page: 232 Line No.: 8 Column: a
Weighted average remaining life is 2 years for deferred excess net power cost mechanisms being amortized.

Schedule Page: 232 Line No.: 8 Column: d
Account 555, Purchased power
Account 431, Other interest expense
Account 182.3, Other regulatory assets

Schedule Page: 232 Line No.: 9 Column: a
Weighted average remaining life is 2 years for deferred excess net power cost mechanisms being amortized, including Monsanto and Agrium net power cost components.

Schedule Page: 232 Line No.: 10 Column: a
Weighted average remaining life is 2 years for deferred excess net power cost mechanisms being amortized.

Schedule Page: 232 Line No.: 10 Column: d
Account 555, Purchased power
Account 431, Other interest expense
Account 182.3, Other regulatory assets

Schedule Page: 232 Line No.: 17 Column: a
Weighted average remaining life is 8 years. Represents frozen values of contracts previously accounted for as derivatives and recorded at fair value.

Schedule Page: 232 Line No.: 18 Column: a
Weighted average remaining life is 4 years.

Schedule Page: 232 Line No.: 20 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 Line No.: 20 Column: d
Pensions are associated with labor and generally charge to operations and maintenance expense, construction work in progress and Account 228.3, Accumulated provision for pensions and benefits.

Schedule Page: 232 Line No.: 21 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 Line No.: 21 Column: d
Other benefits are associated with labor and generally charge to operations and maintenance expense, construction work in progress and Account 228.3, Accumulated provision for pensions and benefits.

Schedule Page: 232 Line No.: 22 Column: a
Weighted average remaining life is 6 years.

Schedule Page: 232 Line No.: 22 Column: d
Other benefits are associated with labor and generally charge to operations and maintenance expense and construction work in progress.

Schedule Page: 232 Line No.: 27 Column: d
Account 440, Residential sales
Account 442, Commercial and industrial sales

Account 254, Other regulatory liabilities

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

Weighted average remaining life is 30 years.

Schedule Page: 232 Line No.: 30 Column: d

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

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

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

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 2013/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)	698,352		557	137,381	560,971
2						
3	Lacomb Irrigation (24)	415,290		557	45,720	369,570
4						
5	Bogus Creek (41)	1,118,000		557	41,280	1,076,720
6						
7	Mead Phoenix Availability and					
8	Transmission Charge (50)	13,001,240		565	377,760	12,623,480
9						
10	TGS Buyout (23)	109,604		557	15,474	94,130
11						
12	Point to Point Transmission	2,779,963	425,965	142	1,602,250	1,603,678
13						
14	Jim Boyd Hydro Buyout (11)	89,765		557	82,860	6,905
15						
16	Hermiston Swap (40)	4,049,098		557	171,693	3,877,405
17						
18	Oregon Prepaid REC Purchases					
19	for RPS Compliance		346,772	555	158,405	188,367
20						
21	Deferred Longwall Costs	1,135,424	2,949,190	151	2,796,364	1,288,250
22						
23	Deferred Coal Costs - Wyodak					
24	Settlement (22)	3,351,818		151	335,182	3,016,636
25						
26	Deferred Coal Costs - Naughton					
27	Settlement (7)	5,504,615		151	1,376,154	4,128,461
28						
29	Deferred Coal Costs - Jim					
30	Bridger Plant	2,916,673				2,916,673
31						
32	Deferred Colstrip Plant					
33	Costs (5)	925,000		501	300,000	625,000
34						
35	Deferred Royalty Reduction -					
36	Craig Plant	742,039	683	151	721,994	20,728
37						
38	LT Lease Commissions					
39	Prepaids (10)	464,020	66,953	931	98,399	432,574
40						
41	Lake Side Maintenance Prepaid	18,058,649	6,373,564	107	4,908,546	19,523,667
42						
43	Chehalis Maintenance Prepaid	9,718,670	3,998,533			13,717,203
44						
45	Currant Creek Maint. Prepaid	812,932	6,459,850			7,272,782
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	86,782,863				90,972,267

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Lease Incentives (10)	804,990		454	155,119	649,871
2						
3	Credit Agreement Costs (5)	1,917,712	1,732,177	427,431	764,366	2,885,523
4						
5	PCRB LOC/SBBPA Costs	203,282	492,090	427	349,156	346,216
6						
7	PCRB Mode Conversion Costs	145,615	212,174	427	98,183	259,606
8						
9	'94 Series Restruct. Costs (16)	754,468		427	80,470	673,998
10						
11	LT Prepaid IBEW 57 Pension					
12	Contribution	5,934,114	296,696			6,230,810
13						
14	BPA LT Transmission Prepaid	8,017,011	276,691	565,131	2,635,125	5,658,577
15						
16	Emission Reduction Credits	2,631,396		557,131	2,324,886	306,510
17						
18	Unamortized contract values	421,569		174	109,302	312,267
19						
20	Sales of Electric Utility					
21	Facilities & Properties	61,554	305,407	102	90,961	276,000
22						
23	Other Deferred Charges		47,025	561	17,336	29,689
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	86,782,863				90,972,267

Schedule Page: 233.1 Line No.: 5 Column: a

Weighted average life is 3 years.

Schedule Page: 233.1 Line No.: 7 Column: a

Weighted average life is 8 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 2013/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	216,807,008	98,584,009
3	Derivative contracts and unamortized contract values	109,033,262	76,128,093
4	State carryforwards	69,029,182	68,472,715
5	Loss contingencies	61,244,886	66,767,632
6	Asset retirement obligations	45,589,770	47,989,295
7	Other	146,514,897	124,625,544
8	TOTAL Electric (Enter Total of lines 2 thru 7)	648,219,005	482,567,288
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)	648,219,005	482,567,288

Notes

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

Description and Location (a)	Bal. at Beg. of Year (b)	Bal. at End of Year (c)
Regulatory Liabilities	$ 39,958,098	$ 36,289,678
Other	106,556,799	88,335,866
	$146,514,897	$124,625,544

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 2013/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	
13				
14	Serial Preferred, Cumulative:	3,500,000		
15	7.00% Series		100.00	
16	6.00% Series		100.00	
17	No Par Serial Preferred	16,000,000		
18	TOTAL PREFERRED STOCK	19,626,533		
19				
20				
21				
22				
23				
24				
25				
26				
27				
28	Authorized and Unissued Capital Stock			
29				
30				
31				
32				
33				
34				
35				
36				
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39				
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42				

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
						12
						13
						14
18,046	1,804,600					15
5,930	593,000					16
						17
23,976	2,397,600					18
						19
						20
						21
						22
						23
						24
						25
						26
						27
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						29
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						41
						42

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

This class of stock is not redeemable.

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

This series of preferred stock is not redeemable.

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

This series of preferred stock is not redeemable.

Schedule Page: 250 Line No.: 28 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, 2013, 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.

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	
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
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26		
27		
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37		
38		
39		
40	TOTAL	1,102,063,956

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, 2013.

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: a

In 2013, PacifiCorp redeemed and canceled all remaining outstanding shares of its redeemable preferred stock at a loss. As a result, the $166,025 previously reported gain on repurchase of certain shares of PacifiCorp’s preferred stock in 2010 was reversed in 2013 by debiting account 211, Miscellaneous paid-in capital, and crediting account 439, Adjustments to retained earnings.

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 2013/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	41,101,061
2		
3	Preferred Stock	
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	41,101,061

Schedule Page: 254   Line No.: 3   Column: a

In 2013, PacifiCorp redeemed and canceled all remaining outstanding shares of its redeemable preferred stock. The charge-off of the related capital stock expense was charged to account 439, Adjustments to retained earnings.

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	8.797% Series due October 1, 2013	16,203,000	
5	5.45% Series due September 15, 2013	200,000,000	1,422,659
6			232,000 D
7	4.95% Series due August 15, 2014	200,000,000	1,442,365
8			728,000 D
9	8.734% Series due October 1, 2014	28,218,000	
10	8.294% Series due October 1, 2015	46,946,000	
11	8.635% Series due October 1, 2016	18,750,000	
12	8.470% Series due October 1, 2017	19,609,000	
13	5.65% Series due July 15, 2018	500,000,000	3,067,221
14			905,000 D
15	5.50% Series due January 15, 2019	350,000,000	2,515,793
16			2,292,500 D
17	3.85% Series due June 15, 2021	400,000,000	3,007,139
18			744,000 D
19	2.95% Series due February 1, 2022	350,000,000	2,424,350
20			308,000 D
21	2.95% Series due February 1, 2022	100,000,000	254,129
22			-81,000 P
23	2.95% Series due June 1, 2023	300,000,000	1,844,850
24			900,000 D
25	7.70% Series due November 15, 2031	300,000,000	2,874,150
26			864,000 D
27	5.90% Series due August 15, 2034	200,000,000	1,892,365
28			722,000 D
29	5.25% Series due June 15, 2035	300,000,000	2,912,021
30			1,080,000 D
31	6.10% Series due August 1, 2036	350,000,000	2,907,881
32			1,141,000 D
33	TOTAL	7,218,221,000	77,560,057

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 2013/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
04/15/1992	10/1/2013	04/15/1992	10/01/2013		101,341	4
09/08/2003	09/15/2013	09/08/2003	09/15/2013		7,720,833	5
						6
08/24/2004	08/15/2014	08/24/2004	08/15/2014	200,000,000	9,900,000	7
						8
04/15/1992	10/01/2014	04/15/1992	10/01/2014	2,623,000	387,287	9
04/15/1992	10/01/2015	04/15/1992	10/01/2015	8,034,000	887,790	10
04/15/1992	10/01/2016	04/15/1992	10/01/2016	4,672,000	488,719	11
04/15/1992	10/01/2017	04/15/1992	10/01/2017	6,131,000	598,448	12
07/17/2008	07/15/2018	07/17/2008	07/15/2018	500,000,000	28,250,000	13
						14
01/08/2009	01/15/2019	01/08/2009	01/15/2019	350,000,000	19,250,000	15
						16
05/12/2011	06/15/2021	05/12/2011	06/15/2021	400,000,000	15,400,000	17
						18
01/06/2012	02/01/2022	01/06/2012	02/01/2022	350,000,000	10,325,000	19
						20
03/06/2012	02/01/2022	03/06/2012	02/01/2022	100,000,000	2,950,000	21
						22
06/03/2013	06/01/2023	06/01/2013	06/01/2023	300,000,000	5,039,583	23
						24
11/21/2001	11/15/2031	11/21/2001	11/15/2031	300,000,000	23,100,000	25
						26
08/24/2004	08/15/2034	08/24/2004	08/15/2034	200,000,000	11,800,000	27
						28
06/13/2005	06/15/2035	06/13/2005	06/15/2035	300,000,000	15,750,000	29
						30
08/10/2006	08/01/2036	08/10/2006	08/01/2036	350,000,000	21,350,000	31
						32
				6,842,300,000	355,945,454	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 2013/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	2,737,911
10			987,000 D
11	8.13% Series E Medium-Term Notes due Jan. 22, 2013	10,000,000	75,827
12	8.53% Series C Medium-Term Notes due Dec. 16, 2021	15,000,000	115,202
13	8.375% Series C Medium-Term Notes due Dec. 31, 2021	5,000,000	38,400
14	8.26% Series C Medium-Term Notes due Jan. 7, 2022	5,000,000	33,243
15	8.27% Series C Medium-Term Notes due Jan. 10, 2022	4,000,000	30,594
16	8.05% Series E Medium-Term Notes due Sept. 1, 2022	15,000,000	131,471
17	8.07% Series E Medium-Term Notes due Sept. 9, 2022	8,000,000	70,118
18	8.12% Series E Medium-Term Notes due Sept. 9, 2022	50,000,000	438,238
19	8.11% Series E Medium-Term Notes due Sept. 9, 2022	12,000,000	105,177
20	8.05% Series E Medium-Term Notes due Sept. 14, 2022	10,000,000	87,648
21	8.08% Series E Medium-Term Notes due Oct. 14, 2022	26,000,000	208,198
22	8.08% Series E Medium-Term Notes due Oct. 14, 2022	25,000,000	200,190
23	8.23% Series E Medium-Term Notes due Jan. 20, 2023	5,000,000	37,914
24	8.23% Series E Medium-Term Notes due Jan. 20, 2023	4,000,000	30,331
25			-81,560 P
26	7.26% Series F Medium-Term Notes due July 21, 2023	27,000,000	246,981
27	7.26% Series F Medium-Term Notes due July 21, 2023	11,000,000	100,622
28	7.23% Series F Medium-Term Notes due Aug. 16, 2023	15,000,000	137,211
29	7.24% Series F Medium-Term Notes due Aug. 16, 2023	30,000,000	274,423
30	6.75% Series F Medium-Term Notes due Sept. 14, 2023	5,000,000	38,250
31	6.75% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
32	6.72% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
33	TOTAL	7,218,221,000	77,560,057

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 2013/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	12,300,000	9
						10
01/20/1993	01/22/2013	01/20/1993	01/22/2013		47,425	11
12/16/1991	12/16/2021	12/16/1991	12/16/2021	15,000,000	1,279,500	12
12/31/1991	12/31/2021	12/31/1991	12/31/2021	5,000,000	418,750	13
01/08/1992	01/07/2022	01/08/1992	01/07/2022	5,000,000	413,000	14
01/09/1992	01/10/2022	01/09/1992	01/10/2022	4,000,000	330,800	15
09/18/1992	09/01/2022	09/18/1992	09/01/2022	15,000,000	1,207,500	16
09/09/1992	09/09/2022	09/09/1992	09/09/2022	8,000,000	645,600	17
09/11/1992	09/09/2022	09/11/1992	09/09/2022	50,000,000	4,060,000	18
09/11/1992	09/09/2022	09/11/1992	09/09/2022	12,000,000	973,200	19
09/14/1992	09/14/2022	09/14/1992	09/14/2022	10,000,000	805,000	20
10/15/1992	10/14/2022	10/15/1992	10/14/2022	26,000,000	2,100,800	21
10/15/1992	10/14/2022	10/15/1992	10/14/2022	25,000,000	2,020,000	22
01/20/1993	01/20/2023	01/20/1993	01/20/2023	5,000,000	411,500	23
01/29/1993	01/20/2023	01/29/1993	01/20/2023	4,000,000	329,200	24
						25
07/22/1993	07/21/2023	07/22/1993	07/21/2023	27,000,000	1,960,200	26
07/22/1993	07/21/2023	07/22/1993	07/21/2023	11,000,000	798,600	27
08/16/1993	08/16/2023	08/16/1993	08/16/2023	15,000,000	1,084,500	28
08/16/1993	08/16/2023	08/16/1993	08/16/2023	30,000,000	2,172,000	29
09/14/1993	09/14/2023	09/14/1993	09/14/2023	5,000,000	337,500	30
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	135,000	31
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	134,400	32
				6,842,300,000	355,945,454	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 Oct. 26, 2023	20,000,000	152,326
2	6.75% Series F Medium-Term Notes due Oct. 26, 2023	16,000,000	121,861
3	6.75% Series F Medium-Term Notes due Oct. 26, 2023	12,000,000	91,396
4	6.71% Series G Medium-Term Notes due Jan. 15, 2026	100,000,000	904,467
5	Subtotal - First Mortgage Bonds	6,563,726,000	66,505,979
6			
7	Pollution Control Obligations - Secured by Pledged First Mortgage Bonds:		
8			
9	Poll Ctrl Rev Refunding Bonds, Moffat County, CO, Series 1994	40,655,000	874,159
10	Poll Ctrl Rev Refunding Bonds, Sweetwater County, WY, Series 1994	21,260,000	510,479
11	Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1994	8,190,000	209,777
12	Poll Ctrl Rev Refunding Bonds, Emery County, UT, Series 1994	121,940,000	3,274,246
13	Poll Ctrl Rev Refunding Bonds, Carbon County, UT, Series 1994	9,365,000	206,519
14	Poll Ctrl Rev Refunding Bonds, Lincoln County, WY, Series 1994	15,060,000	422,858
15	Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1988	17,000,000	155,970
16	Poll Ctrl Rev Refunding Bonds, Lincoln Cnty, WY, Series 1991	45,000,000	771,836
17	Poll Ctrl Revenue Bonds, Sweetwater County, WY, Series 1984	15,000,000	122,887
18			105,000 D
19	Poll Ctrl Revenue Bonds, City of Forsyth, MT, Series 1986	8,500,000	304,824
20	Environ. Imprvmnt Rev Bonds, Converse County, WY, Series 1995	5,300,000	132,043
21	Environ. Imprvmnt Rev Bonds, Lincoln County, WY, Series 1995	22,000,000	404,262
22	Subtotal Pollution Control Obligations - Secured by Pledged First Mortgage Bonds	329,270,000	7,494,860
23			
24			
25	Pollution Control Obligations - Unsecured		
26			
27	Poll Ctrl Rev Refndng Bonds, Emery County, UT, Series 1991	45,000,000	872,505
28	Poll Ctrl Rev Refndng Bonds, City of Forsyth, MT, Series 1988	45,000,000	380,198
29	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Series 1988A	50,000,000	422,443
30	Poll Ctrl Rev Refndng Bonds, City of Gillette, WY, Ser. 1988	41,200,000	351,905
31	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1988B	11,500,000	84,822
32	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1990A	70,000,000	660,750
33	TOTAL	7,218,221,000	77,560,057

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
10/26/1993	10/26/2023	10/26/1993	10/26/2023	20,000,000	1,350,000	1
10/26/1993	10/26/2023	10/26/1993	10/26/2023	16,000,000	1,080,000	2
10/26/1993	10/26/2023	10/26/1993	10/26/2023	12,000,000	810,000	3
01/23/1996	01/15/2026	01/23/1996	01/15/2026	100,000,000	6,710,000	4
				6,245,460,000	347,263,476	5
						6
						7
						8
11/17/1994	05/01/2013	11/17/1994	05/01/2013		161,581	9
11/17/1994	11/01/2024	11/17/1994	11/01/2024	21,260,000	329,541	10
11/17/1994	11/01/2024	11/17/1994	11/01/2024	8,190,000	127,020	11
11/17/1994	11/01/2024	11/17/1994	11/01/2024	121,940,000	1,860,956	12
11/17/1994	11/01/2024	11/17/1994	11/01/2024	9,365,000	143,927	13
11/17/1994	11/01/2024	11/17/1994	11/01/2024	15,060,000	248,733	14
01/01/1988	01/01/2014	01/01/1988	01/01/2014		287,163	15
01/17/1991	01/01/2016	01/17/1991	01/01/2016	45,000,000	617,552	16
12/01/1984	12/01/2014	12/01/1984	12/01/2014	15,000,000	311,523	17
						18
12/01/1986	12/01/2016	12/01/1986	12/01/2016	8,500,000	180,482	19
11/17/1995	11/01/2025	11/17/1995	11/01/2025	5,300,000	109,697	20
11/17/1995	11/01/2025	11/17/1995	11/01/2025	22,000,000	478,218	21
				271,615,000	4,856,393	22
						23
						24
						25
						26
05/23/1991	07/01/2015	05/23/1991	07/01/2015	45,000,000	657,849	27
01/01/1988	01/01/2018	01/01/1988	01/01/2018	45,000,000	656,533	28
01/01/1988	01/01/2017	01/01/1988	01/01/2017	50,000,000	582,079	29
01/01/1988	01/01/2018	01/01/1988	01/01/2018	41,200,000	430,391	30
01/01/1988	01/01/2014	01/01/1988	01/01/2014	11,500,000	119,439	31
07/25/1990	07/01/2015	07/25/1990	07/01/2015	70,000,000	732,275	32
				6,842,300,000	355,945,454	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 2013/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	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992A	9,335,000	167,524
2	Poll Ctrl Rev Refndng Bonds, Converse County, WY, Series 1992	22,485,000	242,163
3	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992B	6,305,000	151,908
4	Environ. Imprvmnt Rev Bonds, Sweetwater County, WY, Series 1995	24,400,000	225,000
5			
6	Subtotal - Pollution Control Obligations - Unsecured	325,225,000	3,559,218
7			
8			
9	TOTAL ACCOUNT 221	7,218,221,000	77,560,057
10			
11	Reacquired Bonds: (Account 222)		
12			
13	Advances from Associated Companies: (Account 223)		
14			
15	Other Long-Term Debt: (Account 224)		
16			
17			
18	Long-Term Debt Authorized but Unissued		
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	7,218,221,000	77,560,057

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.
09/29/1992	12/01/2020	09/29/1992	12/01/2020	9,335,000	95,112	1
09/29/1992	12/01/2020	09/29/1992	12/01/2020	22,485,000	223,997	2
09/29/1992	12/01/2020	09/29/1992	12/01/2020	6,305,000	65,415	3
12/14/1995	11/01/2025	12/14/1995	11/01/2025	24,400,000	262,495	4
						5
				325,225,000	3,825,585	6
						7
						8
				6,842,300,000	355,945,454	9
						10
						11
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						24
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						29
						30
						31
						32
				6,842,300,000	355,945,454	33

Schedule Page: 256 Line No.: 23 Column: a

In June 2013, PacifiCorp issued $300 million of 2.95% First Mortgage Bonds due June 2023. State commission authorizations for this issuance were as follows:

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

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

In June 2013, PacifiCorp redeemed the Pollution Control Revenue Refunding Bonds, Converse County, WY, Series 1988, and transferred the associated unamortized debt expense to Account 189, Unamortized loss on reacquired debt.

Schedule Page: 256.3 Line No.: 9 Column: h

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

Schedule Page: 256.3 Line No.: 9 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.: 18 Column: a

In November 2013, 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 October 2016.

For authorization for the issuance of long-term debt ($2.0 billion authorized; $550 million available as of December 31, 2013), refer to Important Changes During the Quarter/Year, Item 6, in 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, 2013) 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, 2013) 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 2013/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)	682,163,330
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8	Other	79,300,662
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13	Other	1,221,784,029
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18	Other	85,304,455
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25	Other	1,485,136,624
26	State Tax Deductions	-15,444,967
27	Federal Tax Net Income	397,361,975
28	Show Computation of Tax:	
29		
30	Federal Income Tax at 35.00%	139,076,690
31	Provision to Return Adjustment	2,627,525
32	Tax Reserve Changes	29,841
33	Renewable Energy Production Tax Credits	-69,527,495
34	Other Federal Tax Credits	-220,516
35	Other Miscellaneous Adjustments	-39,032
36		
37	Federal Income Tax Accrual	71,947,013
38		
39		
40		
41		
42		
43		
44		

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

Particulars (Details)	Amounts
Contribution in Aid of Construction	48,806,340
Regulatory Asset - BPA Balancing Account - ID	257,229
Reimbursements	1,902,055
Regulatory Liability - Alt Rate for Energy Program (CARE) - CA - Current	896,054
Regulatory Liability - BPA Balancing Account - ID	922,145
Regulatory Liability - GHG Allowance Revenues - CA - Current	9,106,055
Regulatory Liability - Sale of REC - UT - Current	1,521,547
Regulatory Liability - Sale of REC - WA - Current	14,121,277
Regulatory Liability - UT Home Energy Lifeline	998,055
Regulatory Liability - WA Low Energy Program	315,383
Trapper Mining Stock Basis	266,976
Unearned Joint Use Pole Contact Revenue	187,546
Total	$ 79,300,662

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

Particulars (Details)	Amounts
Fed/State Tax Expense	287,955,389
Fed/State Tax Expense-Interest	1,187,488
50% Meals and Entertainment	864,737
Accrued Final Reclamation	247,461
Accrued Royalties	1,119
Avoided Costs	51,869,123
Bear River Settlement Agreement	274,325
Book Cost Depletion	1,581,526
Book Depreciation	674,122,571
Book Depreciation Allocated to Medicare and M&E	56,215
Book Fixed Asset Gain/Loss	10,743
Coal Pile Inventory Adjustment	1,215,354
Deferred Coal Costs - Naughton Contract Settlement	1,376,154
Deferred Compensation - Non Current	1,004,858
Deferred Revenue - Citibank	88,577
Deseret Settlement Receivable	652,544
Environmental Liability - Regulated	2,281,625
ERC Impairment Reserve	2,040,000
FAS 112 Book Reserve - Postemployment Benefits	341,049
Fuel Cost Adjustment	1,250,360
Hermiston Swap	171,693
Hydro Relicensing Obligation	1,298,969
Income Tax Interest	113,960
Injuries and Damages Accrual - Cash Basis	18,188,871
Joseph Settlement	137,381
Lewis River Settlement Agreement	93,452
Lobbying Expenses	2,045,817
Medicare Subsidy	3,927,059
MEHC Insurance Services - Receivable	129,380
Mine Rescue Training Credit Addback	50,735
Penalties	2,279,737
Prepaid Membership Fees	1,890,373
Prepaid Taxes - OR PUC	4,126
Regulatory Asset - Chehalis Generating Facility Deferral - WA	3,000,000
Regulatory Asset - Cholla Plant Transaction Costs	1,122,425
Regulatory Asset - Deferred Excess NPC - CA - Noncurrent	94,422
Regulatory Asset - Deferred Excess NPC - ID - Noncurrent	12,628,376
Regulatory Asset - Deferred Excess NPC - UT - Noncurrent	16,542,262
Regulatory Asset - Deferred Excess NPC - WY '09 & After - Noncurrent	20,806,366
Regulatory Asset - Deferred Independent Evaluator Fee - UT	9,363

Regulatory Asset - Deferred Independent Evaluator Fees - OR	97,202
Regulatory Asset - Deferred Intervenor Funding Grants - ID	13,744
Regulatory Asset - Demand Side Management - Current	1,530,180
Regulatory Asset - DSM Balance Reclass	697,970
Regulatory Asset - Environmental Costs - WA	161,748
Regulatory Asset - FAS 158 Pension Liability	48,029,981
Regulatory Asset - FAS 158 Post Retirement Liability	7,923,283
Regulatory Asset - Goodnoe Hills Settlement - WY	21,250
Regulatory Asset - Klamath Hydroelectric Relicensing Costs - UT	2,695,276
Regulatory Asset - Lake Side Settlement - WY	27,331
Regulatory Asset - Naughton Unit #3 Costs	2,776,067
Regulatory Asset - Naughton Unit #3 Costs - UT	1,808,124
Regulatory Asset - Naughton Unit #3 Costs - WY	557,823
Regulatory Asset - OR Asset Sale Gain GB - Noncurrent	6,945
Regulatory Asset - Pension MMT - UT	283,176
Regulatory Asset - Post Employment Costs	491,743
Regulatory Asset - Post Merger Loss - Reacquired Debt	1,412,851
Regulatory Asset - Post-Ret MMT - CA	17,488
Regulatory Asset - Post-Ret MMT - OR	193,035
Regulatory Asset - Post-Ret MMT - UT	278,648
Regulatory Asset - Powerdale Decommissioning - ID	11,053
Regulatory Asset - Powerdale Decommissioning - WA	283,929
Regulatory Asset - Solar Feed-In Tariff Deferral - OR - Noncurrent	1,945,266
Regulatory Asset - Tax Revenue Requirement Adj - WY	30,857
Regulatory Asset - Utah ECAM	20,649,532
Regulatory Asset - WA Colstrip #3	52,188
Regulatory Liability - Blue Sky - ID	35,703
Regulatory Liability - Blue Sky - OR	93,856
Regulatory Liability - Blue Sky - UT	204,757
Regulatory Liability - Blue Sky - WA	116,538
Regulatory Liability - Blue Sky - WY	57,608
Regulatory Liability - Deferred Excess NPC - OR - Current	2,273,466
Regulatory Liability - Deferred Excess NPC - WA - Current	112,448
Regulatory Liability - OR Energy Conservation Charge	743,447
Regulatory Liability - Property Insurance Reserve - ID	113,544
Regulatory Liability - Property Insurance Reserve - OR	3,553,271
Regulatory Liability - Property Insurance Reserve - UT	1,750,403
Regulatory Liability - Solar Feed-in Tariff Deferral - CA - Current	123,782
Regulatory Liability - Solar Incentive Program - UT - Current	5,982,150
Regulatory Liability - Trojan Decommissioning	492,373
TGS Buyout	15,474
Western Coal Carrier Retiree Medical Accrual	738,000
Intercompany adjustment	424,534
Total	$ 1,221,784,029

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

Particulars (Details)	Amounts
Deferred Revenue - Lease Incentives	(28,089)
Dividend Received Deduction - Deferred Compensation	(107,511)
Foote Creek Contract	(137,640)
MCI F.O.G. Wire Lease	(324)
Officer's Life Insurance	(4,204,253)
Regulatory Asset - Alt Rate for Energy Program (CARE) - CA - Current	(621,982)
Regulatory Asset - REC Sales Deferral - OR - Current	(414,385)
Regulatory Asset - REC Sales Deferral - OR - Noncurrent	(15,076)
Regulatory Asset - REC Sales Deferral - UT - Current	(3,138,483)
Regulatory Asset - REC Sales Deferral - UT - Noncurrent	(15,755,935)
Regulatory Asset - REC Sales Deferral - WY - Current	(3,668,887)
Regulatory Asset - REC Sales Deferral - WY - Noncurrent	(321,406)

Redding Contract	(549,996)
Regulatory Liability - 2010 Protocol Deferral - OR	(222,076)
Regulatory Liability - BPA Balancing Account - OR	(1,580,712)
Regulatory Liability - BPA Balancing Account - WA	(916,135)
Regulatory Liability - Gain on Sale of Assets - OR - Current	(35,161)
Regulatory Liability - GHG Allowance Revenues - CA - Noncurrent	(2,434,344)
Regulatory Liability - OR 2012 GRC Giveback - Noncurrent	(16,236,420)
Regulatory Liability - Powerdale Decommissioning Costs Giveback - UT	(180,277)
Regulatory Liability - Sale of REC - OR - Noncurrent	(606,954)
Regulatory Liability - Sale of REC - UT - Noncurrent	(2,474,146)
Regulatory Liability - Sale of REC - WA - Noncurrent	(14,509,138)
Regulatory Liability - SMUD Revenue Imputation - UT	(2,291,714)
Regulatory Liability - Tax Revenue Requirement Adj - UT	(61,695)
Transmission Service Deposit	(700,211)
Unrealized Gain/Loss from Trading Securities	(694,102)
Equity Earnings in Subsidiaries	(13,397,403)
Total	$ (85,304,455)

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Particulars (Details)	Amounts
Accrued Bonus	(91,402)
Accrued Severance	(86,701)
Accrued Vacation	(1,422,118)
Amortization NOPAs 99-00 RAR	(52,712)
Basis Intangible Difference	(92,988)
Capitalized Depreciation	(5,833,974)
Capitalized labor and benefit costs	(9,133,607)
Cholla SHL NOPA (Lease Amortization)	(136,961)
Coal Mine Extension Costs	(1,252,369)
Cost of Removal	(42,756,350)
CWIP Reserve	(9,160)
Debt AFUDC	(29,227,220)
Environmental Liability - Non-regulated	(2,777,126)
Equity AFUDC-Temp	(57,182,510)
FAS 158 Pension Liability	(22,082,107)
FAS 158 Post-Retirement Liability	(963,166)
FAS 158 SERP Liability	(973,735)
Federal Tax Depreciation	(1,090,720,929)
Federal Tax Fixed Asset Gain/Loss	(2,578,728)
Inventory Reserve	(306,204)
LT Prepaid IBEW 57 Pension Contribution	(296,696)
Mine Safety Sec. 179E Election	(110,218)
Miscellaneous Current and Accrued Liability	(537,384)
N Umpqua Settlement Agreement	(9,336)
Non-deductible Post-Retirement Costs	(3,927,059)
Oregon RA/RL Consolidation	(345,410)
Other Environmental Liabilities	(484)
Pension/Retirement Accrual	(196,213)
Pre-1943 Preferred Stock Dividend - Deduction	(353,861)
Prepaid Aircraft Maintenance	(97,347)
Prepaid Taxes - ID PUC	(24,695)
Prepaid Taxes - Property Taxes	(1,693,070)
Prepaid Taxes - UT PUC	(402,884)
Regulatory Asset - Cholla Plant Transaction Costs - ID	(32,973)
Regulatory Asset - Cholla Plant Transaction Costs - OR	(53,813)
Regulatory Asset - Cholla Plant Transaction Costs - WA	(97,006)
Regulatory Asset - Contra Pension MMT & CTG - CA	(91,920)
Regulatory Asset - Contra Pension MMT & CTG - OR	(1,014,634)
Regulatory Asset - Deferred Excess NPC - CA - Current	(2,195,233)

Regulatory Asset - Deferred Excess NPC - ID - Current	(14,012,780)
Regulatory Asset - Deferred Excess NPC - UT - Current	(35,289,259)
Regulatory Asset - Deferred Excess NPC - WA Hydro - Noncurrent	(103,750)
Regulatory Asset - Deferred Excess NPC - WY - Current	(23,166,651)
Regulatory Asset - Deferred Intervenor Funding Grants - CA	(7,355)
Regulatory Asset - Deferred Intervenor Funding Grants - OR	(217,391)
Regulatory Asset - Deferred Overburden Costs - ID	(15,450)
Regulatory Asset - Deferred Overburden Costs - WY	(26,665)
Regulatory Asset - Demand Side Management - Noncurrent	(697,970)
Regulatory Asset - Environmental Costs	(4,688,608)
Regulatory Asset - GHG Allowances - CA - Current	(7,099,190)
Regulatory Asset - GHG Allowances - CA - Noncurrent	(3)
Regulatory Asset - Liquidation Damages - N2 - WY	(114,152)
Regulatory Asset - Naughton Unit #3 Costs - CA	(102,043)
Regulatory Asset - Naughton Unit #3 Costs - OR - Contra	(2,044,913)
Regulatory Asset - Naughton Unit #3 Costs - WA - Contra	(629,111)
Regulatory Asset - OR Asset Sale Gain GB - Current	(282,555)
Regulatory Asset - OR Sch94 Distribution Safety Surcharge	(6,945)
Regulatory Asset - Powerdale Decommissioning	(164,704)
Regulatory Asset - SB 408 - OR	(11,834)
Regulatory Asset - Solar Feed-In Tariff Deferral - CA - Noncurrent	(354,070)
Regulatory Asset - Solar Feed-in Tariff Deferral - OR - Current	(3,299,335)
Regulatory Asset - Solar Incentive Program - UT - Noncurrent	(867,044)
Regulatory Asset - UT Liquidation Damages	(700,000)
Repairs Deduction	(100,764,600)
Reserve for Bad Debts	(1,865,600)
Regulatory Liability - ARO/Reg Diff - Trojan - WA Portion	(285,034)
Regulatory Liability - Blue Sky - CA	(9,224)
Regulatory Liability - Demand Side Management - Current	(2,228,150)
Regulatory Liability - Injuries & Damages Reserve - OR	(271,755)
Regulatory Liability - Property Insurance Reserve - WY	(1,323,754)
Rogue River - Habitat Enhancement Liability	(8,303)
RTO Grid West N/R - OR	(6,035)
Tax Depletion-SRC	(172,440)
Tax Percentage Depletion - Blundell Steam Field	(475,313)
Tax Percentage Depletion - Deer Creek	(837,121)
USA Power Litigation	(3,636,564)
Wasatch Workers Comp Reserve	(190,650)
Total	$ (1,485,136,624)

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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

MEHC Sub-Group:

Alaska Gas Transmission Company, LLC
American Pacific Finance Company
American Pacific Finance Company II
Arizona HomeServices, LLC
AVSP 1B, LLC
AVSP 2B, 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
CBSHome Commerical, 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
Champion Realty, Inc
Chancellor Title Services, Inc
Cimmred Leasing Company
Columbia Title of Florida, Inc
Commonsite, 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

Employee Transfer Corporation
Esslinger-Wooten-Maxwell, Inc
E-W-M Referral Services, Inc.
F&R/T LLC
FFR, Inc
First Realty, Ltd
First Reserve Insurance, Inc
For Rent, Inc
FRTC, LLC
GPSF-B
Guarantee Appraisal Corporation
Guarantee Real Estate
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 Northeast, LLC
HomeServices of Alabama, Inc.
HomeServices of America, Inc
HomeServices of California, Inc
HomeServices of Connecticut, LLC
HomeServices of Florida, Inc
HomeServices of Georgia, 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 Referral Network, LLC
HomeServices Relocation, LLC
HomeSvc of IL LLC d/b/a Koenig & Strey GMAC RE
HS Franchise Holding, LLC
HSGA Real Estate Group, L.L.C.
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
KR Acquisition 1, LLC
KR Acquisition 2, LLC
KR Holding, LLC
Lands of Sierra, Inc.
Larabee School of Real Estate & Insurance, Inc
M & M Ranch Acquisition Company LLC
M & M Ranch Holding Company LLC

MEC Construction Services Company
MEHC American 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
Midwest Power Transmission Illinois LLC
Midwest Power Transmission Iowa LLC
Midwest Realty Ventures, LLC
MWR Capital, Inc
Nebraska Land Title & Abstract Company
Nebraska Referral, Inc.
Nevada Electric Investment Company
Nevada Power Company dba NV Energy
NMA, LLC
NNGC Acquisition LLC
Northern Aurora Inc
Northern Natural Gas Company
NRS Referral Services, LLC
NV Energy, Inc. fka Sierra Pacific Resources
NVE Holdings, LLC
NVE Insurance Co, Inc.
NW Referral Services, LLC
PCRE, L.L.C.
PFR Staffers, LLC
Pickford Escrow Company, Inc
Pickford Holdings, LLC
Pickford Real Estate, Inc
Pickford Services Company, Inc
Pilot Butte, LLC
Pinon Pine Corporation
Pinon Pine Investment Company
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
PPW Staffers, LLC
Preferred Carolinas Realty, Inc
Preferred Carolinas Title Agency, LLC

Professional Referral Organization, Inc
PW Fox Holding LLC
PW Fox, LLC
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 Associates of Georgia, LLC
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
Rubloff Insurance Agency LLC
Salton Sea Minerals Corporation
San Diego PCRE, Inc
Semonin Realtors, Inc
Sierra Gas Holding Company
Sierra Pacific Power Company dba NV Energy
Solar Star 3, LLC
Solar Star California XIX, LLC
Solar Star California XX, LLC
Solar Star Funding, LLC
Solar Star Projects Holdings, LLC
Southwest Relocation, LLC
SSC XIX, LLC
SSC XX, LLC
Sterling Title Services, LLC
The Escrow Firm
The Referral Company
TIAC LLC
TitleSouth, LLC
TLTC LLC
Topaz Solar Farms, LLC
TPZ Holding, LLC
TRMC 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
Accurate Installations, Inc.
Ace Mailing Services, Inc.
Acme Brick Company
Acme Brick DFW, Inc.

Acme Brick Sales Company
Acme Building Brands, Inc
Acme Investment Company
Acme Management Company
Acme Ochs Brick and Stone, Inc.
Acme Services Company, L.P.
Active Organics, Inc.
Adalet/Scott Fetzer Company
AEG Processing Center No. 35, Inc.
AEG Processing Center No. 58, Inc.
Affiliated Agency Operations Co.
Affordable Housing Partners, Inc.
AJF Warehouse Distributors, Inc.
AL/TEX Homes, Inc.
Albacor Shipping (USA) Inc.
Albecca, Inc.
Alexander Road Insurance Agency, Inc.
Alexander-Otto Company, LLC
All Bilt Uniforms
Alpha Cargo Motor Express, Inc
Amarillo Gear, 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.
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.
Bayport Systems, Inc.
Ben Bridge Jeweler, Inc.
Benjamin Moore & Co.
Benson Industries, Inc.
Benson, Ltd.
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 Nebraska
Berkshire Indemnity Group Inc.
BH Columbia Inc.
BH Finance, Inc.
BH Media Group Holdings, Inc.
BH Media Group, Inc.

BH Shoe Holdings, Inc.
BH, LLC
BHG Life Insurance Company
BHG Structured Settlements, Inc.
BHSF, Inc.
Blue Chip Stamps, Inc.
BN Leasing Corporation
BNJ NetJets, Inc.
BNSF Communications, Inc.
BNSF Logistics International, Inc.
BNSF Railway Company
BNSF Railway International Services, Inc.
BNSF Spectrum, Inc.
Boat America Corporation
Boat Owners Association of the United States
Boat/U.S, Inc.
Boot Royalty Company
Borsheim Jewelry Company, Inc
BR Agency, Inc.
Brainy Toys, Inc.
Brick Acquisition Company
Brilliant National Services, Inc.
Brooks Sports, Inc.
Brookwood Insurance Company
Burlington Northern Railroad Holdings, Inc.
Burlington Northern Santa Fe British Columbia, Ltd.
Burlington Northern Santa Fe Insurance Company, Ltd.
Burlington Northern Santa Fe Manitoba, Inc.
Burlington Northern Santa Fe, LLC
Business Wire, Inc.
C & R Insurance Services, Inc.
C & R Legal Insurance Agency, LLC
California Insurance Company
Camp Manufacturing Company
Campbell Hausfeld/Scott Fetzer Company
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.
Chatwell, Inc.
Chemtool Incorporated
Chippewa Shoe Company
CJE II
Claims Services, Inc.
CLAL U.S. Holdings, Inc.
Clayton Commercial Buildings, Inc.
Clayton Education Corp.
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.
CMH Transport, Inc.
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
Cort Business Services Corporation
Coverage Dynamics Group, 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 Midwest
CTB MN Investments
Cubic Designs, Inc.
Cumberland Asset Management, Inc.
Cypress Insurance Company
Dairy Queen Corporate Stores, Inc.
Dairy Queen Of Georgia, Inc.
Delta Wholesale Liquors, Inc.
Denver Brick Company
Diversified Mailing, Inc.
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.
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 Commercial Trailer, Inc.
Fontaine Engineered Products, Inc.
Fontaine Fifth Wheel Company
Fontaine Modification Company
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 Manufacturing LLC
Forest River, Inc.
France/Scott Fetzer Company
Freedom Warehouse Corp.
FreightWise, 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
Fun Express LLC
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.J. Justin & Sons, Inc.
Halex/Scott Fetzer Company
Hallmark Sweet, Inc.
Hardy Frames, Inc.
Harris Uniforms
Hawthorn Life International Limited
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
J.L. Mining Company
J.S Justin, Inc.
JDS Properties, Inc.
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.
Kansas Bankers Surety Company
Karmelkorn Shoppes, Inc.
Kova Solutions, Inc.
L.A. Terminals, Inc.
LEE Distributing Services, 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 Inter-Americas Corporation
Lubrizol International Management Corporation
Lubrizol Overseas Trading Corporation
LZ Holding Corporation
M W Wholesale, Inc.
Mail Tech, LTD.
Mapletree Transportation, Inc.
Marathon Suspension Systems, Inc.
Marmon Crane Services, Inc.
Marmon Distribution Services, Inc.
Marmon Electrical & Plumbing Products Distribution, Inc.
Marmon Engineered Industrial & Metal Components, Inc.
Marmon Holdings, Inc.
Marmon Natural Resource & Transportation Service
Marmon Retail & End User Technologies, Inc.
Marmon Retail Home Improvement Products, 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
Meyn LLC
Midlands Newspapers, Inc.
Midwest Northwest Properties, Inc.
Miller-Sage, Inc.
Mindware Corporation
MiTek Holdings, Inc.
MiTek Industries, Inc.
MiTek USA, Inc.

Mobile Disaster Structures, Inc
Montana Retail Properties, Inc.
Morgantown-National Supply, Inc.
Mount Vernon Fire Insurance Company
Mount Vernon Specialty 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 Sales, Inc.
NetJets Services, Inc.
NetJets U.S., Inc.
NFM of Kansas, Inc.
NFM SERVICES, LLC
Nick Bloom Uniforms
NJE Holdings, LLC
NJI Sales, 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
Oriental Trading Company, Inc.
OTC Brands, Inc.
OTC Direct, Inc.
OTC Worldwide Holdings, Inc.
Penn Coal Land, Inc.
Penn Pocahontas Coal Co.
Pennsylvania Insurance Company
Perfection Hy-Test Company
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
Ray-Q, Inc
RCP Investment, Inc.
Redwood Fire and Casualty Insurance Company
RENTCO Trailer Corporation
Resolute Management Inc.
Richline Group, Inc
Ringwalt & Liesche Co.
Rio Grande, Inc.
Roberts Men's Shop
Roxell USA, Inc. (fka Agile Manufacturing Inc.)
Royal Cargo Lines
Running with Heels, Inc.
Rush Air Inc
Russell Athletic Corporation
Sager Electrical Supply Co. Inc
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
Soco West, Inc.
Sol Frank Uniforms Inc.
Somerset Services, Inc
Southern Energy Homes, Inc.
Spectra Contract Flooring Puerto Rico, Inc.
SSS Acquisition Inc.
Stahl/Scott Fetzer Company
Star Furniture Company
Star Lake Railroad Company
Stern/Leach 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 Climate Solutions, 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.
UCFS Europe Company
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
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 Insurance Company
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
World Investments, Inc.
World Marketing, Inc.
World Publishing Enterprises, Inc.
World Technologies, Inc.
Worldwide Containers, Inc.
X-L-Co., Inc.
XTRA Companies, Inc.
XTRA Corporation
XTRA Finance Corporation
XTRA Intermodal, Inc.
Zuckerbergs Uniforms

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 2013/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	51,241,091		71,947,013	108,946,084	-39,032
3	FICA	431,843	2,832	35,953,995	35,747,579	
4	Unemployment	4,331		245,558	245,288	
5	Excise Tax - Coal	78,805		2,956,843	2,934,284	
6	Subtotal	51,756,070	2,832	111,103,409	147,873,235	-39,032
7						
8	State:					
9						
10	Arizona:					
11	Property	1,427,469		3,238,051	3,046,495	
12	Income	205,430		421,083	10,883	
13	Subtotal	1,632,899		3,659,134	3,057,378	
14						
15	California:					
16	Property			2,196,241	2,196,241	
17	Unemployment	165	45	33,392	32,321	
18	Franchise-Income	-138,123		1,290,834	1,503,354	
19	Use	13,338		111,578	112,206	
20	Local Franchise	1,255,286		1,202,546	1,192,363	
21	Subtotal	1,130,666	45	4,834,591	5,036,485	
22						
23	Colorado:					
24	Property	1,910,000		2,062,995	1,912,995	
25	Income	2,127		6,236	2,127	
26	Subtotal	1,912,127		2,069,231	1,915,122	
27						
28	Idaho:					
29	Property	3,140,042		5,036,393	4,824,971	
30	Income	71,204		1,538,365	1,534,354	111,495
31	KWh	3,000		35,280	23,193	
32	Unemployment	1,456		75,415	75,035	
33	Use	15,268		169,280	163,681	
34	Subtotal	3,230,970		6,854,733	6,621,234	111,495
35						
36	Montana:					
37	Property	1,776,118		3,954,501	3,762,893	
38	Corporate License-Income	2,584		119,019	110,634	
39	Unemployment			1,239	1,239	
40	Energy License	60,000		185,637	205,637	
41	TOTAL	87,443,808	12,036,297	319,034,603	352,859,192	72,463

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
14,281,052		74,343,217			-2,396,204	2
645,661	10,234				35,953,995	3
4,601					245,558	4
101,364					2,956,843	5
15,032,678	10,234	74,343,217			36,760,192	6
						7
						8
						9
						10
1,619,025		3,238,051				11
615,630		429,795			-8,712	12
2,234,655		3,667,846			-8,712	13
						14
						15
		2,077,544			118,697	16
1,236	45				33,392	17
-350,643		1,307,242			-16,408	18
12,710					111,578	19
1,265,469		1,202,546				20
928,772	45	4,587,332			247,259	21
						22
						23
2,060,000		1,969,416			93,579	24
6,236		6,338			-102	25
2,066,236		1,975,754			93,477	26
						27
						28
3,351,464		4,951,171			85,222	29
-36,280		1,559,558			-21,193	30
15,087		35,280				31
1,836					75,415	32
20,867					169,280	33
3,352,974		6,546,009			308,724	34
						35
						36
1,967,726		3,954,501				37
10,969		120,970			-1,951	38
					1,239	39
40,000		185,637				40
53,535,702	12,025,243	259,757,744			59,276,859	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 2013/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	42,622		133,899	146,521	
2	Subtotal	1,881,324		4,394,295	4,226,924	
3						
4	Nebraska:					
5	Unemployment			357	357	
6	Subtotal			357	357	
7						
8	New Mexico:					
9	Property			6,628	6,628	
10	Income	1,953		77,075	2,003	
11	Subtotal	1,953		83,703	8,631	
12						
13	Oregon:					
14	Property		11,615,331	23,103,236	23,027,833	
15	Unemployment	36,861	4,418	1,619,781	1,601,673	
16	Wilsonville Payroll	675		2,263	2,162	
17	Excise-Income	84,059		3,917,378	4,055,153	
18	City of Portland-Income	6,938		-42,767	-50,960	
19	Multnomah County	1,498		-93,691	-92,193	
20	Department of Energy		413,671	888,597	949,852	
21	Tri-Met	381,339		992,323	962,461	
22	Lane County			2,169	2,169	
23	Franchise	4,402,214		27,490,971	27,366,391	
24	Subtotal	4,913,584	12,033,420	57,880,260	57,824,541	
25						
26	Utah:					
27	Property	-81,186		68,725,315	67,939,917	
28	Income	173,814		8,234,382	7,918,672	
29	Unemployment	4,629		388,511	387,215	
30	Navajo Nation			934	934	
31	Use	286,472		3,291,390	3,168,614	
32	Subtotal	383,729		80,640,532	79,415,352	
33						
34	Washington:					
35	Property	9,400,000		10,420,861	9,730,861	
36	Unemployment	2,025		73,134	72,596	
37	Business & Occupation	3,513		32,684	32,540	
38	Public Utility	1,100,000		13,264,318	13,164,318	
39	Natural Gas Use Tax	44,658		2,237,933	2,157,675	
40	Use	610,675		584,382	1,137,421	
41	TOTAL	87,443,808	12,036,297	319,034,603	352,859,192	72,463

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)	
30,000		133,899				1
2,048,695		4,395,007			-712	2
						3
						4
					357	5
					357	6
						7
						8
		6,628				9
77,025		78,337			-1,262	10
77,025		84,965			-1,262	11
						12
						13
	11,539,928	22,818,790			284,446	14
50,661	110				1,619,781	15
776					2,263	16
-53,716		4,055,736			-138,358	17
15,131		-40,210			-2,557	18
		-93,691				19
	474,926	888,597				20
411,201					992,323	21
					2,169	22
4,526,794		27,490,971				23
4,950,847	12,014,964	55,120,193			2,760,067	24
						25
						26
704,212		58,706,802			10,018,513	27
489,524		8,369,442			-135,060	28
5,925					388,511	29
		934				30
409,248					3,291,390	31
1,608,909		67,077,178			13,563,354	32
						33
						34
10,090,000		10,043,623			377,238	35
2,563					73,134	36
3,657		32,684				37
1,200,000		13,264,318				38
124,916					2,237,933	39
57,636					584,382	40
53,535,702	12,025,243	259,757,744			59,276,859	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 2013/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Subtotal	11,160,871		26,613,312	26,295,411	
2						
3	Wyoming:					
4	Property	7,512,619		14,918,164	14,971,702	
5	Wind generation tax	1,390,284		1,813,575	1,373,012	
6	Unemployment	8,597		423,245	421,401	
7	Franchise	307,400		1,886,074	1,910,374	
8	Use	155,221		1,408,591	1,430,850	
9	Annual Report			70,239	70,239	
10	Subtotal	9,374,121		20,519,888	20,177,578	
11						
12	State Other	46,685		-26,173		
13						
14	Miscellaneous:					
15	Goshute Possessory			23,082	23,082	
16	Sho-Ban Possessory			183,560	183,560	
17	Navajo Possessory	18,809		38,391	38,004	
18	Ute Possessory			29,220	29,220	
19	Crow Possessory			67,500	67,500	
20	Umatilla Possessory			65,578	65,578	
21	Subtotal	65,494		381,158	406,944	
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	87,443,808	12,036,297	319,034,603	352,859,192	72,463

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)	
11,478,772		23,340,625			3,272,687	1
						2
						3
7,459,081		14,468,572			449,592	4
1,830,847		1,813,575				5
10,441					423,245	6
283,100		1,886,074				7
132,962					1,408,591	8
		70,239				9
9,716,431		18,238,460			2,281,428	10
						11
20,512		-26,173				12
						13
						14
		23,082				15
		183,560				16
19,196		38,391				17
		29,220				18
		67,500				19
		65,578				20
39,708		381,158				21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
53,535,702	12,025,243	259,757,744			59,276,859	41

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

$ (39,024) Account 255, Accumulated Deferred Investment Tax Credits (1)
(8) Other
$ (39,032)

(1) Represents the federal impact of the adjustment discussed in footnote (4) of the footnote to line 7 column b of page 266, Accumulated deferred investment tax credits, in this Form No. 1.

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

Account 151, Fuel stock

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

$110,925 Account 408.2, Taxes other than income taxes, other income and deductions
1,569 Account 589, Rents
6,203 Account 107, Construction work in progress
$118,697

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

$ 677 Account 408.2, Taxes other than income taxes, other income and deductions
92,902 Account 107, Construction work in progress
$93,579

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
83,921 Account 107, Construction work in progress
$85,222

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

$111,496 Account 255, Accumulated Deferred Investment Tax Credits (1)
(1) Other
$111,495

(1) Represents the state impact of the adjustment discussed in footnote (4) of the footnote to line 7 column b of page 266, Accumulated deferred investment tax credits, in this Form No. 1.

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.: 5 Column: l

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

Schedule Page: 262.1 Line No.: 10 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: l

$ 14,741	Account 408.2, Taxes other than income taxes, other income and deductions
144,319	Account 589, Rents
125,386	Account 107, Construction work in progress
$284,446	

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

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

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

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

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

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

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

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

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

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

$ 30,763	Account 408.2, Taxes other than income taxes, other income and deductions
551	Account 589, Rents
7,898,009	Account 107, Construction work in progress
2,089,190	Account 151, Fuel stock
$10,018,513	

Schedule Page: 262.1 Line No.: 28 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.: 29 Column: l

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

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

Charged to same account as related goods.

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

$ 82,806 Account 408.2, Taxes other than income taxes, other income and deductions
294,432 Account 107, Construction work in progress
$377,238

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

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

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

Account 151, Fuel stock

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

Charged to same account as related goods.

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

$ 957 Account 408.2, Taxes other than income taxes, other income and deductions
12,187 Account 589, Rents
436,448 Account 107, Construction work in progress
$449,592

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

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

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

Charged to same account as related goods.

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	33,995,519			411.4,420	2,851,419	
6	30%		420	169,781	420	1,768	
7	Idaho	335,498			411.4,420	8,681	-193,191
8	TOTAL	34,331,017		169,781		2,861,868	-193,191
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	Idaho		190	468,027	420	31,512	424,071
12	Total Nonutility			468,027		31,512	424,071
13							
14							
15							
16							
17							
18							
19							
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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
31,144,100	48.37 and 30		5
168,013	24		6
133,626	30		7
31,445,739			8
			9
			10
860,586	30		11
860,586			12
			13
			14
			15
			16
			17
			18
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			47
			48

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

The electric utility subdivision of 10% accumulated deferred investment tax credits are as follows:

Acct. Sub. (a)	Beginning Balance (b)	Deferred for Yr. Acct. (c)	Deferred for Yr. Amount (d)	Allocat. to CY Acct. (e)	Allocat. to CY Amount (f)	Adj. (g)	Ending Balance (h)	Avg. Per. (i)
10%	$31,574,597	-	-	411.4(1)	$1,808,768	$ -	$29,765,829	48.37
10%	2,420,922	-	-	420(2)	1,042,651	-	1,378,271	30
	$33,995,519		-		$2,851,419	$ -	$31,144,100	

(1) Internal Revenue Code 46(f)2
(2) Internal Revenue Code 46(f)1

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

The electric utility subdivision of Idaho accumulated deferred investment tax credits are as follows:

Acct. Sub. (a)	Beginning Balance (b)	Deferred for Yr. Acct. (c)	Deferred for Yr. Amount (d)	Allocat. to CY Acct. (e)	Allocat. to CY Amount (f)	Adj. (g)	Ending Balance (h)	Avg. Per. (i)
Idaho	$ 335,498	-	$ -	411.4(1)	$ 3,296	$(265,663)(2)	$ 66,539	30
Idaho	-	-	-	420(3)	5,385	72,472 (4)	67,087	30
	$ 335,498		$ -		$ 8,681	$(193,191)	$ 133,626	

(1)Internal Revenue Code 46(f)2

(2)Represents an adjustment to the balance at beginning of year:
$ 143,049 Account 410.1, Provision for deferred income taxes
(408,712) Account 411.1, Provision for deferred income taxes-credit
$(265,663)

(3)Internal Revenue Code 46(f)1

(4)Represents an adjustment to the balance at beginning of year:
$ 111,496 Account 409.1, Income taxes-other
(39,024) Account 409.1, Income taxes-federal
$ 72,472

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

For further information, refer to this page Line 7, Column (b).

Schedule Page: 266 Line No.: 11 Column: g

Represents an adjustment to the balance at beginning of year:
$(237,441) Account 411.1, Provision for deferred income taxes-credit
(16,891) Account 420, Investment tax credits
678,403 Account 410.1, Provision for deferred income taxes
$ 424,071

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 2013/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	5,997,934			688,793	6,686,727
2						
3	Reclamation Costs - Trapper Mine	5,258,748			208,059	5,466,807
4						
5	Reclamation Costs - Deseret Mine	476,006	232	24,600		451,406
6						
7	Western Coal Carriers Benefits					
8	Obligation	11,077,000	131	923,770	1,661,770	11,815,000
9						
10	Bank Card Incentives	334,699	921	91,123	179,700	423,276
11						
12	Deferred Revenue - Other (5)	25,000	421	25,000		
13						
14	Deferred Compensation Plan	8,200,305	131,232,241	724,085	1,728,942	9,205,162
15						
16	Redding Contract (20)	1,650,088	456	549,996		1,100,092
17						
18	Foote Creek Contract (15)	292,382	456	137,640		154,742
19						
20	Environmental Liabilities	26,769,085		9,155,845	8,659,860	26,273,100
21						
22	Unearned Joint Use Pole					
23	Contact (1)	2,699,055	454	6,176,296	6,363,842	2,886,601
24						
25	Misc. Security Deposits	2,875	454,456,557	675		2,200
26						
27	Lease Incentives (10)	28,090	931	28,090		
28						
29	Cowlitz/Lewis River O&M (1)	115,085	539	279,046	281,076	117,115
30						
31	Employee Housing Security Deposits	15,775			2,500	18,275
32						
33	Oregon DSM Loans NPV Unearned					
34	Income (10)	15,734	456	15,734		
35						
36	Cogeneration Bonds-Sunnyside	413,417				413,417
37						
38	Transmission Security Deposits	667,243	131,107	155,743	170,000	681,500
39						
40	Transmission Service Deposits	853,435	131	1,601,469	901,259	153,225
41						
42	MCI F.O.G. wire lease (1)	558,214	454	3,347,666	3,347,342	557,890
43						
44	Unamortized contract values	146,226,194	242	22,899,131		123,327,063
45						
46	Loss contingency - USA Power	120,260,000	426.5	5,437,532	1,800,968	116,623,436
47	TOTAL	333,027,535		51,573,441	27,031,350	308,485,444

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 2013/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits	Balance at Beginning of Year	DEBITS		Credits	Balance at End of Year
			Contra Account	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1						
2	Accrued Right-of-Way Obligations	1,091,171			557,186	1,648,357
3						
4	Navajo Tribal Utility Authority					
5	Escrow				480,053	480,053
6						
7						
8						
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16						
17						
18						
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41						
42						
43						
44						
45						
46						
47	TOTAL	333,027,535		51,573,441	27,031,350	308,485,444

Schedule Page: 269 Line No.: 10 Column: a

The weighted average life is 4 years.

Schedule Page: 269 Line No.: 20 Column: c

Account 131, Cash
Account 182.3, Other regulatory assets
Account 232, Accounts payable
Account 426.5, Other deductions

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	208,722,047	21,737,317	3,578,386
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	208,722,047	21,737,317	3,578,386
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)	208,722,047	21,737,317	3,578,386
18	Classification of TOTAL			
19	Federal Income Tax	183,753,060	18,134,016	2,147,401
20	State Income Tax	24,968,987	3,603,301	1,430,985
21	Local Income Tax			

NOTES

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 2013/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits: Account Credited (g)	Debits: Amount (h)	Credits: Account Debited (i)	Credits: Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
						226,880,978	4
							5
							6
							7
						226,880,978	8
							9
							10
							11
							12
							13
							14
							15
							16
						226,880,978	17
							18
						199,739,675	19
						27,141,303	20
							21

NOTES (Continued)

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 2013/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	3,796,825,280	627,266,829	436,011,788
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	3,796,825,280	627,266,829	436,011,788
6	Nonutility			
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	3,796,825,280	627,266,829	436,011,788
10	Classification of TOTAL			
11	Federal Income Tax	3,339,798,865	507,155,316	337,290,386
12	State Income Tax	457,026,415	120,111,513	98,721,402
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
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
		182.3	4,258,141	182.3	7,791,232	3,991,613,412	2
							3
							4
			4,258,141		7,791,232	3,991,613,412	5
							6
							7
							8
			4,258,141		7,791,232	3,991,613,412	9
							10
			-31,782,947		5,500,396	3,546,947,138	11
			36,041,088		2,290,836	444,666,274	12
							13

NOTES (Continued)

Schedule Page: 274   Line No.: 11   Column: h

Includes adjustment to the balance at beginning of year to reflect direct allocation of the federal deferred tax balances.

Schedule Page: 274   Line No.: 12   Column: h

Includes adjustment to the balance at beginning of year to reflect direct allocation of the state deferred tax balances.

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 2013/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	695,709,590	76,645,227	91,527,025
4	Other	32,351,572	5,284,329	6,849,053
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	728,061,162	81,929,556	98,376,078
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)	728,061,162	81,929,556	98,376,078
20	Classification of TOTAL			
21	Federal Income Tax	640,964,707	69,778,623	84,259,562
22	State Income Tax	87,096,455	12,150,933	14,116,516
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits: Account Credited (g)	Debits: Amount (h)	Credits: Account Debited (i)	Credits: Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
14,473,744	47,196,345		141,663,507		19,620,390	526,062,074	3
4,425,708	4,608,277	190,283	17,983,102	190,283	17,697,822	30,318,999	4
							5
							6
							7
							8
18,899,452	51,804,622		159,646,609		37,318,212	556,381,073	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
18,899,452	51,804,622		159,646,609		37,318,212	556,381,073	19
							20
16,101,498	45,070,291		139,650,282		31,992,735	489,857,428	21
2,797,954	6,734,331		19,996,327		5,325,477	66,523,645	22
							23

NOTES (Continued)

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

Account 182.3, Other regulatory assets
Account 190, Accumulated deferred income taxes
Account 283, Accumulated deferred income taxes-other

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

Account 182.3, Other regulatory assets
Account 190, Accumulated deferred income taxes
Account 283, Accumulated deferred income taxes-other

Schedule Page: 276 Line No.: 21 Column: h

Includes adjustment to the balance at beginning of year to reflect direct allocation of the federal deferred tax balances.

Schedule Page: 276 Line No.: 22 Column: h

Includes adjustment to the balance at beginning of year to reflect direct allocation of the state deferred tax balances.

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 2013/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	17,206,905	190	1,138,454		16,068,451
2	Income Tax Reg. Liab. - WA Flow Through	3,785,659			1,001,581	4,787,240
3	Excess Gain on Sale of Assets in Rates - OR (1)	35,161		335,679	300,518	
4	Property Insurance Reserve - OR				445,516	445,516
5	Property Insurance Reserve - ID	201,756			113,544	315,300
6	Property Insurance Reserve - UT	547,631	924	401,833	2,152,236	2,298,034
7	Property Insurance Reserve - WY	621,571	924	1,673,564	1,051,993	
8	SMUD Revenue Imputation (11)	4,114,860	440,442	2,295,647	3,932	1,823,145
9	Utah Home Energy Lifeline	450,629	142	20,724	1,018,779	1,448,684
10	BPA Balancing Account - WA	1,065,877	440,442	916,135		149,742
11	BPA Balancing Account - OR	1,792,701	440,442	1,580,711		211,990
12	BPA Balancing Account - ID				922,145	922,145
13	Asset Retirement Obligations Reg. Difference	12,259,337	230	1,601,948		10,657,389
14	Washington Low Income Program	800,851	142	272,951	588,334	1,116,234
15	Misc. Regulatory Assets/Liabilities - OR	282,755	182.3	368,046	85,291	
16	Blue Sky - OR	2,639,097	440,442	1,631,385	1,725,241	2,732,953
17	Blue Sky - WA	213,744	440,442	54,425	170,963	330,282
18	Blue Sky - CA	97,076	440,442	77,893	68,669	87,852
19	Blue Sky - UT	2,724,989	440,442	2,561,593	2,766,350	2,929,746
20	Blue Sky - ID	55,579	440,442	18,092	53,795	91,282
21	Blue Sky - WY	229,404	440,442	155,520	213,128	287,012
22	OR Energy Conservation Charge	2,319,249	131,232	26,447,000	27,190,447	3,062,696
23	Renewable Energy Credit Sales Deferral	17,590,233		4,722,664	1,253,708	14,121,277
24	Tax Revenue Requirement Adj. - UT (1)	61,696		61,696		
25	2010 Protocol Deferral - OR (1)	222,077		491,346	269,269	
26	Powerdale Decommissioning Costs Giveback - UT (2)	180,278		180,278		
27	Green House Gas Allowance Revenues - CA	2,434,345			6,671,710	9,106,055
28	GRC Invest. in Emission Control Equip. - OR (1)	17,000,000		16,236,420		763,580
29	2013 FERC Rate True-up - OR				2,273,466	2,273,466
30	DSM Regulatory Asset - CA	765,482		2,173,566	1,408,084	
31	DSM Regulatory Asset - ID				2,053	2,053
32	DSM Regulatory Asset - UT	8,206,230		51,076,864	49,061,672	6,191,038
33	DSM Regulatory Asset - WA				367,062	367,062
34	DSM Regulatory Asset - WY				183,406	183,406
35	Alternative Rate for Energy (CARE) - CA	621,982		70,976	345,048	896,054
36	Deferred Excess Net Power Costs - WA Hydro	103,748	555	3	8,703	112,448
37	Deferred Independent Evaluator Fee - UT	114,940	923	18,210	27,573	124,303
38	Deferred Excess RECs in Rates - UT 2012	2,753,648	456	1,379,266	147,165	1,521,547
39	RTO Grid West N/R - OR	6,035	904	7,342	1,307	
40	SB 408 and MCBIT Regulatory Asset - OR	10,904		15,303	4,399	
41	TOTAL	102,737,542		120,576,705	109,373,077	91,533,914

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 2013/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	Solar Feed-In Tariff Deferral - CA	354,070		1,220,826	990,538	123,782
2	Solar Incentive Program - UT	867,043		1,370,345	6,485,452	5,982,150
3						
4						
5						
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36						
37						
38						
39						
40						
41	TOTAL	102,737,542		120,576,705	109,373,077	91,533,914

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

Weighted average life is 48 years.

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

Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting
Account 419, Interest and dividend income

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

Account 456, Other electric revenues
Account 419, Interest and dividend income
Account 182.3, Other regulatory assets

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

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

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
Account 419, Interest and dividend income

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: c

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

Schedule Page: 278 Line No.: 30 Column: c

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

Schedule Page: 278 Line No.: 32 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.: 35 Column: c

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

Schedule Page: 278 Line No.: 40 Column: c

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

Schedule Page: 278.1 Line No.: 1 Column: c

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

Schedule Page: 278.1 Line No.: 2 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

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 2013/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	1,773,896,154	1,611,369,814
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,467,851,627	1,376,215,099
5	Large (or Ind.) (See Instr. 4)	1,365,175,755	1,247,618,388
6	(444) Public Street and Highway Lighting	20,047,674	19,998,454
7	(445) Other Sales to Public Authorities	17,101,922	16,263,330
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	4,644,073,132	4,271,465,085
11	(447) Sales for Resale	325,520,827	330,569,624
12	TOTAL Sales of Electricity	4,969,593,959	4,602,034,709
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	4,969,593,959	4,602,034,709
15	Other Operating Revenues		
16	(450) Forfeited Discounts	9,906,509	9,445,744
17	(451) Miscellaneous Service Revenues	6,310,584	6,413,143
18	(453) Sales of Water and Water Power	1,577	860
19	(454) Rent from Electric Property	17,887,016	18,875,927
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	63,993,962	136,299,293
22	(456.1) Revenues from Transmission of Electricity of Others	85,492,936	76,416,197
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	183,592,584	247,451,164
27	TOTAL Electric Operating Revenues	5,153,186,543	4,849,485,873

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
16,339,122	15,968,423	1,522,173	1,504,514	2
				3
17,057,194	16,828,774	207,690	211,986	4
21,831,865	21,316,760	33,561	33,553	5
142,585	142,675	3,557	3,636	6
292,107	292,709	3	3	7
				8
				9
55,662,873	54,549,341	1,766,984	1,753,692	10
10,206,135	11,869,789			11
65,869,008	66,419,130	1,766,984	1,753,692	12
				13
65,869,008	66,419,130	1,766,984	1,753,692	14

Line 12, column (b) includes $ 258,009,000 of unbilled revenues.

Line 12, column (d) includes 3,378,082 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:

	2013	2012
Account service charges - disconnects/reconnects/returned check charges	$ 4,737,594	$ 4,448,063
Customer contract flat rate billings	1,525,594	1,907,528

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:

	2013	2012
Renewable energy credit sales, including amortization and deferrals	$ 32,904,131	$ 106,970,144
Wind-based ancillary services	12,114,934	12,186,449
Energy exchange credits	10,700,944	7,178,646
Flyash/by-product sales	3,264,830	3,234,313
Steam sales	2,029,668	3,708,368
Power sale and exchange agreements	1,091,292	1,091,292
Phase shifting equipment fee from Western Electricity Coordinating Council	1,062,518	338,147
Revenue from generation interconnection and transmission service request studies	905,164	715,380
Maintenance charges for work on transmission facilities	727,226	783,876
Net profit on sales of materials and supplies inventory	356,039	(a)
Indemnity revenues	346,845	-
Service territory fixed cost recovery fee	276,016	262,676
Deferral of Oregon retail customers' allocated share of the incremental Open Access Transmission Tariff revenues associated with FERC Docket No. ER11-3643-000	(2,220,863)	-

(a) The 2012 amount is less than $250,000.

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL SALES					
2	CALIFORNIA					
3	06CHCK000R-CA RES CHECK M			1		
4	06LNX00311-LINE EXT 80% GTY		1,949			
5	06NETMT135-CA RES NET MTR	745	103,180	112	6,652	0.1385
6	06OALT015R-OUTD AR LGT SR	314	75,804	337	932	0.2414
7	06RESD000D-RES SRVC	181,182	24,471,231	18,049	10,038	0.1351
8	06RESDDL06-CA LOW INCOME	113,839	15,077,666	10,040	11,339	0.1324
9	06RGNSV025-CA SMALL GEN	853	172,754	360	2,369	0.2025
10	06RESD0DM9 - MULTI FAMILY	224	29,304	8	28,000	0.1308
11	06RESD0DS8-MULT FAM SBMET	1,247	135,133	16	77,938	0.1084
12	06RESD00DN-RES SVC-DEL NORT	88,767	11,857,936	7,290	12,177	0.1336
13	06UPPL000R-BASE SCH FALL			2		
14	SMUD REVENUE IMPUTATIONS		39,478			
15	UNBILLED REVENUE	3,175	530,000			0.1669
16	UNBILLED REV - UNCOLLECTIBLE		-3,000			
17	DSM - RESIDENTIAL		417,325			
18	BLUE SKY - RESIDENTIAL		71,689			
19	SOLAR FEED-IN REVENUE		614,423			
20	REVENUE - ACCOUNTING ADJ		-596,584			
21						
22	IDAHO					
23	07LNX00010-MNTHLY 80%GUAR		1,277			
24	07LNX00035-ADV 80%MO GUAR		1,741			
25	07NETMT135-ID RES NET MTR	1,519	150,626	90	16,878	0.0992
26	07OALCO007-CUST OWN LIGHT	10	3,811	1	10,000	0.3811
27	07OALT07AR-SECURITY AR LG	97	39,647	120	808	0.4087
28	07RESD0001-RES SRVC	447,863	51,227,760	44,771	10,003	0.1144
29	07RESD0036-RES SRVC-OPTIO	256,413	24,844,435	13,768	18,624	0.0969
30	07RGNSV23A-ID SM GEN SVC	4,172	478,247	539	7,740	0.1146
31	SMUD REVENUE IMPUTATIONS		53,413			
32	UNBILLED REVENUE	8,016	1,015,000			0.1266
33	UNBILLED REV - UNCOLLECTIBLE		-5,000			
34	DSM - RESIDENTIAL		1,413,723			
35	BLUE SKY - RESIDENTIAL		16,227			
36						
37	OREGON					
38	01CHCK000R-RES CHECK MTR			1		
39	01COST0004 - 01RESD0004	5,201,789	296,221,924			0.0569
40	01COSTR023-RES GEN SRV CST	25,896	1,474,019			0.0569
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
43	TOTAL	55,662,873	4,740,900,075	1,766,984	31,502	0.0852

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 2013/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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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	01FXRENEWR-Fixed Renewable		-3			
2	01HABIT004 - 01RESD0004	39,492	2,200,021			0.0557
3	01HABTR023-RES GEN SVC HAB	34	1,962			0.0577
4	01LNX00102-LINE EXT 80% G		13,272			
5	01LNX00109-REF/NREF ADV +		6,052			
6	01LNX00110-REF/NREF ADV +		1,195			
7	01NETMT135-NET METERING		1,080,461	2,353		
8	01NMTOU135-TOU NET MTR		8,808	17		
9	01OALTB15R-OUTD AR LGT RE	2,379	369,102	2,688	885	0.1552
10	01PTOU0004 - 01RESD0004	18,103	1,059,603			0.0585
11	01RENEW004 - 01RESD0004	252,267	13,859,073			0.0549
12	01RENWR023-RENEW USAGE	125	7,307			0.0585
13	01RESD0004-RES SRVC		283,961,543	474,545		
14	01RESD004T-RES Time Option		892,476	1,190		
15	01RGNSB023-SM GEN SVC-RES		2,152,108	5,689		
16	01RNETM023-NET MTR RES GEN		38	1		
17	01UPPL000R-BASE SCH FALL			2		
18	01VIR04136-OR RES VOL INCTV		196,370	253		
19	OR GAIN ON SALE OF ASSET		164,015			
20	SMUD REVENUE IMPUTATIONS		455,825			
21	SOLAR FEED-IN REVENUE		738,490			
22	UNBILLED REVENUE	-5,231	1,361,000			-0.2602
23	UNBILLED REV - UNCOLLECTIBLE		-8,000			
24	DSM - RESIDENTIAL		14,724,948			
25	BLUE SKY - RESIDENTIAL		465,004			
26	REVENUE - ACCOUNTING ADJ		-495,823			
27						
28	UTAH					
29	08BLSKY01R-BLUESKY ENERGY		-5			
30	08CFR00001-MTH FACILITY S		1,014			
31	08CHCK000R-UT RES CHECK M			1		
32	08COOLKPRR - Utah Cool Keeper			97,347		
33	08LNX00001-MTHLY 80% GUAR		4,631			
34	08LNX00005-MTHLY MIN GUAR		396			
35	08LNX00013-80% MNTHLY MIN		22,348			
36	08LNX00108-ANN COST MTHLY		2,604			
37	08MHTP0006-MOBILE HOME &	11,702	858,289	8	1,462,750	0.0733
38	08MHTP0023-MOBILE HOME &	333	30,805	3	111,000	0.0925
39	08NETMT135-Net Metering	11,518	1,232,865	1,614	7,136	0.1070
40	08OALT007R-SECURITY AR LG	2,707	774,671	2,946	919	0.2862
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
43	TOTAL	55,662,873	4,740,900,075	1,766,984	31,502	0.0852

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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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	08PTLD000R-POST TOP LIGHT	2	131	3	667	0.0655
2	08RESD0001-RES SRVC	6,549,249	692,990,791	696,264	9,406	0.1058
3	08RESD0002-RES SRVC-OPTIO	2,971	307,037	350	8,489	0.1033
4	08RESD0003-LIFELINE PRGRM	221,906	22,974,695	27,556	8,053	0.1035
5	08RGNSV006-GEN SRVC-RES	80,880	6,105,375	215	376,186	0.0755
6	08RGNSV023-GEN SRVC-RES	91,081	9,937,681	11,997	7,592	0.1091
7	08RGNSV06A-UT SM GEN SVC	5,389	446,426	19	283,632	0.0828
8	08RGNSV06B-UT SM GEN SVC	4	468	1	4,000	0.1170
9	08RNM23135-UT NET MTR, GEN	139	14,111	16	8,688	0.1015
10	08UPPL000R-BASE SCH FALL			4		
11	SOLAR FEED-IN REVENUE		520,731			
12	UNBILLED REVENUE	-1,244	960,000			-0.7717
13	UNBILLED REV - UNCOLLECTIBLE		-33,000			
14	DSM - RESIDENTIAL		20,716,225			
15	BLUE SKY - RESIDENTIAL		1,988,616			
16	REVENUE - ACCOUNTING ADJ		-2,288,587			
17	REVENUE ADJ - DEFERRED NPC		7,950,175			
18						
19	WASHINGTON					
20	02BLSKY01R-BLUESKY ENERGY		-2			
21	02LNX00109-REF/NREF ADV +		783			
22	02NETMT135-WA RES NET MTR	1,372	121,143	96	14,292	0.0883
23	02OALTB15R-WA OUTD AR LGT	1,051	156,487	1,133	928	0.1489
24	02RESD0016-WA RES SRVC	1,553,802	135,331,410	100,211	15,505	0.0871
25	02RESD0017-BILL ASSISTANCE	66,140	5,742,704	4,195	15,766	0.0868
26	02RESD0018-WA 3 PHASE RES	2,277	217,410	84	27,107	0.0955
27	02RESD018X-WA 3 PHASE RES	435	40,818	18	24,167	0.0938
28	02RGNSB024-WA SM GEN SVC	7,081	809,006	1,453	4,873	0.1143
29	02UPPL000R-BASE SCH FALL			1		
30	WASHINGTON-CHEHALIS		-1,320,000			
31	SMUD REVENUE IMPUTATIONS		128,745			
32	UNBILLED REVENUE	-5,896	-286,000			0.0485
33	UNBILLED REV - UNCOLLECTIBLE		5,000			
34	DSM - RESIDENTIAL		4,639,763			
35	REVENUE - ACCOUNTING ADJ		-4,765,913			
36	BLUE SKY - RESIDENTIAL		42,672			
37	REVENUE ADJ - DEFERRED NPC		-416,095			
38						
39	WYOMING					
40	05LNX00102-LINE EXT 80% G		924			
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
43	TOTAL	55,662,873	4,740,900,075	1,766,984	31,502	0.0852

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 2013/Q4

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Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	05LNX00109-REF/NREF ADV +		830			
2	05NETMT135-EXPERIMENTAL	1,487	164,348	121	12,289	0.1105
3	05NETMT135-EXPERIMENTAL	248	27,140	14	17,714	0.1094
4	05OALT015R-OUTD AR LGT SR	909	144,678	1,060	858	0.1592
5	05OALT015R-OUTD AR LGT SR		43	1		
6	05RESD0002-WY RES SRVC	959,922	99,423,224	99,417	9,656	0.1036
7	05RESD0002-WY RES SRVC	125,997	13,253,358	12,468	10,106	0.1052
8	05RGNSV025-WY SM GEN SVC	7,550	870,968	1,102	6,851	0.1154
9	05RGNSV025-WY SM GEN SVC	344	56,352	110	3,127	0.1638
10	09OALT207R-SECURITY AR LG	76	22,116	89	854	0.2910
11	09RES00002			2		
12	09RESD0002			4		
13	SMUD REVENUE IMPUTATIONS		71,453			
14	UNBILLED REVENUE	1,063	384,000			0.3612
15	UNBILLED REVENUE	-4,663	-481,000			0.1032
16	UNBILLED REV - UNCOLLECTIBLE		8,000			
17	DSM - RESIDENTIAL		1,201,049			
18	DSM - RESIDENTIAL		187,337			
19	DSM - RESIDENTIAL GEN SVC		16,213			
20	DSM - RESIDENTIAL GEN SVC		1,260			
21	BLUE SKY - RESIDENTIAL		121,262			
22	BLUE SKY - RESIDENTIAL		19,723			
23	REVENUE ADJ - DEFERRED NPC		-708,349			
24	REVENUE - ACCOUNTING ADJ		-5,184			
25						
26	LESS MULTIPLE BILLINGS			-119,993		
27						
28	TOTAL RESIDENTIAL SALES	16,339,122	1,773,896,154	1,522,173	10,734	0.1086
29						
30	COMMERCIAL SALES					
31	CALIFORNIA					
32	06CHCK000N-CA NRES CHECK			1		
33	06GNSV0025-CA GEN SRVC	55,446	8,820,224	6,538	8,481	0.1591
34	06GNSV025F-GEN SRVC-<20	911	159,928	85	10,718	0.1756
35	06GNSV0A32-GEN SRVC-20 KW	82,550	10,842,772	998	82,715	0.1313
36	06LGSV048T-LRG GEN SERV	38,613	3,378,064	8	4,826,625	0.0875
37	06NMT48135-CA GEN SVC NET	1,362	119,185	1	1,362,000	0.0875
38	06LGSV0A36-LRG GEN SRVC-O	72,422	8,063,921	165	438,921	0.1113
39	06LNX00102-LINE EXT 80% G		11,207			
40	06LNX00105-CNTRCT $ MIN G		4,196			
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
43	TOTAL	55,662,873	4,740,900,075	1,766,984	31,502	0.0852

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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	06LNX00109-REF/NREF ADV +		80,943			
2	06LNX00300-80% MTHLY MIN GU		9,891			
3	06LNX00311-LINE EXT 80% GUAR		10,372			
4	06NMT36135-CA GEN SVC NET	2,251	264,277	4	562,750	0.1174
5	06OALT015N-OUTD AR LGT SR	708	173,411	505	1,402	0.2449
6	06RCFL0042-AIRWAY & ATHLE	175	33,562	37	4,730	0.1918
7	06NMT25135-GN SVC NET<20K	95	14,532	7	13,571	0.1530
8	06NMT32135-GN SVC NET>20K	502	78,071	9	55,778	0.1555
9	06LNX00110-REF/NREF ADV +		7,797			
10	SMUD REVENUE IMPUTATIONS		27,921			
11	SOLAR FEED-IN REVENUE		498,016			
12	UNBILLED REVENUE	2,749	430,000			0.1564
13	DSM - COMMERCIAL		276,607			
14	BLUE SKY - COMMERCIAL		5,999			
15	REVENUE - ACCOUNTING ADJ		-492,257			
16						
17	IDAHO					
18	07CISH0019-COMM & IND SPA	5,996	516,035	108	55,519	0.0861
19	07GNSV0006-GEN SRVC-LRG P	206,249	17,176,129	928	222,251	0.0833
20	07GNSV0009-GEN SRVC-HI VO	43,730	2,718,415	2	21,865,000	0.0622
21	07GNSV0023-GEN SRVC-SML P	138,144	13,700,560	6,314	21,879	0.0992
22	07GNSV0035-GEN SRVCOPTION	627	43,941	3	209,000	0.0701
23	07GNSV006A-GEN SRVC-LRG P	31,676	2,758,666	193	164,124	0.0871
24	07GNSV023A-GEN SRVC-SML P	23,821	2,384,682	1,328	17,938	0.1001
25	07GNSV023F-GEN SRVC SML P	7	2,024	5	1,400	0.2891
26	07LNX00010-MNTHLY 80%GUAR		830			
27	07LNX00035-ADV 80%MO GUAR		214,065			
28	07LNX00040-ADV+REFCHG+80%		72,205			
29	07OALT007N-SECURITY AR LG	243	92,714	175	1,389	0.3815
30	07OALT07AN-SECURITY AR LG	11	4,423	12	917	0.4021
31	07LNX00312-ID LINE EXT		3,888			
32	07NMT06135-ID NET MTR-LG GEN	1,667	149,785	4	416,750	0.0899
33	07NMT23135-ID NET MTR-SM GEN	636	56,317	15	42,400	0.0885
34	07LNX00015-ANNUAL 80%GUAR		2,070			
35	07LNX00311-LINE EXT 80% GUAR		35,108			
36	07LNX00300-80% MTHLY MIN GU		11,325			
37	SMUD REVENUE IMPUTATIONS		34,231			
38	UNBILLED REVENUE	-15,175	-1,071,000			0.0706
39	DSM - COMMERCIAL		755,454			
40	BLUE SKY - COMMERCIAL		1,841	1		
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
43	TOTAL	55,662,873	4,740,900,075	1,766,984	31,502	0.0852

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1						
2	OREGON					
3	01COST0023-OR GEN SRV-COST	988,536	54,145,651			0.0548
4	01COST0048 - 01LGSV0048	914,242	44,791,217			0.0490
5	01COST023F-OR GEN SRV-COST	3,193	186,144			0.0583
6	01COSTB023-OR GEN SRV-COST	72,409	4,107,057			0.0567
7	01COSTL030-OR LG GEN SRV	1,058,078	54,036,206			0.0511
8	01COSTS028-OR GEN SERV-COST	1,911,364	109,010,029			0.0570
9	01GNSB0023-BPA GEN SRV<30kW		5,228,633	11,488		
10	01GNSB0028-BPA GEN SRV>30kW		3,647,485	547		
11	01GNSB023T-BPA-OR GEN SRV		27,466	52		
12	01GNSV0023-OR GEN SRV<30kW		50,696,910	55,970		
13	01GNSV0028-OR GEN SRV>30kW		52,491,987	8,742		
14	01GNSV023F-OR GEN SRV-FLAT	10,811	1,663,280	783	13,807	0.1539
15	01GNSV023M-OR GEN SRV-MANU	129	16,628	2	64,500	0.1289
16	01GNSV023T-OR GEN SRV-TOU		182,978	214		
17	01HABT0023-OR HABITAT BLEND	2,595	144,969			0.0559
18	01HABTB023-OR HABITAT BLEND	181	10,490			0.0580
19	01LGSB0030-GEN DEL SRV >200		1,142,871	25		
20	01LGSV0030-LG GEN SRV >1000		24,136,983	612		
21	01LGSV0048-1000kW AND OVR		14,167,603	95		
22	01LGSV048M-LRG GEN SRVC 1	60,568	3,572,046	1	60,568,000	0.0590
23	01LNX00100-LINE EXT 60% G		4,983			
24	01LNX00102-LINE EXT 80% G		320,377			
25	01LNX00103-LINE EXT 80% G		3,897			
26	01LNX00105-CNTRCT $ MIN G		14,384			
27	01LNX00109-REF/NREF ADV +		1,318,215			
28	01LNX00110-REF/NREF ADV +		363			
29	01LNX00120-LINE EXT 60% G		416			
30	01LNX00300-LINE EXT 80% GUAR		191,967			
31	01LNX00310-LINE EXT CONTRACT		758			
32	01LNX00311-LINE EXT 80% G		138,752			
33	01LNX00312-OR IRG LINE EXT		2,197			
34	01LPRS047M-PART REQ SRVC	40,491	3,931,654	5	8,098,200	0.0971
35	01NMT23135-NET MTR GEN <30		159,571	178		
36	01OALT015N-OUTD AR LGT NR	5,665	804,111	2,928	1,935	0.1419
37	01OALTB15N-OUTD AR LGT NR	1,549	247,263	1,113	1,392	0.1596
38	01PTOU0023-OR GEN SRV-TOU	3,437	188,609			0.0549
39	01PTOUB023-OR GEN SRV-TOU	437	24,815			0.0568
40	01RCFL0054-REC FIELD LGT	1,419	134,613	105	13,514	0.0949
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
43	TOTAL	55,662,873	4,740,900,075	1,766,984	31,502	0.0852

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1	01RENW0023-OR RENW USAGE	8,213	459,807			0.0560
2	01RENWB023-OR RENEWABLE	395	22,931			0.0581
3	01STDAY023-DAY STD OFR SCH	2,665	167,228			0.0627
4	01STDAY028-DAY STD OFF SCH	14,988	938,328			0.0626
5	01STDAY030-STD DAY OFF SCH	4,682	273,665			0.0585
6	01STDAY048 - 01LGNSV048	5,725	308,809			0.0539
7	01VIR23136-VOL INCTV <=30 kW		98,546	63		
8	01VIR28136-VOL INCTV >30 kW		442,555	70		
9	01VIR30136-VOL INCTV >200 kW		169,725	5		
10	01VIR48136-VOL INCTV >1000 kW		110,516	1		
11	01LGSB0048-LG GEN SVC >1000		79,764	1		
12	01NMT28135-NET MTR GEN >30		704,429	98		
13	01NMT30135-NET MTR GEN >200		879,947	20		
14	01NMT48135-NET MTR GEN		226,272	3		
15	01LGSV028M-LGSV <1000 kW	532	43,854	1	532,000	0.0824
16	01GNSV030M-GEN SRV 200 kW	500	35,962	1	500,000	0.0719
17	01GNSV0728-GEN SVC DIR ACC		458,163	23		
18	01GNSV0730-GEN SVC DIR ACC		4,312,377	42		
19	01GNSV0748-LG GEN SVC DIR		876,131	3		
20	OR GAIN ON SALE OF ASSET		119,767			
21	SMUD REVENUE IMPUTATIONS		417,009			
22	SOLAR FEED-IN REVENUE		622,188			
23	UNBILLED REVENUE	-19,290	-1,157,000			0.0600
24	01ZZMERGCR-MERGER CREDITS		-2			
25	DSM - COMMERCIAL		10,058,629			
26	BLUE SKY - COMMERCIAL		751,719	150		
27	REVENUE - ACCOUNTING ADJ		-412,096			
28						
29	UTAH					
30	08ABL-NRES - APPLICANT BUILT		7,825			
31	08CFR00051-MTH FAC SRVCHG		38,746			
32	08CFR00052-ANN FAC SVCCHG		2			
33	08COOLKPRN-A/C DIR LOAD			3,508		
34	08GNSV0006-GEN SRVC-DISTR	5,017,120	409,832,112	10,931	458,981	0.0817
35	08GNSV0009-GEN SRVC-HI VO	493,005	27,879,043	27	18,259,444	0.0565
36	08GNSV0023-GEN SRVC-DISTR	1,214,456	117,414,215	65,292	18,600	0.0967
37	08GNSV006A-GEN SRVC-ENERG	230,662	25,894,312	1,950	118,288	0.1123
38	08GNSV006B-GEN SRVC-DEM&	2,690	285,750	27	99,630	0.1062
39	08GNSV006M-MNL DIST VOLTG	1,501	110,404	5	300,200	0.0736
40	08GNSV009A-GEN SRVC HI VO	24,013	1,513,634	2	12,006,500	0.0630
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
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1	08GNSV009M-MANL HIGH VOLT	110,232	5,819,994	1	110,232,000	0.0528
2	08GNSV023F-GEN SRVC FIXED	1,304	183,955	127	10,268	0.1411
3	08GNSV023M-GNSV DIST VOLT	201	17,084	5	40,200	0.0850
4	08GNSV06AM-MNL ENERGY TOD	565	61,451	1	565,000	0.1088
5	08GNSV06MN-GNSV DIST VOLT	34,115	2,561,156	462	73,842	0.0751
6	08LNX00002-MTHLY 80% GUAR		292,355			
7	08LNX00004-ANNUAL 80%GUAR		19,804			
8	08LNX00006-FIXD MTHLY MIN		4,668			
9	08LNX00008-ANNUALMIN GUAR		10,757			
10	08LNX00014-80% MIN MNTHLY		1,548,574			
11	08LNX00017-ADV/REF&80%ANN		183,666			
12	08LNX00158-ANNUALCOST MTH		32,125			
13	08LNX00300-LINE EXT 80% PLUS		97,404			
14	08LNX00310-IRR 80% ANNUAL MIN		54,414			
15	08LNX00312-UT IRG LINE EXT		7,816			
16	08NMT06135-UT NET MTR GEN	46,015	3,815,846	90	511,278	0.0829
17	08NMT08135-NET MTR GEN SVC	20,720	1,502,334	3	6,906,667	0.0725
18	08NMT23135-NET MTR GEN <25	2,622	261,267	126	20,810	0.0996
19	08NMT6A135-NET MTR GEN SVC	1,064	130,704	7	152,000	0.1228
20	08OALT007N-SECURITY AR LG	8,268	1,925,139	4,312	1,917	0.2328
21	08POLE0075-POLES W/LIGHT		226	2		
22	08PRSV031M-BKUP MNT&SUPPL	10,648	899,672	2	5,324,000	0.0845
23	08PTLD000N-POST TOP LIGHT	6	452	2	3,000	0.0753
24	08TOSS015F-TRAFFIC SIG NM	172	15,631	20	8,600	0.0909
25	08TOSS0015-TRAF & OTHER	2,081	224,067	804	2,588	0.1077
26	08MONL0015-MTR OUTDONIGHT	18,009	1,255,580	447	40,289	0.0697
27	08LNX00311-LINE EXT 80% GUAR		318,312			
28	08GNSV0008-GEN SVC TOU >1000	1,014,684	72,780,864	152	6,675,553	0.0717
29	08GNSV008M-GEN SVC TOU	30,452	2,374,021	5	6,090,400	0.0780
30	SOLAR FEED-IN REVENUE		362,045			
31	UNBILLED REVENUE	-46,789	-3,231,000			0.0691
32	DSM - COMMERCIAL		17,986,623			
33	BLUE SKY - COMMERCIAL		460,881	6		
34	REVENUE - ACCOUNTING ADJ		-1,565,804			
35	REVENUE ADJ - DEFERRED NPC		8,257,016			
36						
37	WASHINGTON					
38	02GNSB0024-GEN SRVC DO	40,697	3,772,957	2,792	14,576	0.0927
39	02GNSB024F-GEN SRVC DOM/F	167	19,924	6	27,833	0.1193
40	02GNSB24FP-GEN SVC SEASON	456	114,724	85	5,365	0.2516
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
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1	02GNSV0024-WA GEN SRVC	483,688	41,590,704	13,902	34,793	0.0860
2	02GNSV024F-WA GEN SRVC-FL	1,115	142,335	111	10,045	0.1277
3	02LGSB0036-LRG GEN SVC IRG	89,972	6,477,033	113	796,212	0.0720
4	02LGSV0036-WA LRG GEN SRV	714,509	51,909,016	809	883,200	0.0726
5	02LGSV048T-LRG GEN SRVC 1	172,308	11,358,741	31	5,558,323	0.0659
6	02LNX00102-LINE EXT 80% G		34,589			
7	02LNX00103-LINE EXT 80% G		9,450			
8	02LNX00105-CNTRCT $ MIN G		1,783			
9	02LNX00109-REF/NREF ADV +		291,327			
10	02LNX00110-REF/NREF ADV +		4,142			
11	02LNX00112-YR INCURRED CH		669			
12	02LNX00300-LINE EXT 80% G		10,694			
13	02LNX00310-IRG 80% ANNUAL		1,112			
14	02LNX00311-LINE EXT 80% GUAR		57,278			
15	02LNX00312-WA IRG LINE EXT		4,398			
16	02OALT015N-WA OUTD AR LGT	1,570	217,534	826	1,901	0.1386
17	02OALTB15N-WA OUTD AR LGT	560	83,769	502	1,116	0.1496
18	02RCFL0054-WA REC FIELD L	296	26,870	30	9,867	0.0908
19	02NMT24135-Net metering WA	761	62,012	13	58,538	0.0815
20	02NMT36135-NET MTR LG SVC	1,142	83,301	2	571,000	0.0729
21	02NMT48135-LG SVC NET	718	45,862	1	718,000	0.0639
22	SMUD REVENUE IMPUTATIONS		115,878			
23	WASHINGTON - CHEHALIS		-1,020,000			
24	UNBILLED REVENUE	-4,263	-277,000			0.0650
25	DSM - COMMERCIAL		3,876,602			
26	BLUE SKY - COMMERCIAL		11,667	5		
27	REVENUE ADJ - DEFERRED NPC		-321,503			
28	REVENUE - ACCOUNTING ADJ		-3,994,653			
29						
30	WYOMING					
31	05CHCK000N-WY NRES CHECK			1		
32	05GNS28025-GEN SVC	-41	-2,735			0.0667
33	05GNSV0025-WY GEN SRVC	233,269	22,187,313	17,422	13,389	0.0951
34	05GNSV0025-WY GEN SRVC	32,559	3,057,586	2,302	14,144	0.0939
35	05GNSV0028-GEN SVC >15 kW	918,980	74,932,139	3,369	272,775	0.0815
36	05GNSV0028-GEN SVC >15 kW	99,377	8,075,279	412	241,206	0.0813
37	05GNSV025F-GEN SRVC-FL RA	1,009	132,102	182	5,544	0.1309
38	05GNSV025F-GEN SRVC-FL RA	198	24,507	33	6,000	0.1238
39	05LGSV0046-WY LRG GEN SRV	245,789	16,092,551	18	13,654,944	0.0655
40	05LGSV048T-LRG GENSRV TIM	13,104	894,206	1	13,104,000	0.0682
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
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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	05LNX00100-LINE EXT 60% G		12,881			
2	05LNX00102-LINE EXT 80% G		577,798			
3	05LNX00102-LINE EXT 80% G		8,819			
4	05LNX00103-LINE EXT 80% G		18,938			
5	05LNX00105-CNTRCT $ MIN G		5,343			
6	05LNX00109-REF/NREF ADV +		640,629			
7	05LNX00109-REF/NREF ADV +		187,096			
8	05LNX00110-REF/NREF ADV +		5,750			
9	05LNX00110-REF/NREF ADV +		1,624			
10	05LNX00114-TEMP SVC 12MO>		274			
11	05LNX00114-TEMP SVC 12MO>		109			
12	05NMT25135-NET MTR GEN <25	273	24,759	17	16,059	0.0907
13	05NMT25135-NET MTR GEN <25	6	935	2	3,000	0.1558
14	05NMT28135-NET MTR SM GEN	6,238	571,753	17	366,941	0.0917
15	05NMT28135-NET MTR SM GEN	517	46,069	3	172,333	0.0891
16	05OALT015N-OUTD AR LGT SR	2,818	452,237	1,703	1,655	0.1605
17	05RCFL0054-WY REC FIELD L	711	55,528	50	14,220	0.0781
18	05LNX00300-LINE EXT 80% GUAR		71,152			
19	05LNX00310-LINE EXT CONTRACT		97			
20	05LNX00311-LINE EXT 80% GUAR		87,597			
21	05LNX00312 - WY IRG LINE EXT		2,225			
22	09OALT207N-SECURITY AR LG	276	70,318	138	2,000	0.2548
23	09MONL0213-WY MTR OUTDOOR	274	13,413	11	24,909	0.0490
24	05LNX00300-LINE EXT 80% GUAR		843			
25	05LNX00311-LINE EXT 80% GUAR		2,079			
26	SMUD REVENUE IMPUTATIONS		106,855			
27	UNBILLED REVENUE	-22,805	-1,577,000			0.0692
28	UNBILLED REVENUE	-5,800	-473,000			0.0816
29	DSM - SMALL COMMERCIAL		1,565,828			
30	301271-DSM REVENUE-SM COMM		176,236			
31	DSM - LARGE COMMERCIAL		73,395			
32	BLUE SKY - COMMERCIAL		5,806	1		
33	301280-BLUE SKY		892			
34	REVENUE ADJ - DEFERRED NPC		-1,013,963			
35	REVENUE - ACCOUNTING ADJ		-6,141			
36						
37	LESS MULTIPLE BILLINGS			-26,323		
38						
39	TOTAL COMMERCIAL SALES	17,057,194	1,467,851,627	207,690	82,128	0.0861
40						
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
43	TOTAL	55,662,873	4,740,900,075	1,766,984	31,502	0.0852

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

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1	INDUSTRIAL SALES					
2	CALIFORNIA					
3	06GNSV0025-CA GEN SRVC	676	110,780	92	7,348	0.1639
4	06GNSV0A32-GEN SRVC-20 kW	1,765	274,841	23	76,739	0.1557
5	06LGSV048T-LRG GEN SERV	35,540	3,290,381	9	3,948,889	0.0926
6	06LGSV0A36-LRG GEN SRVC-O	4,881	589,517	12	406,750	0.1208
7	SMUD REVENUE IMPUTATIONS		2,632			
8	SOLAR FEED-IN REVENUE		39,695			
9	UNBILLED REVENUE	967	56,000			0.0579
10	DSM - INDUSTRIAL		52,049			
11	BLUE SKY - INDUSTRIAL		182			
12	REVENUE - ACCOUNTING ADJ		-65,243			
13						
14	IDAHO					
15	07CFR00001-MTH FACILITY S		2,217			
16	07CISH0019-COMM & IND SPA	100	8,973	3	33,333	0.0897
17	07GNSV0006-GEN SRVC-LRG P	90,586	6,537,560	104	871,019	0.0722
18	07GNSV0009-GEN SRVC-HI VO	76,683	5,059,890	15	5,112,200	0.0660
19	07GNSV0023-GEN SRVC-SML P	12,563	1,209,071	340	36,950	0.0962
20	07GNSV0035-GEN SRVCOPTION	778	54,876	1	778,000	0.0705
21	07GNSV006A-GEN SRVC-LRG P	4,499	381,924	27	166,630	0.0849
22	07GNSV023A-GEN SRVC-SML P	2,507	270,162	225	11,142	0.1078
23	07GNSV023S-ID TRAFFIC SIGNALS	5	775	1	5,000	0.1550
24	07LNX00035-ADV 80%MO GUAR		2,204			
25	07LNX00108-ANN COST MTHLY		1,996			
26	07OALT007N-SECURITY AR LG	13	5,122	17	765	0.3940
27	07OALT07AN-SECURITY AR LG		237	1		
28	07SPCL0001	1,461,600	86,483,195	1	1,461,600,000	0.0592
29	07SPCL0002	112,098	6,378,879	1	112,098,000	0.0569
30	SMUD REVENUE IMPUTATIONS		131,992			
31	UNBILLED REVENUE	10,472	1,326,000			0.1266
32	DSM - INDUSTRIAL		268,620			
33						
34	OREGON					
35	01COST0023-GEN SRV CST BSD	20,641	1,133,328			0.0549
36	01COST0048 - 01LGSV0048	1,723,539	83,823,263			0.0486
37	01COST023F-GEN SRV CST BSD	1	60			0.0600
38	01COSTB023-GEN SRV CST BSD	354	19,856			0.0561
39	01COSTL030-LG GEN SRV CST	216,047	11,063,839			0.0512
40	01COSTS028-GEN SRV COST >30	92,568	5,266,459			0.0569
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
43	TOTAL	55,662,873	4,740,900,075	1,766,984	31,502	0.0852

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1	01GNSB0023-GEN SRV BPA <30		27,454	54		
2	01GNSB0028-GEN SRV BPA >30		24,727	6		
3	01GNSV0023-OR GEN SRV <30 kW		1,113,987	1,121		
4	01GNSV0028-OR GEN SRV >30 kW		3,397,556	464		
5	01GNSV023F-GEN SRV - FLAT	3	722	2	1,500	0.2407
6	01GNSV023M-GEN SRV MANUAL	46	4,557	1	46,000	0.0991
7	01GNSV023T-GEN SRV TOU Option		2,651	4		
8	01GNSV0728-GEN SVC DIR		50,549	3		
9	01GNSV0730-GEN SVC DIR		54,733	2		
10	01GNSV0748-LG GEN SVC DIR		1,641,588	2		
11	01LGSV0030-LG GEN SRV >1000		7,049,268	148		
12	01LGSV0048-1000kW AND OVR		24,034,371	91		
13	01LGSV048M-LRG GEN SRVC 1	85,343	6,175,625	4	21,335,750	0.0724
14	01LNX00102-LINE EXT 80% G		47,042			
15	01LNX00300-LINE EXT 80% GUAR		17,818			
16	01LPRS047M-PART REQ SRVC	15,576	1,390,891	2	7,788,000	0.0893
17	01NMT23135-NET MTR GEN <30		929	1		
18	01NMT28135-NET MTR GEN >30		22,576	3		
19	01NMT30135-NET MTR GEN >200		17,718	1		
20	01OALT015N-OUTD AR LGT NR	299	41,409	132	2,265	0.1385
21	01OALTB15N-OR OUTD AR LGT	5	658	5	1,000	0.1316
22	01PTOU0023-GEN SRV TOU ENG	34	2,005			0.0590
23	01RENW0023-RNW USAGE SPLY	105	5,569			0.0530
24	01RENWB023-OR RENEWABLE		9			
25	01STDAY023-DAY STD OFR SCH	20	1,241			0.0621
26	01STDAY028-DAY STD OFF SCH	155	9,862			0.0636
27	01VIR23136-VOL INCTV <=30 kW		1,309	1		
28	01VIR30136-VOL INCTV >200 kW		30,846	1		
29	OR GAIN ON SALE OF ASSET		42,584			
30	SMUD REVENUE IMPUTATIONS		179,663			
31	SOLAR FEED-IN REVENUE		413,060			
32	UNBILLED REVENUE	15,300	1,419,000			0.0927
33	DSM - INDUSTRIAL		800,016			
34	BLUE SKY - INDUSTRIAL		414,340	32		
35	REVENUE - ACCOUNTING ADJ		-350,288			
36						
37	UTAH					
38	08CFR00051-MTH FAC SRVCHG		18,725			
39	08EFOP0021-ELEC FURNACE O	2,019	205,415	2	1,009,500	0.1017
40	08EFOP021M-ELEC FURNACE O	1,137	157,457	3	379,000	0.1385
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
43	TOTAL	55,662,873	4,740,900,075	1,766,984	31,502	0.0852

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1	08GNSV0006-GEN SRVC-DISTR	655,131	56,482,005	1,108	591,273	0.0862
2	08GNSV0009-GEN SRVC-HI VO	3,365,911	177,632,112	113	29,786,823	0.0528
3	08GNSV0023-GEN SRVC-DISTR	57,268	5,638,575	3,379	16,948	0.0985
4	08GNSV006A-GEN SRVC-ENERG	62,137	7,272,430	263	236,262	0.1170
5	08GNSV006B-GEN SRVC-DEM&	703	5,272	2	351,500	0.0075
6	08GNSV009A-GEN SRVC HI VO	15,745	1,315,808	6	2,624,167	0.0836
7	08GNSV009M-MANL HIGH VOLT	603,245	30,655,621	9	67,027,222	0.0508
8	08GNSV023F-GEN SRVC FIXED	4	2,561	1	4,000	0.6403
9	08GNSV06MN-GNSV DIST VOLT	1,340	114,889	26	51,538	0.0857
10	08GNSV09AM-MAN TOD HIVOLT	1,197	112,092	1	1,197,000	0.0936
11	08LNX00002-MTHLY 80% GUAR		120,053			
12	08LNX00014-80% MIN MNTHLY		7,123			
13	08LNX00017-ADV/REF&80%ANN		243			
14	08LNX00311-LINE EXT 80% GUAR		1,638			
15	08LNX00300-LINE EXT 80% PLUS		9,193			
16	08LNX00310-IRR 80% ANNUAL MIN		6,356			
17	08OALT007N-SECURITY AR LG	1,214	261,409	465	2,611	0.2153
18	08TOSS0015-TRAF & OTHER S	17	2,040	10	1,700	0.1200
19	08MONL0015-MTR OUTDONIGHT	16	3,158	7	2,286	0.1974
20	08NMT06135-NET MTR GEN SVC	3,846	392,122	5	769,200	0.1020
21	08NMT23135-NET MTR GEN <25	83	7,471	4	20,750	0.0900
22	08NMT6A135-NET MTR GEN SVC	21	4,754	1	21,000	0.2264
23	08PRSV031M-BKUP MNT&SUPPL	4,621	730,315	1	4,621,000	0.1580
24	08SPCL0001	588,186	28,520,035	1	588,186,000	0.0485
25	08SPCL0002	990,973	41,197,541	1	990,973,000	0.0416
26	08SPCL0003	1,086,466	49,361,366	1	1,086,466,000	0.0454
27	08GNSV06AM-MNL ENERGY TOD	310	38,074	2	155,000	0.1228
28	08GNSV0008-GEN SVC TOU >1000	979,466	71,667,765	104	9,417,942	0.0732
29	08GNSV008M-GEN SVC TOU	60,877	4,554,170	7	8,696,714	0.0748
30	SOLAR FEED-IN REVENUE		451,529			
31	UNBILLED REVENUE	198,366	10,528,000			0.0531
32	DSM - INDUSTRIAL		8,108,380			
33	BLUE SKY - INDUSTRIAL		112,058	7		
34	REVENUE - ACCOUNTING ADJ		-2,001,079			
35	REVENUE ADJ - DEFERRED NPC		5,101,238			
36						
37	WASHINGTON					
38	02GNSB0024-WA GEN SRVC DO	2,044	192,406	90	22,711	0.0941
39	02GNSB24FP-GEN SVC SEASON	10	2,842	1	10,000	0.2842
40	02GNSV0024-WA GEN SRVC	17,253	1,482,310	350	49,294	0.0859
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
43	TOTAL	55,662,873	4,740,900,075	1,766,984	31,502	0.0852

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1	02GNSV024F-WA GEN SRVC-FL	33	7,854	4	8,250	0.2380
2	02LGSV0036-WA LRG GEN SRV	102,694	7,783,071	106	968,811	0.0758
3	02LGSV048T-LRG GEN SRVC 1	677,586	39,610,319	32	21,174,563	0.0585
4	02OALT015N-WA OUTD AR LGT	114	14,761	41	2,780	0.1295
5	02OALTB15N-WA OUTD AR LGT	29	4,231	15	1,933	0.1459
6	02PRSV47TM-LRG PART REQMT	2,049	292,763	1	2,049,000	0.1429
7	02LGSB0036-LRG GEN SVC IRG	3,532	419,914	26	135,846	0.1189
8	WASHINGTON - CHEHALIS		-510,000			
9	SMUD REVENUE IMPUTATIONS		66,246			
10	UNBILLED REVENUE	-12,861	-1,046,000			0.0813
11	DSM - INDUSTRIAL		1,683,434			
12	REVENUE ADJ - DEFERRED NPC		-160,707			
13	REVENUE - ACCOUNTING ADJ		-1,734,474			
14						
15	WYOMING					
16	05GNSV0025-WY GEN SRVC	21,114	1,895,712	1,111	19,005	0.0898
17	05GNSV0025-WY GEN SRVC	4,444	413,838	290	15,324	0.0931
18	05GNSV0028-GEN SVC >15 kW	260,664	18,806,813	493	528,730	0.0721
19	05GNSV0028-GEN SVC >15 kW	57,049	4,135,763	79	722,139	0.0725
20	05GNSV025F-GEN SRVC-FL RA	26	4,211	8	3,250	0.1620
21	05GNSV028M-GEN SVC >15 KW	4,143	243,678	3	1,381,000	0.0588
22	05LGSV0046-WY LRG GEN SRV	1,711,512	107,741,565	55	31,118,400	0.0630
23	05LGSV0046-WY LRG GEN SRV	50,907	3,349,174	4	12,726,750	0.0658
24	05LGSV046M-WY LRG GEN SRV	120,859	7,353,047	2	60,429,500	0.0608
25	05LGSV048M-TOU>1000KW MAN	286,176	15,563,127	1	286,176,000	0.0544
26	05LGSV048M-TOU>1000KW MAN	237,638	13,645,898	4	59,409,500	0.0574
27	05LGSV048T-LRG GENSRV TIM	1,511,165	84,632,513	10	151,116,500	0.0560
28	05LGSV048T-LRG GENSRV TIM	1,238,989	72,847,079	11	112,635,364	0.0588
29	05LNX00100-LINE EXT 60% G		38,807			
30	05LNX00102-LINE EXT 80% G		192,843			
31	05LNX00102-LINE EXT 80% G		44,915			
32	05LNX00105-CNTRCT $ MIN G		35,212			
33	05LNX00109-REF/NREF ADV +		218,808			
34	05LNX00109-REF/NREF ADV +		2,446,708			
35	05OALT015N-OUTD AR LGT SR	84	12,081	41	2,049	0.1438
36	05PRSV033M-PART SERV REQ	1,312,862	83,046,997	6	218,810,333	0.0633
37	05LNX00300-LINE EXT 80% GUAR		18,724			
38	05LNX00300-LINE EXT 80% GUAR		1,566			
39	05LNX00311-LINE EXT 80% GUAR		15,706			
40	05PRSV033M-PART SERV REQ	101,943	6,209,586	2	50,971,500	0.0609
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
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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	09OALT207N-SECURITY AR LG	5	1,063	3	1,667	0.2126
2	SMUD REVENUE IMPUTATIONS		464,306			
3	UNBILLED REVENUE	-5,652	116,000			-0.0205
4	UNBILLED REVENUE	-17,680	-1,102,000			0.0623
5	DSM - SMALL INDUSTRIAL		329,417			
6	DSM - SMALL INDUSTRIAL		77,298			
7	DSM - LARGE INDUSTRIAL		1,187,412			
8	DSM - LARGE INDUSTRIAL		378,471			
9	BLUE SKY - INDUSTRIAL		7,819	1		
10	BLUE SKY - INDUSTRIAL		17			
11	REVENUE ADJ - DEFERRED NPC		-4,752,545			
12	REVENUE - ACCOUNTING ADJ		-19,440			
13						
14	LESS MULTIPLE BILLINGS			-977		
15						
16	TOTAL INDUSTRIAL SALES	20,354,799	1,228,376,450	10,294	1,977,346	0.0603
17						
18	IRRIGATION SALES					
19	CALIFORNIA					
20	06APSV0020-AG PMP SRVC	70,142	8,537,342	1,352	51,880	0.1217
21	06LGSV048T-LRG GEN SERV	1,658	176,388	1	1,658,000	0.1064
22	06NMT20135-AGRICULTURAL	380	63,305	4	95,000	0.1666
23	06LNX00103-LINE EXT 80% G		2,805			
24	06LNX00110-REF/NREF ADV +		35,940			
25	06LNX00310-IRG 80% ANNUAL MIN		932			
26	06LNX00312-CA IRG LINE EXT		6,098			
27	06USBR0020-KLAM IRG ONPRJ	28,280	3,799,085	656	43,110	0.1343
28	SOLAR FEED-IN REVENUE		62,480			
29	UNBILLED REVENUE	22	25,000			1.1364
30	DSM - IRRIGATION		162,030			
31	BLUE SKY - IRRIGATION		23			
32	REVENUE - ACCOUNTING ADJ		-235,569			
33						
34	IDAHO					
35	07APSA010L-IRG & Pump Large	437,214	39,795,807	2,720	160,740	0.0910
36	07APSA010S-IRG & Pump Small	4,835	531,656	356	13,581	0.1100
37	07APSAL10X-IRG & PUMP-Large I	197,934	17,862,542	1,418	139,587	0.0902
38	07APSAS10X-IRG & PUMP-Small I	3,477	397,083	323	10,765	0.1142
39	07APSVCNLL-LRG LOAD CANAL	45,729	3,683,729	48	952,688	0.0806
40	07APSVCNLS-SML LOAD CANAL	120	16,806	11	10,909	0.1401
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
43	TOTAL	55,662,873	4,740,900,075	1,766,984	31,502	0.0852

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

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1	07LNX00015-ANNUAL 80%GUAR		39			
2	07LNX00040-ADV+REFCHG+80%		157,591			
3	07LNX00310 80% ANNUAL GUAR		77			
4	07LNX00311-LINE EXT 80% GUAR		1,845			
5	07LNX00312-ID LINE EXT		27,411			
6	07APSN010L-ID LG IRR & PUMP	1,962	198,165	26	75,462	0.1010
7	07APSN010S-IRR SM 3 PH	33	4,370	4	8,250	0.1324
8	07APSNS10X-IRR SM 3 PHASE	188	21,108	12	15,667	0.1123
9	UNBILLED REVENUE	-6				
10	DSM - IRRIGATION		1,322,553			
11	BLUE SKY - IRRIGATION		23	1		
12						
13	OREGON					
14	01APSV0041-AG PMP SRVC		2,515,761	4,761		
15	01APSV041L-Pumping Serv >30 kW		3,845,061	1,101		
16	01APSV041T-AGR PUMP SRV-TOU		26,208	54		
17	01APSV041X-AG PMP SRVC		83,151	190		
18	01APSV41XL-Pumping Serv no BPA		190,391	35		
19	01COST0041- 01APSV0041	136,233	7,505,737			0.0551
20	01COST0048 - 01LGSV0048	22,885	1,123,364			0.0491
21	01COSTS028-GEN SRV CST >30	335	19,187			0.0573
22	01CSTUSB41-USBR IRR CONTRAC	91,970	5,044,276			0.0548
23	01GNSV0028-GEN SRV >30 kW		16,258	3		
24	01HABIT041-01APSV0041 AG PMP	6	326			0.0543
25	01LGSB0048-LG GEN SVC >1000		112,801	1		
26	01LGSV0030-3P,DEMAND VAR			1		
27	01LGSV0048-1000KW AND OVR		355,360	4		
28	01LNX00103-LINE EXT 80% G		40,634			
29	01LNX00110-REF/NREF ADV +		189,705			
30	01LNX00310-LINE EXTENSION		14,374			
31	01PTOU0041 - 01APSV0041 AG	516	27,526			0.0533
32	01RENEW041 - 01APSV0041 AG	150	8,346			0.0556
33	01SLX00005-KLAMATH FALLS		-2,405			
34	01STDAY041-Daily Standard Offer	92	5,927			0.0644
35	01USBGV041-IRG TOU W/O BPA	38	70,680	10	3,800	1.8600
36	01USBOF033-KLAMATH BASIN	110	7,898	572	192	0.0718
37	01USBOF041-KLAMATH BASIN IRG	283	1,770,653	581	487	6.2567
38	01USBON033-KLAMATH BASIN	212	14,639	1,282	165	0.0691
39	01USBON041-KLAMATH BASIN	651	2,379,411	1,279	509	3.6550
40	01VIR33136-VOL INCTV USB	99	6,730	53	1,868	0.0680
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
43	TOTAL	55,662,873	4,740,900,075	1,766,984	31,502	0.0852

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

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1	01VIR41136-VOL INCTV-AGRI		18,939	8		
2	01VRU41136-VOL INCTV USB	76	236,216	69	1,101	3.1081
3	01USBGV033-IRG TOU W/O BPA	1,080	59,876	10	108,000	0.0554
4	01LNX00312-OR IRG LINE EXT		13,635			
5	01NMT33135-NET MTR - PROJECT			2		
6	01NMT41135-NETMTR AG PMP		2,544	4		
7	01NMU41135-NET MTR PROJECT		3,091	2		
8	OR GAIN ON SALE OF ASSET		4,325			
9	SOLAR FEED-IN REVENUE		14,695			
10	UNBILLED REVENUE	82	30,000			0.3659
11	DSM - IRRIGATION		721,518			
12	BLUE SKY - IRRIGATION		322			
13	REVENUE - ACCOUNTING ADJ		-8,321			
14						
15	UTAH					
16	08APSV0010-IRR & SOIL DRA	210,552	15,335,770	2,819	74,690	0.0728
17	08APSV10NS-Irg Soil Drain Pump N	32,848	2,138,545	179	183,508	0.0651
18	08LNX00004-ANNUAL 80%GUAR		8,281			
19	08LNX00014-80% MIN MNTHLY		12,680			
20	08LNX00017-ADV/REF&80%ANN		212,459			
21	08LNX00310-IRR 80% ANNUAL MIN		10,178			
22	08LNX00312-UT IRG LINE EXT		26,455			
23	08NMT10135-UT IRR SOIL DRNG	13	1,214	2	6,500	0.0934
24	SOLAR FEED-IN REVENUE		10,552			
25	UNBILLED REVENUE	-343	-17,000			0.0496
26	DSM - IRRIGATION		447,106			
27	BLUE SKY - IRRIGATION		37			
28	REVENUE - ACCOUNTING ADJ		-46,726			
29						
30	WASHINGTON					
31	02APSV0040-WA AG PMP SRVC	155,908	12,822,363	5,071	30,745	0.0822
32	02APSV040X-WA AG PMP SRVC	5,474	453,169	187	29,273	0.0828
33	02LNX00103-LINE EXT 80% G		6,771			
34	02LNX00105-CNTRCT $ MIN G		81			
35	02LNX00109-REF/NREF ADV +		5,226			
36	02LNX00110-REF/NREF ADV +		177,557			
37	02LNX00310-IRG 80% ANNUAL MIN		7,271			
38	02LNX00311-LINE EXT 80% GUAR		205			
39	02LNX00312-WA IRG LINE EXT		38,092			
40	02NMT40135-WA NET MTR IRG	13	1,043	2	6,500	0.0802
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
43	TOTAL	55,662,873	4,740,900,075	1,766,984	31,502	0.0852

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

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1	WASHINGTON - CHEHALIS		-120,000			
2	UNBILLED REVENUE	-212	-33,000			0.1557
3	DSM - IRRIGATION		450,938			
4	REVENUE - ACCOUNTING ADJ		-457,544			
5	BLUE SKY - IRRIGATION		85	4		
6						
7	WYOMING					
8	05APS00040-AG PUMPING SVC	20,895	1,665,841	664	31,468	0.0797
9	05APS00040-AG PUMPING SVC		-332	2		
10	05LNX00110-REF/NREF ADV +		57,319			
11	05LNX00110-REF/NREF ADV +		14,373			
12	05LNX00103-LINE EXT 80% G		8,848			
13	05LNX00103-LINE EXT 80% G		1,232			
14	05LNX00312-WY IRG LINE EXT		5,237			
15	05LNX00312-WY IRG LINE EXT		997			
16	09APSV0210-IRR & SOIL DRA	5,142	388,829	85	60,494	0.0756
17	UNBILLED REVENUE	-10	-1,000			0.1000
18	DSM - IRRIGATION		32,810			
19	DSM - IRRIGATION		7,838			
20	BLUE SKY - IRRIGATION		2			
21						
22	LESS MULTIPLE BILLINGS			-2,702		
23						
24	TOTAL IRRIGATION SALES	1,477,066	136,799,305	23,267	63,483	0.0926
25						
26	PUBLIC STREET & HWY LIGHTING					
27	CALIFORNIA					
28	06CUSL053F-SPECIAL CUST O	1,430	214,769	109	13,119	0.1502
29	06CUSL058F-CUST OWND STR	237	39,681	22	10,773	0.1674
30	06HPSV0051-HI PRESSURE SO	708	193,117	80	8,850	0.2728
31	SOLAR FEED-IN REVENUE		6,212			
32	UNBILLED REVENUE	17	4,000			0.2353
33	DSM REVENUE - PSHL		3,457			
34	REVENUE - ACCOUNTING ADJ		-7,063			
35						
36	IDAHO					
37	07GNSV023S-IDAHO TRAFFIC	148	17,827	24	6,167	0.1205
38	07SLCO0011-STR LGT CO-OWN	74	33,553	33	2,242	0.4534
39	07SLCU012E-ENGY STR LGT	323	36,169	23	14,043	0.1120
40	07SLCU012F-FULL MNT STR	1,884	373,942	198	9,515	0.1985
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
43	TOTAL	55,662,873	4,740,900,075	1,766,984	31,502	0.0852

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1	07SLCU012P-PART MNT STR LGT	192	27,909	16	12,000	0.1454
2	UNBILLED REVENUE	-91	-15,000			0.1648
3	DSM REVENUE - PSHL		9,595			
4						
5	OREGON					
6	01COSL0052-STR LGT SRVC C	427	61,886	39	10,949	0.1449
7	01CUSL0053-CUS-OWNED MTRD	770	55,035	73	10,548	0.0715
8	01CUSL053E-STR LGT SVC	8,388	599,097	159	52,755	0.0714
9	01CUSL053F-STR LGT SRVC C	154	18,264	11	14,000	0.1186
10	01HPSV0051-HI PRESSURE SO	19,453	3,958,682	718	27,093	0.2035
11	01LEDSL051-LED PILOT ST LIGHT	33	10,018	15	2,200	0.3036
12	01MVSL0050-MERC VAPSTR LG	8,562	1,095,908	246	34,805	0.1280
13	01OALT015N-OUTD AR LGT NR		129	1		
14	OR GAIN ON SALE OF ASSET		1,996			
15	SOLAR FEED-IN REVENUE		3,584			
16	UNBILLED REVENUE	-1,041	-189,000			0.1816
17	DSM REVENUE - PSHL		141,889			
18	REVENUE - ACCOUNTING ADJ		-633			
19						
20	UTAH					
21	08CFR00012-STR LGTS (CONV		54			
22	08CFR00051-MTH FAC SRVCHG		4,529			
23	08CFR00062-STREET LIGHTS		79			
24	08OALT007N-SECURITY AR LG		84	2		
25	08TOSS015F-TRAFFIC SIG NM	1,159	103,770	123	9,423	0.0895
26	08SLCO0011-STR LGT CO-OWN	16,040	4,885,747	808	19,851	0.3046
27	08TOSS0015-TRAF & OTHER S	3,064	352,684	1,532	2,000	0.1151
28	08MONL0015-MTR OUTDONIGHT	798	63,260	59	13,525	0.0793
29	08SLCU012P-STR LGT CUST-O	5,188	638,617	216	24,019	0.1231
30	08SLCU012F-STR LGT CUST-O	1,588	223,392	96	16,542	0.1407
31	08SLCU012E-DECOR CUST-OWN	50,685	3,336,954	556	91,160	0.0658
32	SOLAR FEED-IN REVENUE		10,415			
33	UNBILLED REVENUE	1,583	187,000			0.1181
34	DSM REVENUE - PSHL		279,072			
35	REVENUE - ACCOUNTING ADJ		-46,396			
36						
37	WASHINGTON					
38	02CFR00012-STR LGTS (CONV		91			
39	02COSL0052-WA STR LGT SRV	220	37,773	15	14,667	0.1717
40	02CUSL053F-WA STR LGT SRV	3,235	232,145	112	28,884	0.0718
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
43	TOTAL	55,662,873	4,740,900,075	1,766,984	31,502	0.0852

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1	02CUSL053M-WA STR LGT SRV	1,153	81,927	105	10,981	0.0711
2	02HPSV0051-WA HI PRESSURE	3,527	697,460	160	22,044	0.1977
3	02MVSL0057-WA MERC VAPSTR	1,939	241,434	42	46,167	0.1245
4	WASHINGTON - CHEHALIS		-30,000			
5	UNBILLED REVENUE	-1,008	-126,000			0.1250
6	DSM REVENUE - PSHL		26,851			
7	REVENUE - ACCOUNTING ADJ		-27,450			
8						
9	WYOMING					
10	05COSL0057-CO-OWND STR LG	269	59,333	18	14,944	0.2206
11	05CUSL058M-CUST OWND STR	81	5,519	11	7,364	0.0681
12	05CUSL0E58-CUST OWND ST LT	1,067	72,317	30	35,567	0.0678
13	05CUSL0M58-CUST OWND ST LT	44	3,539	3	14,667	0.0804
14	05HPSV0051-HI PRESSURE SO	5,147	1,146,660	171	30,099	0.2228
15	05MVS00053-MERCURY VAPOR	3,774	512,457	256	14,742	0.1358
16	05OALT015N-OUTD AR LGT SR	27	3,292	1	27,000	0.1219
17	09MONL0213-WY MTR OUTDOOR	25	2,232	1	25,000	0.0893
18	09SLCO0211-STR LGT CO-OWN	1,464	400,731	51	28,706	0.2737
19	09SLCUP212-CUST OWND ST LT	45	7,285	6	7,500	0.1619
20	09TOSS0213-TRAFFIC & OTHER	62	2,700	14	4,429	0.0435
21	UNBILLED REVENUE	60	10,000			0.1667
22	UNBILLED REVENUE	-319	-82,000			0.2571
23	DSM REVENUE - PSHL		28,473			
24	DSM REVENUE - PSHL		6,714			
25	REVENUE - ACCOUNTING ADJ		-93			
26						
27	LESS MULTIPLE BILLINGS			-2,598		
28						
29	TOTAL PUBLIC STREET & HWY	142,585	20,047,674	3,557	40,086	0.1406
30						
31	OTHER SALES TO PUBLIC AUTH					
32	UTAH					
33	08GNSV009M-MANL HIGH VOLT	253,786	13,876,269	2	126,893,000	0.0547
34	08PRSV031M-BKUP MNT&SUPPL	36,496	2,679,992	1	36,496,000	0.0734
35	SOLAR FEED-IN REVENUE		15,074			
36	UNBILLED REVENUE	1,825	178,000			0.0975
37	DSM REVENUE - OSPA		419,207			
38	REVENUE - ACCOUNTING ADJ		-66,620			
39						
40	TOTAL OTHER SALES TO PUBLIC	292,107	17,101,922	3	97,369,000	0.0585
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
43	TOTAL	55,662,873	4,740,900,075	1,766,984	31,502	0.0852

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 2013/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2	FORFEITED DISCOUNTS					
3	CALIFORNIA					
4	06LPAY0300-LATEFEE		347,643			
5						
6	IDAHO					
7	07LPAY0300-LATEFEE		559,231			
8						
9	OREGON					
10	01LPAY0300-LATEFEE		3,761,604			
11						
12	UTAH					
13	08LPAY0300-LATEFEE		3,744,504			
14	OTHER		-3,512			
15						
16	WASHINGTON					
17	02LPAY0300-LATEFEE		675,829			
18						
19	WYOMING					
20	05LPAY0300-RES-LATEFEE		466,367			
21	05LPAY0300-COM-LATEFEE		156,332			
22	05LPAY0300-IND-LATEFEE		199,799			
23	05LPAY0300-Other-LATEFEE		-1,288			
24						
25	TOTAL FORFEITED DISCOUNTS		9,906,509			
26						
27	MISCELLANEOUS SERVICE REV					
28	CALIFORNIA					
29	06CFR00003-MTH MAINTENANC		1,454			
30	06CONN0300-CA RECONNECTIO		39,340			
31	06FCBUYOUT		57,816			
32	06RCHK0300-CA RET CHK CHR		12,780			
33	06TAMP0300-CA TAMP & UNAU		1,575			
34	06TEMP0300-CA TEMP SRVC C		765			
35	06TRBL0300-CA TROUBLE CAL		30			
36	06XMTRTAMP-TAMPERING-UNAU		133			
37	HOME COMFORT		544			
38						
39	IDAHO					
40	07CFR00001-MTH FAC SRVCHG		1,682			
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
43	TOTAL	55,662,873	4,740,900,075	1,766,984	31,502	0.0852

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

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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	07CONN0300-ID RECONNECTIO		59,775			
2	07FCBUYOUT-FAC CHG BUYOUT		27,907			
3	07RCHK0300-ID RET CHK CHR		32,320			
4	07TAMP0300		375			
5	07TEMP0014-TEMP SRVC CONN		15,990			
6	07XMTRTAMP-TAMPERING-UNAU		17			
7	OTHER		811			
8						
9	OREGON					
10	01CFR00001-MTH FACILITY S		135,233			
11	01CFR00003-MTH MAINTENANC		25,966			
12	01CFR00004-EMRGNCY ST&BY		25,716			
13	01CFR00005-INTERMTNT SRVC		35,398			
14	01CFR00013-MTH MISC CHRG		2,284			
15	01CFR00014-YR MISC CHRG		5			
16	01CONN0300-RECONNECTION C		417,055			
17	01CONTSERV-3RD PRTY OUTSIDE		13,022			
18	01ESSC0600-ESS charges		490			
19	01FCBUYOUT-FAC CHG BUYOUT		243,474			
20	01RCHK0300-RETURNED CHECK		299,380			
21	01TAMP0300-TAMP & UNAUTH		15,000			
22	01TEMP0300-TEMP SRVC CHRG		144,340			
23	01XMTRTAMP-TAMPERING-UNAU		3,461			
24	OTHER		-62,108			
25						
26	UTAH					
27	08CFR00013-MTH MISC CHRG		147,885			
28	08CFR00051-MTH FAC SRVCHG		87,026			
29	08CFR00052-ANN FAC SVCCHG		424			
30	08CFR00053-MTHLY MAINTFEE		11,265			
31	08CFR00054-NRES EMERG		2,073			
32	08CFR00063-MTH MISC CHARG		2,361			
33	08CFR00064-ANN MISC CHARG		6,660			
34	08CONN0300-RECONN&DISCONN		640,110			
35	08CONTSERV-3RD PARTY O/S		79,336			
36	08FCBUYOUT-FAC CHG BUYOUT		284,192			
37	08NCON0300-UT FEE NRES RE		7,350			
38	08NSMTR300-NON STNDRD MTR		1,981			
39	08PRINT300-SCREEN PRINT FOR		536			
40	08RCHK0300-UT RET CHK CHR		480,360			
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
43	TOTAL	55,662,873	4,740,900,075	1,766,984	31,502	0.0852

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1	08RCON0001-CONNECT FEE		1,644,800			
2	08RESD0001-RES SRVC		693			
3	08TAMP0300-TAMPERING&UNAU		11,625			
4	08TEMP0014-TEMP SRVC CONN		485,580			
5	08XMTRTAMP-TAMPERING-UNAU		1,307			
6	08VISIT300-UT Visit Service Call		29,120			
7	ENERGY FINANSWER NEW COM		7,255			
8	OTHER		43,329			
9						
10	WASHINGTON					
11	02CFR00003-MTH MAINTENANC		1,320			
12	02CFR00004-EMRGNCY ST&BY		5,931			
13	02CFR00005-INTERMTNT SRVC		4,264			
14	02CONN0300-WA RECONNECTIO		126,410			
15	02FCBUYOUT - FAC CHG BUYOUT		9,222			
16	02RCHK0300-WA RET CHK CHR		59,840			
17	02TAMP0300-WA TAMP & UNAU		3,075			
18	02TEMP0300-WA TEMP SRVC C		20,690			
19	02XMTRTAMP-TAMPERING-UNAU		949			
20	HOME COMFORT		891			
21	ENERGY FINANSWER NEW COM		46			
22	OTHER		-8,575			
23						
24	WYOMING					
25	05CFR00003-MTH MAINTENANC		1,768			
26	05CFR00004-EMRGNCY ST&BY		18,817			
27	05CFR00005-INTERMTNT SRVC		10,217			
28	05CFR00013-MTH MISC CHRG		3,186			
29	05CONN0300-WY RECONNECTIO		81,150			
30	05CONN0300-WY RECONNECTIO		15,650			
31	05FCBUYOUT-FAC CHG BUYOUT		118,855			
32	05FCBUYOUT-FAC CHG BUYOUT		185,551			
33	05RCHK0300-WY RET CHK CHR		73,350			
34	05RCHK0300-WY RET CHK CHR		9,390			
35	05TAMP0300		825			
36	05TAMP0300		150			
37	05TEMP0300-WY TEMP SRVC C		37,495			
38	05TEMP0300-WY TEMP SRVC C		1,360			
39	05XMTRTAMP-TAMPERING-UNAU		86			
40	09CFR00005-INTERMTNT SRVC		339			
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
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1	09CFR00001-MTH FAC SRVCHG		5,065			
2	09CFR00014-YR MISC CHRG		3			
3	ENERGY FINANSWER 12,000		83			
4	OTHER		-3,924			
5	OTHER		-193			
6						
7	TOTAL MISC SERVICE REV		6,310,584			
8						
9	SALES OF WATER AND WTR PWR					
10	UTAH		1,577			
11						
12	TOTAL WATER AND WATER PWR		1,577			
13						
14	RENT FROM ELEC PROPERTIES					
15	CALIFORNIA					
16	06CFR00006-MTH RNTAL CHRG		1,710			
17	RENT REVENUE - HYDRO		1,200			
18	RENT REVENUE - SUBLEASES		19,200			
19	JOINT USE		471,217			
20						
21	IDAHO					
22	07CFR00009-YR LSE CHRG-EQ		788			
23	07INVCHG00-INVEST MNT CHG		161			
24	07POLE0075-STEEL POLES US		277			
25	RENT REVENUE - HYDRO		66,960			
26	RENT REVENUE - SUBLEASES		2,216			
27	JOINT USE		152,113			
28						
29	OREGON					
30	01CFR00006-MTH RNTAL CHRG		740,865			
31	RENTS - COMMON		568,165			
32	RENTS - NON COMMON		50			
33	MCI FOGWIRE REVENUE		3,347,666			
34	RENT REVENUE - SUBLEASES		177,744			
35	RENT REV - TRANSMISSION		256,294			
36	RENT REV - DISTRIBUTION		58,721			
37	RENT REVENUE - HYDRO		22,831			
38	RENT REV - GEN(COMM)		48,027			
39	JOINT USE		2,707,379			
40						
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
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1	UTAH					
2	08CFR00056-MTH EQUIP RENT		33			
3	08CFR00058-MTH EQUIP LEAS		676,099			
4	08INVCHG0N-INVEST MNT CHG		4,406			
5	08INVCHG0R-INVEST MNT CHG		255			
6	08POLE0075-STEEL POLES US		55,048			
7	RENTS - NON COMMON		3,600			
8	RENT REVENUE - STEAM		116,271			
9	RENT REV - TRANSMISSION		1,015,041			
10	RENT REV - DISTRIBUTION		535,499			
11	RENT REVENUE - HYDRO		78,737			
12	RENT REV - GEN(COMM)		13,634			
13	RENT REVENUE - SUBLEASES		2,648,443			
14	INTERCOMPANY RENT REVENUE		91,739			
15	JOINT USE		2,103,705			
16						
17	WASHINGTON					
18	02CFR00001-MTH FACILITY S		2,104			
19	02CFR00006-MTH RNTAL CHRG		9,073			
20	RENT REV - TRANSMISSION		17,371			
21	RENT REV - DISTRIBUTION		17,616			
22	RENT REVENUE - HYDRO		337,375			
23	RENT REV - GEN(COMM)		40,250			
24	RENT REVENUE - SUBLEASES		8,059			
25	JOINT USE		974,514			
26						
27	WYOMING					
28	05CFR00001-MTH FACILITY S		11,524			
29	05CFR00006-MTH RNTAL CHRG		2,482			
30	09POLE0075-STEEL POLES US		18,317			
31	RENT REVENUE - STEAM		54,019			
32	RENT REVENUE - STEAM		4,675			
33	RENT REV - TRANSMISSION		2,606			
34	RENT REV - DISTRIBUTION		150			
35	RENT REVENUE - HYDRO		33,038			
36	RENT REV - GEN(COMM)		31,736			
37	RENT REVENUE - SUBLEASES		7,055			
38	JOINT USE		328,917			
39	JOINT USE		41			
40						
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
42	Total Unbilled Rev.(See Instr. 6)	73,318	7,359,000	0	0	0.1004
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1	TOTAL RENT FROM ELEC PROP		17,887,016			
2						
3	OTHER ELECTRIC REVENUE					
4	WIND BASED ANCILLARY SVC		12,114,934			
5	RENEWABLE ENERGY CREDIT		12,967,601			
6	GREEN CREDIT SALES		15,535,015			
7	RENEWABLE ENERGY CR AMORT		4,383,115			
8	NON-WHEELING SYSTEM		12,177,493			
9	OTHER ELECTRIC ESTIMATE		246,823			
10	OTHER ELECTRIC (EXCL		21,210			
11	ELECTRIC INCOME - OTHER		2,000			
12	FERC TRANSMISSION REFUND		-2,220,863			
13	REC SALES WIND WAKE LOSS		18,400			
14						
15	CALIFORNIA					
16	3RD PARTY TRANS O&M		20,227			
17	FISH, WILDLIFE, RECR		6,376			
18						
19	IDAHO					
20	3RD PARTY TRANS O&M		133,191			
21	OTHER ELECTRIC (EXCL		-542			
22						
23	OREGON					
24	3RD PARTY TRANS O&M		174,417			
25	OTHER ELECTRIC DSR CARRY		17,090			
26	OTHER ELECTRIC (EXCL WHL		2,034,112			
27	I/C TRANS O&M REVENUE -		10,244			
28						
29	UTAH					
30	3RD PARTY TRANS O&M		329,960			
31	FISH, WILDLIFE, RECR		2,300			
32	FLYASH SALES		1,823,965			
33	M&S INVENTORY REVENUE		1,113,002			
34	ELECTRIC INCOME - OTHER		81,141			
35						
36	WASHINGTON					
37	3RD PARTY TRANS O&M		479			
38	FISH, WILDLIFE, RECR		6,634			
39	WA - COLSTRIP 3		-52,188			
40	OTHER ELECTRIC (EXCL WHL		-458			
41	TOTAL Billed	55,589,555	4,733,541,075	1,766,984	31,460	0.0852
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1						
2	WYOMING					
3	3RD PARTY TRANS O&M		58,708			
4	FLYASH SALES		1,439,192			
5	FLYASH SALES		1,673			
6	WY-REGULATORY RECOVERY		276,016			
7	ELECTRIC INCOME - OTHER		15			
8	DSM REVENUE - WY SBC - CAT 2		-25			
9						
10	TOTAL OTHER ELEC REVENUE		62,721,257			
11						
12						
13						
14						
15						
16						
17						
18						
19						
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43	TOTAL	55,662,873	4,740,900,075	1,766,984	31,502	0.0852

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 2013/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	Requirement Sales					
2	Brigham City Corporation	RQ	T-12	21	21	20
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	3 Phases Renewables, LLC	SF	T-12	NA	NA	NA
14	Arizona Public Service Company	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
125,517	2,797,856	3,506,889		6,304,745	2
802	11,454	14,368		25,822	3
6,633	120,700	117,297		237,997	4
3,754	72,477	66,399		138,876	5
986	18,182	17,181		35,363	6
9,388	139,402	159,774	19,791	318,967	7
11,447		1,059,831		1,059,831	8
72,332	1,663,276	2,014,956		3,678,232	9
-577			-64,480	-64,480	10
					11
					12
12,956		582,754		582,754	13
103,946		3,429,634		3,429,634	14
230,282	4,823,347	6,956,695	-44,689	11,735,353	
9,975,853	11,737,326	429,548,120	-127,499,972	313,785,474	
10,206,135	**16,560,673**	**436,504,815**	**-127,544,661**	**325,520,827**	

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 2013/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	Avista Corporation	SF	T-12	NA	NA	NA
2	Avista Corporation	SF	T-13	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	AD	T-11	NA	NA	NA
6	Basin Electric Power Cooperative	SF	T-12	NA	NA	NA
7	Black Hills Power, Inc.	AD	441	NA	NA	NA
8	Black Hills Power, Inc.	LF	441	50	52	47
9	Black Hills Power, Inc.	SF	T-12	NA	NA	NA
10	Bonneville Power Administration	AD	T-11	NA	NA	NA
11	Bonneville Power Administration	AD	T-12	NA	NA	NA
12	Bonneville Power Administration	LF	368	NA	NA	NA
13	Bonneville Power Administration	LF	T-11	NA	NA	NA
14	Bonneville Power Administration	LU	519	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.
73,399		2,100,087		2,100,087	1
96			3,098	3,098	2
90,097		2,839,433		2,839,433	3
23,575		800,371		800,371	4
			-8	-8	5
23,722		799,061		799,061	6
-1,824			-36,701	-36,701	7
338,283	7,341,126	6,309,504	-384,413	13,266,217	8
203,244		5,439,959		5,439,959	9
-2,059			-48,263	-48,263	10
			180,917	180,917	11
2,305			71,328	71,328	12
11,149			343,501	343,501	13
34,076		2,451,087		2,451,087	14
230,282	4,823,347	6,956,695	-44,689	11,735,353	
9,975,853	11,737,326	429,548,120	-127,499,972	313,785,474	
10,206,135	**16,560,673**	**436,504,815**	**-127,544,661**	**325,520,827**	

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 2013/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.
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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.
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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	Bonneville Power Administration	SF	T-11	NA	NA	NA
2	Bonneville Power Administration	SF	T-12	NA	NA	NA
3	Bonneville Power Administration	SF	T-13	NA	NA	NA
4	British Columbia Hydro and Power	SF	T-13	NA	NA	NA
5	Brookfield Energy Marketing L.P.	SF	T-12	NA	NA	NA
6	California Independent System Operator	AD	T-12	NA	NA	NA
7	California Independent System Operator	SF	T-12	NA	NA	NA
8	Calpine Energy Services, L.P.	AD	T-12	NA	NA	NA
9	Calpine Energy Services, L.P.	SF	T-12	NA	NA	NA
10	Cargill Power Markets, LLC	AD	T-11	NA	NA	NA
11	Cargill Power Markets, LLC	AD	T-12	NA	NA	NA
12	Cargill Power Markets, LLC	IF	T-12	NA	NA	NA
13	Cargill Power Markets, LLC	SF	T-11	NA	NA	NA
14	Cargill Power Markets, LLC	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
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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.
496			14,827	14,827	1
180,298		4,827,193		4,827,193	2
110			3,553	3,553	3
79			3,196	3,196	4
41,231		1,182,151		1,182,151	5
1,504			22,490	22,490	6
		157		157	7
182			4,924	4,924	8
267,780		7,921,043		7,921,043	9
-1,578			-31,240	-31,240	10
290			11,051	11,051	11
246,400		16,601,200		16,601,200	12
5,012			183,680	183,680	13
706,344		22,880,176		22,880,176	14
230,282	4,823,347	6,956,695	-44,689	11,735,353	
9,975,853	11,737,326	429,548,120	-127,499,972	313,785,474	
10,206,135	**16,560,673**	**436,504,815**	**-127,544,661**	**325,520,827**	

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 2013/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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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	City of Anaheim	SF	T-12	NA	NA	NA
2	City of Burbank	SF	T-12	NA	NA	NA
3	City of Glendale	SF	T-12	NA	NA	NA
4	City of Hurricane	LF	T-12	NA	NA	NA
5	City of Redding	SF	T-12	NA	NA	NA
6	City of Santa Clara	SF	T-12	NA	NA	NA
7	Clatskanie People's Utility District	SF	T-12	NA	NA	NA
8	Constellation Energy Commodities Group	AD	T-11	NA	NA	NA
9	Constellation Energy Commodities Group	SF	T-11	NA	NA	NA
10	Constellation Energy Commodities Group	SF	T-12	NA	NA	NA
11	Deseret Generation & Transmission	SF	T-11	NA	NA	NA
12	EDF Trading North America, LLC	AD	T-11	NA	NA	NA
13	EDF Trading North America, LLC	AD	T-12	NA	NA	NA
14	EDF Trading North America, LLC	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
48,755		2,004,775		2,004,775	1
236,236		6,814,166		6,814,166	2
4,976		170,064		170,064	3
205		13,325		13,325	4
71,360		2,165,437		2,165,437	5
60,000		1,884,612		1,884,612	6
1,056		31,880		31,880	7
-1,410			-15,496	-15,496	8
50			1,805	1,805	9
37,033		1,145,180		1,145,180	10
7			178	178	11
-17			-257	-257	12
1,334			24,177	24,177	13
876,001		28,670,956		28,670,956	14
230,282	4,823,347	6,956,695	-44,689	11,735,353	
9,975,853	11,737,326	429,548,120	-127,499,972	313,785,474	
10,206,135	**16,560,673**	**436,504,815**	**-127,544,661**	**325,520,827**	

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 2013/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	El Paso Electric Company	SF	T-12	NA	NA	NA
2	Enel Cove Fort, LLC	LF	711	NA	NA	NA
3	Eugene Water & Electric Board	AD	T-11	NA	NA	NA
4	Eugene Water & Electric Board	SF	T-12	NA	NA	NA
5	Exelon Generation Company, LLC	SF	T-12	NA	NA	NA
6	Gila River Power LLC	SF	T-12	NA	NA	NA
7	Iberdrola Renewables, LLC	AD	T-11	NA	NA	NA
8	Iberdrola Renewables, LLC	LF	T-11	NA	NA	NA
9	Iberdrola Renewables, LLC	SF	T-11	NA	NA	NA
10	Iberdrola Renewables, LLC	SF	T-11	NA	NA	NA
11	Iberdrola Renewables, LLC	SF	T-12	NA	NA	NA
12	Idaho Power Company	AD	T-11	NA	NA	NA
13	Idaho Power Company	LF	T-11	NA	NA	NA
14	Idaho 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.
33,832		1,090,900		1,090,900	1
595			25,884	25,884	2
			-1	-1	3
14,738		463,444		463,444	4
777,210		26,613,451		26,613,451	5
121,280		3,466,800		3,466,800	6
-2,499			-57,952	-57,952	7
3,329			104,253	104,253	8
10,779			348,891	348,891	9
58			1,785	1,785	10
792,705		24,800,670		24,800,670	11
-638			-15,465	-15,465	12
2,814			102,112	102,112	13
669			24,105	24,105	14
230,282	4,823,347	6,956,695	-44,689	11,735,353	
9,975,853	11,737,326	429,548,120	-127,499,972	313,785,474	
10,206,135	**16,560,673**	**436,504,815**	**-127,544,661**	**325,520,827**	

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 2013/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Idaho Power Company	SF	T-12	NA	NA	NA
2	Idaho Power Company	SF	T-13	NA	NA	NA
3	J. Aron & Company	SF	T-12	NA	NA	NA
4	J.P. Morgan Ventures Energy Corporation	AD	T-11	NA	NA	NA
5	J.P. Morgan Ventures Energy Corporation	SF	T-11	NA	NA	NA
6	J.P. Morgan Ventures Energy Corporation	SF	T-11	NA	NA	NA
7	J.P. Morgan Ventures Energy Corporation	SF	T-12	NA	NA	NA
8	Los Angeles Dept. of Water and Power	AD	T-11	NA	NA	NA
9	Los Angeles Dept. of Water and Power	LU	301	NA	NA	NA
10	Los Angeles Dept. of Water and Power	SF	T-11	NA	NA	NA
11	Los Angeles Dept. of Water and Power	SF	T-12	NA	NA	NA
12	Macquarie Energy LLC	SF	T-11	NA	NA	NA
13	Macquarie Energy LLC	SF	T-12	NA	NA	NA
14	Modesto Irrigation District	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 2013/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.
12,573		354,752		354,752	1
251			8,799	8,799	2
822,456		27,129,794		27,129,794	3
-595			-12,752	-12,752	4
27			840	840	5
3,130			90,381	90,381	6
36,550		1,030,904		1,030,904	7
-40			-944	-944	8
568,255		28,954,728		28,954,728	9
188			5,184	5,184	10
18,772		540,654		540,654	11
1,557			57,347	57,347	12
105,108		3,152,302		3,152,302	13
89,435		3,138,191		3,138,191	14
230,282	4,823,347	6,956,695	-44,689	11,735,353	
9,975,853	11,737,326	429,548,120	-127,499,972	313,785,474	
10,206,135	**16,560,673**	**436,504,815**	**-127,544,661**	**325,520,827**	

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 2013/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	Morgan Stanley Capital Group, Inc.	AD	T-11	NA	NA	NA
2	Morgan Stanley Capital Group, Inc.	SF	T-11	NA	NA	NA
3	Morgan Stanley Capital Group, Inc.	SF	T-12	NA	NA	NA
4	Municipal Energy Agency of Nebraska	SF	T-12	NA	NA	NA
5	NaturEner Power Watch, LLC	SF	T-13	NA	NA	NA
6	Nevada Power Company	SF	T-11	NA	NA	NA
7	Nevada Power Company	SF	T-12	NA	NA	NA
8	NextEra Energy Power Marketing, LLC	AD	T-11	NA	NA	NA
9	NextEra Energy Power Marketing, LLC	LF	T-11	NA	NA	NA
10	NextEra Energy Power Marketing, LLC	SF	T-11	NA	NA	NA
11	NextEra Energy Power Marketing, LLC	SF	T-11	NA	NA	NA
12	NextEra Energy Power Marketing, LLC	SF	T-12	NA	NA	NA
13	Noble Americas Gas & Power Corp.	SF	T-12	NA	NA	NA
14	NorthWestern 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 2013/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.
-1,504			-36,766	-36,766	1
11,446			352,848	352,848	2
94,300		3,129,581		3,129,581	3
123,450		3,193,665		3,193,665	4
17			422	422	5
86			3,083	3,083	6
70,821		1,832,661		1,832,661	7
-1,457			-33,108	-33,108	8
10,122			299,238	299,238	9
8			224	224	10
2			64	64	11
132		5,016		5,016	12
3,600		123,800		123,800	13
1,910		55,285		55,285	14
230,282	4,823,347	6,956,695	-44,689	11,735,353	
9,975,853	11,737,326	429,548,120	-127,499,972	313,785,474	
10,206,135	**16,560,673**	**436,504,815**	**-127,544,661**	**325,520,827**	

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 2013/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	NorthWestern Corporation	SF	T-13	NA	NA	NA
2	Northern California Power Agency	SF	T-12	NA	NA	NA
3	Northpoint Energy Solutions Inc.	SF	T-12	NA	NA	NA
4	PPL EnergyPlus, LLC	SF	T-12	NA	NA	NA
5	PPL Montana, LLC	AD	T-11	NA	NA	NA
6	PPL Montana, LLC	SF	T-11	NA	NA	NA
7	Pacific Gas & Electric Company	AD	T-12	NA	NA	NA
8	Pacific Summit Energy LLC	SF	T-12	NA	NA	NA
9	Portland General Electric Company	AD	T-11	NA	NA	NA
10	Portland General Electric Company	SF	T-11	NA	NA	NA
11	Portland General Electric Company	SF	T-12	NA	NA	NA
12	Portland General Electric Company	SF	T-13	NA	NA	NA
13	Powerex Corporation	AD	T-11	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**

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 2013/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
186			6,124	6,124	1
1,000		21,400		21,400	2
2,974		85,543		85,543	3
20,472		606,032		606,032	4
-44			-1,166	-1,166	5
185			6,641	6,641	6
588			14,302	14,302	7
61,597		4,966,566		4,966,566	8
-2			-54	-54	9
487			17,176	17,176	10
281,529		8,352,129		8,352,129	11
149			5,595	5,595	12
-12,650			-280,542	-280,542	13
16,819			517,681	517,681	14
230,282	4,823,347	6,956,695	-44,689	11,735,353	
9,975,853	11,737,326	429,548,120	-127,499,972	313,785,474	
10,206,135	**16,560,673**	**436,504,815**	**-127,544,661**	**325,520,827**	

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 2013/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	T-12	NA	NA	NA
4	Public Service Company of Colorado	SF	T-11	NA	NA	NA
5	Public Service Company of Colorado	SF	T-12	NA	NA	NA
6	Public Service Company of New Mexico	SF	T-12	NA	NA	NA
7	PUD #1 of Chelan County	SF	T-13	NA	NA	NA
8	PUD #1 of Clark County	SF	T-12	NA	NA	NA
9	PUD #1 of Snohomish County	SF	T-12	NA	NA	NA
10	PUD #2 of Grant County	SF	T-12	NA	NA	NA
11	PUD #2 of Grant County	SF	T-13	NA	NA	NA
12	Puget Sound Energy, Inc.	SF	T-12	NA	NA	NA
13	Puget Sound Energy, Inc.	SF	T-13	NA	NA	NA
14	Rainbow Energy Marketing Corporation	AD	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.
28,003			820,913	820,913	1
371,021		8,368,991	52,550	8,421,541	2
-108			-3,801	-3,801	3
34			757	757	4
105,984		2,877,327		2,877,327	5
217,341		6,855,497		6,855,497	6
3			123	123	7
2,463		119,378		119,378	8
8,218		262,546		262,546	9
16,065		450,874		450,874	10
14			414	414	11
82,820		2,272,746		2,272,746	12
44			1,664	1,664	13
-339			-5,867	-5,867	14
230,282	4,823,347	6,956,695	-44,689	11,735,353	
9,975,853	11,737,326	429,548,120	-127,499,972	313,785,474	
10,206,135	**16,560,673**	**436,504,815**	**-127,544,661**	**325,520,827**	

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 2013/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	Rainbow Energy Marketing Corporation	SF	T-11	NA	NA	NA
2	Rainbow Energy Marketing Corporation	SF	T-12	NA	NA	NA
3	Riverside, City of	SF	T-12	NA	NA	NA
4	Sacramento Municipal Utility District	AD	250	NA	NA	NA
5	Sacramento Municipal Utility District	LF	250	NA	NA	NA
6	Sacramento Municipal Utility District	LF	751	NA	NA	NA
7	Sacramento Municipal Utility District	SF	T-12	NA	NA	NA
8	Sacramento Municipal Utility District	SF	T-13	NA	NA	NA
9	Salt River Project	SF	T-11	NA	NA	NA
10	Salt River Project	SF	T-12	NA	NA	NA
11	Seattle City Light	SF	T-12	NA	NA	NA
12	Seattle City Light	SF	T-13	NA	NA	NA
13	Sempra Generation, LLC	SF	T-12	NA	NA	NA
14	Shell Energy North America (US), L.P.	AD	T-11	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
328			8,312	8,312	1
208,745		6,222,589		6,222,589	2
51,525		2,161,500		2,161,500	3
			698,634	698,634	4
569,389		15,151,441		15,151,441	5
69			2,546	2,546	6
136,217		4,143,071		4,143,071	7
6			180	180	8
97			3,491	3,491	9
231,506		6,447,782		6,447,782	10
45,035		1,294,345		1,294,345	11
36			840	840	12
213,030		6,715,522		6,715,522	13
-46			-1,239	-1,239	14
230,282	4,823,347	6,956,695	-44,689	11,735,353	
9,975,853	11,737,326	429,548,120	-127,499,972	313,785,474	
10,206,135	**16,560,673**	**436,504,815**	**-127,544,661**	**325,520,827**	

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 2013/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	Shell Energy North America (US), L.P.	IF	T-12	NA	NA	NA
2	Shell Energy North America (US), L.P.	SF	T-11	NA	NA	NA
3	Shell Energy North America (US), L.P.	SF	T-12	NA	NA	NA
4	Sierra Pacific Power Company	AD	T-11	NA	NA	NA
5	Sierra Pacific Power Company	SF	T-3	NA	NA	NA
6	Sierra Pacific Power Company	SF	T-11	NA	NA	NA
7	Sierra Pacific Power Company	SF	T-12	NA	NA	NA
8	Sierra Pacific Power Company	SF	T-13	NA	NA	NA
9	Southern California Edison Company	AD	T-11	NA	NA	NA
10	Southern California Edison Company	AD	T-11	NA	NA	NA
11	Southern California Edison Company	SF	T-11	NA	NA	NA
12	Southern California Edison Company	SF	T-11	NA	NA	NA
13	Southern California Edison Company	SF	T-12	NA	NA	NA
14	Southern California Public Power Auth.	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.
153,595		5,858,032		5,858,032	1
1,901			59,889	59,889	2
246,000		8,253,783		8,253,783	3
-144			-3,419	-3,419	4
140		3,254		3,254	5
615			30,310	30,310	6
25,957		685,389		685,389	7
363			11,581	11,581	8
-2,545			-58,750	-58,750	9
-37			-922	-922	10
9,440			388,219	388,219	11
35			1,086	1,086	12
356,251		10,443,683		10,443,683	13
9			246	246	14
230,282	4,823,347	6,956,695	-44,689	11,735,353	
9,975,853	11,737,326	429,548,120	-127,499,972	313,785,474	
10,206,135	**16,560,673**	**436,504,815**	**-127,544,661**	**325,520,827**	

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 2013/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (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	Southwestern Public Service Company	SF	T-12	NA	NA	NA
2	Tacoma Power	SF	T-12	NA	NA	NA
3	Tacoma Power	SF	T-13	NA	NA	NA
4	Tenaska Power Services Co.	AD	T-11	NA	NA	NA
5	Tenaska Power Services Co.	SF	T-11	NA	NA	NA
6	Tenaska Power Services Co.	SF	T-12	NA	NA	NA
7	The Energy Authority, Inc.	AD	T-11	NA	NA	NA
8	The Energy Authority, Inc.	SF	T-11	NA	NA	NA
9	The Energy Authority, Inc.	SF	T-12	NA	NA	NA
10	Thermo No. 1 BE-01, LLC	AD	T-11	NA	NA	NA
11	Thermo No. 1 BE-01, LLC	LF	T-11	NA	NA	NA
12	TransAlta Energy Marketing (U.S.) Inc.	AD	T-11	NA	NA	NA
13	TransAlta Energy Marketing (U.S.) Inc.	AD	T-12	NA	NA	NA
14	TransAlta Energy Marketing (U.S.) Inc.	SF	T-11	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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.
22,850		717,200		717,200	1
41,635		1,054,461		1,054,461	2
2			127	127	3
-205			-5,299	-5,299	4
3,010			104,522	104,522	5
426,419		12,525,903		12,525,903	6
-12			-176	-176	7
41			977	977	8
42,675		1,383,973		1,383,973	9
-346			-7,967	-7,967	10
2,881			91,040	91,040	11
-199			-3,684	-3,684	12
225			8,349	8,349	13
1,395			40,795	40,795	14
230,282	4,823,347	6,956,695	-44,689	11,735,353	
9,975,853	11,737,326	429,548,120	-127,499,972	313,785,474	
10,206,135	**16,560,673**	**436,504,815**	**-127,544,661**	**325,520,827**	

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 2013/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	TransAlta Energy Marketing (U.S.) Inc.	SF	T-12	NA	NA	NA
2	TransCanada Energy Sales Ltd.	SF	T-12	NA	NA	NA
3	Tri-State Gen. & Trans.	AD	T-11	NA	NA	NA
4	Tri-State Gen. & Trans.	SF	T-11	NA	NA	NA
5	Tri-State Gen. & Trans.	SF	T-12	NA	NA	NA
6	Tucson Electric Power Company	SF	T-12	NA	NA	NA
7	Turlock Irrigation District	SF	T-12	NA	NA	NA
8	Twin Eagle Resource Management, LLC	SF	T-12	NA	NA	NA
9	UNS Electric, Inc.	SF	T-12	NA	NA	NA
10	Utah Associated Municipal Power Systems	AD	T-11	NA	NA	NA
11	Utah Associated Municipal Power Systems	SF	T-11	NA	NA	NA
12	Utah Associated Municipal Power Systems	SF	T-12	NA	NA	NA
13	Utah Municipal Power Agency	LF	433	34	34	34
14	Utah Municipal Power Agency	SF	T-3	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.
393,129		11,440,499		11,440,499	1
600		18,800		18,800	2
-339			-8,608	-8,608	3
751			24,257	24,257	4
213,650		5,814,391		5,814,391	5
382,774		11,067,994		11,067,994	6
1,002		39,568		39,568	7
6,488		175,587		175,587	8
308,825		9,169,276		9,169,276	9
-65			-1,722	-1,722	10
134			4,182	4,182	11
44,657		1,266,781		1,266,781	12
223,194	4,396,200	5,187,029		9,583,229	13
25,832		666,437		666,437	14
230,282	4,823,347	6,956,695	-44,689	11,735,353	
9,975,853	11,737,326	429,548,120	-127,499,972	313,785,474	
10,206,135	**16,560,673**	**436,504,815**	**-127,544,661**	**325,520,827**	

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 2013/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Western Area Power Administration	AD	T-11	NA	NA	NA
2	Western Area Power Administration	SF	T-11	NA	NA	NA
3	Western Area Power Administration	SF	T-12	NA	NA	NA
4	Reserve for potential refunds		NA	NA	NA	NA
5	Netting - Bookouts		NA	NA	NA	NA
6	Netting - Trading		NA	NA	NA	NA
7	Accrual		NA	NA	NA	NA
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 2013/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.
-310			-6,068	-6,068	1
23			838	838	2
516,945		16,259,998		16,259,998	3
			634,716	634,716	4
-3,558,566			-129,340,690	-129,340,690	5
			-1,479,332	-1,479,332	6
2,217			-1,470,562	-1,470,562	7
					8
					9
					10
					11
					12
					13
					14
230,282	4,823,347	6,956,695	-44,689	11,735,353	
9,975,853	11,737,326	429,548,120	-127,499,972	313,785,474	
10,206,135	**16,560,673**	**436,504,815**	**-127,544,661**	**325,520,827**	

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.: 7 Column: j

Settlement adjustment.

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

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

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

Reserve share.

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

Settlement adjustment.

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

Transmission losses.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 310.1 Line No.: 8 Column: b

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

Schedule Page: 310.1 Line No.: 8 Column: j

Liquidated damages.

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

Settlement adjustment.

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

Transmission losses.

Schedule Page: 310.1 Line No.: 11 Column: b

Settlement adjustment.

Schedule Page: 310.1 Line No.: 11 Column: j

Settlement adjustment.

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

Bonneville Power Administration - FERC, 5th revised R.S. 368 [Use of Facilities Agreement for Malin Transformer under the AC Intertie Agreement with BPA] - Contract termination date: Upon Mutual agreement.

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

Transmission losses.

Schedule Page: 310.1 Line No.: 13 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.: 13 Column: j

Transmission losses.

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

Transmission losses.

Schedule Page: 310.2 Line No.: 3 Column: j

Reserve share.

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

This footnote applies to all occurrences of "British Columbia Hydro and Power" on pages 310-311. Complete name is British Columbia Hydro and Power Authority.

Schedule Page: 310.2 Line No.: 4 Column: j
Reserve share.
Schedule Page: 310.2 Line No.: 6 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.: 6 Column: b
Settlement adjustment.
Schedule Page: 310.2 Line No.: 6 Column: j
Settlement adjustment.
Schedule Page: 310.2 Line No.: 8 Column: b
Settlement adjustment.
Schedule Page: 310.2 Line No.: 8 Column: j
Settlement adjustment.
Schedule Page: 310.2 Line No.: 10 Column: b
Settlement adjustment.
Schedule Page: 310.2 Line No.: 10 Column: j
Transmission losses.
Schedule Page: 310.2 Line No.: 11 Column: b
Settlement adjustment.
Schedule Page: 310.2 Line No.: 11 Column: j
Settlement adjustment.
Schedule Page: 310.2 Line No.: 13 Column: j
Transmission losses.
Schedule Page: 310.3 Line No.: 4 Column: b
City of Hurricane - FERC T-12 - Contract termination date: August 31, 2017.
Schedule Page: 310.3 Line No.: 8 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.: 8 Column: b
Settlement adjustment.
Schedule Page: 310.3 Line No.: 8 Column: j
Transmission losses.
Schedule Page: 310.3 Line No.: 9 Column: j
Transmission losses.
Schedule Page: 310.3 Line No.: 11 Column: a
This footnote applies to all occurrences of "Deseret Generation & Transmission" on pages 310-311. Complete name is Deseret Generation and Transmission Co-operative.
Schedule Page: 310.3 Line No.: 11 Column: j
Transmission losses.
Schedule Page: 310.3 Line No.: 12 Column: b
Settlement adjustment.
Schedule Page: 310.3 Line No.: 12 Column: j
Transmission losses.
Schedule Page: 310.3 Line No.: 13 Column: b
Settlement adjustment.
Schedule Page: 310.3 Line No.: 13 Column: j
Settlement adjustment.
Schedule Page: 310.4 Line No.: 2 Column: b
Enel Cove Fort, LLC - FERC 711 - (4th revised S.A. 706) - Contract termination date: April 30, 2045.
Schedule Page: 310.4 Line No.: 2 Column: j
Transmission losses.
Schedule Page: 310.4 Line No.: 3 Column: b
Settlement adjustment.

Schedule Page: 310.4 Line No.: 3 Column: j
Transmission losses.
Schedule Page: 310.4 Line No.: 7 Column: b
Settlement adjustment.
Schedule Page: 310.4 Line No.: 7 Column: j
Transmission losses.
Schedule Page: 310.4 Line No.: 8 Column: b
Iberdrola Renewables, LLC - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (8th revised S.A. 279)] - Contract termination date: April 30, 2019.
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.: 10 Column: j
Unauthorized use charges.
Schedule Page: 310.4 Line No.: 12 Column: b
Settlement adjustment.
Schedule Page: 310.4 Line No.: 12 Column: j
Transmission losses.
Schedule Page: 310.4 Line No.: 13 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, 2019.
Schedule Page: 310.4 Line No.: 13 Column: j
Transmission losses.
Schedule Page: 310.4 Line No.: 14 Column: j
Transmission losses.
Schedule Page: 310.5 Line No.: 2 Column: j
Reserve share.
Schedule Page: 310.5 Line No.: 4 Column: b
Settlement adjustment.
Schedule Page: 310.5 Line No.: 4 Column: j
Transmission losses.
Schedule Page: 310.5 Line No.: 5 Column: j
Unauthorized use charges.
Schedule Page: 310.5 Line No.: 6 Column: j
Transmission losses.
Schedule Page: 310.5 Line No.: 8 Column: a
This footnote applies to all occurrences of "Los Angeles Dept. of Water and Power" on pages 310-311. Complete name is Los Angeles Department of Water and Power.
Schedule Page: 310.5 Line No.: 8 Column: b
Settlement adjustment.
Schedule Page: 310.5 Line No.: 8 Column: j
Transmission losses.
Schedule Page: 310.5 Line No.: 10 Column: j
Transmission losses.
Schedule Page: 310.5 Line No.: 12 Column: j
Transmission losses.
Schedule Page: 310.6 Line No.: 1 Column: b
Settlement adjustment.
Schedule Page: 310.6 Line No.: 1 Column: j
Transmission losses.
Schedule Page: 310.6 Line No.: 2 Column: j
Transmission losses.

Schedule Page: 310.6 Line No.: 5 Column: j
Reserve share.
Schedule Page: 310.6 Line No.: 6 Column: a
This footnote applies to all occurrences of "Nevada Power Company" on pages 310-311. Nevada Power Company is a principal subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of MidAmerican Energy Holdings Company.
Schedule Page: 310.6 Line No.: 6 Column: j
Transmission losses.
Schedule Page: 310.6 Line No.: 8 Column: b
Settlement adjustment.
Schedule Page: 310.6 Line No.: 8 Column: j
Transmission losses.
Schedule Page: 310.6 Line No.: 9 Column: b
NextEra Energy Power Marketing, LLC - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (2nd revised S.A. 733)] - Contract termination date: November 17, 2017.
Schedule Page: 310.6 Line No.: 9 Column: j
Transmission losses.
Schedule Page: 310.6 Line No.: 10 Column: j
Transmission losses.
Schedule Page: 310.6 Line No.: 11 Column: j
Unauthorized use charges.
Schedule Page: 310.7 Line No.: 1 Column: j
Reserve share.
Schedule Page: 310.7 Line No.: 5 Column: b
Settlement adjustment.
Schedule Page: 310.7 Line No.: 5 Column: j
Transmission losses.
Schedule Page: 310.7 Line No.: 6 Column: j
Transmission losses.
Schedule Page: 310.7 Line No.: 7 Column: b
Settlement adjustment.
Schedule Page: 310.7 Line No.: 7 Column: j
Settlement adjustment.
Schedule Page: 310.7 Line No.: 9 Column: b
Settlement adjustment.
Schedule Page: 310.7 Line No.: 9 Column: j
Transmission losses.
Schedule Page: 310.7 Line No.: 10 Column: j
Transmission losses.
Schedule Page: 310.7 Line No.: 12 Column: j
Reserve share.
Schedule Page: 310.7 Line No.: 13 Column: b
Settlement adjustment.
Schedule Page: 310.7 Line No.: 13 Column: j
Transmission losses.
Schedule Page: 310.7 Line No.: 14 Column: b
Powerex Corporation - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (8th revised S.A. 169)] - Contract termination date: October 31, 2020.
Schedule Page: 310.7 Line No.: 14 Column: j
Transmission losses.
Schedule Page: 310.8 Line No.: 1 Column: j
Transmission losses.
Schedule Page: 310.8 Line No.: 2 Column: j

Pond sales.

Schedule Page: 310.8 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 310.8 Line No.: 3 Column: j

Settlement adjustment.

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

Transmission losses.

Schedule Page: 310.8 Line No.: 7 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: 310.8 Line No.: 7 Column: j

Reserve share.

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

This footnote applies to all occurrences of "PUD #1 of Clark County" on pages 310-311. Complete name is Public Utility District No. 1 of Clark County.

Schedule Page: 310.8 Line No.: 9 Column: a

This footnote applies to all occurrences of "PUD #1 of Snohomish County" on pages 310-311. Complete name is Public Utility District No. 1 of Snohomish County.

Schedule Page: 310.8 Line No.: 10 Column: a

This footnote applies to all occurrences of "PUD #2 of Grant County" on pages 310-311. Complete name is Public Utility District No. 2 of Grant County.

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

Reserve share.

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

Reserve share.

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

Settlement adjustment.

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

Transmission losses.

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

Transmission losses.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 310.9 Line No.: 5 Column: b

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

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

Sacramento Municipal Utility District - FERC 751 [Point-to-Point Transmission Service under the Open Access Transmission Tariff] - Contract termination date: September 30, 2018.

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

Transmission losses.

Schedule Page: 310.9 Line No.: 8 Column: j

Reserve share.

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

Transmission losses.

Schedule Page: 310.9 Line No.: 12 Column: j

Reserve share.

Schedule Page: 310.9 Line No.: 14 Column: b

Settlement adjustment.

Schedule Page: 310.9 Line No.: 14 Column: j

Transmission losses.

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

Schedule Page: 310.10 Line No.: 4 Column: a
This footnote applies to all occurrences of "Sierra Pacific Power Company" on pages 310-311. Sierra Pacific Power Company is a principal subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of MidAmerican Energy Holdings Company.

Schedule Page: 310.10 Line No.: 4 Column: b
Settlement adjustment.

Schedule Page: 310.10 Line No.: 4 Column: j
Transmission losses.

Schedule Page: 310.10 Line No.: 6 Column: j
Transmission losses.

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

Schedule Page: 310.10 Line No.: 9 Column: b
Settlement adjustment.

Schedule Page: 310.10 Line No.: 9 Column: j
Transmission losses.

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

Schedule Page: 310.10 Line No.: 10 Column: j
Unauthorized use charges.

Schedule Page: 310.10 Line No.: 11 Column: j
Transmission losses.

Schedule Page: 310.10 Line No.: 12 Column: j
Unauthorized use charges.

Schedule Page: 310.10 Line No.: 14 Column: a
This footnote applies to all occurrences of "Southern California Public Power Auth." on pages 310-311. Complete name is Southern California Public Power Authority.

Schedule Page: 310.10 Line No.: 14 Column: j
Unauthorized use charges.

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

Schedule Page: 310.11 Line No.: 4 Column: b
Settlement adjustment.

Schedule Page: 310.11 Line No.: 4 Column: j
Transmission losses.

Schedule Page: 310.11 Line No.: 5 Column: j
Transmission losses.

Schedule Page: 310.11 Line No.: 7 Column: b
Settlement adjustment.

Schedule Page: 310.11 Line No.: 7 Column: j
Transmission losses.

Schedule Page: 310.11 Line No.: 8 Column: j
Transmission losses.

Schedule Page: 310.11 Line No.: 10 Column: b
Settlement adjustment.

Schedule Page: 310.11 Line No.: 10 Column: j
Transmission losses.

Schedule Page: 310.11 Line No.: 11 Column: b
Thermo No. 1 BE-01, LLC - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (3rd revised S.A. 568)] - Contract termination date: April 30, 2029.

Schedule Page: 310.11 Line No.: 11 Column: j

Transmission losses.

Schedule Page: 310.11 Line No.: 12 Column: b

Settlement adjustment.

Schedule Page: 310.11 Line No.: 12 Column: j

Transmission losses.

Schedule Page: 310.11 Line No.: 13 Column: b

Settlement adjustment.

Schedule Page: 310.11 Line No.: 13 Column: j

Settlement adjustment.

Schedule Page: 310.11 Line No.: 14 Column: j

Transmission losses.

Schedule Page: 310.12 Line No.: 3 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: 310.12 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 310.12 Line No.: 3 Column: j

Transmission losses.

Schedule Page: 310.12 Line No.: 4 Column: j

Transmission losses.

Schedule Page: 310.12 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 310.12 Line No.: 10 Column: j

Transmission losses.

Schedule Page: 310.12 Line No.: 11 Column: j

Transmission losses.

Schedule Page: 310.12 Line No.: 13 Column: b

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

Schedule Page: 310.13 Line No.: 1 Column: b

Settlement adjustment.

Schedule Page: 310.13 Line No.: 1 Column: j

Transmission losses.

Schedule Page: 310.13 Line No.: 2 Column: j

Transmission losses.

Schedule Page: 310.13 Line No.: 4 Column: j

Transmission losses.

Schedule Page: 310.13 Line No.: 5 Column: j

Reflects transactions that did not physically settle.

Schedule Page: 310.13 Line No.: 6 Column: j

Reflects transactions that did not physically settle.

Schedule Page: 310.13 Line No.: 7 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 2013/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	18,091,723	19,142,283
5	(501) Fuel	836,194,561	768,997,788
6	(502) Steam Expenses	43,916,579	41,809,206
7	(503) Steam from Other Sources	4,312,439	3,937,027
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	3,949,096	3,896,688
10	(506) Miscellaneous Steam Power Expenses	55,018,295	56,759,531
11	(507) Rents	496,045	396,587
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	961,978,738	894,939,110
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	7,331,481	6,378,884
16	(511) Maintenance of Structures	29,996,120	25,384,395
17	(512) Maintenance of Boiler Plant	103,206,206	107,992,173
18	(513) Maintenance of Electric Plant	31,091,746	35,012,328
19	(514) Maintenance of Miscellaneous Steam Plant	14,777,438	12,158,343
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	186,402,991	186,926,123
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	1,148,381,729	1,081,865,233
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	7,551,949	4,711,673
45	(536) Water for Power	197,600	134,519
46	(537) Hydraulic Expenses	4,009,780	4,265,329
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	15,446,587	18,412,058
49	(540) Rents	1,075,124	661,711
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	28,281,040	28,185,290
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	506	388
54	(542) Maintenance of Structures	1,156,074	825,279
55	(543) Maintenance of Reservoirs, Dams, and Waterways	2,292,070	2,088,303
56	(544) Maintenance of Electric Plant	2,907,970	1,974,573
57	(545) Maintenance of Miscellaneous Hydraulic Plant	4,284,443	2,936,126
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	10,641,063	7,824,669
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	38,922,103	36,009,959

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 2013/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	448,713	369,904
63	(547) Fuel	321,290,415	364,507,540
64	(548) Generation Expenses	14,406,401	17,430,953
65	(549) Miscellaneous Other Power Generation Expenses	10,582,172	9,147,157
66	(550) Rents	4,649,553	3,662,580
67	TOTAL Operation (Enter Total of lines 62 thru 66)	351,377,254	395,118,134
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	3,029,122	2,291,254
71	(553) Maintenance of Generating and Electric Plant	17,613,519	25,781,191
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	3,121,555	1,966,376
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	23,764,196	30,038,821
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	375,141,450	425,156,955
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	666,554,057	535,586,277
77	(556) System Control and Load Dispatching	1,439,706	1,546,050
78	(557) Other Expenses	66,410,600	62,779,248
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	734,404,363	599,911,575
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,296,849,645	2,142,943,722
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	6,231,709	5,532,584
84			
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	7,218,959	6,733,470
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	292,567	239,500
89	(561.5) Reliability, Planning and Standards Development	1,114,579	850,396
90	(561.6) Transmission Service Studies	89,710	127,861
91	(561.7) Generation Interconnection Studies	861,392	617,977
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	3,029,593	2,984,932
94	(563) Overhead Lines Expenses	353,289	285,237
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	137,182,304	142,125,115
97	(566) Miscellaneous Transmission Expenses	4,162,643	3,696,068
98	(567) Rents	2,755,216	1,497,301
99	TOTAL Operation (Enter Total of lines 83 thru 98)	163,291,961	164,690,441
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,608,159	2,486,358
102	(569) Maintenance of Structures	181,944	1,145
103	(569.1) Maintenance of Computer Hardware	247,522	203,102
104	(569.2) Maintenance of Computer Software	318,385	1,001,012
105	(569.3) Maintenance of Communication Equipment	3,584,282	3,270,838
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	10,141,753	11,423,719
108	(571) Maintenance of Overhead Lines	18,707,537	20,575,947
109	(572) Maintenance of Underground Lines	72,498	82,622
110	(573) Maintenance of Miscellaneous Transmission Plant	516,090	2,748,898
111	TOTAL Maintenance (Total of lines 101 thru 110)	35,378,170	41,793,641
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	198,670,131	206,484,082

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 2013/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	13,049,994	14,093,118
135	(581) Load Dispatching	12,422,223	13,036,839
136	(582) Station Expenses	4,264,228	4,078,201
137	(583) Overhead Line Expenses	6,083,986	5,526,165
138	(584) Underground Line Expenses	496	249
139	(585) Street Lighting and Signal System Expenses	202,145	222,740
140	(586) Meter Expenses	7,072,984	7,071,031
141	(587) Customer Installations Expenses	11,097,401	12,473,499
142	(588) Miscellaneous Expenses	4,751,998	4,562,147
143	(589) Rents	3,698,889	3,366,940
144	TOTAL Operation (Enter Total of lines 134 thru 143)	62,644,344	64,430,929
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	6,186,943	4,472,548
147	(591) Maintenance of Structures	1,710,762	1,310,306
148	(592) Maintenance of Station Equipment	11,897,335	10,993,806
149	(593) Maintenance of Overhead Lines	89,950,166	88,718,266
150	(594) Maintenance of Underground Lines	21,363,704	20,313,015
151	(595) Maintenance of Line Transformers	1,024,257	957,612
152	(596) Maintenance of Street Lighting and Signal Systems	3,591,531	3,704,762
153	(597) Maintenance of Meters	6,666,726	6,749,398
154	(598) Maintenance of Miscellaneous Distribution Plant	3,403,630	2,027,649
155	TOTAL Maintenance (Total of lines 146 thru 154)	145,795,054	139,247,362
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	208,439,398	203,678,291
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	2,441,991	2,603,420
160	(902) Meter Reading Expenses	19,662,071	20,679,578
161	(903) Customer Records and Collection Expenses	52,388,395	53,770,351
162	(904) Uncollectible Accounts	12,924,355	14,337,468
163	(905) Miscellaneous Customer Accounts Expenses	117,514	142,188
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	87,534,326	91,533,005

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 2013/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	331,132	301,706
168	(908) Customer Assistance Expenses	112,671,756	103,156,102
169	(909) Informational and Instructional Expenses	3,484,752	3,294,390
170	(910) Miscellaneous Customer Service and Informational Expenses	117,029	204,557
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	116,604,669	106,956,755
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	76,754,883	74,368,102
182	(921) Office Supplies and Expenses	8,363,743	8,706,781
183	(Less) (922) Administrative Expenses Transferred-Credit	29,238,955	27,128,855
184	(923) Outside Services Employed	16,481,262	13,277,918
185	(924) Property Insurance	13,818,764	16,404,849
186	(925) Injuries and Damages	36,151,606	48,931,701
187	(926) Employee Pensions and Benefits		
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	22,768,237	22,965,972
190	(929) (Less) Duplicate Charges-Cr.	4,347,767	4,869,262
191	(930.1) General Advertising Expenses	1,546	4,948
192	(930.2) Miscellaneous General Expenses	7,526,075	7,338,998
193	(931) Rents	6,318,601	6,720,354
194	TOTAL Operation (Enter Total of lines 181 thru 193)	154,597,995	166,721,506
195	Maintenance		
196	(935) Maintenance of General Plant	21,202,085	21,518,172
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	175,800,080	188,239,678
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	3,083,898,249	2,939,835,533

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, 2013 and 2012, pensions and benefits expense was $145,750,552 and $144,687,083, 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 2013/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	LF		NA	NA	NA
4	Arizona Public Service Company	SF		NA	NA	NA
5	Avista Corporation	SF		NA	NA	NA
6	BP Energy Company	SF		NA	NA	NA
7	Ballard Hog Farms Inc.	LU		0.01	0.01	0.01
8	Barclays Bank PLC	AD		NA	NA	NA
9	Barclays Bank PLC	SF		NA	NA	NA
10	Basin Electric Power Cooperative	SF		NA	NA	NA
11	Beaver City Corporation	LF		NA	NA	NA
12	Bell Mountain Hydro, LLC	LU		NA	NA	NA
13	Big Top, LLC	LU		NA	NA	NA
14	Biomass One, L.P.	LU		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 2013/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
1,640				73,570		73,570	2
93,837				3,153,294		3,153,294	3
101,786				3,832,474	177,358	4,009,832	4
135,605				4,435,355	7,668	4,443,023	5
336,844				10,302,589	2,083,345	12,385,934	6
63			680	2,387		3,067	7
231							8
122,800				4,113,800	471,315	4,585,115	9
1,162				29,648		29,648	10
71				5,979		5,979	11
631				48,729		48,729	12
3,763				254,612		254,612	13
171,997				11,983,883	2,087,168	14,071,051	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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 2013/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	Birch Power Company, Inc.	LU		NA	NA	NA
2	Black Cap Solar, LLC	LU		NA	NA	NA
3	Black Hills Power, Inc.	SF		NA	NA	NA
4	Blanding City Corporation	LF		NA	NA	NA
5	Bonneville Power Administration	LF		NA	NA	NA
6	Bonneville Power Administration	OS		NA	NA	NA
7	Bonneville Power Administration	OS		NA	NA	NA
8	Bonneville Power Administration	SF		NA	NA	NA
9	Box Canyon Limited Partnership	LU		2.3	2.2	1.3
10	Brookfield Energy Marketing L.P.	SF		NA	NA	NA
11	Butter Creek Power, LLC	LU		NA	NA	NA
12	C Drop Hydro, LLC	LU		NA	NA	NA
13	CDM Hydroelectric Company	LU		NA	NA	NA
14	CE2 Environmental Markets L.P.	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)	
12,243				723,842		723,842	1
248				7,499		7,499	2
13,566				682,382		682,382	3
297				22,274		22,274	4
					1,132,440	1,132,440	5
1,617					61,938	61,938	6
					32,500	32,500	7
382,957				12,833,312	67,267	12,900,579	8
10,837			219,208	1,323,252		1,542,460	9
4,600				455,100		455,100	10
13,494				908,634		908,634	11
1,904				103,477		103,477	12
24,615				1,451,550		1,451,550	13
					44,010	44,010	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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 2013/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	CE2 Environmental Opportunities I L.P.	OS		NA	NA	NA
2	CER Generation II, LLC	IU		200	NA	NA
3	California Independent System Operator	AD		NA	NA	NA
4	California Independent System Operator	SF		NA	NA	NA
5	Calpine Energy Services, L.P.	AD		NA	NA	NA
6	Calpine Energy Services, L.P.	SF		NA	NA	NA
7	Cameron A. Curtiss	LU		NA	NA	NA
8	Cargill Power Markets, LLC	AD		NA	NA	NA
9	Cargill Power Markets, LLC	IF		NA	NA	NA
10	Cargill Power Markets, LLC	SF		NA	NA	NA
11	Cargill, Incorporated	LU		NA	NA	NA
12	Central Oregon Irrigation District	LU		5.6	3.7	2.5
13	Chevron U.S.A. Inc.	LU		NA	NA	NA
14	City of Albany	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)	
					27,990	27,990	1
346,843			7,368,000		21,673,353	29,041,353	2
-1,109					15,169	15,169	3
190,320				8,669,593		8,669,593	4
92					1,995	1,995	5
513,424				18,343,619		18,343,619	6
60				3,289		3,289	7
-76					-8,907	-8,907	8
245,428				17,945,382		17,945,382	9
144,816				6,619,013	-271,096	6,347,917	10
7,192				473,257		473,257	11
39,232			577,297	3,629,166		4,206,463	12
43,971				2,939,829		2,939,829	13
					-1	-1	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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	City of Albany	LU		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 Pasadena	SF		NA	NA	NA
6	City of Portland, Water Bureau	LU		NA	NA	NA
7	City of Preston Idaho	LU		NA	NA	NA
8	Clatskanie People's Utility District	SF		NA	NA	NA
9	Commercial Energy Management Inc.	LU		NA	NA	NA
10	Constellation Energy Commodities Group	SF		NA	NA	NA
11	Cottonwood Hydro, LLC	IU		NA	NA	NA
12	Crook County Solar 1, LLC	LU		NA	NA	NA
13	Deschutes Valley Water District	LU		5.7	3.7	3.1
14	Deseret Generation & Transmission Coop	LF		100	100	87
	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)	
2,044				141,108		141,108	1
10,162				560,456		560,456	2
400				15,000		15,000	3
1,962				127,553		127,553	4
1,520				79,600		79,600	5
137				7,406		7,406	6
2,962				161,534		161,534	7
8,230				109,714		109,714	8
1,142				62,369		62,369	9
26,000				757,886	77,436	835,322	10
3,345				210,763		210,763	11
145				5,830		5,830	12
26,675			561,548	3,088,962		3,650,510	13
678,610			15,445,275	13,363,006	4,035,350	32,843,631	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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	Deutsche Bank AG	SF		NA	NA	NA
2	Douglas County	LU		0.8	0.9	0.7
3	Douglas County, Inc.	AD		NA	NA	NA
4	Douglas County, Inc.	LU		NA	NA	NA
5	Draper Irrigation Company	IU		NA	NA	NA
6	Dry Creek LLC	LU		NA	NA	NA
7	Duane Wiggins Hydro, Inc.	IU		NA	NA	NA
8	EDF Trading North America, LLC	AD		NA	NA	NA
9	EDF Trading North America, LLC	SF		NA	NA	NA
10	eBay Inc.	LU		NA	NA	NA
11	Eagle Point Irrigation District	LU		0.7	0.5	0.3
12	El Paso Electric Company	SF		NA	NA	NA
13	Eugene Water & Electric Board	SF		NA	NA	NA
14	Eurus Combine Hills I, 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)	
					-2,804,354	-2,804,354	1
5,749			91,027	746,774		837,801	2
532					20,863	20,863	3
12,342				387,336		387,336	4
26				1,214		1,214	5
5,158				266,511		266,511	6
1				56		56	7
209					11,420	11,420	8
214,992				6,509,757	367,388	6,877,145	9
740				25,664		25,664	10
3,021			39,326	369,030		408,356	11
510				14,430	352	14,782	12
18,117				656,151		656,151	13
102,419				3,947,242		3,947,242	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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 2013/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	Evergreen BioPower, LLC	LU		NA	NA	NA
2	Exelon Generation Company, LLC	IF		NA	NA	NA
3	Exelon Generation Company, LLC	SF		NA	NA	NA
4	ExxonMobil Production Company	LU		NA	NA	NA
5	Falls Creek H.P. Limited Partnership	LU		2.9	3.8	1.6
6	Farm Power Misty Meadow, LLC	LU		NA	NA	NA
7	Farmers Irrigation District	LU		NA	NA	NA
8	Fillmore City Corporation	LF		NA	NA	NA
9	Finley BioEnergy, LLC	LU		NA	NA	NA
10	Flathead Electric Cooperative, Inc.	LF		NA	NA	NA
11	Four Corners Windfarm, LLC	LU		NA	NA	NA
12	Four Mile Canyon Windfarm, LLC	LU		NA	NA	NA
13	George DeRuyter & Sons Dairy	LU		0.7	0.9	0.7
14	Georgetown Irrigation Company	LU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
34,190				2,218,076		2,218,076	1
123,054				5,619,679		5,619,679	2
100,608				2,523,971	147,508	2,671,479	3
151				4,564		4,564	4
15,794			203,884	1,835,257		2,039,141	5
2,810				139,332		139,332	6
22,759				1,477,026		1,477,026	7
182				19,680		19,680	8
34,266				2,362,039		2,362,039	9
432					13,919	13,919	10
29,364				1,978,574		1,978,574	11
26,947				1,816,914		1,816,914	12
6,124			19,672	194,627		214,299	13
1,776				102,947		102,947	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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	Gila River Power LLC	SF		NA	NA	NA
2	Grand Valley Power	LF		NA	NA	NA
3	GrowPro, Inc.	IU		NA	NA	NA
4	Harold Foster & Robert Walker	LU		NA	NA	NA
5	Hermiston Generating Company, L.P.	AD		NA	NA	NA
6	Hermiston Generating Company, L.P.	LU		231	231	184
7	Iberdrola Renewables, LLC	AD		NA	NA	NA
8	Iberdrola Renewables, LLC	SF		NA	NA	NA
9	Idaho Falls, City of	AD		NA	NA	NA
10	Idaho Falls, City of	LU		NA	NA	NA
11	Idaho Power Company	OS		NA	NA	NA
12	Idaho Power Company	SF		NA	NA	NA
13	Ingram Warm Springs Ranch Partnership	LU		NA	NA	NA
14	Intermountain Power Agency	LU		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 2013/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)	
39,248				1,607,409		1,607,409	1
89				17,161		17,161	2
				1		1	3
954				35,907		35,907	4
					-876,467	-876,467	5
1,291,921			36,496,342	62,918,909	454,679	99,869,930	6
400							7
1,109,345				39,944,984	-697,223	39,247,761	8
					-84,913	-84,913	9
42,705					2,921,763	2,921,763	10
					4,750	4,750	11
34,791				1,062,479	2,509	1,064,988	12
1,023				60,519		60,519	13
568,255				28,954,728		28,954,728	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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 2013/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	J Bar 9 Ranch, Inc.	AD		NA	NA	NA
2	J Bar 9 Ranch, Inc.	LU		NA	NA	NA
3	J. Aron & Company	SF		NA	NA	NA
4	JP Morgan Ventures Energy Corporation	SF		NA	NA	NA
5	Jake Amy	LU		NA	NA	NA
6	Joseph Community Solar LLC	LU		NA	NA	NA
7	Lacomb Irrigation District	LU		NA	NA	NA
8	Los Angeles Dept. of Water & Power	AD		NA	NA	NA
9	Los Angeles Dept. of Water & Power	SF		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	AD		NA	NA	NA
14	Macquarie Energy LLC	SF		NA	NA	NA
	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 2013/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)	
					-198	-198	1
68				1,525		1,525	2
359,981				16,084,423	163,858	16,248,281	3
80,900				2,025,127	-1,700,247	324,880	4
1,219				66,910		66,910	5
735				23,662		23,662	6
3,659				127,884	36,850	164,734	7
					-750	-750	8
40,795				2,317,004		2,317,004	9
5,067				315,597		315,597	10
1,279				70,768		70,768	11
340				22,501		22,501	12
415							13
169,957				6,738,922		6,738,922	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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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	Marsh Valley Hydro Electric Company	LU		NA	NA	NA
2	Meadow Creek Project Company LLC	LU		NA	NA	NA
3	Middle Fork Irrigation District	LU		NA	NA	NA
4	Mink Creek Hydro LLC	LU		NA	NA	NA
5	Modesto Irrigation District	SF		NA	NA	NA
6	Monsanto Company	IU		NA	NA	NA
7	Morgan City Corporation	LF		NA	NA	NA
8	Morgan Stanley Capital Group, Inc.	SF		NA	NA	NA
9	Mountain Energy, Inc.	LU		NA	NA	NA
10	Mountain Wind Power II, LLC	LU		NA	NA	NA
11	Mountain Wind Power, LLC	LU		NA	NA	NA
12	Municipal Energy Agency of Nebraska	SF		NA	NA	NA
13	NaturEner Power Watch, LLC	SF		NA	NA	NA
14	Nephi City Corporation	LF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,230				191,278		191,278	1
307,676				18,289,862		18,289,862	2
26,144				1,702,598		1,702,598	3
5,953				335,321		335,321	4
450				12,150		12,150	5
					20,000,910	20,000,910	6
24				2,417		2,417	7
390,959				16,747,543	275,101	17,022,644	8
29				2,026		2,026	9
227,852				14,497,482		14,497,482	10
166,926				9,227,299		9,227,299	11
2,530				134,320		134,320	12
4					103	103	13
7				882		882	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Nevada Power Company	SF		NA	NA	NA
2	NextEra Energy Power Marketing, LLC	SF		NA	NA	NA
3	Nicholson's Sunny Bar Ranch	LU		NA	NA	NA
4	Noble Americas Gas & Power Corp.	SF		NA	NA	NA
5	NorthWestern Corporation	SF		NA	NA	NA
6	Northpoint Energy Solutions Inc.	SF		NA	NA	NA
7	Nucor Corporation	IF		NA	NA	NA
8	O.J. Power Company	LU		NA	NA	NA
9	OneEnergy, Inc.	OS		NA	NA	NA
10	Oregon Environmental Industries, LLC	LU		NA	NA	NA
11	Oregon Environmental Industries, LLC	OS		NA	NA	NA
12	Oregon State University	LU		NA	NA	NA
13	Oregon Trail Windfarm, LLC	LU		NA	NA	NA
14	PPL EnergyPlus, LLC	SF		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 2013/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	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.
35,699				1,350,007	273,127	1,623,134	1
24,824				790,095		790,095	2
1,580				92,388		92,388	3
9,000				281,600		281,600	4
243					7,225	7,225	5
187				3,470		3,470	6
					5,763,000	5,763,000	7
481				24,881		24,881	8
					35,985	35,985	9
21,616				1,407,382		1,407,382	10
					5,990	5,990	11
181				5,061		5,061	12
26,822				1,804,918		1,804,918	13
112,666				3,860,396		3,860,396	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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 2013/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	Pacific Canyon Windfarm, LLC	LU		NA	NA	NA
2	Pacific Summit Energy LLC	SF		NA	NA	NA
3	Paul Luckey	LU		NA	NA	NA
4	Payson City Corporation	LF		NA	NA	NA
5	Platte River Power Authority	SF		NA	NA	NA
6	Portland General Electric Company	AD		NA	NA	NA
7	Portland General Electric Company	LF		NA	NA	NA
8	Portland General Electric Company	SF		NA	NA	NA
9	Power County Wind Park North, LLC	LU		NA	NA	NA
10	Power County Wind Park South, LLC	LU		NA	NA	NA
11	Powerex Corporation	AD		NA	NA	NA
12	Powerex Corporation	SF		NA	NA	NA
13	Provo City Corporation	LF		NA	NA	NA
14	Public Service Company of Colorado	SF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
20,098				1,357,755		1,357,755	1
61,524				5,367,969		5,367,969	2
288				39,641		39,641	3
4				458		458	4
2,275					75,272	75,272	5
					-103,559	-103,559	6
12,000					320,000	320,000	7
77,057				2,613,839	9,131	2,622,970	8
63,984				3,788,855		3,788,855	9
57,523				3,416,416		3,416,416	10
3							11
605,523				32,727,689	559,823	33,287,512	12
50				4,394		4,394	13
2,300				103,530		103,530	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Public Service Company of New Mexico	AD		NA	NA	NA
2	Public Service Company of New Mexico	SF		NA	NA	NA
3	PUD No. 1 of Clark County	SF		NA	NA	NA
4	PUD No. 1 of Chelan County	OS		NA	NA	NA
5	PUD No. 1 of Chelan County	SF		NA	NA	NA
6	PUD No. 1 of Cowlitz County	OS		NA	NA	NA
7	PUD No. 1 of Douglas County	AD		NA	NA	NA
8	PUD No. 1 of Douglas County	AD		NA	NA	NA
9	PUD No. 1 of Douglas County	LF		NA	NA	NA
10	PUD No. 1 of Douglas County	LU		NA	NA	NA
11	PUD No. 1 of Douglas County	SF		NA	NA	NA
12	PUD No. 1 of Snohomish County	SF		NA	NA	NA
13	PUD No. 2 of Grant County	AD		NA	NA	NA
14	PUD No. 2 of Grant County	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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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.
					-23,159	-23,159	1
14,654				490,427		490,427	2
2,230				84,270		84,270	3
					24,156	24,156	4
31,327				1,066,066	3,780	1,069,846	5
					-355,482	-355,482	6
					-55,912	-55,912	7
					-128,105	-128,105	8
73,057				1,955,593		1,955,593	9
250,922					3,321,835	3,321,835	10
61,093				2,099,606	593	2,100,199	11
43,396				1,415,128		1,415,128	12
550					-519,157	-519,157	13
128,302					-7,211,199	-7,211,199	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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 2013/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. 2 of Grant County	SF		NA	NA	NA
2	Puget Sound Energy, Inc.	SF		NA	NA	NA
3	RES Ag - Oak Lea LLC	LU		NA	NA	NA
4	Rainbow Energy Marketing Corporation	AD		NA	NA	NA
5	Rainbow Energy Marketing Corporation	SF		NA	NA	NA
6	Ralphs Ranch, Inc.	AD		NA	NA	NA
7	Riverside, City of	SF		NA	NA	NA
8	Rock River 1, LLC	LU		NA	NA	NA
9	Roseburg Forest Products Company	LU		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.	LU		NA	NA	NA
13	Sacramento Municipal Utility District	AD		NA	NA	NA
14	Sacramento Municipal Utility District	LF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
44,714				1,520,026	3,934	1,523,960	1
277,053				10,541,549	12,231	10,553,780	2
832				45,459		45,459	3
400							4
30,436				976,694		976,694	5
6					817	817	6
640				7,080		7,080	7
141,574				5,023,060		5,023,060	8
92,739				4,072,004		4,072,004	9
12,071				651,928		651,928	10
1,363				78,045		78,045	11
278				19,202		19,202	12
					107,302	107,302	13
178,868				3,504,024		3,504,024	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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 2013/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	SF		NA	NA	NA
2	Salt River Project	SF		NA	NA	NA
3	San Diego Gas & Electric Company	SF		NA	NA	NA
4	Sand Ranch Windfarm, LLC	LU		NA	NA	NA
5	Santiam Water Control District	LU		0.2	0.2	0.2
6	Seattle City Light	SF		NA	NA	NA
7	Sempra Generation, LLC	AD		NA	NA	NA
8	Sempra Generation, LLC	SF		NA	NA	NA
9	Shell Energy North America (US), L.P.	AD		NA	NA	NA
10	Shell Energy North America (US), L.P.	IF		NA	NA	NA
11	Shell Energy North America (US), L.P.	SF		NA	NA	NA
12	Shoshone Irrigation District	LU		2.5	1.4	1.0
13	Sierra Pacific Power Company	SF		NA	NA	NA
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		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
8,950				335,400		335,400	1
57,035				2,357,447	70,672	2,428,119	2
4,800				323,950		323,950	3
24,926				1,681,447		1,681,447	4
1,494			13,632	154,860		168,492	5
110,624				3,549,121	3,524	3,552,645	6
-1					-36	-36	7
16,800				623,700		623,700	8
925							9
61,407				2,905,585		2,905,585	10
382,600				12,484,454	-3,605,397	8,879,057	11
9,683			186,682	425,452		612,134	12
853					71,800	71,800	13
2,755				94,865	1,683	96,548	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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 2013/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	Simplot Phosphates LLC	LU		10	13	9
2	Slate Creek Hydro Company, Inc.	LU		3.1	1.1	0.6
3	Solwatt LLC	LU		NA	NA	NA
4	Southern California Edison Company	SF		NA	NA	NA
5	Spanish Fork Wind Park 2, LLC	LU		NA	NA	NA
6	Sprague Hydro, LLC	LU		0.4	0.5	0.2
7	Springville City Corporation	LF		NA	NA	NA
8	Stahlbush Island Farms, Inc.	IU		NA	NA	NA
9	Strawberry Electric Service District	LF		NA	NA	NA
10	Sunnyside Cogeneration Associates	LU		52	53	47
11	Swalley Irrigation District	LU		NA	NA	NA
12	TMF Biofuels, LLC	AD		NA	NA	NA
13	TMF Biofuels, LLC	LU		NA	NA	NA
14	Tacoma Power	AD		NA	NA	NA
	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 2013/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)	
79,212			494,000	4,114,911		4,608,911	1
5,483			90,853	601,424		692,277	2
511				16,084		16,084	3
2,310				65,583		65,583	4
46,031				2,446,795		2,446,795	5
2,601			43,494	315,772		359,266	6
28				3,378		3,378	7
5,980				325,720		325,720	8
55				4,398		4,398	9
414,217			10,726,151	16,193,977		26,920,128	10
2,266				156,483		156,483	11
56					1,387	1,387	12
21,457				1,072,082		1,072,082	13
2					50,000	50,000	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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 2013/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.

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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	Tacoma Power	SF		NA	NA	NA
2	Tenaska Power Services Co.	SF		NA	NA	NA
3	Tesoro Refining & Marketing Company	LU		NA	NA	NA
4	Thayn Hydro LLC	LU		0.3	0.4	0.3
5	The Energy Authority, Inc.	SF		NA	NA	NA
6	The Town of the City of Buffalo	LU		0.2	0.2	0.2
7	Three Buttes Windpower, LLC	LU		NA	NA	NA
8	Threemile Canyon Wind I, LLC	LU		NA	NA	NA
9	Top of The World Wind Energy LLC	LU		NA	NA	NA
10	TransAlta Energy Marketing (U.S.) Inc.	AD		NA	NA	NA
11	TransAlta Energy Marketing (U.S.) Inc.	SF		NA	NA	NA
12	Tri-State Gen. & Trans.	AD		NA	NA	NA
13	Tri-State Gen. & Trans.	LF		25	24	18
14	Tri-State Gen. & Trans.	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.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
61,753				1,645,531	1,228	1,646,759	1
19,135				928,093		928,093	2
30,148				894,129		894,129	3
2,861			90,623	253,448		344,071	4
117,850				4,504,388		4,504,388	5
1,846			35,218	190,534		225,752	6
337,785				21,529,508		21,529,508	7
22,982				1,573,813		1,573,813	8
642,164				42,382,819		42,382,819	9
50							10
757,406				27,099,375		27,099,375	11
9					229	229	12
121,509			6,378,000	3,511,610		9,889,610	13
10,574				181,018	214,412	395,430	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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	Tuana Springs Energy, LLC	OS		NA	NA	NA
2	Tucson Electric Power Company	SF		NA	NA	NA
3	Twin Eagle Resource Management, LLC	SF		NA	NA	NA
4	U.S. Department of the Interior	LU		NA	NA	NA
5	UNS Electric, Inc.	SF		NA	NA	NA
6	US Magnesium LLC	LF		NA	NA	NA
7	United States Air Force at Hill Base	LU		NA	NA	NA
8	Utah Associated Municipal Power	OS		NA	NA	NA
9	Wagon Trail, LLC	LU		NA	NA	NA
10	Ward Butte Windfarm, LLC	LU		NA	NA	NA
11	Wasatch Integrated Waste Management	LU		NA	NA	NA
12	Weber County	LU		NA	NA	NA
13	Western Area Power Administration	LF		NA	NA	NA
14	Western Area Power Administration	SF		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 2013/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
					254,073	254,073	1
14,781				439,250	150,909	590,159	2
9,200				414,616		414,616	3
20				466		466	4
53,879				1,934,071		1,934,071	5
					6,441,608	6,441,608	6
13,703				649,254		649,254	7
54,840				1,567,390	553,400	2,120,790	8
7,823				527,834		527,834	9
17,935				1,205,942		1,205,942	10
368				20,297		20,297	11
4,387				212,749		212,749	12
30,486					1,145,825	1,145,825	13
14,235					520,709	520,709	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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 2013/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	Western Area Power Administration	SF		NA	NA	NA
2	Wolverine Creek Energy, LLC	LU		NA	NA	NA
3	Yakima-Tieton Irrigation District	LU		1.7	1.5	0.9
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	AD	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)	
1,738				46,435	29	46,464	1
154,015				8,744,766		8,744,766	2
6,454			19,909	205,106		225,015	3
6,615				214,140		214,140	4
					-50,000	-50,000	5
					-1,479,332	-1,479,332	6
-3,558,121					-129,340,690	-129,340,690	7
					-4,237,655	-4,237,655	8
					1,103,395	1,103,395	9
							10
							11
	569,772	571,377			-1,666,947	-1,666,947	12
	1,823						13
	22	-6			371	371	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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 2013/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	Basin Electric Power Cooperative	EX	T-11	NA	NA	NA
2	Bonneville Power Administration	AD	T-11	NA	NA	NA
3	Bonneville Power Administration	AD	237	NA	NA	NA
4	Bonneville Power Administration	EX	237	NA	NA	NA
5	Bonneville Power Administration	EX	368	NA	NA	NA
6	Bonneville Power Administration	EX	519	NA	NA	NA
7	Bonneville Power Administration	EX	554	NA	NA	NA
8	Bonneville Power Administration	EX	T-11	NA	NA	NA
9	Bonneville Power Administration	EX	T-12	NA	NA	NA
10	City of Redding	EX	364	NA	NA	NA
11	Cyrg Energy	EX	T-11	NA	NA	NA
12	Deseret Generation & Transmission Coop	AD	280	NA	NA	NA
13	Deseret Generation & Transmission Coop	EX	280	NA	NA	NA
14	Emerald People's Utility District	EX	351	NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	9,659	160			297,772	297,772	1
	439	-604			3,804	3,804	2
	9,634				24,082	24,082	3
		26,393			-65,981	-65,981	4
	155,901	155,901					5
	102,898	94,200			276,984	276,984	6
	222,511	10,937					7
	13,259	8,785			137,621	137,621	8
	27,203				1,075,578	1,075,578	9
	110,006	109,287			-130,201	-130,201	10
	2,168	2,090			3,942	3,942	11
	2,359	-85			-50,703	-50,703	12
	54,246	47,951			-95,436	-95,436	13
		706			-17,664	-17,664	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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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.

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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	Eugene Water & Electric Board	EX	T-12	NA	NA	NA
2	Iberdrola Renewables, LLC	EX	T-11	NA	NA	NA
3	Idaho Power Company	EX	380	NA	NA	NA
4	JP Morgan Ventures Energy Corporation	EX	T-11	NA	NA	NA
5	Los Angeles Dept. of Water & Power	EX	OV-1	NA	NA	NA
6	Milford Wind Corridor Phase I, LLC	EX	OV-1	NA	NA	NA
7	Milford Wind Corridor Phase II, LLC	EX	OV-1	NA	NA	NA
8	NextEra Energy Power Marketing, LLC	EX	T-11	NA	NA	NA
9	Noble Americas Energy Solutions LLC	AD	T-11	NA	NA	NA
10	Noble Americas Energy Solutions LLC	EX	T-11	NA	NA	NA
11	Portland General Electric Company	EX	554	NA	NA	NA
12	Public Service Company of Colorado	AD	334	NA	NA	NA
13	Public Service Company of Colorado	EX	319	NA	NA	NA
14	Public Service Company of Colorado	EX	334	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)	
	16,966	16,549			11,139	11,139	1
	1,481	3,593			-79,247	-79,247	2
	431,225	267,826					3
	1,937	1,086			24,275	24,275	4
	6,581				357,807	357,807	5
		3,723			-234,217	-234,217	6
		2,858			-165,110	-165,110	7
	93,973	60,467			980,924	980,924	8
	751	-657			6,089	6,089	9
	10,677	3,683			179,030	179,030	10
	158,278	157,094					11
	3						12
	3,035						13
	1,313,932	1,303,377			5,400,000	5,400,000	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Public Service Company of Colorado	EX	T-12	NA	NA	NA
2	PUD No. 1 of Cowlitz County	EX	554	NA	NA	NA
3	Seattle City Light	EX	554	NA	NA	NA
4	Southern California Edison Company	EX	T-11	NA	NA	NA
5	Southern California Public Power Auth.	EX	T-11	NA	NA	NA
6	Tri-State Gen. and Trans.	AD	319	NA	NA	NA
7	Tri-State Gen. and Trans.	AD	T-11	NA	NA	NA
8	Tri-State Gen. and Trans.	EX	319	NA	NA	NA
9	Tri-State Gen. and Trans.	EX	T-11	NA	NA	NA
10	Utah Associated Municipal Power	AD	T-11	NA	NA	NA
11	Utah Associated Municipal Power	EX	T-11	NA	NA	NA
12	Utah Municipal Power Agency	AD	T-11	NA	NA	NA
13	Utah Municipal Power Agency	EX	T-11	NA	NA	NA
14	Warm Springs Power Enterprises	EX	T-11	NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	80,919	78,992			115,552	115,552	1
	164,497	209,840					2
	354,485	363,404			534,412	534,412	3
	77,491	64,293			387,600	387,600	4
	349	1,772			-46,020	-46,020	5
					-515	-515	6
	74	-391			565	565	7
	3,035				51,084	51,084	8
	3,700	6,115			-71,627	-71,627	9
	5,494	-4,241			38,456	38,456	10
	133,209	55,739			2,382,054	2,382,054	11
	1,991	-1,577			9,986	9,986	12
	30,206	11,024			568,632	568,632	13
	9,571	1,932			222,306	222,306	14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

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 2013/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	Western Area Power Administration	AD	LAS-4	NA	NA	NA
2	Western Area Power Administration	EX	LAS-4	NA	NA	NA
3	System Deviation	NA		NA	NA	NA
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	77	11,472			-300,043	-300,043	1
	701	49,802			-1,225,439	-1,225,439	2
-25,182							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
12,096,279	4,186,538	3,694,867	79,100,821	654,538,801	-67,085,565	666,554,057	

Schedule Page: 326 Line No.: 3 Column: b
Arizona Public Service Company - contract termination date: October 31, 2020.

Schedule Page: 326 Line No.: 4 Column: l
Line loss.

Schedule Page: 326 Line No.: 5 Column: l
Reserve share.

Schedule Page: 326 Line No.: 6 Column: l
Financial swap.

Schedule Page: 326 Line No.: 8 Column: b
Settlement adjustment.

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

Schedule Page: 326 Line No.: 11 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326 Line No.: 14 Column: l
Non-generation agreement.

Schedule Page: 326.1 Line No.: 2 Column: a
PacifiCorp has 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.

Schedule Page: 326.1 Line No.: 4 Column: b
Blanding City Corporation - contract termination date: September 26, 2013.

Schedule Page: 326.1 Line No.: 5 Column: b
Bonneville Power Administration - contract termination date: 30 days written notice.

Schedule Page: 326.1 Line No.: 5 Column: l
Ancillary services.

Schedule Page: 326.1 Line No.: 6 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.1 Line No.: 6 Column: l
Ancillary services.

Schedule Page: 326.1 Line No.: 7 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.1 Line No.: 7 Column: l
Purchase of renewable energy credit certificates for Oregon renewable portfolio standard requirements.

Schedule Page: 326.1 Line No.: 8 Column: l
Reserve share.

Schedule Page: 326.1 Line No.: 14 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.1 Line No.: 14 Column: l
Purchase of renewable energy credit certificates for Oregon renewable portfolio standard requirements.

Schedule Page: 326.2 Line No.: 1 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.2 Line No.: 1 Column: l
Purchase of renewable energy credit certificates for Oregon renewable portfolio standard requirements.

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.: 5 Column: b
Settlement adjustment.
Schedule Page: 326.2 Line No.: 5 Column: l
Settlement adjustment.
Schedule Page: 326.2 Line No.: 8 Column: b
Settlement adjustment.
Schedule Page: 326.2 Line No.: 8 Column: l
Settlement adjustment.
Schedule Page: 326.2 Line No.: 10 Column: l
Financial swap.
Schedule Page: 326.2 Line No.: 14 Column: b
Settlement adjustment.
Schedule Page: 326.2 Line No.: 14 Column: l
Settlement adjustment.
Schedule Page: 326.3 Line No.: 4 Column: b
City of Hurricane - contract termination date: August 31, 2017.
Schedule Page: 326.3 Line No.: 6 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.: 10 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.: 10 Column: l
Financial swap.
Schedule Page: 326.3 Line No.: 14 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: 326.3 Line No.: 14 Column: b
Deseret Generation and Transmission Cooperative - contract termination date: September 30, 2024.
Schedule Page: 326.3 Line No.: 14 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.: 1 Column: l
Financial swap.
Schedule Page: 326.4 Line No.: 3 Column: b
Settlement adjustment.
Schedule Page: 326.4 Line No.: 3 Column: l
Settlement adjustment.
Schedule Page: 326.4 Line No.: 8 Column: b
Settlement adjustment.
Schedule Page: 326.4 Line No.: 8 Column: l
Settlement adjustment.
Schedule Page: 326.4 Line No.: 9 Column: l
Financial swap.
Schedule Page: 326.4 Line No.: 12 Column: l
Line loss.
Schedule Page: 326.5 Line No.: 3 Column: l
Financial swap.
Schedule Page: 326.5 Line No.: 8 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.5 Line No.: 10 Column: b

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

Schedule Page: 326.5 Line No.: 10 Column: l

Line loss.

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

Under Electric Service Agreement subject to termination upon timely notification.

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

This footnote applies to all occurrences of "Hermiston Generating Company, L.P." on pages 326-327. 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) in this Form No. 1 for further information on the Hermiston Generating Plant.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 326.6 Line No.: 6 Column: l

On peak incentive, supplemental dispatch efficiency expense, start-up charges and committee settlements.

Schedule Page: 326.6 Line No.: 7 Column: b

Settlement adjustment.

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

Financial swap.

Schedule Page: 326.6 Line No.: 9 Column: b

Settlement adjustment.

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

Labor, equipment and administration fees associated with hydro project in Idaho Falls, Idaho.

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

Labor, equipment and administration fees associated with hydro project in Idaho Falls, Idaho.

Schedule Page: 326.6 Line No.: 11 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.6 Line No.: 11 Column: l

Purchase of renewable energy credit certificates for Oregon renewable portfolio standard requirements.

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

Reserve share.

Schedule Page: 326.7 Line No.: 1 Column: b

Settlement adjustment.

Schedule Page: 326.7 Line No.: 1 Column: l

Settlement adjustment.

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

Financial swap.

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

Financial swap.

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

Fixed annual payment.

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

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

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

Compensation for interruptible service and operating reserves.

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

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.8 Line No.: 8 Column: l

Financial swap.

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

Reserve share.

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

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.9 Line No.: 1 Column: a

Nevada Power Company is a principal subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of MidAmerican Energy Holdings Company.

Schedule Page: 326.9 Line No.: 1 Column: l

Line loss.

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

Reserve share.

Schedule Page: 326.9 Line No.: 7 Column: l

Ancillary services.

Schedule Page: 326.9 Line No.: 9 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.9 Line No.: 9 Column: l

Purchase of renewable energy credit certificates for Oregon renewable portfolio standard requirements.

Schedule Page: 326.9 Line No.: 11 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.9 Line No.: 11 Column: l

Purchase of renewable energy credit certificates for Oregon renewable portfolio standard requirements.

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

Under Electric Service Agreement subject to termination upon timely notification.

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

Line loss.

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

Settlement adjustment.

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

Operation expense plus amortization of unrecovered costs of Cove Project.

Schedule Page: 326.10 Line No.: 7 Column: b

Portland General Electric Company - contract termination date: terminates when the Round Butte project is no longer operating for power production purposes.

Schedule Page: 326.10 Line No.: 7 Column: l

Operation expense plus amortization of unrecovered costs of Cove Project.

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

Reserve share.

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

Settlement adjustment.

Schedule Page: 326.10 Line No.: 12 Column: l

Financial swap.

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

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.11 Line No.: 1 Column: b

Settlement adjustment.

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

Line loss.

Schedule Page: 326.11 Line No.: 3 Column: a

This footnote applies to all occurrences of "PUD No. 1 of Clark County" on pages 326-327. Complete name is Public Utility District No. 1 of Clark County.

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

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: 326.11 Line No.: 4 Column: l

Purchase of renewable energy credit certificates for Oregon renewable portfolio standard requirements.

Schedule Page: 326.11 Line No.: 5 Column: l

Reserve share.

Schedule Page: 326.11 Line No.: 6 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.: 6 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.11 Line No.: 6 Column: l

Liability associated with paper pond at hydro facility located on the Lewis River in Washington.

Schedule Page: 326.11 Line No.: 7 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.: 7 Column: b

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 326.11 Line No.: 8 Column: b

Settlement adjustment.

Schedule Page: 326.11 Line No.: 8 Column: l

Operating expense, bond interest, amortization and taxes.

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

Public Utility District No. 1 of Douglas County - contract termination date: August 31, 2018.

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

Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.11 Line No.: 11 Column: l

Reserve share.

Schedule Page: 326.11 Line No.: 12 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.: 13 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.: 13 Column: b

Settlement adjustment.

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

Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.11 Line No.: 14 Column: l
Operating expense, bond interest, amortization and taxes.
Schedule Page: 326.12 Line No.: 1 Column: l
Reserve share.
Schedule Page: 326.12 Line No.: 2 Column: l
Reserve share.
Schedule Page: 326.12 Line No.: 4 Column: b
Settlement adjustment.
Schedule Page: 326.12 Line No.: 6 Column: b
Settlement adjustment.
Schedule Page: 326.12 Line No.: 6 Column: l
Settlement adjustment.
Schedule Page: 326.12 Line No.: 13 Column: b
Settlement adjustment.
Schedule Page: 326.12 Line No.: 13 Column: l
Settlement adjustment.
Schedule Page: 326.12 Line No.: 14 Column: b
Sacramento Municipal Utility District - contract termination date: December 31, 2014.
Schedule Page: 326.13 Line No.: 2 Column: l
Line loss.
Schedule Page: 326.13 Line No.: 6 Column: l
Reserve share.
Schedule Page: 326.13 Line No.: 7 Column: b
Settlement adjustment.
Schedule Page: 326.13 Line No.: 7 Column: l
Settlement adjustment.
Schedule Page: 326.13 Line No.: 9 Column: b
Settlement adjustment.
Schedule Page: 326.13 Line No.: 11 Column: l
Financial swap.
Schedule Page: 326.13 Line No.: 13 Column: a
This footnote applies to all occurrences of "Sierra Pacific Power Company" on pages 326-327. Sierra Pacific Power Company is a principal subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of MidAmerican Energy Holdings Company.
Schedule Page: 326.13 Line No.: 13 Column: l
Line loss.
Schedule Page: 326.13 Line No.: 14 Column: l
Reserve share.
Schedule Page: 326.14 Line No.: 7 Column: b
Under Electric Service Agreement subject to termination upon timely notification.
Schedule Page: 326.14 Line No.: 9 Column: b
Under Electric Service Agreement subject to termination upon timely notification.
Schedule Page: 326.14 Line No.: 12 Column: b
Settlement adjustment.
Schedule Page: 326.14 Line No.: 12 Column: l
Settlement adjustment.
Schedule Page: 326.14 Line No.: 14 Column: b
Settlement adjustment.
Schedule Page: 326.14 Line No.: 14 Column: l
Settlement of Pacific Northwest Refund case.
Schedule Page: 326.15 Line No.: 1 Column: l
Reserve share.
Schedule Page: 326.15 Line No.: 3 Column: a
This footnote applies to all occurrences of "Tesoro Refining & Marketing Company" on pages

326-327. Complete name is Tesoro Refining & Marketing Company, LLC.

Schedule Page: 326.15 Line No.: 10 Column: b

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

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

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

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

Line loss.

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

Secondary, economy and/or non-firm.

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

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

Schedule Page: 326.16 Line No.: 2 Column: l

Line loss.

Schedule Page: 326.16 Line No.: 4 Column: a

This footnote applies to all occurrences of "U.S. Department of the Interior" on pages 326-327. Complete name is U.S. Department of the Interior - Bureau of Land Management.

Schedule Page: 326.16 Line No.: 6 Column: b

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

Schedule Page: 326.16 Line No.: 6 Column: l

Ancillary services.

Schedule Page: 326.16 Line No.: 7 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.: 8 Column: a

This footnote applies to all occurrences of "Utah Associated Municipal Power" on pages 326-327. Complete name is Utah Associated Municipal Power Systems.

Schedule Page: 326.16 Line No.: 8 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.16 Line No.: 8 Column: l

Start-up and variable operation and maintenance charges.

Schedule Page: 326.16 Line No.: 11 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.: 13 Column: b

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

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

Line loss.

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

Line loss.

Schedule Page: 326.17 Line No.: 1 Column: l

Reserve share.

Schedule Page: 326.17 Line No.: 5 Column: l

Reversal of reserve for potential 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 during this period.

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

Exchange energy expense.

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

Settlement adjustment.

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

Imbalance energy.

Schedule Page: 326.18 Line No.: 1 Column: l

Imbalance energy.

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

Settlement adjustment.

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

Imbalance energy.

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

Settlement adjustment.

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

Storage and exchange charges.

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

Storage and exchange charges.

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

Exchange energy expense.

Schedule Page: 326.18 Line No.: 8 Column: l

Imbalance energy.

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

Imbalance energy.

Schedule Page: 326.18 Line No.: 10 Column: l

Exchange energy expense.

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

Imbalance energy.

Schedule Page: 326.18 Line No.: 12 Column: b

Settlement adjustment.

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

Storage and exchange charges.

Schedule Page: 326.19 Line No.: 1 Column: l

Exchange energy expense.

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

Station service for third party wind project.

Schedule Page: 326.19 Line No.: 6 Column: l

Reimbursement for providing station service to third party wind project.

Schedule Page: 326.19 Line No.: 7 Column: l

Reimbursement for providing station service to third party wind project.

Schedule Page: 326.19 Line No.: 8 Column: l

Imbalance energy.

Schedule Page: 326.19 Line No.: 9 Column: b

Settlement adjustment.

Schedule Page: 326.19 Line No.: 9 Column: l

Imbalance energy.

Schedule Page: 326.19 Line No.: 10 Column: l

Imbalance energy.

Schedule Page: 326.19 Line No.: 12 Column: b

Settlement adjustment.

Schedule Page: 326.19 Line No.: 14 Column: l

Storage and exchange charges.

Schedule Page: 326.20 Line No.: 1 Column: l

Exchange energy expense.

Schedule Page: 326.20 Line No.: 3 Column: l

Exchange energy expense.

Schedule Page: 326.20 Line No.: 4 Column: l

Imbalance energy.

Schedule Page: 326.20 Line No.: 5 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.: 5 Column: l

Imbalance energy.

Schedule Page: 326.20 Line No.: 6 Column: b

Settlement adjustment.

Schedule Page: 326.20 Line No.: 6 Column: l

Imbalance energy.

Schedule Page: 326.20 Line No.: 7 Column: b

Settlement adjustment.

Schedule Page: 326.20 Line No.: 7 Column: l

Imbalance energy.

Schedule Page: 326.20 Line No.: 8 Column: l

Imbalance energy.

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: b

Settlement adjustment.

Schedule Page: 326.20 Line No.: 12 Column: l

Imbalance energy.

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: 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 2013/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	Arizona Public Service Company	Arizona Public Service Company		OS
2	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	FNO
3	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	AD
4	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	AD
5	Black Hills/Colorado Electric Utility Company			NF
6	Black Hills/Colorado Electric Utility Company			AD
7	Black Hills/Colorado Electric Utility Company			SFP
8	Black Hills/Colorado Electric Utility Company			AD
9	Black Hills Corporation		Montana-Dakota Utilities	FNO
10	Black Hills Corporation		Montana-Dakota Utilities	AD
11	Black Hills Corporation			NF
12	Black Hills Corporation			AD
13	Black Hills Corporation			SFP
14	Black Hills Corporation			AD
15	Black Hills Corporation		Black Hills Corporation	LFP
16	Black Hills Corporation		Black Hills Corporation	AD
17	Bonneville Power Administration			OS
18	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
19	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
20	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	LFP
21	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
22	Bonneville Power Administration	Bonneville Power Administration	Umpqua Indian Utility Cooperative	FNO
23	Bonneville Power Administration	Bonneville Power Administration	Umpqua Indian Utility Cooperative	AD
24	Bonneville Power Administration	Bonneville Power Administration	Benton REA	FNO
25	Bonneville Power Administration	Bonneville Power Administration	Benton REA	AD
26	Bonneville Power Administration	Bonneville Power Administration	Umatilla Electric & Columbia	FNO
27	Bonneville Power Administration	Bonneville Power Administration	Umatilla Electric & Columbia	AD
28	Bonneville Power Administration	U. S. Bureau of Reclamation	Bonneville Power Administration	LFP
29	Bonneville Power Administration	U. S. Bureau of Reclamation	Bonneville Power Administration	AD
30	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
31	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
32	Bonneville Power Administration	Bonneville Power Administration	Yakama Power	FNO
33	Bonneville Power Administration	Bonneville Power Administration	Yakama Power	AD
34	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	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.
R.S. 436		Borah/Brady Sub				1
V11-1,2,3	Yellowtail Sub	Sheridan Substation	1	3,960	3,960	2
V11-1,2,3	Yellowtail Sub	Sheridan Substation	1	877	877	3
V11-1,2	Various	Various				4
V11-1,2,8	Various	Various		137	137	5
V11-1,2	Various	Various				6
V11-1,2,7	Various	Various		1,278	1,278	7
V11-1,2	Various	Various		120	120	8
V11-1,2	Various	Sheridan Substation	48	7,655	7,655	9
V11-1,2	Various	Sheridan Substation	48	2,637	2,637	10
V11-1,2,8	Various	Various		16,569	16,569	11
V11-1,2,8	Various	Various		4,189	4,189	12
V11-1,2,7	Various	Various		3,608	3,608	13
V11-1,2,7	Various	Various		689	689	14
V11-1,2,7	Various	Wyodak Substation	52	159,922	159,922	15
V11-1,2,7	Various	Wyodak Substation	53	13,126	13,126	16
R.S. 369	Midpoint Substation	Summer Lake Sub				17
R.S. 237	Various	Various	316	1,089,709	1,089,709	18
R.S. 237	Various	Various	292	107,030	107,030	19
V11-2,7	Lost Creek Hydro Plt	Alvey Substation	58	190,684	190,684	20
V11-2,7	Lost Creek Hydro Plt	Alvey Substation	59	-8,836	-8,836	21
V11-1,2,3,4	Bonneville Power Adm	Gazley Substation	3	23,751	23,751	22
V11-1,2,3	Bonneville Power Adm	Gazley Substation	4	2,505	2,505	23
V11-1,2,3	Bonneville Power Adm	Tieton Substation	1	5,332	5,332	24
V11-1,2,3	Bonneville Power Adm	Tieton Substation	1	908	908	25
V11-1,2,3	McNary Substation	Hinkle Substation	1	894	894	26
V11-1,2,3	McNary Substation	Hinkle Substation	1	94	94	27
V11-2,7	USBR Green Springs	Bonneville Power Adm	19	57,151	57,151	28
V11-2,7	USBR Green Springs	Bonneville Power Adm	19	-6,524	-6,524	29
R.S. 368	Malin Substation	Malin Substation		691,534	691,534	30
R.S. 368	Malin Substation	Malin Substation		60,638	60,638	31
V11-1,2,3,4	Bonneville Power Adm		6	33,631	33,631	32
V11-1,2,3,4	Bonneville Power Adm		5	3,187	3,187	33
R.S. 299	Various	Various	198	1,030,985	1,030,985	34
			4,438	**12,830,379**	**12,712,106**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
				1
13,925		25,025	38,950	2
		-86	-86	3
		-4	-4	4
	375	57	432	5
		-26	-26	6
	9,516	734	10,250	7
		-11	-11	8
1,117,870		49,419	1,167,289	9
		-54,126	-54,126	10
	29,091	1,882	30,973	11
		1,566	1,566	12
	18,020	1,024	19,044	13
		927	927	14
1,210,316		53,395	1,263,711	15
		-83,042	-83,042	16
				17
4,529,672		55,593	4,585,265	18
		346,660	346,660	19
1,355,561		14,540	1,370,101	20
		-110,855	-110,855	21
77,588		152,589	230,177	22
		6,797	6,797	23
15,423		2,141	17,564	24
		-670	-670	25
1,541		212	1,753	26
		-701	-701	27
435,718		4,594	440,312	28
		-38,242	-38,242	29
		246,946	246,946	30
		22,450	22,450	31
129,682		107,271	236,953	32
		-6,729	-6,729	33
896,621		1,024,573	1,921,194	34
38,697,973	**12,779,898**	**34,015,065**	**85,492,936**	

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 2013/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	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
2	Bonneville Power Administration			NF
3	Bonneville Power Administration			AD
4	Bonneville Power Administration			SFP
5	Bonneville Power Administration			AD
6	Bonneville Power Administration	Bonneville Power Administration	Clark Public Utilities	FNO
7	Bonneville Power Administration	Bonneville Power Administration	Clark Public Utilities	AD
8	Cargill Power Markets, LLC			NF
9	Cargill Power Markets, LLC			AD
10	Cargill Power Markets, LLC			SFP
11	Cargill Power Markets, LLC			AD
12	Constellation Energy Commodities Group			NF
13	Constellation Energy Commodities Group			AD
14	Constellation Energy Commodities Group			SFP
15	Constellation Energy Commodities Group			AD
16	Coral Power			NF
17	Coral Power			AD
18	Coral Power			SFP
19	Cowlitz County PUD	Cowlitz County PUD	Bonneville Power Administration	OS
20	Cowlitz County PUD	Cowlitz County PUD	Bonneville Power Administration	AD
21	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	OS
22	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	AD
23	Deseret Generation & Trans.			NF
24	EDF Trading North America, LLC			AD
25	EDF Trading North America, LLC			AD
26	Enel Cove Fort, LLC	Enel Cove Fort, LLC		LFP
27	Enel Cove Fort, LLC	Enel Cove Fort, LLC		LFP
28	Eugene Water & Electric Board			AD
29	Fall River Rural Electric Cooperative	Marysville Hydro Partners	Idaho Power Company	OS
30	Fall River Rural Electric Cooperative	Marysville Hydro Partners	Idaho Power Company	AD
31	Foote Creek III, LLC	Foote Creek III, LLC		OS
32	Foote Creek III, LLC	Foote Creek III, LLC		AD
33	Iberdrola Renewables, LLC			NF
34	Iberdrola Renewables, LLC			AD
	TOTAL			

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
R.S. 299	Various	Various	207	104,202	104,202	1
V11-1,2,3,8	Various	Various		3,076	3,076	2
V11-1,2,3,8	Various	Various		2,422	2,422	3
V11-1,2,3,7	Various	Various		7,602	7,602	4
V11-1,2,3,7	Various	Various		8,322	8,322	5
V11-1,2,3,4	Cardwell-Merwin		19	108,186	108,186	6
V11-1,2,3,4,11	Cardwell-Merwin			2,939	2,939	7
V11-1,2,8	Various	Various		100,801	100,801	8
V11-1,2,8	Various	Various		-34,564	-34,564	9
V11-1,2,7	Various	Various		1,899	1,899	10
V11-1,2	Various	Various		-863	-863	11
V11-1,2,8	Various	Various		375	375	12
V11-1,2	Various	Various		-33,104	-33,104	13
V11-1-3,7	Various	Various		400	400	14
V11-1,2	Various	Various				15
V11-1,2,8	Various	Various		7,837	7,837	16
V11-1,2,8	Various	Various		-970	-970	17
V11-1,2,7	Various	Various		25,210	25,210	18
R.S. 234	Swift Unit No. 2	Woodland Substation				19
R.S. 234	Swift Unit No. 2	Woodland Substation				20
R.S. 280	Various	Various	104	632,463	632,463	21
R.S. 280	Various	Various	91	61,799	61,799	22
V11-1,2	Various	Various		154	154	23
V11-1,2	Various	Various		-256	-256	24
V11-1,2	Various	Various		-145	-145	25
V11	Enel Cove Fort	Red Butte Substation				26
V11	Enel Cove Fort	Mona Substation				27
V11-1,2	Various	Various		-1	-1	28
R.S. 322	Targhee Substation	Goshen Substation				29
R.S. 322	Targhee Substation	Goshen Substation				30
S.A 130	Foote Creek Sub	Various				31
S.A 130	Foote Creek Sub	Various				32
V11-1-3,8,9,11	Various	Various		197,421	197,421	33
V11-1-3,8,9,11	Various	Various		-16,770	-16,770	34
			4,438	**12,830,379**	**12,712,106**	

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 (I), 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.
		175,086	175,086	1
	16,992	725	17,717	2
		12,704	12,704	3
	35,093	1,631	36,724	4
		41,658	41,658	5
430,388		65,378	495,766	6
		-69,223	-69,223	7
	847,448	36,725	884,173	8
		-14,878	-14,878	9
	16,944	10,906	27,850	10
		-573	-573	11
	1,745	76	1,821	12
		-84	-84	13
		-43,812	-43,812	14
		-33,550	-33,550	15
	49,962	2,810	52,772	16
		-619	-619	17
	98,816	4,245	103,061	18
		117,403	117,403	19
		10,181	10,181	20
1,977,392		2,372,865	4,350,257	21
		1,075,146	1,075,146	22
	453	21	474	23
		-413	-413	24
		-201	-201	25
		50,625	50,625	26
		81,000	81,000	27
		-1	-1	28
		138,699	138,699	29
		12,609	12,609	30
		33,168	33,168	31
		3,015	3,015	32
	1,404,099	252,460	1,656,559	33
		258,158	258,158	34
38,697,973	**12,779,898**	**34,015,065**	**85,492,936**	

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	Iberdrola Renewables, LLC			SFP
2	Iberdrola Renewables, LLC	Iberdrola Renewables, LLC		OS
3	Iberdrola Renewables, LLC	Iberdrola Renewables, LLC		AD
4	Iberdrola Renewables, LLC	Exxon Mobil	Nevada Power Company	LFP
5	Iberdrola Renewables, LLC	Exxon Mobil	Nevada Power Company	AD
6	Iberdrola Renewables, LLC	Bonneville Power Administration	Oregon Direct Access	FNO
7	Iberdrola Renewables, LLC	Iberdrola Renewables, LLC		LFP
8	Idaho Power Company	Idaho Power Company	Idaho Power Company	OS
9	Idaho Power Company	Exxon Mobil	Nevada Power Company	LFP
10	Idaho Power Company	Exxon Mobil	Nevada Power Company	AD
11	Idaho Power Company			OS
12	Idaho Power Company			AD
13	Idaho Power Company			OS
14	Idaho Power Company			AD
15	Idaho Power Company			NF
16	Idaho Power Company			AD
17	Idaho Power Company			SFP
18	Idaho Power Company			AD
19	JP Morgan Ventures Energy Corp.			NF
20	JP Morgan Ventures Energy Corp.			AD
21	JP Morgan Ventures Energy Corp.			SFP
22	JP Morgan Ventures Energy Corp.			AD
23	Los Angeles Department of Water & Power			SFP
24	Los Angeles Department of Water & Power			NF
25	Los Angeles Department of Water & Power			AD
26	Macquarie Energy, LLC			NF
27	Macquarie Energy, LLC			SFP
28	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	OS
29	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	AD
30	Morgan Stanley Capital Group, Inc.			NF
31	Morgan Stanley Capital Group, Inc.			AD
32	Morgan Stanley Capital Group, Inc.			SFP
33	Morgan Stanley Capital Group, Inc.			AD
34	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	Grant County PUD	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)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
V11-1,2,7	Various	Various		12,988	12,988	1
V11-5,6						2
V11-5,6						3
V11-1,2,7	Trona Substation	Red Butte/Mona Sub	31	66,531	66,531	4
V11-1,2,7	Trona Substation	Red Butte/Mona Sub	32	-4,788	-4,788	5
V11-1,2,3	Ponderosa Substation	Various	1	11,114	11,114	6
V11	Malin 500 Substation	Round Mountain Sub				7
R.S. 427	Goshen Substation	Goshen Substation				8
V11-1,2,7	Trona Substation	Red Butte/Mona Sub	78	66,060	66,060	9
V11-1,2,7	Trona Substation	Red Butte/Mona Sub		-4,421	-4,421	10
R.S. 257	Antelope Substation	Antelope Substation		188,742	188,742	11
R.S. 257	Antelope Substation	Antelope Substation		22,528	22,528	12
R.S. 203	Jim Bridger Sub	Bridger Pump Sub		42,883	42,883	13
R.S. 203	Jim Bridger Sub	Bridger Pump Sub		3,801	3,801	14
V11-1,2,8	Various	Various		12,900	12,900	15
V11-1,2,8	Various	Various		-6,841	-6,841	16
V11-1,2,7	Various	Various		2,610	2,610	17
V11-1,2,7	Various	Various		-2,209	-2,209	18
V11-1-3,8,11	Various	Various		68,205	68,205	19
V11-1,2,3	Various	Various		-4,816	-4,816	20
V11-1,2,7	Various	Various				21
V11-1,2,7	Various	Various		-2	-2	22
V11-1,2,7	Various	Various		4,415	4,415	23
V11-1,2,8	Various	Various				24
V11-1,2,9	Various	Various		-937	-937	25
V11-1,2,8	Various	Various		19,253	19,253	26
V11-1,2,7	Various	Various				27
R.S. 302	Duchesne	Duchesne		24,489	24,489	28
R.S. 302	Duchesne	Duchesne		1,862	1,862	29
V11-1-3,8	Various	Various		240,605	240,605	30
V11-1-3,8	Various	Various		8,088	8,088	31
V11-1,2,7	Various	Various		15,520	15,520	32
V11-1,2,7	Various	Various		-12,536	-12,536	33
	Wallula Substation	Wala-MIDC path	94	212,356	212,356	34
			4,438	**12,830,379**	**12,712,106**	

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.
	176,733	26,755	203,488	1
		217,287	217,287	2
		23,220	23,220	3
726,189		32,037	758,226	4
		-49,825	-49,825	5
24,279		3,987	28,266	6
		303,750	303,750	7
				8
842,430		35,522	877,952	9
		-122,000	-122,000	10
		67,672	67,672	11
		6,152	6,152	12
		14,927	14,927	13
		1,357	1,357	14
	72,558	3,177	75,735	15
		3,411	3,411	16
	14,125	710	14,835	17
		17,895	17,895	18
	903,476	178,215	1,081,691	19
		-10,866	-10,866	20
	36,290	-4,874	31,416	21
		47,661	47,661	22
	28,307	1,256	29,563	23
	3		3	24
		-966	-966	25
	70,706	2,963	73,669	26
	3,629	10,064	13,693	27
		17,655	17,655	28
		1,605	1,605	29
	1,231,770	65,368	1,297,138	30
		137,713	137,713	31
	84,798	3,733	88,531	32
		-1,612	-1,612	33
2,487,695		1,019,404	3,507,099	34
38,697,973	**12,779,898**	**34,015,065**	**85,492,936**	

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 2013/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	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	Grant County PUD	AD
2	NextEra Energy Resources, LLC			NF
3	NextEra Energy Resources, LLC			AD
4	Nevada Power Company			NF
5	Noble Americas Energy Solutions LLC	Bonneville Power Administration	Oregon Direct Access	FNO
6	Noble Americas Energy Solutions LLC	Bonneville Power Administration	Oregon Direct Access	AD
7	Pacific Gas & Electric Company			OS
8	Pacific Gas & Electric Company			AD
9	Pacific Gas & Electric Company			OS
10	Portland General Electric Company			NF
11	Portland General Electric Company			AD
12	Portland General Electric Company			SFP
13	Portland General Electric Company			OS
14	Powder River Energy Corporation	Western Area Power Administration	Sheridan-Johnson Rural Elect.	OS
15	Powder River Energy Corporation	Western Area Power Administration	Sheridan-Johnson Rural Elect.	AD
16	Powerex Corporation	Bonneville Power Administration	CAISO	LFP
17	Powerex Corporation	Bonneville Power Administration	CAISO	AD
18	Powerex Corporation	Powerex Corporation	CAISO	LFP
19	Powerex Corporation	Powerex Corporation	CAISO	AD
20	Powerex Corporation	Powerex Corporation	CAISO	LFP
21	Powerex Corporation	Powerex Corporation	CAISO	AD
22	Powerex Corporation	Powerex Corporation	CAISO	LFP
23	Powerex Corporation	Powerex Corporation	CAISO	AD
24	Powerex Corporation			NF
25	Powerex Corporation			AD
26	Powerex Corporation			SFP
27	Powerex Corporation			AD
28	PPL Energy Plus, LLC			NF
29	PPL Energy Plus, LLC			AD
30	PPL Energy Plus, LLC			SFP
31	PPL Energy Plus, LLC			AD
32	Public Svc. Co. of CO			SFP
33	Rainbow Energy Marketing Corporation			NF
34	Rainbow Energy Marketing Corporation			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.
V11-5,6,7,9	Wallula Substation	Wala-MIDC path	104	1,891	1,891	1
V11-1,2,8	Various	Various		99	99	2
V11-1,2,8	Various	Various		76	76	3
V11-1,2,8	Various	Various		1,560	1,560	4
V11-1,2,3,4	Bonneville Power Adm	Various	26	191,994	191,994	5
V11-1,2,3,4	Bonneville Power Adm	Various	25	17,047	17,047	6
R.S. 607						7
V11-1,2	Various	Various				8
R.S. 298	Sigurd-Glen Canyon	Pinto-Four Corners				9
V11-1,2,8	Various	Various		8,767	8,767	10
V11-1,2,8	Various	Various		207	207	11
V11-1,2,7	Various	Various		295	295	12
R.S. 137	Various	Various				13
R.S. 123	Various	Buffalo Substation				14
R.S. 123	Various	Buffalo Substation				15
V11-1,2,7	Bonneville Power Adm	CRAG View Substation	83	380,866	380,866	16
V11-1,2,7	Bonneville Power Adm	CRAG View Substation	84	-58,690	-58,690	17
V11-1,7	Malin 500 Substation	Round Mountain Sub	50			18
V11-1,7	Malin 500 Substation	Round Mountain Sub	50			19
V11-1,7	Malin 500 Substation	Round Mountain Sub	50			20
V11-1,7	Malin 500 Substation	Round Mountain Sub	50			21
V11-1,7	Malin 500 Substation	Round Mountain Sub	50			22
V11-1,7	Malin 500 Substation	Round Mountain Sub	50			23
V11-1,2,8	Various	Various		575,984	575,984	24
V11-1,2,8	Various	Various		-153,684	-153,684	25
V11-1,2,7	Various	Various		76,587	76,587	26
V11-1,2,7	Various	Various		-54,264	-54,264	27
V11-1,2,8	Various	Various		807	807	28
V11-1,2,8	Various	Various		-791	-791	29
V11-1,2,7	Various	Various		2,891	2,891	30
V11-1,2	Various	Various		-149	-149	31
V11-1,2,7	Various	Various		800	800	32
V11-1,2,8	Various	Various		929	929	33
V11-1,2	Various	Various		-6,662	-6,662	34
			4,438	**12,830,379**	**12,712,106**	

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 2013/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		-665,697	-665,697	1
	20,482	3,241	23,723	2
		-1,058	-1,058	3
	9,878	460	10,338	4
356,153		66,107	422,260	5
		-34,255	-34,255	6
		14,500,000	14,500,000	7
		-5	-5	8
		271,951	271,951	9
	52,233	2,308	54,541	10
		2,290	2,290	11
	3,067	129	3,196	12
		3,314	3,314	13
		337	337	14
		28	28	15
1,936,508		85,434	2,021,942	16
		-77,044	-77,044	17
1,553,607		34,848	1,588,455	18
		-7,399	-7,399	19
1,553,607		34,848	1,588,455	20
		-7,399	-7,399	21
1,530,413		34,328	1,564,741	22
		-7,399	-7,399	23
	3,700,210	165,274	3,865,484	24
		-65,297	-65,297	25
	958,456	73,068	1,031,524	26
		-13,041	-13,041	27
	4,391	187	4,578	28
		-317	-317	29
	17,518	752	18,270	30
		-115	-115	31
	2,469	103	2,572	32
	3,910	170	4,080	33
		-3,436	-3,436	34
38,697,973	**12,779,898**	**34,015,065**	**85,492,936**	

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 2013/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	Rainbow Energy Marketing Corporation			SFP
2	Rainbow Energy Marketing Corporation			AD
3	Sacramento Municipal Utility District	Sacramento Municipal Util. Dist.	Sacramento Municipal Util. Dist.	LFP
4	Sacramento Municipal Utility District	Sacramento Municipal Util. Dist.	Sacramento Municipal Util. Dist.	LFP
5	Salt River Project			NF
6	Salt River Project			SFP
7	Seattle City Light	FPL Energy Vansycle, LLC	Grant County PUD	AD
8	Sierra Pacific Power Company			OS
9	Sierra Pacific Power Company			AD
10	Sierra Pacific Power Company			NF
11	Sierra Pacific Power Company			AD
12	Sierra Pacific Power Company			SFP
13	Sierra Pacific Power Company			AD
14	Southern California Edison Company			NF
15	Southern California Edison Company			AD
16	Southern California Edison Company			OS
17	Southern California Public Power Authority	Powerex Corporation		OS
18	State of South Dakota	Western Area Power Administration	Black Hills Corporation	LFP
19	State of South Dakota	Western Area Power Administration	Black Hills Corporation	AD
20	Tenaska Power Services Company			NF
21	Tenaska Power Services Company			AD
22	Tenaska Power Services Company			SFP
23	Tenaska Power Services Company			AD
24	The Energy Authority, Inc.			NF
25	The Energy Authority, Inc.			AD
26	Thermo No. 1 BE-01, LLC	Thermo Geothermal Project		LFP
27	Thermo No. 1 BE-01, LLC	Thermo Geothermal Project		AD
28	TransAlta Energy Marketing			NF
29	TransAlta Energy Marketing			AD
30	TransAlta Energy Marketing			SFP
31	Tri-State Generation & Trans.		Tri-State Generation & Trans.	OS
32	Tri-State Generation & Trans.		Tri-State Generation & Trans.	AD
33	Tri-State Generation & Trans.		Tri-State Generation & Trans.	FNO
34	Tri-State Generation & Trans.		Tri-State Generation & Trans.	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.
V11-1,2,7	Various	Various		5,566	5,566	1
V11-1,2	Various	Various		-1,300	-1,300	2
V11-1,2,7	Malin Substation	Malin Substation	31			3
V11	Malin Substation	Malin Substation				4
V11-1,2,3,8	Various	Various		195	195	5
V11-1,2,3,7	Various	Various		491	491	6
V11-1,2	Wallula Substation	Wala-MIDC path				7
R.S. 674	Sigurd Substation	Utah-Nevada Border				8
R.S. 674	Sigurd Substation	Utah-Nevada Border				9
V11-1,2,8	Various	Various		14,229	14,229	10
V11-1,2	Various	Various		-1,637	-1,637	11
V11-1,2,7	Various	Various		200	200	12
V11-1,2	Various	Various		-1,742	-1,742	13
V11-1-3,8,9,11	Various	Various		292,921	292,921	14
V11-1-3,8,9,11	Various	Various		-19,718	-19,718	15
R.S. 298	Sigurd-Glen Canyon	Pinto-Four Corners				16
V11-9,11	Tieton Substation	Various		205	205	17
V11-1,2,7	Yellowtail Sub	Wyodak Substation	4	17,821	17,821	18
V11-1,2,7	Yellowtail Sub	Wyodak Substation	4	1,845	1,845	19
V11-1,2,8	Various	Various		4,705	4,705	20
V11-1,2	Various	Various		-2,430	-2,430	21
V11-1,2,3,7	Various	Various		46,567	46,567	22
V11-1,2	Various	Various		-2,390	-2,390	23
V11-1,2,8	Various	Various		967	967	24
V11-1,2,8	Various	Various		144	144	25
	South Milford Sub	Mona Substation	11	61,635	61,635	26
	South Milford Sub	Mona Substation	12	4,385	4,385	27
V11-1,2,8	Various	Various		30,798	30,798	28
V11-1,2,8	Various	Various		-3,844	-3,844	29
V11-1,2,7	Various	Various		146	146	30
R.S. 123	Various	Various	36	177,352	177,352	31
R.S. 123	Various	Various	34	17,895	17,895	32
V11-1,2,3,4	Dave Johnston Sub	Thermopolis Sub	3	40,378	40,378	33
V11-1,2,3,4	Dave Johnston Sub	Thermopolis Sub	1	249	249	34
			4,438	**12,830,379**	**12,712,106**	

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.
	21,465	954	22,419	1
		-639	-639	2
134,789		5,683	140,472	3
		130,043	130,043	4
	870	134	1,004	5
	6,108	942	7,050	6
		-5,252	-5,252	7
		68,919	68,919	8
		6,265	6,265	9
	87,415	3,690	91,105	10
		-1,069	-1,069	11
	5,184	219	5,403	12
		-1,042	-1,042	13
	2,180,045	917,821	3,097,866	14
		333,001	333,001	15
		271,951	271,951	16
		9,034	9,034	17
96,818		4,273	101,091	18
		-6,650	-6,650	19
	11,884	521	12,405	20
		-1,480	-1,480	21
	251,189	16,167	267,356	22
		-1,259	-1,259	23
	4,180	192	4,372	24
		1,229	1,229	25
266,276		91,893	358,169	26
		-36,213	-36,213	27
	162,693	7,174	169,867	28
		174	174	29
	986	42	1,028	30
101,745			101,745	31
		9,867	9,867	32
61,641		28,010	89,651	33
		-67,731	-67,731	34
38,697,973	**12,779,898**	**34,015,065**	**85,492,936**	

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 2013/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Tri-State Generation & Trans.			NF
2	Tri-State Generation & Trans.			AD
3	Tri-State Generation & Trans.			AD
4	U. S. Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	FNO
5	U. S. Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	AD
6	U. S. Bureau of Reclamation	Western Area Power Administration	Weber Basin Water Conserv.	OS
7	U. S. Bureau of Reclamation	Western Area Power Administration	Weber Basin Water Conserv.	AD
8	U. S. Bureau of Reclamation	Bonneville Power Administration	Crooked River Irrigation District	OS
9	Utah Associated Municipal Power Systems	Utah Associated Municipal Power	Utah Associated Municipal Power	OS
10	Utah Associated Municipal Power Systems	Utah Associated Municipal Power	Utah Associated Municipal Power	AD
11	Utah Associated Municipal Power Systems			NF
12	Utah Associated Municipal Power Systems			AD
13	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	OS
14	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	AD
15	Warm Springs Power Enterprises	Warm Springs Power Enterprises	Portland General Electric Co	OS
16	Warm Springs Power Enterprises	Warm Springs Power Enterprises	Portland General Electric Co	AD
17	Western Area Power Administration	Western Area Power Administration		OS
18	Western Area Power Administration	Western Area Power Administration		AD
19	Western Area Power Administration	Western Area Power Administration		OS
20	Western Area Power Administration	Western Area Power Administration		AD
21	Western Area Power Administration	Western Area Power Administration		OS
22	Western Area Power Administration	Western Area Power Administration	Western Area Power Administration	FNO
23	Western Area Power Administration	Western Area Power Administration	Western Area Power Administration	AD
24	Western Area Power Adm. CO River	Western Area Power Adm. CO River		NF
25	Western Area Power Adm. CO River	Western Area Power Adm. CO River		AD
26	Western Area Power Adm. CO River	Western Area Power Adm. CO River		AD
27	Western Area Power Adm. CO MO	Western Area Power Adm. CO MO		AD
28	Western Area Power Adm. CO MO	Western Area Power Adm. CO MO		AD
29	Accrual			
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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		17,364	17,364	1
V11-1,2	Various	Various		-7,330	-7,330	2
V11-1,2	Various	Various		-633	-633	3
V11-1,2,3	Walla Walla Sub	Burbank Pumps	1	2,361	2,361	4
V11-1,2,3	Walla Walla Sub	Burbank Pumps	1	3	3	5
R.S. 286	Various	Various		28,798	28,798	6
R.S. 286	Various	Various		986	986	7
R.S. 67	Redmond Substation	Crooked River Pumps		11,219	11,219	8
R.S. 297	Various	Various	444	2,431,316	2,431,316	9
R.S. 297	Various	Various	521	217,249	217,249	10
V11-1,2,8	Various	Various		3,051	3,051	11
V11-1,2	Various	Various		-1,514	-1,514	12
R.S. 637	Various	Various	113	644,731	644,731	13
R.S. 637	Various	Various	97	48,262	48,262	14
R.S. 591	Pelton Reregulating	Round Butte Sub		76,161	76,161	15
R.S. 591	Pelton Reregulating	Round Butte Sub		8,974	8,974	16
R.S. 262	Various	Various	330	1,685,843	1,584,694	17
R.S. 262	Various	Various	330	171,661	161,362	18
R.S. 263	Various	Various		84,691	79,313	19
R.S. 263	Various	Various		8,557	8,073	20
R.S. 664	Dave Johnston Sub	Various				21
V11-1,2	Wyoming Distribution	Wyoming Distribution		11,051	11,051	22
V11-1,2	Wyoming Distribution	Wyoming Distribution				23
V11-1,2,8	Various	Various		654	654	24
V11-1,2,8	Various	Various		-85	-85	25
V11-1,2	Various	Various		-615	-615	26
V11-1,2	Various	Various		-1,665	-1,665	27
V11-1,2	Various	Various		-4,893	-4,893	28
				57,714	56,751	29
						30
						31
						32
						33
						34
			4,438	**12,830,379**	**12,712,106**	

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.
	94,288	4,239	98,527	1
		-4,450	-4,450	2
		-428	-428	3
6,956		10,742	17,698	4
		-1,160	-1,160	5
		28,798	28,798	6
		793	793	7
12,543			12,543	8
10,027,476		2,344,193	12,371,669	9
		125,698	125,698	10
	16,609	2,640	19,249	11
		-3,021	-3,021	12
2,676,688		625,801	3,302,489	13
		-176,837	-176,837	14
		109,725	109,725	15
		9,975	9,975	16
2,076,355		550,000	2,626,355	17
		227,294	227,294	18
		-11,156	-11,156	19
		5,825	5,825	20
				21
34,108		44,534	78,642	22
		-4,679	-4,679	23
	13,419	607	14,026	24
		114	114	25
		-186	-186	26
		-2,327	-2,327	27
		-899	-899	28
		5,474,456	5,474,456	29
				30
				31
				32
				33
				34
38,697,973	**12,779,898**	**34,015,065**	**85,492,936**	

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
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, in this Form No. 1.

Schedule Page: 328 Line No.: 1 Column: f
Glenn Canyon/Four Corners Substation

Schedule Page: 328 Line No.: 2 Column: d
Network transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 505) terminating no earlier than 12 months from notice by the customer.

Schedule Page: 328 Line No.: 2 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.: 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. December 2012 transmission and ancillary services. Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328 Line No.: 4 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 4 Column: m
Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328 Line No.: 5 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.: 5 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 5 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 5 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 5 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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
Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

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
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 8 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 8 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 8 Column: m
Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328 Line No.: 9 Column: b
PacifiCorp Energy, a business unit of PacifiCorp responsible for generation and commercial and 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
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 10 Column: b
PacifiCorp Energy, a business unit of PacifiCorp responsible for generation and commercial and trading activities.

Schedule Page: 328 Line No.: 10 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.: 10 Column: m
December 2012 transmission and ancillary services. Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

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
Scheduling, system control and dispatch service. Reactive supply and voltage control 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
December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

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
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 14 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 14 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 14 Column: m
December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328 Line No.: 15 Column: b
PacifiCorp Energy, a business unit of PacifiCorp responsible for generation and commercial and trading activities.

Schedule Page: 328 Line No.: 15 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 67) terminating on December 31, 2023.

Schedule Page: 328 Line No.: 15 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 16 Column: b
PacifiCorp Energy, a business unit of PacifiCorp responsible for generation and commercial and trading activities.

Schedule Page: 328 Line No.: 16 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 67) terminating on December 31, 2023.

Schedule Page: 328 Line No.: 16 Column: m
December 2012 transmission and ancillary services. Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328 Line No.: 17 Column: b
Capacity exchanged and operated by each transmission provider with no receipt or delivery of energy.

Schedule Page: 328 Line No.: 17 Column: c
Capacity exchanged and operated by each transmission provider with no receipt or delivery of energy.

Schedule Page: 328 Line No.: 17 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, in this Form No. 1.

Schedule Page: 328 Line No.: 18 Column: d
Legacy contract (3rd 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.

Schedule Page: 328 Line No.: 19 Column: d

Legacy contract (3rd 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.: 19 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. December 2012 transmission and ancillary services.

Schedule Page: 328 Line No.: 20 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 656) terminating on August 31, 2030.

Schedule Page: 328 Line No.: 20 Column: m

Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 21 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 656) terminating on August 31, 2030.

Schedule Page: 328 Line No.: 21 Column: m

December 2012 transmission and ancillary services.

Schedule Page: 328 Line No.: 22 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (7th Revised Service Agreement 229) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 22 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.: 22 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.: 23 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (7th Revised Service Agreement 229) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 23 Column: m

Distribution voltage service charge. Primary delivery service. December 2012 transmission and ancillary services. Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328 Line No.: 24 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.: 24 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (2nd Revised Service Agreement 539) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 24 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328 Line No.: 25 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (2nd Revised Service Agreement 539) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 25 Column: m

December 2012 transmission and ancillary services. Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328 Line No.: 26 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.: 26 Column: d

Network transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 538) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 26 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328 Line No.: 27 Column: d

Network transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 538) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 27 Column: m

December 2012 transmission and ancillary services. Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328 Line No.: 28 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.: 28 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (4th Revised Service Agreement 179) terminating on September 30, 2025.

Schedule Page: 328 Line No.: 28 Column: m

Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 29 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (4th Revised Service Agreement 179) terminating on September 30, 2025.

Schedule Page: 328 Line No.: 29 Column: m

December 2012 transmission and ancillary services. Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328 Line No.: 30 Column: d

Legacy contract (5th Revised Rate Schedule 368) executed between PacifiCorp and BPA 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.

Schedule Page: 328 Line No.: 31 Column: d

Legacy contract (5th Revised Rate Schedule 368) executed between PacifiCorp and BPA 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.: 31 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 2012 transmission and ancillary services.

Schedule Page: 328 Line No.: 32 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (5th Revised Service Agreement 328) terminating on July 31, 2028.

Schedule Page: 328 Line No.: 32 Column: g

White Swan/Toppenish Substations

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. Scheduling, system control and dispatch service.

Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328 Line No.: 33 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (5th Revised Service Agreement 328) terminating on July 31, 2028.

Schedule Page: 328 Line No.: 33 Column: g

White Swan/Toppenish Substations

Schedule Page: 328 Line No.: 33 Column: m

Distribution voltage service charge. Primary delivery service. December 2012 transmission and ancillary services. Penalty revenues covering imbalance charges per Schedules 4 and 9. Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

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.

Schedule Page: 328.1 Line No.: 1 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: 328.1 Line No.: 1 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. December 2012 transmission and ancillary services.

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

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.: 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

December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.1 Line No.: 4 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 4 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 4 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 4 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.: 5 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 5 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 5 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 5 Column: m
December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.1 Line No.: 6 Column: d
Network transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 735) terminating on September 30, 2028.

Schedule Page: 328.1 Line No.: 6 Column: g
Chelatchie/View 115kV

Schedule Page: 328.1 Line No.: 6 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.: 7 Column: d
Network transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 735) terminating on September 30, 2028.

Schedule Page: 328.1 Line No.: 7 Column: g
Chelatchie/View 115kV

Schedule Page: 328.1 Line No.: 7 Column: m
Unauthorized use of transmission service. December 2012 transmission and ancillary services. Penalty revenues covering imbalance charges per Schedules 4 and 9. Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

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: 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
December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

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. Scheduling, system control and dispatch service. Reactive supply and voltage control 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
Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

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.

Schedule Page: 328.1 Line No.: 13 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 13 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 13 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 13 Column: m
Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.1 Line No.: 14 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 14 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 Line No.: 14 Column: m
Transmission resales, purchase of point-to-point transmission. Scheduling, system control and dispatch service. Reactive supply and voltage control 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
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.: 15 Column: m
Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

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

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 16 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 17 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 17 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 Line No.: 17 Column: m

December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.1 Line No.: 18 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 18 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 18 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 18 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 19 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.: 19 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.: 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.

Schedule Page: 328.1 Line No.: 20 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.: 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. December 2012 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 21 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.: 21 Column: d

Legacy contract executed between PacifiCorp and Deseret Generation and Transmission Co-operative for transmission service over agreed-upon facilities (6th Amended and Restated Transmission Service and Operating Agreement, Rate Schedule 280). Agreement subject to termination upon mutual agreement.

Schedule Page: 328.1 Line No.: 21 Column: m

Distribution voltage service charge. 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. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 22 Column: d

Legacy contract executed between PacifiCorp and Deseret Generation and Transmission Co-operative for transmission service over agreed-upon facilities (6th Amended and Restated Transmission Service and Operating Agreement, Rate Schedule 280). Agreement subject to termination upon mutual agreement.

Schedule Page: 328.1 Line No.: 22 Column: m

Distribution voltage service charge. Meter interrogation services. December 2012 transmission and ancillary services. Penalty revenues covering imbalance charges per Schedules 4 and 9. Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643. Refunds of transmission service covering prior years.

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: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 24 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 24 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 24 Column: m

Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.1 Line No.: 25 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 25 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 25 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 25 Column: m

Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.1 Line No.: 26 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 26 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (1st Revised

Service Agreement 711) terminating on November 30, 2018.

Schedule Page: 328.1 Line No.: 26 Column: m

Extension of commencement date fee.

Schedule Page: 328.1 Line No.: 27 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 27 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (10th Revised Service Agreement 426) terminating on April 30, 2044.

Schedule Page: 328.1 Line No.: 27 Column: m

Extension of commencement date fee.

Schedule Page: 328.1 Line No.: 28 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 28 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 Line No.: 28 Column: m

Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.1 Line No.: 29 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.: 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: 328.1 Line No.: 30 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.: 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 2012 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 31 Column: c

PacifiCorp Energy, a business unit of PacifiCorp responsible for generation and commercial and trading activities.

Schedule Page: 328.1 Line No.: 31 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.: 31 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.: 32 Column: c

PacifiCorp Energy, a business unit of PacifiCorp responsible for generation and commercial and trading activities.

Schedule Page: 328.1 Line No.: 32 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.: 32 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. December 2012 transmission and ancillary services.

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 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.2 Line No.: 1 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 1 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 1 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 1 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control 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.

Schedule Page: 328.2 Line No.: 3 Column: c
Iberdrola Renewables, LLC and Utah Associated Municipal Power Systems

Schedule Page: 328.2 Line No.: 3 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.: 3 Column: f
Long Hollow, Wyoming Switching Station

Schedule Page: 328.2 Line No.: 3 Column: g
Long Hollow, Wyoming Switching Station

Schedule Page: 328.2 Line No.: 3 Column: m
December 2012 transmission and ancillary services. Refunds for ancillary services pursuant

to FERC Docket No. ER11-3643.

Schedule Page: 328.2 Line No.: 4 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 279). Terminating on April 30, 2019.

Schedule Page: 328.2 Line No.: 4 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 5 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 279). Terminating on April 30, 2019.

Schedule Page: 328.2 Line No.: 5 Column: m

December 2012 transmission and ancillary services. Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.2 Line No.: 6 Column: d

Network transmission service under the Open Access Transmission Tariff (Service Agreement 742) terminating on April 30, 2018.

Schedule Page: 328.2 Line No.: 6 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328.2 Line No.: 7 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 7 Column: d

Point-to-point transmission service agreements under the Open Access Transmission Tariff (Service Agreements 697, 698, 699) terminated in 2013.

Schedule Page: 328.2 Line No.: 7 Column: m

Extension of commencement date fee.

Schedule Page: 328.2 Line No.: 8 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, in this Form No. 1.

Schedule Page: 328.2 Line No.: 9 Column: d

Point-to-point transmission Service under the Open Access Transmission Tariff (8th Revised Service Agreement 212) terminating on May 31, 2019.

Schedule Page: 328.2 Line No.: 9 Column: m

Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.2 Line No.: 10 Column: d

Point-to-point transmission Service under the Open Access Transmission Tariff (8th Revised Service Agreement 212) terminating on May 31, 2019.

Schedule Page: 328.2 Line No.: 10 Column: m

Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.2 Line No.: 11 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 11 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 11 Column: d

Legacy contract (Rate Schedule 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.: 11 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.: 12 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 12 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 12 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.: 12 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. December 2012 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 13 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 13 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 13 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.: 13 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.: 14 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 14 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 14 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.: 14 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. December 2012 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 15 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 15 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control 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
December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

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: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 18 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 18 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 18 Column: m
December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.2 Line No.: 19 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.: 19 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 19 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 19 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 19 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: 328.2 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
Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

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
Penalty revenues covering imbalance charges per Schedules 4 and 9. Scheduling, system

control and dispatch service. Reactive supply and voltage control 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

December 2012 transmission and ancillary services. Penalty revenues covering imbalance charges per Schedules 4 and 9. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.2 Line No.: 23 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 23 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 23 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 23 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 24 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 24 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 24 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 25 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 25 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 25 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 25 Column: m

Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control 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
Transmission resales, purchase of point-to-point transmission. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 28 Column: d
Legacy contract (3rd 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.: 28 Column: m
Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.2 Line No.: 29 Column: d
Legacy contract (3rd 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.: 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. December 2012 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 30 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 30 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 30 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 30 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.2 Line No.: 31 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 31 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 31 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 31 Column: m
December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.2 Line No.: 32 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 32 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 32 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 32 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 33 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 33 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 33 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 33 Column: m
December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.2 Line No.: 34 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.: 34 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 733) terminating on November 30, 2017.

Schedule Page: 328.2 Line No.: 34 Column: e
V11-1-3,5-6,7,9,11

Schedule Page: 328.2 Line No.: 34 Column: m
Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643. 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.: 1 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 733) terminating on November 30, 2017.

Schedule Page: 328.3 Line No.: 1 Column: m
December 2012 transmission and ancillary services. Penalty revenues covering imbalance charges per Schedules 4 and 9. Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.3 Line No.: 2 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 2 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 2 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 2 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.3 Line No.: 3 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 3 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 3 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 3 Column: m
December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.3 Line No.: 4 Column: a
This footnote applies to all occurrences of "Nevada Power Company" on pages 328-330. Nevada Power Company is a principal subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of MidAmerican Energy Holdings Company.

Schedule Page: 328.3 Line No.: 4 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 4 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 4 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 4 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 5 Column: d

Transmission service under the Open Access Transmission Tariff (5th 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: 328.3 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: 328.3 Line No.: 6 Column: d

Transmission service under the Open Access Transmission Tariff (5th 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: 328.3 Line No.: 6 Column: m

December 2012 transmission and ancillary services. Penalty revenues covering imbalance charges per Schedules 4 and 9. Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.3 Line No.: 7 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 7 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 7 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: 328.3 Line No.: 7 Column: f

Malin to Indian Springs line segment

Schedule Page: 328.3 Line No.: 7 Column: g

Malin to Indian Springs line segment

Schedule Page: 328.3 Line No.: 7 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

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

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: 328.3 Line No.: 8 Column: m

Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.3 Line No.: 9 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 9 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 9 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 230kV transmission line and Pinto-Four Corners 345kV transmission line). Terminating on February 12, 2020.

Schedule Page: 328.3 Line No.: 9 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.: 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.

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

December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 13 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 13 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 13 Column: d

Legacy contract (1st Revised Rate Schedule 137) executed between PacifiCorp and Portland General Electric Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge for the Dalreed Substation, which terminated December 2013.

Schedule Page: 328.3 Line No.: 13 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.: 14 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.: 14 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.: 14 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.: 15 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.: 15 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. December 2012 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 16 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.: 16 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 169) terminating on October 31, 2020.

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: d

Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 169) terminating on October 31, 2020.

Schedule Page: 328.3 Line No.: 17 Column: m

December 2012 transmission and ancillary services. Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.3 Line No.: 18 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 700) terminating on March 31, 2017.

Schedule Page: 328.3 Line No.: 18 Column: m

Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 19 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 700) terminating on March 31, 2017.

Schedule Page: 328.3 Line No.: 19 Column: m

December 2012 transmission and ancillary services. Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 20 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 701) terminating on March 31, 2017.

Schedule Page: 328.3 Line No.: 20 Column: m

Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 21 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 701) terminating on March 31, 2017.

Schedule Page: 328.3 Line No.: 21 Column: m

December 2012 transmission and ancillary services. Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 22 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 702) terminating on March 31, 2017.

Schedule Page: 328.3 Line No.: 22 Column: m
Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 23 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 702) terminating on March 31, 2017.

Schedule Page: 328.3 Line No.: 23 Column: m
December 2012 transmission and ancillary services. Scheduling, system control and dispatch 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
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response 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
December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

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
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
December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.3 Line No.: 28 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 28 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 28 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 29 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 29 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 29 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 29 Column: m
December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.3 Line No.: 30 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 30 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 30 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 30 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 31 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 31 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 31 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 31 Column: m
Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.3 Line No.: 32 Column: a
This footnote applies to all occurrences of "Public Svc. Co. of CO" on pages 328 - 330. Complete name is Public Service Company of Colorado.

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.

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
Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.
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
Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.
Schedule Page: 328.4 Line No.: 3 Column: b
This footnote applies to all occurrences of "Sacramento Municipal Util. Dist." on pages 328 - 330. Complete name is Sacramento Municipal Utility District.
Schedule Page: 328.4 Line No.: 3 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 751) terminating on September 30, 2018.
Schedule Page: 328.4 Line No.: 3 Column: m
Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.
Schedule Page: 328.4 Line No.: 4 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 552) terminating on September 30, 2018.
Schedule Page: 328.4 Line No.: 4 Column: m
Extension of commencement date fee.
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: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 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: 328.4 Line No.: 5 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.: 6 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 Line No.: 6 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 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: 328.4 Line No.: 7 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 289) terminating on February 28, 2018.

Schedule Page: 328.4 Line No.: 7 Column: m

Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.4 Line No.: 8 Column: a

This footnote applies to all occurrences of "Sierra Pacific Power Company" on pages 328-330. Sierra Pacific Power Company is a principal subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of MidAmerican Energy Holdings Company.

Schedule Page: 328.4 Line No.: 8 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 8 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 8 Column: d

Legacy contract (Rate Schedule 674) executed between PacifiCorp and Sierra Pacific Power Company for transmission service over agreed-upon facilities and/or
subject to a sole-use or facilities charge. Terminating in September 2022.

Schedule Page: 328.4 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: 328.4 Line No.: 9 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 9 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 9 Column: d

Legacy contract (Rate Schedule 674) executed between PacifiCorp and Sierra Pacific Power Company for transmission service over agreed-upon facilities and/or
subject to a sole-use or facilities charge. Terminating in September 2022.

Schedule Page: 328.4 Line No.: 9 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. December 2012 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 10 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 10 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 10 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 11 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 11 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 11 Column: m
Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.
Schedule Page: 328.4 Line No.: 12 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 Line No.: 12 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 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: 328.4 Line No.: 12 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.
Schedule Page: 328.4 Line No.: 13 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 Line No.: 13 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 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: 328.4 Line No.: 13 Column: m
Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.
Schedule Page: 328.4 Line No.: 14 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 Line No.: 14 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 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: 328.4 Line No.: 14 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: 328.4 Line No.: 15 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 Line No.: 15 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 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: 328.4 Line No.: 15 Column: m
Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9. December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.
Schedule Page: 328.4 Line No.: 16 Column: b
Operation, maintenance or facility lease services with no receipt or delivery of energy.
Schedule Page: 328.4 Line No.: 16 Column: c
Operation, maintenance or facility lease services with no receipt or delivery of energy.
Schedule Page: 328.4 Line No.: 16 Column: d
Use of Facilities Agreement - Phase shifting transformers at Sigurd-Glen Canyon 230kV transmission line and Pinto-Four Corners 345kV transmission line (Rate Schedule 298) terminating on February 12, 2020.
Schedule Page: 328.4 Line No.: 16 Column: m
Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.4 Line No.: 17 Column: c

Southern California Public Power Authority

Schedule Page: 328.4 Line No.: 17 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: 328.4 Line No.: 17 Column: m

Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.4 Line No.: 18 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (11th Revised Service Agreement 170) terminating on May 31, 2014.

Schedule Page: 328.4 Line No.: 18 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 19 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (11th Revised Service Agreement 170) terminating on May 31, 2014.

Schedule Page: 328.4 Line No.: 19 Column: m

December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.4 Line No.: 20 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 20 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 20 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 21 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 21 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 21 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 21 Column: m

Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.4 Line No.: 22 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 22 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 22 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 22 Column: m

Transmission resales, amount paid by seller. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.4 Line No.: 23 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 23 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 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: 328.4 Line No.: 23 Column: m
Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.
Schedule Page: 328.4 Line No.: 24 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 Line No.: 24 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 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: 328.4 Line No.: 24 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.
Schedule Page: 328.4 Line No.: 25 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 Line No.: 25 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.4 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: 328.4 Line No.: 25 Column: m
December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.
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
Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 568) terminating on April 30, 2029.
Schedule Page: 328.4 Line No.: 26 Column: e
V11-1-3,5-6,7,9
Schedule Page: 328.4 Line No.: 26 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: 328.4 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
Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 568) terminating on April 30, 2029.
Schedule Page: 328.4 Line No.: 27 Column: e
V11-1-3,5-6,7,9
Schedule Page: 328.4 Line No.: 27 Column: m
December 2012 transmission and ancillary services. Penalty revenues covering imbalance charges per Schedules 4 and 9. Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.
Schedule Page: 328.4 Line No.: 28 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 29 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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

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.: 29 Column: m

December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.4 Line No.: 30 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 30 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 30 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 30 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 31 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.: 31 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 31 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.: 32 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 32 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.: 32 Column: m

December 2012 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 33 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 33 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.: 33 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.: 34 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 34 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.: 34 Column: m

December 2012 transmission and ancillary services. Penalty revenues covering imbalance charges per Schedules 4 and 9. Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.5 Line No.: 1 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 1 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 1 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 2 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 2 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 2 Column: m

Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.5 Line No.: 3 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 3 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 3 Column: m

Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.5 Line No.: 4 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (Service Agreement 506) terminating upon written notification.

Schedule Page: 328.5 Line No.: 4 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: 328.5 Line No.: 5 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (Service Agreement 506) terminating upon written notification.

Schedule Page: 328.5 Line No.: 5 Column: m

Distribution voltage service charge. Primary delivery service. December 2012 transmission and ancillary services. Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.5 Line No.: 6 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: 328.5 Line No.: 6 Column: d

Legacy contract (3rd 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 138kV. Agreement terminates any time after April 1, 2040 with four years written notification.

Schedule Page: 328.5 Line No.: 6 Column: m

Energy consumption charge for deliveries at and below 138kV.

Schedule Page: 328.5 Line No.: 7 Column: d

Legacy contract (3rd 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 138kV. Agreement terminates any time after April 1, 2040 with four years written notification.

Schedule Page: 328.5 Line No.: 7 Column: m

Distribution voltage service charge. Primary delivery service. December 2012 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 8 Column: d

Legacy contract (3rd Amended Rate Schedule 67) executed between PacifiCorp and United States Department of the Interior, Bureau of Reclamation Crooked River Irrigation District for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Agreement termination with one year written notice.

Schedule Page: 328.5 Line No.: 9 Column: b

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: 328.5 Line No.: 9 Column: d

Legacy contract executed between PacifiCorp and Utah Associated Municipal Power Systems for transmission service over agreed-upon facilities (3rd Amended and Restated Transmission Service and Operating Agreement, 3rd Revised Rate Schedule 297). Agreement subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.5 Line No.: 9 Column: m

Distribution voltage service charge. 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: 328.5 Line No.: 10 Column: d

Legacy contract executed between PacifiCorp and Utah Associated Municipal Power Systems for transmission service over agreed-upon facilities (3rd Amended and Restated Transmission Service and Operating Agreement, 3rd Revised Rate Schedule 297). Agreement subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.5 Line No.: 10 Column: m

Distribution voltage service charge. December 2012 transmission and ancillary services. Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.5 Line No.: 11 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 11 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 11 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 12 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 12 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 12 Column: m
Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.5 Line No.: 13 Column: d
Legacy contract (5th 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: 328.5 Line No.: 13 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: 328.5 Line No.: 14 Column: d
Legacy contract (5th 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: 328.5 Line No.: 14 Column: m
December 2012 transmission and ancillary services. Penalty revenues covering imbalance charges per Schedules 4 and 9. Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.5 Line No.: 15 Column: c
This footnote applies to all occurrences of "Portland General Electric Co" on pages 328 - 330. Complete name is Portland General Electric Company.

Schedule Page: 328.5 Line No.: 15 Column: d
Legacy contract (Rate Schedule 591) executed between PacifiCorp and Warm Springs Power Enterprises for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating on January 31, 2032.

Schedule Page: 328.5 Line No.: 15 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: 328.5 Line No.: 16 Column: d
Legacy contract (Rate Schedule 591) executed between PacifiCorp and Warm Springs Power Enterprises for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating on January 31, 2032.

Schedule Page: 328.5 Line No.: 16 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 2012 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 17 Column: c
Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.5 Line No.: 17 Column: d
Legacy contract (Rate Schedule 262) executed between PacifiCorp and Western Area Power Administration for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge for load service to preferential customers for deliveries of Colorado River Storage Project power and energy. Agreement termination upon three years after written notice and mutual consent.

Schedule Page: 328.5 Line No.: 17 Column: m
Fixed termination fee associated with a contract cancellation applied for the duration of this agreement.

Schedule Page: 328.5 Line No.: 18 Column: c
Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.5 Line No.: 18 Column: d
Legacy contract (Rate Schedule 262) executed between PacifiCorp and Western Area Power Administration for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge for load service to preferential

customers for deliveries of Colorado River Storage Project power and energy. Agreement termination upon three years written notice and mutual consent.

Schedule Page: 328.5 Line No.: 18 Column: m

Fixed termination fee associated with a contract cancellation applied for the duration of this agreement. December 2012 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 19 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.5 Line No.: 19 Column: d

Legacy contract (Rate Schedule 263) executed between PacifiCorp and Western Area Power Administration for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge for load service to low-voltage customers for deliveries of power and energy from Salt Lake City Area Integrated Projects, including the Colorado River Storage Projects, to certain municipalities at service below 138kV. Agreement termination upon three years written notice and mutual consent.

Schedule Page: 328.5 Line No.: 19 Column: m

Charges for low-voltage transmission of power and energy.

Schedule Page: 328.5 Line No.: 20 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.5 Line No.: 20 Column: d

Legacy contract (Rate Schedule 263) executed between PacifiCorp and Western Area Power Administration for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge for load service to low-voltage customers for deliveries of power and energy from Salt Lake City Area Integrated Projects, including the Colorado River Storage Projects, to certain municipalities at service below 138kV. Agreement termination upon three years written notice and mutual consent.

Schedule Page: 328.5 Line No.: 20 Column: m

Charges for low-voltage transmission of power and energy. December 2012 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 21 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 21 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, in this Form No. 1.

Schedule Page: 328.5 Line No.: 22 Column: d

Evergreen network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 175).

Schedule Page: 328.5 Line No.: 22 Column: m

Distribution voltage service charge. Primary delivery service. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 23 Column: d

Evergreen network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 175).

Schedule Page: 328.5 Line No.: 23 Column: m

Refunds for transmission and ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.5 Line No.: 24 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: 328.5 Line No.: 24 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 24 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 25 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 25 Column: m

December 2012 transmission and ancillary services. Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.5 Line No.: 26 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 26 Column: m

Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.5 Line No.: 27 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: 328.5 Line No.: 27 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 27 Column: m

Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.5 Line No.: 28 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 28 Column: m

Refunds for ancillary services pursuant to FERC Docket No. ER11-3643.

Schedule Page: 328.5 Line No.: 29 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 of 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 of others, during the period.

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 2013/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	324,224	324,224	1,289,153			1,289,153
2	Arizona Public Service	NF	90,107	90,107	440,288			440,288
3	Arizona Public Service	OS	46	46		9,506	8,473	17,979
4	Arizona Public Service	OS						
5	Arizona Public Service	SFP	13,940	13,940	69,235			69,235
6	Ashland, City of	FNS	2,453	2,453		23,471		23,471
7	Avista Corporation	FNS	58,144	60,577	213,342			213,342
8	Avista Corporation	NF	43,970	43,970	218,702			218,702
9	Avista Corporation	SFP	10,080	10,080	38,766			38,766
10	Basin Elect. Power Coop	NF	91,732	91,732		148,595		148,595
11	Big Horn Rural Electric	OLF					197,474	197,474
12	Black Hills Power, Inc.	AD			-79,056			-79,056
13	Black Hills Power, Inc.	NF	3,358	3,358	7,617			7,617
14	Bonneville Power Admin	AD			20,810	44,805	-312,299	-246,684
15	Bonneville Power Admin	FNS			6,323,965			6,323,965
16	Bonneville Power Admin	LFP	4,001,799	4,001,799	49,722,211			49,722,211
	TOTAL		14,366,419	14,832,184	116,749,567	3,806,761	16,625,976	137,182,304

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 2013/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	NF	133,795	133,795		592,328		592,328
2	Bonneville Power Admin	OLF	3,306,781	3,519,332	31,691,759	27,270	91,505	31,810,534
3	Bonneville Power Admin	OS	30,174	30,174		5,392	2,161,341	2,166,733
4	Bonneville Power Admin	OS						
5	Bonneville Power Admin	SFP	253,705	253,705		1,195,629		1,195,629
6	CA Ind Sys Oper Corp	AD				59,409	-105,154	-45,745
7	CA Ind Sys Oper Corp	OS					443,390	443,390
8	CA Ind Sys Oper Corp	SFP	190,423	190,423		1,665,643		1,665,643
9	Deseret Gen & Trans	LFP	130,341	130,341	4,603,580			4,603,580
10	Deseret Gen & Trans	NF	285,318	285,318	1,729,784			1,729,784
11	El Paso Electric Co.	NF	7,506	7,506	5,205			5,205
12	El Paso Electric Co.	OS					724	724
13	Flathead Elect Coop Inc	OS					76,508	76,508
14	Hermiston Gen Co L.P.	OS					188,315	188,315
15	Idaho Power Company	AD			67,031		734,544	801,575
16	Idaho Power Company	FNS			8,463			8,463
	TOTAL		14,366,419	14,832,184	116,749,567	3,806,761	16,625,976	137,182,304

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 2013/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	Idaho Power Company	LFP	2,418,342	2,663,040	6,593,851			6,593,851
2	Idaho Power Company	NF	117,813	117,813	441,955	32,901		474,856
3	Idaho Power Company	OS			-23,946		12,527,593	12,503,647
4	Idaho Power Company	OS						
5	Idaho Power Company	SFP	273,264	273,264	680,901			680,901
6	LA Dept of Water & Pwr	NF	400	400	3,600			3,600
7	Moon Lake Elect. Assoc.	FNS					294,174	294,174
8	Morgan City Corporation	LFP	13	13		1,812		1,812
9	Nevada Power Company	NF	32,429	32,429	186,911			186,911
10	Nevada Power Company	OS					246,447	246,447
11	Nevada Power Company	SFP	239,518	239,518	985,280			985,280
12	NorthWestern Corp.	NF	356,978	356,978	1,549,329			1,549,329
13	NorthWestern Corp.	OS					112,754	112,754
14	NorthWestern Corp.	SFP	130,013	130,013	785,276			785,276
15	Platte River Pwr Auth	LFP	126,414	126,414	849,700			849,700
16	Platte River Pwr Auth	OS					6,501	6,501
	TOTAL		14,366,419	14,832,184	116,749,567	3,806,761	16,625,976	137,182,304

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 2013/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	Portland Gen. Electric	NF	1	1	1			1
2	Portland Gen. Electric	OLF					848	848
3	Public Service Co of CO	LFP	68,753	71,793	966,469			966,469
4	Public Service Co of NM	AD			-271,290			-271,290
5	Salt River Project	NF	83,419	83,419	221,730			221,730
6	Salt River Project	OS					36,232	36,232
7	Sierra Pacific Pwr Co	NF	35,400	35,400	245,389			245,389
8	Sierra Pacific Pwr Co	OS					26,362	26,362
9	Sierra Pacific Pwr Co	SFP	1,540	1,540	13,338			13,338
10	Surprise Valley Electr.	OLF					8,062	8,062
11	Tri-State Gen & Transm	LFP	61,312	64,355	966,469			966,469
12	Tri-State Gen & Transm	NF	145,781	145,781	545,211			545,211
13	Tri-State Gen & Transm	OS					134,008	134,008
14	Tucson Electric Power	LFP	192,720	192,720	596,442			596,442
15	Tucson Electric Power	NF	3,950	3,950	17,198			17,198
16	Tucson Electric Power	OS					54,882	54,882
	TOTAL		14,366,419	14,832,184	116,749,567	3,806,761	16,625,976	137,182,304

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 2013/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	Westport Field Svc LLC	LFP			-3,615,444			-3,615,444
2	Western Area Power Admn	AD			-3,198		160,660	157,462
3	Western Area Power Admn	FNS			6,112,866			6,112,866
4	Western Area Power Admn	LFP	733,826	733,826	1,780,000			1,780,000
5	Western Area Power Admn	NF	340,471	340,471	696,529			696,529
6	Western Area Power Admn	OS					1,207,646	1,207,646
7	Western Area Power Admn	OS						
8	Western Area Power Admn	SFP	26,166	26,166	54,145			54,145
9	Accrual						-611,558	-611,558
10	Reserve	AD					-1,063,456	-1,063,456
11								
12								
13								
14								
15								
16								
	TOTAL		14,366,419	14,832,184	116,749,567	3,806,761	16,625,976	137,182,304

Schedule Page: 332 Line No.: 1 Column: b

Arizona Public Service Company - contract termination dates: 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, in this Form No. 1.

Schedule Page: 332 Line No.: 11 Column: b

Big Horn Rural Electric Company - contract termination date: March 10, 2015

Schedule Page: 332 Line No.: 11 Column: g

Use of facilities.

Schedule Page: 332 Line No.: 12 Column: b

Settlement adjustment.

Schedule Page: 332 Line No.: 12 Column: e

Settlement adjustment.

Schedule Page: 332 Line No.: 14 Column: b

Settlement adjustment.

Schedule Page: 332 Line No.: 14 Column: g

Ancillary services.

Schedule Page: 332 Line No.: 16 Column: b

Bonneville Power Administration - contract termination dates: 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.: 2 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.: 2 Column: g

Use of facilities.

Schedule Page: 332.1 Line No.: 3 Column: g

Ancillary services. Use of facilities.

Schedule Page: 332.1 Line No.: 4 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, in this Form No. 1.

Schedule Page: 332.1 Line No.: 6 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.: 6 Column: b

Settlement adjustment.

Schedule Page: 332.1 Line No.: 6 Column: g

Ancillary services.

Schedule Page: 332.1 Line No.: 7 Column: g

Ancillary services.

Schedule Page: 332.1 Line No.: 9 Column: b

Deseret Generation and Transmission Cooperative - contract termination dates: January 1, 2018 and September 1, 2018

Schedule Page: 332.1 Line No.: 12 Column: g
Ancillary services.

Schedule Page: 332.1 Line No.: 13 Column: g
Use of facilities.

Schedule Page: 332.1 Line No.: 14 Column: a
Hermiston Generating Company, L.P. operates the Hermiston Generating Plant, which is jointly owned. PacifiCorp owns 50% of the plant.

Schedule Page: 332.1 Line No.: 14 Column: g
Use of facilities.

Schedule Page: 332.1 Line No.: 15 Column: b
Settlement adjustment.

Schedule Page: 332.1 Line No.: 15 Column: g
PacifiCorp's portion of specified costs of certain facilities.

Schedule Page: 332.2 Line No.: 1 Column: b
Idaho Power Company - contract termination dates: April 1, 2025 and July 1, 2025

Schedule Page: 332.2 Line No.: 3 Column: e
Credit for unreserved use.

Schedule Page: 332.2 Line No.: 3 Column: g
Ancillary services. Use of facilities. PacifiCorp's portion of specified costs of certain facilities.

Schedule Page: 332.2 Line No.: 4 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, in this Form No. 1.

Schedule Page: 332.2 Line No.: 6 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.: 7 Column: g
Use of facilities.

Schedule Page: 332.2 Line No.: 8 Column: b
Morgan City Corporation - contract termination date: Evergreen

Schedule Page: 332.2 Line No.: 9 Column: a
This footnote applies to all occurrences of "Nevada Power Company" on page 332. Nevada Power Company is a principal subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of MidAmerican Energy Holdings Company.

Schedule Page: 332.2 Line No.: 10 Column: g
Ancillary services.

Schedule Page: 332.2 Line No.: 13 Column: g
Ancillary services.

Schedule Page: 332.2 Line No.: 15 Column: b
Platte River Power Authority - contract termination date: October 31, 2017

Schedule Page: 332.2 Line No.: 16 Column: g
Ancillary services.

Schedule Page: 332.3 Line No.: 2 Column: b
Portland General Electric Company - contract termination date: Upon two years written notice

Schedule Page: 332.3 Line No.: 2 Column: g
Use of facilities.

Schedule Page: 332.3 Line No.: 3 Column: 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.: 4 Column: b

Settlement adjustment.

Schedule Page: 332.3 Line No.: 4 Column: e

Settlement adjustment.

Schedule Page: 332.3 Line No.: 6 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 7 Column: a

This footnote applies to all occurrences of "Sierra Pacific Pwr Co" on page 332. Sierra Pacific Power Company is a principal subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of MidAmerican Energy Holdings Company.

Schedule Page: 332.3 Line No.: 8 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 10 Column: b

Surprise Valley Electrification Corp. - contract termination date: Evergreen

Schedule Page: 332.3 Line No.: 10 Column: g

Use of facilities.

Schedule Page: 332.3 Line No.: 11 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: 332.3 Line No.: 13 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 14 Column: b

Tucson Electric Power Company - contract termination date: December 1, 2015

Schedule Page: 332.3 Line No.: 16 Column: g

Ancillary services.

Schedule Page: 332.4 Line No.: 1 Column: b

Westport Field Services, LLC - contract termination date: Evergreen

Schedule Page: 332.4 Line No.: 1 Column: e

Reimbursement for third-party service provided.

Schedule Page: 332.4 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 332.4 Line No.: 2 Column: e

Settlement adjustment.

Schedule Page: 332.4 Line No.: 2 Column: g

Ancillary services.

Schedule Page: 332.4 Line No.: 4 Column: b

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

Schedule Page: 332.4 Line No.: 6 Column: g

Ancillary services. Use of facilities.

Schedule Page: 332.4 Line No.: 7 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, in this Form No. 1.

Schedule Page: 332.4 Line No.: 9 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 this period.

Schedule Page: 332.4 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 332.4 Line No.: 10 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 2013/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,673,683
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	Alberta Main Street	5,000
10	Albina Opportunities Corporation	5,000
11	American Leadership Forum	5,000
12	Casper Area Economic Development Alliance	5,000
13	Clatsop Economic Development	6,000
14	Economic Development Corporation of Utah	19,100
15	Economic Development for Central Oregon	9,000
16	Equal Employment Advisory Council	7,446
17	Four County Economic Development Corporation	10,000
18	Gorge Oregon Entrepreneurs Network	5,000
19	Grow Oregon	15,000
20	Idaho Economic Development Association	7,000
21	Intermountain Electrical Assoication	9,000
22	Klamath County Chamber of Commerce	5,735
23	North Davis Chamber of Commerce	7,390
24	Northern Tier Transmission Group	595,784
25	Oregon Business Association	13,250
26	Oregon Business Council	25,938
27	Oregon Economic Development Association	12,000
28	Oregon Sports Authority Foundation	5,000
29	Oregon State University	15,000
30	Pacific Northwest Utilities Conference	74,153
31	Portland Business Alliance	38,950
32	Redmond Economic Development	7,000
33	Rocky Mountain Electrical League	16,000
34	Salt Lake Area Chamber of Commerce	30,742
35	Siskiyou County Economic Development	5,000
36	South Coast Development Council, Inc.	6,000
37	Tree Research and Education Endowment Fund	10,000
38	Utah Governor's Economic Summit	15,000
39	Utah Manufacturers Association	6,600
40	Utah Taxpayers Association	18,700
41	Watson & Renner	52,450
42	Western Electricity Coordinating Council	3,725,747
43	Western Energy Institute	44,690
44	Western Energy Supply and Transmission Associates	15,694
45	Wyoming Business Alliance	6,000
46	TOTAL	7,526,075

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 2013/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
6	Wyoming Business Council	5,000
7	Wyoming Taxpayers Association	11,223
8	Yakima County Development	7,500
9	Other (Individually < $5,000)	161,745
10		
11	Directors' Fees - Regional Advisory Boards	22,945
12		
13	Rating Agency and Trustee Fees:	
14	The Bank of New York Mellon	169,602
15	Computershare Shareowner Services, LLC	58,205
16	Financial Industry Regulatory Authority, Inc.	6,400
17	Fitch, Inc.	54,575
18	Moody's Investors Service, Inc.	175,015
19	Standard and Poor's Financial Services, LLC	258,000
20	U.S. Bank National Association	9,682
21	Other (Individually < $5,000)	3,094
22		
23	General:	
24	Other	456
25		
26	Regulatory Asset Amortization:	
27	Generating Plant Liquidated Damages - WY	48,581
28		
29		
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46	TOTAL	7,526,075

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 2013/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			43,538,777		43,538,777
2	Steam Production Plant	166,446,520				166,446,520
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	25,014,943		273,912		25,288,855
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	115,859,652				115,859,652
7	Transmission Plant	94,564,623				94,564,623
8	Distribution Plant	159,821,396				159,821,396
9	Regional Transmission and Market Operation					
10	General Plant	39,122,546		1,621,977		40,744,523
11	Common Plant-Electric					
12	TOTAL	600,829,680		45,434,666		646,264,346

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 2013/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			-3.59		6.00
15	330.40 OR/CA	1			-3.76		6.00
16	331.00 OR/CA	14,044			8.66		6.00
17	332.00 OR/CA	34,145			5.67		6.00
18	333.00 OR/CA	17,883			7.88		6.00
19	334.00 OR/CA	15,622			10.66		6.00
20	335.00 OR/CA	183			4.28		6.00
21	336.00 OR/CA	2,567			6.78		6.00
22							
23	Cutler						
24	332.20	1			8.34		11.00
25							
26							
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50							

Schedule Page: 336 Line No.: 12 Column: b

Depreciation expense associated with transportation equipment is generally charged to operations and maintenance expense and construction work in progress. During the year ended December 31, 2013, depreciation expense associated with transportation equipment was $15,921,062.

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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	4,858,574		4,858,574	
3	Rate Case		1,282,915	1,282,915	
4					
5	Oregon Public Utility Commission:				
6	Annual Fee	3,273,471		3,273,471	
7	Rate Case		1,219,564	1,219,564	
8	Deferred Intervenor Funding Grants				585,536
9					
10	Wyoming Public Service Commission:				
11	Annual Fee	1,525,742		1,525,742	
12	Rate Case		228,179	228,179	
13					
14	Washington Utilities and Transportation				
15	Commission:				
16	Annual Fee	553,548		553,548	
17	Rate Case		1,882,949	1,882,949	
18					
19	Idaho Public Utilities Commission:				
20	Annual Fee	563,383		563,383	
21	Rate Case		243,493	243,493	
22	Deferred Intervenor Funding Grants (2)		19,500	19,500	69,206
23					
24	California Public Utilities Commission:				
25	Annual Fee	1,099		1,099	
26	Rate Case		538,867	538,867	
27	Deferred Intervenor Funding Grants				32,952
28					
29	California Environmental Protection Agency:				
30	Industry Compliance Fee	43,433	17,244	60,677	
31					
32	Rate Cases - All States		713,472	713,472	
33					
34	Federal Energy Regulatory Commission:				
35	Annual Fee	1,883,087		1,883,087	
36	Annual Fee - Hydro	2,350,790		2,350,790	
37	Transmission Rate Case		254,925	254,925	
38	Other Regulatory		1,243,762	1,243,762	
39					
40	Other Regulatory		68,285	68,285	
41					
42	Charges for services from MidAmerican Energy				
43	Holdings Company and its affiliates:				
44	Washington - Rate Case		1,421	1,421	
45	FERC - Transmission Rate Case		534	534	
46	TOTAL	15,053,127	7,715,110	22,768,237	687,694

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	4,858,574					2
Electric	928	1,282,915					3
							4
							5
Electric	928	3,273,471					6
Electric	928	1,219,564					7
			217,390			802,926	8
							9
							10
Electric	928	1,525,742					11
Electric	928	228,179					12
							13
							14
							15
Electric	928	553,548					16
Electric	928	1,882,949					17
							18
							19
Electric	928	563,383					20
Electric	928	243,493					21
Electric	928	19,500	5,756	928	19,500	55,462	22
							23
							24
Electric	928	1,099					25
Electric	928	538,867					26
			7,355			40,307	27
							28
							29
Electric	928	60,677					30
							31
Electric	928	713,472					32
							33
							34
Electric	928	1,883,087					35
Electric	928	2,350,790					36
Electric	928	254,925					37
Electric	928	1,243,762					38
							39
Electric	928	68,285					40
							41
							42
							43
Electric	928	1,421					44
Electric	928	534					45
		22,768,237	230,501		19,500	898,695	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 2013/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	B. Electric R, D & D Performed Externally:	
2	(1) Research Support	Electric Power Research Institute
3		- Toxic Release Inventory reporting for power plants program
4	(2) Research Support	Edison Electric Institute
5		- Avian Power Line Interaction Committee - membership dues
6		
7		
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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 Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
	15,000	557	15,000		3
					4
	2,500	930.2	2,500		5
					6
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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 2013/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	95,938,433		
4	Transmission	12,303,303		
5	Regional Market			
6	Distribution	36,478,819		
7	Customer Accounts	39,530,024		
8	Customer Service and Informational	6,206,300		
9	Sales			
10	Administrative and General	40,980,627		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	231,437,506		
12	Maintenance			
13	Production	48,511,570		
14	Transmission	10,595,957		
15	Regional Market			
16	Distribution	69,062,051		
17	Administrative and General	1,837,373		
18	TOTAL Maintenance (Total of lines 13 thru 17)	130,006,951		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	144,450,003		
21	Transmission (Enter Total of lines 4 and 14)	22,899,260		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	105,540,870		
24	Customer Accounts (Transcribe from line 7)	39,530,024		
25	Customer Service and Informational (Transcribe from line 8)	6,206,300		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	42,818,000		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	361,444,457		361,444,457
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 2013/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru 47)			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	361,444,457		361,444,457
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	137,795,183		137,795,183
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	137,795,183		137,795,183
72	Plant Removal (By Utility Departments)			
73	Electric Plant	8,060,331		8,060,331
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	8,060,331		8,060,331
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock	2,125,458		2,125,458
79	Miscellaneous Other Income Deductions	677,250		677,250
80	Charges to Affiliates	558,584		558,584
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	3,361,292		3,361,292
96	TOTAL SALARIES AND WAGES	510,661,263		510,661,263

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 2013/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	599,396	2,731,410	4,571,210	8,684,762
3	Net Sales (Account 447)	(16,815)	(11,343)	(22,647)	(22,647)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
11					
12					
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15					
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44					
45					
46	TOTAL	582,581	2,720,067	4,548,563	8,662,115

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch				148,574,179	MWh	10,147,822
2	Reactive Supply and Voltage	109,647,672	MWh	-26,122	120,147,582	MWh	-210,228
3	Regulation and Frequency Response	82,131,450	MWh	26,889,201	92,553,762	MWh	29,568,048
4	Energy Imbalance				-255,953	MWh	-7,556,884
5	Operating Reserve - Spinning	65,546,498	MWh	20,974,879	73,290,551	MWh	23,768,254
6	Operating Reserve - Supplement	65,546,498	MWh	20,950,006	68,694,640	MWh	22,090,479
7	Other						
8	Total (Lines 1 thru 7)	322,872,118		68,787,964	503,004,761		77,807,491

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 2013/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	15,670	14	1800	9,028	115	4,237		498	1,792
2	February	14,431	11	800	8,252	107	4,237		208	1,627
3	March	14,186	4	800	8,066	108	3,951		514	1,547
4	Total for Quarter 1	44,287			25,346	330	12,425		1,220	4,966
5	April	13,451	9	800	7,604	108	3,951		327	1,461
6	May	14,450	14	1600	8,350	103	3,951		368	1,678
7	June	16,606	28	1600	10,148	110	4,109		197	2,042
8	Total for Quarter 2	44,507			26,102	321	12,011		892	5,181
9	July	17,745	1	1600	10,823	115	4,109		566	2,132
10	August	16,182	19	1500	9,857	113	4,109		163	1,940
11	September	15,847	5	1600	9,141	108	4,369		350	1,879
12	Total for Quarter 3	49,774			29,821	336	12,587		1,079	5,951
13	October	14,108	30	800	7,771	97	4,401		424	1,415
14	November	14,617	21	1800	8,389	115	4,243		252	1,618
15	December	16,379	9	1800	9,656	131	4,269		515	1,808
16	Total for Quarter 4	45,104			25,816	343	12,913		1,191	4,841
17	Total Year to Date/Year	183,672			107,085	1,330	49,936		4,382	20,939

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 2013 Net System Load information was estimated using metering and/or scheduling data. Reflects actual peak net system load for self at time of Transmission System Peak. Peak load includes 690 megawatts of behind-the-meter generation for the quarter.

Schedule Page: 400 Line No.: 4 Column: f

1st Quarter 2013 Net System Load information was estimated 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 2013 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 2013 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 2013 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

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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 2013 Net System Load information was estimated using metering and/or scheduling data. Reflects actual peak net system load for self at time of Transmission System Peak. Peak load includes 825 megawatts of behind-the-meter generation for the quarter.

Schedule Page: 400 Line No.: 8 Column: f

2nd Quarter 2013 Net System Load information was estimated 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 2013 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. 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 2013 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 2013 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 2013 Net System Load information was estimated using metering and/or scheduling data. Reflects actual peak net system load for self at time of Transmission System Peak. Peak load includes 927 megawatts of behind-the-meter generation for the quarter.

Schedule Page: 400 Line No.: 12 Column: f

3rd Quarter 2013 Net System Load information was estimated 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 2013 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. 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 2013 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 2013 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 2013 Net System Load information was estimated using metering and/or scheduling data. Reflects actual peak net system load for self at time of Transmission System Peak. Peak load includes 663 megawatts of behind-the-meter generation for the quarter.

Schedule Page: 400 Line No.: 16 Column: f

4th Quarter 2013 Net System Load information was estimated 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 2013 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. 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 2013 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 2013 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 2013/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)	55,662,873
3	Steam	46,010,930			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	230,282
5	Hydro-Conventional	3,167,941			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	9,975,853
7	Other	9,202,064			
8	Less Energy for Pumping	4,363	25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	58,376,572	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	146,698
10	Purchases	12,096,279	27	Total Energy Losses	4,601,324
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	70,617,030
12	Received	4,186,538			
13	Delivered	3,694,867			
14	Net Exchanges (Line 12 minus line 13)	491,671			
15	Transmission For Other (Wheeling)				
16	Received	12,830,379			
17	Delivered	12,712,106			
18	Net Transmission for Other (Line 16 minus line 17)	118,273			
19	Transmission By Others Losses	-465,765			
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	70,617,030			

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	6,434,963	882,817	8,825	14	1800 PST
30	February	5,529,546	832,058	8,052	11	0800 PST
31	March	5,615,389	823,326	7,780	4	0800 PST
32	April	5,377,407	917,507	7,338	9	0800 PDT
33	May	5,422,233	683,636	8,106	14	1600 PDT
34	June	5,718,492	557,062	9,833	28	1600 PDT
35	July	6,429,745	615,054	10,507	1	1600 PDT
36	August	6,221,862	706,835	9,571	19	1500 PDT
37	September	5,780,942	1,081,292	8,822	5	1500 PDT
38	October	5,727,662	989,707	7,512	30	0800 PDT
39	November	5,897,169	1,070,176	8,213	22	0800 PST
40	December	6,461,620	816,383	9,451	9	1800 PST
41	TOTAL	70,617,030	9,975,853			

Schedule Page: 401 Line No.: 26 Column: b

For metered locations only.

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)			177			385
7	Plant Hours Connected to Load			8714			7351
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			58			0
12	Net Generation, Exclusive of Plant Use - KWh			1197765000			2393681000
13	Cost of Plant: Land and Land Rights			956546			2634927
14	Structures and Improvements			15572243			62589051
15	Equipment Costs			104471837			470480250
16	Asset Retirement Costs			7036834			39000
17	Total Cost			128037460			535743228
18	Cost per KW of Installed Capacity (line 17/5) Including			678.8837			1294.0658
19	Production Expenses: Oper, Supv, & Engr			98985			1591767
20	Fuel			26055932			56227346
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			1532464			8008051
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			1974477			933545
26	Misc Steam (or Nuclear) Power Expenses			4086786			2155158
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			0			2635668
30	Maintenance of Structures			422120			928885
31	Maintenance of Boiler (or reactor) Plant			3885492			5588245
32	Maintenance of Electric Plant			1427205			693907
33	Maintenance of Misc Steam (or Nuclear) Plant			390544			4089307
34	Total Production Expenses			39874005			82851879
35	Expenses per Net KWh			0.0333			0.0346
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	565299	2475	0	1360563	2967	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12127	138000	0	9326	128637	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	45.045	140.214	0.000	39.291	147.143	0.000
41	Average Cost of Fuel per Unit Burned	45.478	140.214	0.000	41.006	147.143	0.000
42	Average Cost of Fuel Burned per Million BTU	1.875	24.192	1.898	2.199	27.235	2.214
43	Average Cost of Fuel Burned per KWh Net Gen	0.021	0.000	0.021	0.023	0.000	0.023
44	Average BTU per KWh Net Generation	11447.018	11.977	11458.995	10601.257	6.697	10607.954

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
153	168	739	6
8587	8557	8760	7
0	0	0	8
148	166	762	9
0	0	0	10
0	0	188	11
837293000	1017613000	5308783000	12
1788103	137086	10449793	13
60600305	37619781	154773550	14
161516721	142410204	823783706	15
39236	35149	12395036	16
223944365	180202220	1001402085	17
1439.2311	1047.0786	1226.0065	18
42881	390267	270242	19
13373215	19463157	64218514	20
0	0	0	21
868394	1876621	500025	22
0	0	0	23
0	0	0	24
46461	818263	0	25
1171565	1104254	18410395	26
20596	940	89716	27
0	0	0	28
247232	847093	0	29
370814	612875	2798820	30
2694697	5201028	11002634	31
538267	2274296	5472546	32
347860	1171426	2023789	33
19721982	33760220	104786681	34
0.0236	0.0332	0.0197	35

(d) Coal	(d) Oil	(d) Composite	(e) Coal	(e) Oil	(e) Composite	(f) Coal	(f) Oil	(f) Composite	Line No.
Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
523604	1131	0	505363	22	0	3686523	12788	0	38
8464	140000	0	9983	133693	0	8077	138000	0	39
23.602	132.611	0.000	37.265	126.158	0.000	17.395	133.120	0.000	40
25.254	132.611	0.000	38.318	126.158	0.000	16.958	133.120	0.000	41
1.492	22.551	1.508	1.919	22.542	1.929	1.050	22.968	1.077	42
0.016	0.000	0.016	0.019	0.000	0.019	0.012	0.000	0.012	43
10585.699	7.943	10593.642	9915.736	0.119	9915.855	11217.306	13.962	11231.268	44

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 2013/Q4

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

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

Line No.	Item (a)	Plant Name: *Hayden* (b)			Plant Name: *Hunter Unit No. 1* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Steam			Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Outdoor Boiler			Outdoor Boiler
3	Year Originally Constructed			1965			1978
4	Year Last Unit was Installed			1976			1978
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			81.40			457.70
6	Net Peak Demand on Plant - MW (60 minutes)			75			422
7	Plant Hours Connected to Load			8760			8223
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			646108000			2858108000
13	Cost of Plant: Land and Land Rights			683069			9688975
14	Structures and Improvements			17674475			63457669
15	Equipment Costs			66895845			314151491
16	Asset Retirement Costs			532363			1976952
17	Total Cost			85785752			389275087
18	Cost per KW of Installed Capacity (line 17/5) Including			1053.8790			850.5027
19	Production Expenses: Oper, Supv, & Engr			201094			0
20	Fuel			16238571			56217088
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			907330			3089428
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			223553			-55967
26	Misc Steam (or Nuclear) Power Expenses			471736			2190948
27	Rents			0			-559
28	Allowances			0			0
29	Maintenance Supervision and Engineering			337693			0
30	Maintenance of Structures			749591			3280523
31	Maintenance of Boiler (or reactor) Plant			994074			7406991
32	Maintenance of Electric Plant			265846			2310964
33	Maintenance of Misc Steam (or Nuclear) Plant			480996			252079
34	Total Production Expenses			20870484			74691495
35	Expenses per Net KWh			0.0323			0.0261
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	309815	283	0	1313405	6539	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11202	137191	0	11312	138000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	50.229	144.576	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	52.252	144.576	0.000	42.109	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.332	25.090	2.339	1.861	24.018	1.889
43	Average Cost of Fuel Burned per KWh Net Gen	0.025	0.000	0.025	0.019	0.000	0.019
44	Average BTU per KWh Net Generation	10743.313	2.527	10745.840	10396.815	13.261	10410.076

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

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

Plant Name: *Hunter Unit No. 2* (d)			Plant Name: *Hunter Unit No. 3* (e)			Plant Name: *Hunter - Total Plant* (f)			Line No.
Steam			Steam			Steam			1
Outdoor Boiler			Outdoor Boiler			Outdoor Boiler			2
1980			1983			1978			3
1980			1983			1983			4
294.50			495.60			1247.80			5
275			478			1160			6
8626			8369			8760			7
0			0			0			8
269			471			1158			9
0			0			0			10
0			0			219			11
1987634000			3222147000			8067889000			12
9688975			10275401			29653351			13
52330697			90900788			206689154			14
242846489			431012160			988010140			15
1976952			1976952			5930856			16
306843113			534165301			1230283501			17
1041.9121			1077.8154			985.9621			18
0			0			0			19
36679012			61940439			154836539			20
0			0			0			21
2319226			3364983			8773637			22
0			0			0			23
0			0			0			24
57894			-53273			-51346			25
-1052422			2398987			3537513			26
-360			-630			-1549			27
0			0			0			28
0			0			0			29
2097254			3023496			8401273			30
5777677			10703589			23888257			31
1013320			1654915			4979199			32
283864			478844			1014787			33
47175465			83511350			205378310			34
0.0237			0.0259			0.0255			35
Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
868601	585	0	1439329	9676	0	3621335	16800	0	38
11524	138000	0	11325	138000	0	11368	138000	0	39
0.000	0.000	0.000	0.000	0.000	0.000	42.708	138.309	0.000	40
42.137	0.000	0.000	42.107	0.000	0.000	42.115	138.309	0.000	41
1.828	23.203	1.832	1.859	23.798	1.897	1.852	23.863	1.878	42
0.018	0.000	0.018	0.019	0.000	0.019	0.019	0.000	0.019	43
10071.695	1.706	10073.401	10118.118	17.406	10135.524	10205.411	12.070	10217.481	44

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

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

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

Line No.	Item (a)	Plant Name: *Huntington* (b)			Plant Name: *Jim Bridger* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Steam			Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Outdoor Boiler			Semi-Outdoor
3	Year Originally Constructed			1974			1974
4	Year Last Unit was Installed			1977			1979
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			996.00			1550.65
6	Net Peak Demand on Plant - MW (60 minutes)			912			1423
7	Plant Hours Connected to Load			8760			8760
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			164			345
12	Net Generation, Exclusive of Plant Use - KWh			6768625000			9936388000
13	Cost of Plant: Land and Land Rights			2386782			1161925
14	Structures and Improvements			118613800			138651627
15	Equipment Costs			703371377			957423038
16	Asset Retirement Costs			4179560			4750344
17	Total Cost			828551519			1101986934
18	Cost per KW of Installed Capacity (line 17/5) Including			831.8790			710.6613
19	Production Expenses: Oper, Supv, & Engr			12135			14626617
20	Fuel			111058721			220562489
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			9245363			4195088
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			2941
26	Misc Steam (or Nuclear) Power Expenses			12978016			-10856086
27	Rents			1522			362252
28	Allowances			0			0
29	Maintenance Supervision and Engineering			1407281			622763
30	Maintenance of Structures			2731649			11044905
31	Maintenance of Boiler (or reactor) Plant			8277705			26652581
32	Maintenance of Electric Plant			1587328			7917751
33	Maintenance of Misc Steam (or Nuclear) Plant			1240962			2566169
34	Total Production Expenses			148540682			277697470
35	Expenses per Net KWh			0.0219			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	2891832	4368	0	5434450	12125	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12003	138000	0	9339	138000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	40.364	140.939	0.000	37.815	133.981	0.000
41	Average Cost of Fuel per Unit Burned	38.191	140.939	0.000	40.287	133.981	0.000
42	Average Cost of Fuel Burned per Million BTU	1.591	24.317	1.599	2.157	23.116	2.171
43	Average Cost of Fuel Burned per KWh Net Gen	0.016	0.000	0.016	0.022	0.000	0.022
44	Average BTU per KWh Net Generation	10256.196	3.741	10259.937	10215.569	7.073	10222.642

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

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

Plant Name: *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	283	161	6
8760	8223	5312	7
0	0	0	8
687	268	238	9
0	0	0	10
134	65	34	11
5533895000	1975401000	222396000	12
1094739	210526	1252090	13
116741815	51295214	15102770	14
635993498	393360506	65900473	15
20721266	490453	587008	16
774551318	445356699	82842341	17
1095.2366	1537.3031	329.2621	18
362513	217876	259921	19
116935308	20435057	16789712	20
0	0	0	21
6827303	321768	0	22
0	0	0	23
0	0	0	24
1202	0	0	25
12253566	4475333	4242458	26
1282	15039	0	27
0	0	0	28
1233751	0	0	29
1158048	308539	87796	30
7350601	6123857	1339761	31
1960476	1239636	1021357	32
822674	130614	420123	33
148906724	33267719	24161128	34
0.0269	0.0168	0.1086	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
2951673	67897	0	1504512	4169	0	3240573	0	0	38
10012	1050	0	7939	138000	0	1021	0	0	39
39.363	8.628	0.000	13.127	135.319	0.000	5.181	0.000	0.000	40
39.418	8.628	0.000	13.208	135.319	0.000	5.181	0.000	0.000	41
1.968	8.216	1.976	0.832	23.347	0.855	5.073	0.000	0.000	42
0.021	0.000	0.021	0.010	0.000	0.010	0.075	0.000	0.000	43
10680.842	12.885	10693.727	12092.393	12.232	12104.625	14882.624	0.000	0.000	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: *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			38		
7	Plant Hours Connected to Load	8014			8314		
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			24		
12	Net Generation, Exclusive of Plant Use - KWh	1293909000			250722000		
13	Cost of Plant: Land and Land Rights	842245			41195596		
14	Structures and Improvements	12844996			8245638		
15	Equipment Costs	158857742			71389327		
16	Asset Retirement Costs	214373			1744133		
17	Total Cost	172759356			122574694		
18	Cost per KW of Installed Capacity (line 17/5) Including	617.8804			3217.1836		
19	Production Expenses: Oper, Supv, & Engr	0			17425		
20	Fuel	61105462			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			860535		
23	Steam From Other Sources	0			4312439		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	7066609			0		
26	Misc Steam (or Nuclear) Power Expenses	0			987601		
27	Rents	0			6247		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			380805		
31	Maintenance of Boiler (or reactor) Plant	0			207274		
32	Maintenance of Electric Plant	0			1713932		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			78187		
34	Total Production Expenses	68172071			8564445		
35	Expenses per Net KWh	0.0527			0.0342		
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	9845424	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1023	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	6.206	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	6.206	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	6.069	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.047	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	7781.617	0.000	0.000	0.000	0.000	0.000

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

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

Plant Name: *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
22	494	121	6
5941	4403	3614	7
0	0	0	8
14	518	120	9
0	0	0	10
0	18	0	11
62089000	1674194000	117464000	12
0	1973790	0	13
5733734	23907901	4273000	14
28718343	313293868	76946995	15
0	689117	0	16
34452077	339864676	81219995	17
560.1964	572.8378	448.4815	18
0	192329	0	19
0	68274999	8830233	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	2048664	525061	25
421378	694005	0	26
0	49584	0	27
0	0	0	28
0	0	0	29
0	49830	165998	30
0	0	0	31
0	2332424	1012398	32
0	0	114628	33
421378	73641835	10648318	34
0.0068	0.0440	0.0907	35

(d)			(e)			(f)			Line No.
			Gas			Gas			36
			MCF			MCF			37
0	0	0	11912103	0	0	1504686	0	0	38
0	0	0	1042	0	0	1120	0	0	39
0.000	0.000	0.000	5.732	0.000	0.000	5.868	0.000	0.000	40
0.000	0.000	0.000	5.732	0.000	0.000	5.868	0.000	0.000	41
0.000	0.000	0.000	5.501	0.000	0.000	5.238	0.000	0.000	42
0.000	0.000	0.000	0.041	0.000	0.000	0.075	0.000	0.000	43
0.000	0.000	0.000	7412.944	0.000	0.000	14352.457	0.000	0.000	44

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)	550			553		
7	Plant Hours Connected to Load	8625			7876		
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	20			29		
12	Net Generation, Exclusive of Plant Use - KWh	2359924000			2508960000		
13	Cost of Plant: Land and Land Rights	3403277			17278683		
14	Structures and Improvements	44185107			28221081		
15	Equipment Costs	324569362			323085508		
16	Asset Retirement Costs	134848			0		
17	Total Cost	372292594			368585272		
18	Cost per KW of Installed Capacity (line 17/5) Including	656.7165			623.3473		
19	Production Expenses: Oper, Supv, & Engr	74681			181703		
20	Fuel	89904876			93174845		
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	1815653			2586791		
26	Misc Steam (or Nuclear) Power Expenses	788639			1006461		
27	Rents	58			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	221060			2590159		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	1242948			750576		
33	Maintenance of Misc Steam (or Nuclear) Plant	77060			78720		
34	Total Production Expenses	94124975			100369255		
35	Expenses per Net KWh	0.0399			0.0400		
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	17147926	0	0	17434244	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1041	0	0	1038	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	5.243	0.000	0.000	5.344	0.000	0.000
41	Average Cost of Fuel per Unit Burned	5.243	0.000	0.000	5.344	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	5.036	0.000	0.000	5.149	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.038	0.000	0.000	0.037	0.000	0.000
44	Average BTU per KWh Net Generation	7565.569	0.000	0.000	7213.003	0.000	0.000

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

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

Plant Name: *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
									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: 403 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: 403 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: 403 Line No.: 11 Column: d
PacifiCorp does not have employees at the Colstrip Plant.

Schedule Page: 403 Line No.: 11 Column: e
PacifiCorp does not have employees at the Craig Plant.

Schedule Page: 403 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 2013 were $1.5 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 403.1 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 2013 were $7.2 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 403.1 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: 403.1 Line No.: 11 Column: d
Refer to Hunter - Total Plant on page 403.1 for the average number of employees.

Schedule Page: 403.1 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

2013 were $27.2 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 403.2 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 2013 were $3.7 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, in 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: 403.3 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: 403.3 Line No.: 11 Column: d

PacifiCorp does not have employees at the Camas Co-Generation unit at Georgia-Pacific Corporation's Camas, Washington paper mill.

Schedule Page: 403.3 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 2013/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)	25	29
7	Plant Hours Connect to Load	6,251	6,080
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	67,577,000	83,609,000
13	Cost of Plant		
14	Land and Land Rights	107,019	20,914
15	Structures and Improvements	1,615,906	2,342,432
16	Reservoirs, Dams, and Waterways	2,933,710	2,954,724
17	Equipment Costs	5,278,956	10,396,954
18	Roads, Railroads, and Bridges	105,442	479,588
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	10,041,033	16,194,612
21	Cost per KW of Installed Capacity (line 20 / 5)	502.0517	599.8004
22	Production Expenses		
23	Operation Supervision and Engineering	40,381	29,190
24	Water for Power	-1,734	-2,341
25	Hydraulic Expenses	1,846	2,492
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	921,504	1,225,104
28	Rents	34,453	46,512
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	3,699	5,506
31	Maintenance of Reservoirs, Dams, and Waterways	95,732	88,429
32	Maintenance of Electric Plant	107,103	249,711
33	Maintenance of Misc Hydraulic Plant	12,405	16,745
34	Total Production Expenses (total 23 thru 33)	1,215,389	1,661,348
35	Expenses per net KWh	0.0180	0.0199

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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: Clearwater No. 1 (d)	FERC Licensed Project No. 1927 Plant Name: Clearwater No. 2 (e)	FERC Licensed Project No. 2420 Plant Name: Cutler (f)	Line No.
Run-of-River	Run-of-River	Storage	1
Outdoor	Outdoor	Conventional	2
1953	1953	1927	3
1953	1953	1927	4
15.00	26.00	30.00	5
12	23	17	6
8,190	8,118	5,314	7
			8
18	31	29	9
18	31	29	10
1	1	3	11
37,778,000	39,381,000	31,877,000	12
			13
0	0	3,511,105	14
1,228,415	1,738,004	3,969,986	15
5,130,185	14,743,489	7,580,966	16
1,326,944	1,976,274	14,609,362	17
50,817	250,151	572,059	18
0	0	0	19
7,736,361	18,707,918	30,243,478	20
515.7574	719.5353	1,008.1159	21
			22
30,048	30,786	106,308	23
1,212	2,101	3,749	24
57,262	99,254	54,212	25
0	0	0	26
258,655	391,227	443,247	27
33,236	57,609	-500	28
39	68	0	29
50,539	57,674	37,039	30
10,723	67,658	9,711	31
109,899	56,770	21,270	32
91,376	123,431	231,346	33
642,989	886,578	906,382	34
0.0170	0.0225	0.0284	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 2013/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	17
7	Plant Hours Connect to Load	2,327	6,688
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	15,766,000	70,991,000
13	Cost of Plant		
14	Land and Land Rights	0	62,169
15	Structures and Improvements	989,738	1,964,387
16	Reservoirs, Dams, and Waterways	12,379,990	10,964,143
17	Equipment Costs	1,865,730	4,338,635
18	Roads, Railroads, and Bridges	533,015	341,093
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	15,768,473	17,670,427
21	Cost per KW of Installed Capacity (line 20 / 5)	1,433.4975	535.4675
22	Production Expenses		
23	Operation Supervision and Engineering	12,997	87,844
24	Water for Power	889	4,123
25	Hydraulic Expenses	41,992	59,634
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	261,197	1,345,200
28	Rents	24,373	4,330
29	Maintenance Supervision and Engineering	29	0
30	Maintenance of Structures	21,200	77,198
31	Maintenance of Reservoirs, Dams, and Waterways	87,902	56,422
32	Maintenance of Electric Plant	28,442	71,240
33	Maintenance of Misc Hydraulic Plant	43,664	163,256
34	Total Production Expenses (total 23 thru 33)	522,685	1,869,247
35	Expenses per net KWh	0.0332	0.0263

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 2013/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	78	27	6
8,292	5,270	8,014	7
			8
19	83	32	9
19	83	32	10
1	2	1	11
85,349,000	166,834,000	123,888,000	12
			13
341,706	25,845	0	14
6,639,458	3,445,932	2,471,874	15
13,695,754	14,559,725	15,366,409	16
2,716,356	15,295,677	6,844,208	17
1,095,742	886,710	484,728	18
0	0	0	19
24,489,016	34,213,889	25,167,219	20
1,360.5009	349.1926	786.7214	21
			22
1,365,809	308,557	38,127	23
-1,561	-8,496	2,585	24
41,822	10,206	122,121	25
0	0	0	26
836,885	800,712	519,841	27
31,074	122,680	70,881	28
0	0	83	29
40,040	6,417	105,801	30
24,499	9,330	108,310	31
192,132	79,168	107,282	32
11,165	59,869	125,643	33
2,541,865	1,388,443	1,200,674	34
0.0298	0.0083	0.0097	35

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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	144
7	Plant Hours Connect to Load	8,317	8,760
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	150,001,000	460,852,000
13	Cost of Plant		
14	Land and Land Rights	0	1,086,564
15	Structures and Improvements	4,371,431	51,335,863
16	Reservoirs, Dams, and Waterways	31,376,412	25,767,703
17	Equipment Costs	11,748,386	18,512,487
18	Roads, Railroads, and Bridges	1,955,909	2,978,357
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	49,452,138	99,680,974
21	Cost per KW of Installed Capacity (line 20 / 5)	1,284.4711	732.9483
22	Production Expenses		
23	Operation Supervision and Engineering	46,312	1,231,090
24	Water for Power	3,112	6,787
25	Hydraulic Expenses	146,972	714,351
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	552,618	385,275
28	Rents	85,306	99,592
29	Maintenance Supervision and Engineering	100	0
30	Maintenance of Structures	94,035	19,811
31	Maintenance of Reservoirs, Dams, and Waterways	225,784	36,174
32	Maintenance of Electric Plant	79,238	71,305
33	Maintenance of Misc Hydraulic Plant	151,211	374,946
34	Total Production Expenses (total 23 thru 33)	1,384,688	2,939,331
35	Expenses per net KWh	0.0092	0.0064

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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	21	36	6
8,043	8,319	8,626	7
			8
45	28	36	9
45	28	36	10
1	2	1	11
195,898,000	28,182,000	215,139,000	12
			13
0	36,698	105,168	14
4,057,415	1,888,351	3,525,896	15
12,783,603	6,083,220	30,122,382	16
3,786,254	5,626,866	6,778,960	17
264,441	503,332	305,160	18
0	0	0	19
20,891,713	14,138,467	40,837,566	20
491.5697	471.2822	1,276.1739	21
			22
58,347	79,380	103,060	23
3,435	3,749	102,218	24
162,242	54,212	8,481	25
0	0	0	26
546,867	654,229	1,053,083	27
94,169	2,182	4,052	28
111	0	0	29
92,229	33,227	73,164	30
138,116	-3,679	338,925	31
236,812	272,057	354,888	32
166,921	162,086	716,683	33
1,499,249	1,257,443	2,754,554	34
0.0077	0.0446	0.0128	35

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 1927 Plant Name: 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)	16	8
7	Plant Hours Connect to Load	8,318	7,319
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	18	14
10	(b) Under the Most Adverse Oper Conditions	18	14
11	Average Number of Employees	1	2
12	Net Generation, Exclusive of Plant Use - Kwh	53,119,000	15,674,000
13	Cost of Plant		
14	Land and Land Rights	0	511,083
15	Structures and Improvements	2,186,187	732,396
16	Reservoirs, Dams, and Waterways	14,872,403	8,721,281
17	Equipment Costs	8,966,627	5,361,205
18	Roads, Railroads, and Bridges	463,083	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	26,488,300	15,325,965
21	Cost per KW of Installed Capacity (line 20 / 5)	1,471.5722	1,094.7118
22	Production Expenses		
23	Operation Supervision and Engineering	22,287	37,044
24	Water for Power	3,053	1,749
25	Hydraulic Expenses	68,714	25,299
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	297,879	444,011
28	Rents	39,883	1,018
29	Maintenance Supervision and Engineering	47	0
30	Maintenance of Structures	65,113	30,043
31	Maintenance of Reservoirs, Dams, and Waterways	19,862	-9,892
32	Maintenance of Electric Plant	76,458	58,036
33	Maintenance of Misc Hydraulic Plant	79,514	51,033
34	Total Production Expenses (total 23 thru 33)	672,810	638,341
35	Expenses per net KWh	0.0127	0.0407

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 1927 Plant Name: Soda Springs (d)	FERC Licensed Project No. 2111 Plant Name: Swift No. 1 (e)	FERC Licensed Project No. 2071 Plant Name: Yale (f)	Line No.
Storage (Re-Reg)	Storage	Storage	1
Outdoor	Conventional	Conventional	2
1952	1958	1953	3
1952	1958	1953	4
11.00	240.00	134.00	5
12	258	164	6
8,411	6,115	7,268	7
			8
12	264	164	9
12	263	164	10
1	2	2	11
45,782,000	574,493,000	506,285,000	12
			13
0	14,163,614	8,363,013	14
3,964,411	68,071,694	8,316,865	15
86,742,403	46,650,810	29,579,039	16
2,345,095	20,162,067	15,035,574	17
2,068,792	1,009,965	1,471,230	18
0	0	0	19
95,120,701	150,058,150	62,765,721	20
8,647.3365	625.2423	468.4009	21
			22
12,997	2,067,645	1,190,920	23
889	11,977	6,687	24
69,783	1,474,531	703,846	25
0	0	0	26
397,059	403,561	378,285	27
24,373	177,614	98,127	28
29	0	0	29
29,378	32,138	29,525	30
75,966	7,962	23,931	31
48,554	70,052	16,478	32
43,203	620,619	356,411	33
702,231	4,866,099	2,804,210	34
0.0153	0.0085	0.0055	35

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Olmsted (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	
2	Plant Construction type (Conventional or Outdoor)	Conventional	
3	Year Originally Constructed	1904	
4	Year Last Unit was Installed	1922	
5	Total installed cap (Gen name plate Rating in MW)	10.30	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	7	0
7	Plant Hours Connect to Load	6,351	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	8,225,000	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	188,467	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)	233,022	0
21	Cost per KW of Installed Capacity (line 20 / 5)	22.6235	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	36,499	0
24	Water for Power	1,287	0
25	Hydraulic Expenses	18,613	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	150,175	0
28	Rents	-172	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	20,270	0
31	Maintenance of Reservoirs, Dams, and Waterways	38,316	0
32	Maintenance of Electric Plant	7,980	0
33	Maintenance of Misc Hydraulic Plant	180,672	0
34	Total Production Expenses (total 23 thru 33)	453,640	0
35	Expenses per net KWh	0.0552	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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.

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 2013/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	7.2	34,536,000	32,977,104
3	Bend	1913	1.11	1.0	1,925,000	1,335,093
4	Big Fork 2652	1910	4.15	4.6	30,165,000	7,372,638
5	Eagle Point	1957	2.81	3.0	16,334,000	1,891,013
6	East Side 2082	1924	3.20			1,991,695
7	Fall Creek 2082	1903	2.20	2.0	9,864,000	1,403,014
8	Fountain Green	1922	0.16			594,282
9	Granite	1896	2.00	1.3	5,671,000	5,234,569
10	Gunlock	1917	0.75	0.5	1,053,000	683,045
11	Last Chance	1983	1.73	1.2	3,257,000	2,806,715
12	Paris	1910	0.72	0.7	1,400,000	432,494
13	Pioneer 2722	1897	5.00	2.7	7,718,000	10,963,262
14	Prospect No. 1 2630	1912	3.76	2.0	20,789,000	2,589,697
15	Prospect No. 3 2337	1932	7.20	6.0	33,745,000	8,783,219
16	Prospect No. 4 2630	1944	1.00	0.9	4,178,000	2,410,023
17	Sand Cove	1926	0.80	0.4	855,000	933,722
18	Stairs 597	1895	1.00	1.2	3,909,000	1,721,394
19	St. Anthony 2381	1915	0.50			2,098
20	Veyo	1920	0.50	0.2	787,000	893,411
21	Viva Naughton	1986	0.74		-119,000	1,194,486
22	Wallowa Falls 308	1921	1.10	1.0	5,340,000	2,865,244
23	Weber 1744	1911	3.85	2.0	8,908,000	2,962,109
24	West Side 2082	1908	0.60	0.6	926,000	468,574
25	Keno Regulating Dam 2082					7,527,975
26	Upper Klamath Lake 2082					3,847,587
27	North Umpqua 1927					15,448,123
28						
29	Pumping Plant:					
30	Lifton	1917	-4.50	-3.0	-4,363,000	19,383,248
31						
32	Wind:					
33	Dunlap Ranch 1	2010	111.00	112.0	409,613,000	239,703,012
34	Foote Creek	1999	32.15	30.6	89,042,000	36,515,908
35	Glenrock	2008	99.00	100.0	322,390,000	201,863,767
36	Glenrock III	2009	39.00	40.0	121,920,000	87,422,570
37	Rolling Hills	2009	99.00	100.0	294,834,000	202,658,156
38	Goodnoe Hills	2008	94.00	91.0	227,258,000	183,564,537
39	Leaning Juniper 1	2006	100.50	96.0	206,164,000	176,493,722
40	Marengo	2007	140.40	136.0	331,240,000	240,176,300
41	Marengo II	2008	70.20	69.0	154,612,000	129,350,625
42	Seven Mile Hill	2008	99.00	100.0	356,097,000	200,853,550
43	Seven Mile Hill II	2008	19.50	20.0	77,049,000	42,253,626
44	High Plains	2009	99.00	101.0	341,250,000	219,781,632
45	McFadden Ridge I	2009	28.50	29.0	103,727,000	56,962,923
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
4,921,956	474,309		91,561	Water		2
1,202,786	125,821		46,484	Water		3
1,776,539	249,507		121,517	Water		4
672,958	266,588		133,733	Water		5
622,405	122,786		8,857	Water		6
637,734	159,176		138,103	Water		7
3,714,263	5,271		1,171	Water		8
2,617,285	142,274		36,998	Water		9
910,727	41,386		10,151	Water		10
1,622,379	107,064		15,522	Water		11
600,686	70,477		65,809	Water		12
2,192,652	221,161		133,160	Water		13
688,749	194,814		150,329	Water		14
1,219,892	415,438		596,435	Water		15
2,410,023	69,086		44,133	Water		16
1,167,153	40,103		37,806	Water		17
1,721,394	158,398		40,258	Water		18
4,196	35,346		2,717	Water		19
1,786,822	48,279		185,131	Water		20
1,614,170	63,074		13,643	Water		21
2,604,767	56,230		67,643	Water		22
769,379	192,361		104,185	Water		23
780,957	31,118		12,311	Water		24
	10,737		5,369			25
	320,020		14,964			26
						27
						28
						29
-4,307,388	322,146		92,494	Water		30
						31
						32
2,159,487	352,624		2,329,809	Wind		33
1,135,798	1,957,740		741,698	Wind		34
2,039,028	635,932		1,085,043	Wind		35
2,241,604	235,747		417,112	Wind		36
2,047,052	491,385		1,058,824	Wind		37
1,952,814	1,277,218		1,120,969	Wind		38
1,756,156	1,673,711		1,589,215	Wind		39
1,710,657	1,306,188		2,162,549	Wind		40
1,842,601	740,521		883,674	Wind		41
2,028,824	889,139		1,232,534	Wind		42
2,166,853	198,362		241,749	Wind		43
2,220,016	1,313,683		2,494,427	Wind		44
1,998,699	368,796		737,080	Wind		45
						46

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 2013/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	2.0	4,699,000	74,986
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
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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 2013/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
37,493	453,533			Solar		2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
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						41
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						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

The St. Anthony hydroelectric generating facility was sold in September 2013 to St. Anthony Hydro LLC. For more information, refer to Important Changes During the Quarter/Year, Item 3, in this 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.: 30 Column: a

Lifton

Used in regulating the release of water from Bear Lake and in maintaining proper water surface level in the Bear River near St. Charles, Idaho.

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 line 34 represents PacifiCorp's share.

Schedule Page: 410.1 Line No.: 2 Column: a

Black Cap

PacifiCorp has 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.

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 2013/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 , 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, 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 #3, UT	345.00	345.00	Steel SP	11.00		1
18	90TH SOUTH, UT	CAMP WILLIAMS #4, 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	90TH SOUTH, UT	TERMINAL, UT	345.00	345.00			16.00	1
21	TERMINAL, UT	CAMP WILLIAMS #2, UT	345.00	345.00	Steel SP	15.00	11.00	1
22	TERMINAL, UT	BORAH, ID	345.00	345.00	Wood - H	138.00		1
23	TERMINAL, UT	BORAH, ID	345.00	345.00	Steel SP		47.00	1
24	BEN LOMOND, UT	POPULUS #1, ID	345.00	345.00			82.00	1
25	BEN LOMOND, UT	POPULUS #2, ID	345.00	345.00	Steel SP	86.00		1
26	BEN LOMOND, UT	CAMP WILLIAMS, UT	345.00	345.00	Steel SP	69.00		1
27	BEN LOMOND, UT	TERMINAL, UT	345.00	345.00		47.00		1
28	BEN LOMOND, UT	TERMINAL, UT	345.00	345.00	Steel SP		47.00	1
29	CAMP WILLIAMS, UT	MONA, UT	345.00	345.00	Wood - H	47.00		1
30	CAMP WILLIAMS, UT	MONA #1, UT	345.00	345.00	Wood - H	47.00		1
31	CAMP WILLIAMS, UT	MONA #2, UT	345.00	345.00	Steel Tower	47.00		1
32	CAMP WILLIAMS, UT	MONA #4 UT	345.00	345.00		5.00	42.00	1
33	CURRANT CREEK, UT	MONA, UT	345.00	345.00	Steel SP	1.00		1
34	EMERY, UT	CAMP WILLIAMS, UT	345.00	345.00	Steel Tower	121.00		1
35	EMERY, UT	HUNTINGTON, UT	345.00	345.00	Wood - H	20.00		1
36					TOTAL	16,219.00	693.00	273

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
795 KCM ACSR								8
795 KCM ACSR								9
795 KCM ACSR								10
795 KCM ACSR								11
795 KCM ACSR								12
	13,339,699	266,055,247	279,394,946	6,500	642,185	523,691	1,172,376	13
								14
	13,339,699	266,055,247	279,394,946	6,500	642,185	523,691	1,172,376	15
								16
								17
								18
1272 ACSR 45/7								19
1272 ACSR 45/7								20
1272 ACSR 45/7								21
954 ACSR 45/7								22
1272 ACSR 45/7								23
1272 ACSR 45/7								24
1272 ACSR 45/7								25
1272 ACSR 45/7								26
1272 ACSR 45/7								27
1272 ACSR 45/7								28
954 ACSR 45/7								29
1272 ACSR 45/7								30
954 ACSR 45/7								31
954 ACSR 45/7								32
954 ACSR 54/7								33
1272 ACSR 45/7								34
954 ACSR 45/7								35
	206,909,237	2,968,482,206	3,175,391,443	353,289	18,780,035	2,755,216	21,888,540	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 2013/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	EMERY, UT	SIGURD #1, UT	345.00	345.00	Steel - H	74.00		1
2	EMERY, UT	SIGURD, #2 UT	345.00	345.00	Steel - H	75.00		1
3	FOUR CORNERS, NM	PINTO, UT	345.00	345.00	Wood - H	100.00		1
4	GOSHEN, ID	KINPORT, ID	345.00	345.00	Wood - H	41.00		1
5	HUNTINGTON, UT	HUNT PLANT 1, UT	345.00	345.00	Steel Tower	1.00		1
6	HUNTINGTON, UT	HUNT PLANT 2, UT	345.00	345.00	Steel Tower	1.00		1
7	HUNTINGTON, UT	PINTO, UT	345.00	345.00	Steel SP	158.00		1
8	HUNTINGTON, UT	SPANISH FORK, UT	345.00	345.00	Steel Tower	78.00		1
9	JIM BRIDGER, WY	BORAH, ID	345.00	345.00	Steel Tower	240.00		1
10	JIM BRIDGER, WY	KINPORT, ID	345.00	345.00	Steel SP	234.00		1
11	MONA, UT	SIGURD #1, UT	345.00	345.00	Wood - H	69.00		1
12	MONA, UT	SIGURD #2, UT	345.00	345.00	Steel SP		69.00	1
13	MONA, UT	HUNTINGTON, UT	345.00	345.00	Steel SP	60.00		1
14	SIGURD, UT	UT/NV STATE LINE	345.00	345.00	Steel Tower	190.00		1
15	SPANISH FORK, UT	CAMP WILLIAMS, UT	345.00	345.00			35.00	1
16	TERMINAL, UT	CAMP WILLIAMS, UT	345.00	345.00			23.00	1
17	CLOVER, UT	OQUIRRH, UT	345.00	345.00	Steel Tower	100.00		1
18	345 kV costs and expenses							
19								
20	Subtotal 345 kV					2,086.00	383.00	36
21								
22	ALVEY, OR	DIXONVILLE, OR	230.00	230.00	Wood - H	59.00		1
23	ANTELOPE, ID	ANACONDA, MT	230.00	230.00	Wood - H	76.00		1
24	ANTELOPE, ID	LOST RIVER, ID	230.00	230.00	Wood - H	20.00		1
25	ATLANTIC CITY, WY	COLUMBIA GENEVA, WY	230.00	230.00	Wood - H	1.00		1
26	BEN LOMOND, UT	NAUGHTON, WY	230.00	230.00	Wood - H	88.00		1
27	BEN LOMOND, UT	NAUGHTON, WY	230.00	230.00	Wood - H	88.00		1
28	BIRCH CREEK, UT	RAILROAD, WY	230.00	230.00	Wood - H	19.00		1
29	BITTER CREEK, WY	MONELL, WY	230.00	230.00	Wood - H	3.00		1
30	BRIDGER PUMP, WY	MANS FACE, WY	230.00	230.00	Wood - H	1.00		1
31	BUFFALO, WY	CASPER, WY	230.00	230.00	Wood - H	107.00		1
32	CASPER, WY	DAVE JOHNSTON, WY	230.00	230.00	Wood - H	36.00		1
33	CASPER, WY	RIVERTON, WY	230.00	230.00	Wood - H	110.00		1
34	CHAPPEL CREEK, WY	CRAVEN CREEK, WY	230.00	230.00	Steel-SP	30.00		1
35	CHAPPEL CREEK, WY	JONAH GAS, WY	230.00	230.00	Wood - H	32.00		1
36					TOTAL	16,219.00	693.00	273

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 2013/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.
954 ACSR 45/7								1
954 ACSR 54/7								2
795 ACSR 45/7								3
795 ACSR 26/7								4
2156 ACSR 8419								5
2156 ACSR 8419								6
795 ACSR 45/7								7
1272 ACSR 45/7								8
1272 ACSR 36/1								9
1272 ACSR 36/1								10
795 ACSR 45/7								11
954 ACSR 45/7								12
954 ACSR 54/7								13
954 ACSR 54/7								14
1272 ACSR 45/7								15
1272 ACSR 45/7								16
1949 ACSR 45/7								17
	133,780,840	1,321,625,567	1,455,406,407		1,729,855	640,985	2,370,840	18
								19
	133,780,840	1,321,625,567	1,455,406,407		1,729,855	640,985	2,370,840	20
								21
1272 ACSR 36/1								22
1272 ACSR 45/7								23
795 ACSR 45/7								24
1272 ACSR 36/1								25
795 ACSR 26/7								26
795 ACSR 26/7								27
954 ACSR 54/7								28
795 ACSR 26/7								29
1272 ACSR 36/1								30
1272 ACSR 36/1								31
								32
1272 ACSR 36/1								33
954 ACSR 54/7								34
1272 ACSR 45/7								35
	206,909,237	2,968,482,206	3,175,391,443	353,289	18,780,035	2,755,216	21,888,540	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 2013/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	CHAPPEL CREEK, WY	RILEY RIDGE, WY	230.00	230.00	Wood - H	29.00	6.00	1
2	CRAVEN CREEK, WY	PIONEER, WY	230.00	230.00	Wood - H	2.00		1
3	DAVE JOHNSTON, WY	SPENCE, WY	230.00	230.00	Wood - H	31.00		1
4	DAVE JOHNSTON, WY	WYODAK, WY	230.00	230.00	Wood - H	69.00		1
5	DIXONVILLE 500kV, OR	DIXONVILLE 230kV, OR	230.00	230.00	Wood - H	1.00		1
6	DIXONVILLE, OR	RESTON BPA, OR	230.00	230.00	Wood - H	17.00		1
7	FAIRVIEW BPA, OR	ISTHMUS, OR	230.00	230.00	Wood - H	12.00		1
8	FIREHOLE, WY	MONUMENT, WY	230.00	230.00	Wood - H	49.00		1
9	FRY, OR	BETHEL, OR	230.00	230.00	Wood - H	26.00		1
10	FRY, OR	ALVEY, OR	230.00	230.00	Wood - H	45.00		1
11	GLEN CANYON, AZ	SIGURD, UT	230.00	230.00	Wood - H	159.00		1
12	GONDER, UT - NV STATE	PAVANT, UT	230.00	230.00	Wood - H	98.00		1
13	SHERIDAN, WY	BUFFALO, WY	230.00	230.00	Wood - H	43.00		1
14	GRANTS PASS, OR	DIXONVILLE, OR	230.00	230.00	Wood - H	62.00		1
15	HURRICANE, OR	WALLA WALLA, WA	230.00	230.00	Wood - H	78.00		1
16	POINT OF ROCKS, WY	DAVE JOHNSTON, WY	230.00	230.00	Wood - H	209.00		1
17	JIM BRIDGER, WY	SPENCE, WY	230.00	230.00	Wood - H	149.00		1
18	JONES CANYON (BPA), OR	LEANING JUNIPER, OR	230.00	230.00	Wood - H	1.00		1
19	KLAMATH FALLS, OR	MALIN, OR	230.00	230.00	Wood - H	35.00		1
20	LIMA, WY	ROBERSON, WY	230.00	230.00	Wood - H	2.00		1
21	LONE PINE, OR	KLAMATH FALLS, OR	230.00	230.00	Wood - H	76.00		1
22	LONE PINE, OR	MERIDIAN #1, OR	230.00	230.00	Steel SP	5.00		1
23	LONE PINE, OR	MERIDIAN #2, OR	230.00	230.00	Steel SP	5.00		1
24	MCNARY (BPA), WA	WALLA WALLA, WA	230.00	230.00	Wood - H	56.00		1
25	MERIDIAN, OR	GRANTS PASS, OR	230.00	230.00	Wood - H	35.00		1
26	MINERS, WY	HIGH PLAINS, WY	230.00	230.00	Wood - H	39.00		1
27	MONUMENT, WY	EXXON, WY	230.00	230.00	Wood - H	13.00		1
28	MONUMENT, WY	CRAVEN CREEK, WY	230.00	230.00	Wood - H	20.00		1
29	NAUGHTON, WY	TREASURETON, ID	230.00	230.00	Wood - H	80.00		1
30	NAUGHTON, WY	MONUMENT , WY	230.00	230.00	Wood - H	30.00		1
31	NAUGHTON, WY	CRAVEN CREEK, WY	230.00	230.00	Wood - H	16.00		1
32	OREGON BASIN (PAC), WY	OR BASIN (MART OIL), WY	230.00	230.00	Wood - H	1.00		1
33	PALISADES SS, WY	BLUE RIM, WY	230.00	230.00	Wood - H	4.00		1
34	PAROWAN VALLEY, UT	SIGURD, UT	230.00	230.00	Wood - H	94.00		1
35	PAROWAN VALLEY, UT	WEST CEDAR, UT	230.00	230.00	Wood - H	26.00		1
36					TOTAL	16,219.00	693.00	273

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 2013/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272 ACSR 45/7								1
1272 ACSR 45/7								2
1272 ACSR 45/7								3
1272 ACSR 36/1								4
1272 ACSR 36/1								5
795 ACSR 26/7								6
1272 ACSR 36/1								7
1272 ACSR 45/7								8
1272 ACSR 36/1								9
1272 ACSR 36/1								10
954 ACSR 45/7								11
795 ACSR 45/7								12
795 ACSR 26/7								13
1272 ACSR 36/1								14
1272 ACSR 36/1								15
1272 ACSR 36/1								16
1272 ACSR 36/1								17
1272 ACSR 45/7								18
1272 ACSR 36/1								19
1272 ACSR 45/7								20
795 ACSR 26/7								21
1272 ACSR 54/19								22
1272 ACSR 36/1								23
1272 ACSR 36/1								24
1272 ACSR 36/1								25
1272 ACSR 45/7								26
1272 ACSR 36/1								27
1272 ACSR 45/7								28
1272 ACSR 45/7								29
1272 ACSR 36/1								30
954 ACSR 54/7								31
1272 ACSR 45/7								32
1272 ACSR 36/1								33
795 ACSR 45/7								34
795 ACSR 45/7								35
	206,909,237	2,968,482,206	3,175,391,443	353,289	18,780,035	2,755,216	21,888,540	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 2013/Q4

TRANSMISSION LINE STATISTICS

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5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	PAVANT, UT	SIGURD, UT	230.00	230.00	Wood - H	43.00		1
2	JIM BRIDGER, WY	ROCK SPRINGS, WY	230.00	230.00	Wood - H	35.00		1
3	POMONA, WA	UNION GAP, WA	230.00	230.00	Wood - H	8.00		1
4	RIVERTON, WY	ROCK SPRINGS, WY	230.00	230.00	Wood - H	118.00		1
5	RIVERTON, WY	THERMOPOLIS, WY	230.00	230.00	Wood - H	51.00		1
6	ROCK CREEK (BPA), WA	GOODNOE HILLS, WA	230.00	230.00	Wood - H	1.00		1
7	ROCK SPRINGS, WY	FLAMING GORGE, UT	230.00	230.00	Wood - H	55.00		1
8	ROCK SPRINGS, WY	JIM BRIDGER, WY	230.00	230.00	Wood - H	35.00		1
9	ROCK SPRINGS, WY	MONUMENT, WY	230.00	230.00	Wood - H	41.00		1
10	SHIRLEY BASIN, WY	DUNLAP RANCH, WY	230.00	230.00	Wood - H	12.00		1
11	SWIFT No. 1, WA	SWIFT No. 2, WA	230.00	230.00	Wood - H	2.00		1
12	SWIFT No. 2, WA	WOODLAND BPA SS, WA	230.00	230.00	Wood - H	23.00		1
13	TALBOT, WA	MARENGO II, WA	230.00	230.00	Wood - H	7.00		1
14	TAP TO HANNA, OR	NICKEL MOUNTAIN, OR	230.00	230.00	Wood - H	9.00		1
15	THERMOPOLIS, WY	YELLOWTAIL, MT	230.00	230.00	Wood - H	176.00		1
16	TREASURETON, ID	BRADY, ID	230.00	230.00	Wood - H	66.00		1
17	TROUTDALE (BPA), OR	GRESHAM (PGE), OR	230.00	230.00	Steel Tower	6.00		1
18	TROUTDALE (BPA), OR	LINNEMAN (PGE), OR	230.00	230.00			6.00	1
19	TROUTDLE-LINNEMN, OR	TROUTDALE PP&L, OR	230.00	230.00	Wood - H	1.00		1
20	UNION GAP, WA	MIDWAY BPA, WA	230.00	230.00	Wood - H	39.00		1
21	WALLA WALLA, WA	AVISTA LEWISTON, ID	230.00	230.00	Wood - H	45.00		1
22	WALLA WALLA, WA	WANAPUM (GPUD), WA	230.00	230.00	Wood - H	33.00		1
23	WANAPUM, WA	POMONA, WA	230.00	230.00	Wood - H	37.00		1
24	WINDSTAR, WY	GLENROCK, WY	230.00	230.00	Wood - H	13.00		1
25	WYODAK, WY	BUFFALO, WY	230.00	230.00	Wood - H	69.00		1
26	YAMSAY, OR	KLAMATH FALLS, OR	230.00	230.00	Wood - H	63.00		1
27	YELLOWTAIL, WY	SHERIDAN, WY	230.00	230.00	Wood - H	59.00		1
28	230 kV costs and expenses							
29								
30	Subtotal 230 kV					3,334.00	12.00	76
31								
32	ANACONDA, ID	JEFFERSON, ID	161.00	161.00	Wood - H		61.00	1
33	ANTELOPE, ID	GOSHEN, ID	161.00	161.00	Wood - H	45.00		1
34	BONNEVILLE, ID	EAGLEROCK, ID	161.00	161.00	Wood SP	9.00		1
35	EAGLEROCK, ID	SUGARMILL, ID	161.00	161.00	Wood SP	3.00		1
36					TOTAL	16,219.00	693.00	273

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 2013/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795 ACSR 45/7								1
1272 ACSR 45/7								2
1272 ACSR 36/1								3
1272 ACSR 36/1								4
1272 ACSR 36/1								5
1272 ACSR 45/7								6
1272 ACSR 36/1								7
1272 ACSR 36/1								8
1272 ACSR 36/1								9
795 ACSR 26/7								10
954 ACSR 45/7								11
954 ACSR 45/7								12
795 ACSR 26/7								13
795 ACSR 26/7								14
1272 ACSR 36/1								15
795 ACSR 26/7								16
954 ACSR 45/7								17
900 ACSR 54/7								18
1272 ACSR 36/1								19
954 ACSR 45/7								20
1272 ACSR 36/1								21
1272 ACSR 36/1								22
1272 ACSR 36/1								23
1272 ACSR 45/7								24
1272 ACSR 36/1								25
795 ACSR 26/7								26
795 ACSR 26/7								27
	18,092,842	365,472,752	383,565,594	51,898	5,025,192	539,922	5,617,012	28
								29
	18,092,842	365,472,752	383,565,594	51,898	5,025,192	539,922	5,617,012	30
								31
250HH CU /7								32
397.5 ACSR 26/7								33
954 ACSR 45/7								34
954 ACSR 45/7								35
	206,909,237	2,968,482,206	3,175,391,443	353,289	18,780,035	2,755,216	21,888,540	36

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 2013/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	GOSHEN, ID	GRACE, ID	161.00	161.00	Wood - H	57.00		1
2	GOSHEN, ID	RIGBY, ID	161.00	161.00	Wood - H	31.00		1
3	GOSHEN, ID	SUGAR MILL, ID	161.00	161.00	Wood SP	17.00		1
4	SUGARMILL, ID	RIGBY, ID	161.00	161.00	Wood SP	17.00		1
5	EAGLEROCK, ID	GOSHEN, ID	161.00	161.00	Wood - H	12.00		1
6	YELLOWTAIL, MT	RIMROCK, MT	161.00	161.00	Wood - H	46.00		1
7	RIGBY, ID	JEFFERSON, ID	161.00	161.00	Wood SP	18.00		1
8	GOSHEN, ID	JEFFERSON, ID	161.00	161.00	Wood - H		30.00	1
9	161 kV costs and expenses							
10								
11	Subtotal 161 kV					255.00	91.00	12
12								
13	90TH SOUTH , UT	SANDY , UT	138.00	138.00	Steel - SP	1.00		1
14	90TH SOUTH , UT	DUMAS #1, UT	138.00	138.00	Wood - H	12.00		1
15	90TH SOUTH , UT	DUMAS #2, UT	138.00	138.00	Wood - H	6.00		1
16	90TH SOUTH , UT	OQUIRRH , UT	138.00	138.00	Wood SP	10.00		1
17	ABAJO , UT	PINTO , UT	138.00	138.00	Wood - H	44.00		1
18	AGRIUM , UT	THREEMILE KNOLL , ID	138.00	138.00	Wood - H	4.00		1
19	ANSCHTZ CO-GEN, WY	EVANSTON , WY	138.00	138.00	Wood - H	22.00		1
20	ANTELOPE , ID	SCOVILLE #1 , WY	138.00	138.00	Wood - H	1.00		1
21	ANTELOPE , ID	SCOVILLE #2 , WY	138.00	138.00	Wood - H	1.00		1
22	ASHGROVE , UT	CLOVER , UT	138.00	138.00	Wood - H	26.00		1
23	ASHLEY , UT	CARBON , UT	138.00	138.00	Wood - H	92.00		1
24	ASHLEY , UT	VERNAL , UT	138.00	138.00	Wood - H	12.00		1
25	BANGERTER , UT	OQUIRRH , UT	138.00	138.00	Wood - H		6.00	1
26	BEN LOMOND , UT	BRIGHAM CITY , UT	138.00	138.00	Wood - H	14.00		1
27	BEN LOMOND #1 , UT	EL MONTE , UT	138.00	138.00	Steel - SP	14.00		1
28	BEN LOMOND #2 , UT	EL MONTE , UT	138.00	138.00			13.00	1
29	BEN LOMOND , UT	HONEYVILLE , UT	138.00	138.00	Steel Tower	22.00		1
30	BEN LOMOND , UT	SYRACUSE , UT	138.00	230.00	Steel Tower	7.00	13.00	1
31	BEN LOMOND , UT	ANGEL #2 , UT	138.00	138.00	Steel - SP	28.00		1
32	BEN LOMOND , UT	W ZIRCONIUM , UT	138.00	138.00	Wood -SP	14.00		1
33	BEN LOMOND , UT	WHEELON , UT	138.00	138.00	Steel Tower	42.00		1
34	BEN LOMOND , UT	SYRACUSE , UT	138.00	138.00	Steel Tower	25.00		1
35	BONANZA , UT	CHAPITA , UT	138.00	138.00	Wood - H	9.00		1
36					TOTAL	16,219.00	693.00	273

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 2013/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.
250HH CU /7								1
397.5 ACSR 26/7								2
795 AAC /37								3
397.5 ACSR 26/7								4
1272 ACSR 45/7								5
556.5 ACSR 26/7								6
397.5 ACSR 26/7								7
250HH CU /7								8
	623,490	21,342,243	21,965,733		205,978	610	206,588	9
								10
	623,490	21,342,243	21,965,733		205,978	610	206,588	11
								12
795 AAC /37								13
795 AAC /37								14
795 AAC /37								15
795 ACSR 26/7								16
397.5 ACSR 26/7								17
397.5 ACSR 26/7								18
795 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
397.5 ACSR 26/7								24
								25
1272 ACSR 45/7								26
795 ACSR 45/7								27
795 ACSR 45/7								28
250 CUHD /12								29
795 AAC /37								30
397.5 ACSR 26/7								31
795 AAC /37								32
250 CUHD /12								33
1272 ACSR 45/7								34
795 ACSR 26/7								35
	206,909,237	2,968,482,206	3,175,391,443	353,289	18,780,035	2,755,216	21,888,540	36

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 2013/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	BRIDGERLAND , UT	GREEN CANYON , UT	138.00	138.00	Wood -SP	16.00		1
2	BRIGHAM CITY , UT	WHEELON , UT	138.00	138.00	Wood - H	24.00		1
3	BUTLERVILLE , UT	90TH SOUTH , UT	138.00	138.00	Steel - SP	9.00		1
4	CAMERON , UT	PAROWAN , UT	138.00	138.00	Wood - H	35.00		1
5	CAMERON , UT	SIGURD , UT	138.00	138.00	Wood - H	64.00		1
6	CANYON COMP, WY	STR 204 , WY	138.00	138.00	Wood - H	12.00		1
7	CARBON , UT	HELPER #2 , UT	138.00	138.00	Wood - H	2.00		1
8	CARBON, UT	SPANISH FORK #1, UT	138.00	138.00	Steel Tower	54.00		1
9	CARBON, UT	SPANISH FORK #2, UT	138.00	138.00		52.00		1
10	CARBON , UT	MOAB , UT	138.00	138.00	Wood - H	120.00		1
11	CLEAR CREEK , WY	PAINTER , UT	138.00	138.00	Wood -SP	5.00		1
12	CLOVER , UT	NEBO , UT	138.00	138.00	Wood -SP	8.00		1
13	COLUMBIA , UT	SUNNYSIDE , UT	138.00	138.00	Wood - H	2.00		1
14	COTTONWOOD , UT	MCCLELLAND , UT	138.00	138.00	Steel - SP	6.00		1
15	COTTONWOOD , UT	HAMMER , UT	138.00	138.00	Wood -SP	5.00		1
16	COTTONWOOD , UT	SILVER CREEK , UT	138.00	138.00	Wood -SP	29.00		1
17	CUTLER , UT	WHEELON , UT	138.00	138.00	Wood -SP	1.00		1
18	DRY CREEK , UT	SPANISH FORK , UT	138.00	138.00	Steel - SP	5.00		1
19	DUMAS , UT	WESTFIELD , UT	138.00	138.00	Wood -SP	18.00		1
20	DYNAMO , UT	TRI-CITY #1 , UT	138.00	138.00	Steel - SP	2.00		1
21	DYNAMO , UT	TRI-CITY #2 , UT	138.00	138.00			3.00	1
22	EAST LAYTON , UT	105 TAP , UT	138.00	138.00	Steel - SP	15.00		1
23	EBAY TAP , UT	OQUIRRH , UT	138.00	138.00	Wood -SP	1.00		1
24	EL MONTE , UT	STR 30B , UT	138.00	138.00	Steel - SP	4.00		1
25	EL MONTE , UT	PIONEER , UT	138.00	138.00	Steel - SP	1.00		1
26	EVANSTON , WY	RAILROAD , UT	138.00	138.00	Wood -SP	3.00		1
27	FRANKLIN , ID	TREASURETON , ID	138.00	138.00	Wood -SP	10.00		1
28	FRANKLIN , ID	GREEN CANYON , UT	138.00	138.00	Wood -SP	25.00		1
29	GADSBY , UT	JORDAN , UT	138.00	138.00	Wood -SP	1.00		1
30	GADSBY , UT	THIRD WEST , UT	138.00	138.00	Wood -SP	1.00		1
31	GADSBY , UT	TERMINAL , UT	138.00	138.00	Wood -SP	6.00		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	16,219.00	693.00	273

TRANSMISSION LINE STATISTICS (Continued)

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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272 ACSR 45/7								1
795 ACSR 26/7								2
795 AAC /37								3
397.5 ACSR 26/7								4
397.5 ACSR 26/7								5
795 ACSR 26/7								6
556.5 ACSR 26/7								7
795 ACSR 26/7								8
1272 ACSR 45/7								9
954 ACSR 54/7								10
795 ACSR 26/7								11
1272 ACSR 45/7								12
397.5 ACSR 26/7								13
795 AAC /37								14
795 AAC /37								15
397.5 ACSR 26/7								16
250 CUHD /12								17
1272 ACSR 45/7								18
795 ACSR 26/7								19
795 ACSR 26/7								20
795 ACSR 26/7								21
795 ACSR 26/7								22
795 ACSR 26/7								23
1272 ACSR 45/7								24
1272 ACSR 45/7								25
795 ACSR 26/7								26
795 ACSR 26/7								27
397.5 ACSR 26/7								28
1272 ACSR 45/7								29
1272 AAC /61								30
1272 ACSR 45/7								31
1272 ACSR 45/7								32
397.5 ACSR 26/7								33
397.5 ACSR 26/7								34
1272 ACSR 45/7								35
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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 2013/Q4

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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 On Structures of Another Line (g)	Number Of Circuits (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	BARNEYS, UT	GRINDING, 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 #2, UT	COTTONWOOD , UT	138.00	138.00	Wood -SP	5.00		1
18	MID VALLEY #1, 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 , UT	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	BINGHAM CANYON (KCC),	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, UT	TERMINAL #1, UT	138.00	138.00	Steel - SP	16.00		1
34	PARRISH, UT	TERMINAL #2, UT	138.00	138.00			14.00	1
35	PARRISH #105 , UT	TERMINAL , UT	138.00	138.00	Steel - SP	14.00		1
36					TOTAL	16,219.00	693.00	273

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 2013/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 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 26/7								34
795 AAC 45/7								35
	206,909,237	2,968,482,206	3,175,391,443	353,289	18,780,035	2,755,216	21,888,540	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 2013/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	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) #2 , UT	SAINT GEORGE , UT	138.00	138.00	Steel - SP	20.00		1
4	CENTRAL (UAMPS) #3 , 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		7.00	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			9.00	1
15	TAP TO ANGEL NORTH , UT	TAP TO PARRISH , UT	138.00	138.00	Wood - H	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	16,219.00	693.00	273

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 2013/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795 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
	206,909,237	2,968,482,206	3,175,391,443	353,289	18,780,035	2,755,216	21,888,540	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 2013/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	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 #1, UT	TREASURETON , ID	138.00	138.00	Steel Tower	29.00		1
7	WHEELON #2, UT	TREASURETON , ID	138.00	138.00			29.00	1
8	WHEELON #3, UT	TREASURETON , ID	138.00	138.00	Wood - H	29.00		1
9	FORT DOUGLAS, UT	MCCLELLAND, UT	138.00	138.00	Wood - SP	3.00		1
10	138 kV costs and expenses							
11								
12	Subtotal 138 kV					2,038.00	207.00	137
13								
14	All 115 kV Lines					1,620.00		
15								
16	All 69 kV Lines					2,992.00		
17								
18	All 57 kV Lines					113.00		
19								
20	All 46 kV Lines					2,569.00		
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	16,219.00	693.00	273

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 2013/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
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
								9
	19,136,816	326,244,179	345,380,995	126,083	1,580,578	131,331	1,837,992	10
								11
	19,136,816	326,244,179	345,380,995	126,083	1,580,578	131,331	1,837,992	12
								13
	5,077,360	170,671,280	175,748,640		3,372,964	619,803	3,992,767	14
								15
	7,140,496	255,019,466	262,159,962	53,538	3,370,620	233,094	3,657,252	16
								17
	46,327	10,254,180	10,300,507		59,713	4,169	63,882	18
								19
	9,671,367	231,797,292	241,468,659	115,270	2,792,950	61,611	2,969,831	20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	206,909,237	2,968,482,206	3,175,391,443	353,289	18,780,035	2,755,216	21,888,540	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 in 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 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 line 3 column (a).

Schedule Page: 422 Line No.: 5 Column: a

See footnote on page 422 for line 3 column (a).

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 line 3 column (a).

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 reflect 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 reflect 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 reflect 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 reflect 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 reflect PacifiCorp's share.

Schedule Page: 422 Line No.: 17 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422 Line No.: 18 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.1 Line No.: 32 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 reflect PacifiCorp's share.

Schedule Page: 422.1 Line No.: 32 Column: i

1557 ACSS/TW 45/7

Schedule Page: 422.4 Line No.: 25 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 reflect PacifiCorp's share.

Schedule Page: 422.7 Line No.: 4 Column: a

See footnote on page 422.7 for line 3 column (a).

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

Schedule Page: 422.8 Line No.: 9 Column: i

1557.4 ACSR/TW 36/7

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 2013/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	Clover, UT	Oquirrh, UT	100.00	Steel Tower	8.00	1	1
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		100.00		8.00	1	1

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.
3-1949	ACSR	Vertical 27'	345	19,703,015	199,062,352	115,868,548		334,633,915	1
									2
									3
									4
									5
									6
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									9
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									39
									40
									41
									42
									43
				19,703,015	199,062,352	115,868,548		334,633,915	44

Schedule Page: 424 Line No.: 1 Column: a

This line is also known as the Mona-Oquirrh transmission line.

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 2013/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	CASTELLA SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
5	CLEAR LAKE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	DOG CREEK SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
7	DORRIS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	FORT JONES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	GASQUET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	GREENHORN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	HAMBURG SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
12	HAPPY CAMP SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	HORNBROOK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	INTERNATIONAL PAPER SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
15	LAKE EARL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	LITTLE SHASTA SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
17	LUCERNE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	MACDOEL SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
19	MCCLOUD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	MILLER REDWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	MONTAGUE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	MORRISON CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.50	
23	MOUNT SHASTA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	NEWELL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	NORTH DUNSMUIR SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	NORTHCREST SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	NUTGLADE SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
28	PATRICKS CREEK SUB	DISTRIBUTION-UNATTEN	115.00	7.20	
29	PEREZ SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	REDWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	SCOTT BAR SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	SEIAD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	SHASTINA SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
34	SHOTGUN CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	SMITH RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	SNOW BRUSH SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
37	SOUTH DUNSMUIR SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
38	TULELAKE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	TUNNEL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	WALKER BRYAN 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.
						1
25	1					2
6	1					3
1	3					4
4	3					5
	1					6
7	3					7
6	1					8
9	1					9
12	1					10
1	1					11
7	3					12
4	3					13
9	3					14
12	1					15
2	3					16
4	1					17
30	2					18
6	1					19
4	3					20
6	1					21
14	1					22
16	4					23
12	1					24
6	6					25
20	4					26
1	3					27
1	1					28
1	3					29
9	3					30
2	3					31
2	3					32
6	3					33
1	1					34
6	3					35
1	3					36
2	3					37
20	1					38
6	6					39
9	3					40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WEED SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	YUBA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	YUROK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	Total		3036.00	465.96	
5	Number of Substations-42				
6					
7	ALTURAS SUB	T/D-UNATTENDED	115.00	12.47	69.00
8	YREKA SUB	T/D-UNATTENDED	115.00	12.47	69.00
9	Total		230.00	24.94	138.00
10	Number of Substations-2				
11					
12	COPCO #2 230 SUB	TRANSMISSION-ATTENDE	230.00	115.00	
13	COPCO #2 SUB	TRANSMISSION-ATTENDE	115.00	69.00	12.47
14	AGER SUB	TRANSMISSION-UNATTEN	115.00	69.00	
15	CRAG VIEW SUB	TRANSMISSION-UNATTEN	115.00	69.00	
16	DEL NORTE SUB	TRANSMISSION-UNATTEN	115.00	69.00	
17	WEED JUNCTION SUB	TRANSMISSION-UNATTEN	115.00	69.00	
18	Total		805.00	460.00	12.47
19	Number of Substations-6				
20					
21	IDAHO				
22	ALEXANDER	DISTRIBUTION-UNATTEN	46.00	12.47	
23	AMMON	DISTRIBUTION-UNATTEN	69.00	12.47	
24	ANDERSON	DISTRIBUTION-UNATTEN	69.00	12.47	
25	ARCO	DISTRIBUTION-UNATTEN	69.00	12.47	
26	ARIMO	DISTRIBUTION-UNATTEN	46.00	12.47	
27	BANCROFT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	BELSON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	BERENICE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	CAMAS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	CANYON CREEK SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
32	CHESTERFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	CLEMENTS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	CLIFTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	COVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	DOWNEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	DUBOIS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	EASTMONT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	EGIN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	EIGHT MILE 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)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
25	1					1
4	3					2
4	3					3
323	99					4
						5
						6
31	4					7
95	2					8
126	6					9
						10
						11
500	2					12
51	4					13
5	3					14
19	3					15
150	2					16
37	3					17
762	17					18
						19
						20
						21
4	1					22
14	1					23
20	1					24
6	1					25
7	1					26
4	1					27
12	1					28
10	1					29
14	1					30
20	1					31
5	1					32
5	1					33
4	1					34
6	1					35
5	1					36
12	1					37
14	1					38
14	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 2013/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	GEORGETOWN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	GRACE CITY SUBSTATION	DISTRIBUTION-UNATTEN	46.00	12.47	
3	HAMER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	HAYES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	HENRY SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
6	HOLBROOK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	HOOPES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	HORSLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	IDAHO FALLS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	INDIAN CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	JEFFCO SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
12	KETTLE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
13	LAVA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	LUND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	MCCAMMON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	MENAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	MERRILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	MILLER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	MONTPELIER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	MOODY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	NEWDALE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	OSGOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	PRESTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	RAYMOND SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	RENO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	REXBURG SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	RIRIE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	ROBERTS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	RUBY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	SAND CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	SANDUNE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
32	SHELLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	SMITH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	SOUTH FORK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	SPUD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	ST. CHARLES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	SUGAR CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	SUNNYDELL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	TANNER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	TARGHEE 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 2013/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.
6	1					1
5	1					2
14	1					3
9	1					4
1	1					5
6	1					6
9	1					7
4	1					8
20	1					9
3	1					10
22	1					11
14	1					12
3	1					13
5	1					14
3	1					15
10	1					16
20	1					17
5	1					18
8	1					19
14	1					20
20	1					21
20	1					22
12	1					23
2	1					24
20	1					25
32	2					26
9	1					27
8	1					28
7	1					29
40	2					30
20	1					31
20	1					32
20	1					33
14	1					34
8	1					35
5	1					36
12	1					37
12	1					38
4	1					39
4	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.
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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	THORNTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	UCON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	WATKINS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	WEBSTER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	WESTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	WINDSPER SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
7	Total		4002.00	867.43	
8	Number of Substations-65				
9					
10	CINDER BUTTE SUB	T/D-UNATTENDED	161.00	12.47	
11	MALAD SUB	T/D-UNATTENDED	138.00	46.00	12.47
12	MUD LAKE SUB	T/D-UNATTENDED	69.00	12.47	
13	RIGBY SUB	T/D-UNATTENDED	161.00	12.47	69.00
14	SAINT ANTHONY SUB	T/D-UNATTENDED	69.00	46.00	12.47
15	Total		598.00	129.41	93.94
16	Number of Substations-5				
17					
18	AMPS SUB	TRANSMISSION-UNATTEN	230.00	69.00	12.47
19	ANTELOPE SUB	TRANSMISSION-UNATTEN	230.00	161.00	12.47
20	ASHTON PLANT	TRANSMISSION-UNATTEN	46.00	12.47	
21	BIG GRASSY SUB	TRANSMISSION-UNATTEN	161.00	69.00	
22	BONNEVILLE SUB	TRANSMISSION-UNATTEN	161.00	69.00	
23	CONDA SUB	TRANSMISSION-UNATTEN	138.00	46.00	
24	FISH CREEK SUB	TRANSMISSION-UNATTEN	161.00	46.00	
25	FRANKLIN SUB	TRANSMISSION-UNATTEN	138.00	46.00	
26	GOSHEN SUB	TRANSMISSION-UNATTEN	345.00	161.00	69.00
27	GRACE SUB	TRANSMISSION-UNATTEN	161.00	138.00	46.00
28	JEFFERSON SUB	TRANSMISSION-UNATTEN	161.00	69.00	
29	OVID SUB	TRANSMISSION-UNATTEN	138.00	69.00	
30	SCOVILLE SUB	TRANSMISSION-UNATTEN	138.00	69.00	
31	SUGARMILL SUB	TRANSMISSION-UNATTEN	161.00	46.00	69.00
32	THREEMILE KNOLL SUB	TRANSMISSION-UNATTEN	345.00	138.00	46.00
33	TREASURETON SUB	TRANSMISSION-UNATTEN	230.00	138.00	
34	Total		2944.00	1346.47	254.94
35	Number of Substations-16				
36					
37	MONTANA				
38	BROADVIEW SUB	TRANSMISSION-UNATTEN	500.00	230.00	
39	COLSTRIP SUB	TRANSMISSION-UNATTEN	500.00	230.00	
40	YELLOWTAIL SUB	TRANSMISSION-UNATTEN	230.00	161.00	

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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
7	1					2
14	1					3
20	1					4
4	1					5
20	1					6
721	67					7
						8
						9
60	2	1				10
71	4	1				11
14	1					12
189	4					13
40	2					14
374	13	2				15
						16
						17
75	1	1				18
445	3					19
13	1					20
67	1					21
67	1					22
67	1					23
25	3					24
75	1					25
938	5					26
217	2					27
233	3					28
30	1					29
76	2					30
168	3					31
775	2					32
533	2					33
3804	32	1				34
						35
						36
						37
32	2					38
68	2					39
100	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 2013/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Total		1230.00	621.00	
2	Number of Substations-3				
3					
4	OREGON				
5	26TH STREET	DISTRIBUTION-UNATTEN	20.80	4.16	
6	35TH STREET	DISTRIBUTION-UNATTEN	20.80	2.40	
7	AGNESS AVE	DISTRIBUTION-UNATTEN	115.00	12.47	
8	ALDERWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	ARLINGTON	DISTRIBUTION-UNATTEN	69.00	12.47	
10	ATHENA	DISTRIBUTION-UNATTEN	69.00	12.47	
11	BANDON TIE SUB	DISTRIBUTION-UNATTEN	20.80	12.47	
12	BEACON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	BEALL LANE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	BEATTY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
15	BELKNAP SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	BLALOCK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	BLOSS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	BLY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	BOISE CASCADE SUB	DISTRIBUTION-UNATTEN	69.00	11.00	
20	BONANZA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	BOND STREET SUB	DISTRIBUTION-UNATTEN	69.00	12.50	
22	BROOKHURST SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
23	BROWNSVILLE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
24	BRYANT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	BUCHANAN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
26	BUCKAROO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	CAMPBELL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
28	CANNON BEACH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
29	CARNES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	CASEBEER SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
31	CAVEMAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
32	CHERRY LANE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	CHILOQUIN MARKET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	CHINA HAT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	CIRCLE BLVD SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
36	CLEVELAND AVE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	CLOAKE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
38	COBURG SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
39	COLISEUM SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
40	COLUMBIA SUB	DISTRIBUTION-UNATTEN	115.00	12.47	57.00

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.
200	5					1
						2
						3
						4
5	1					5
30	6					6
25	1					7
45	2					8
5	1					9
9	1					10
8	3	1				11
11	3					12
25	1					13
6	1					14
40	2					15
2	3					16
32	2					17
8	3					18
3	1					19
8	3					20
25	1					21
50	2					22
13	1					23
34	2					24
45	2					25
34	2					26
20	2					27
13	1					28
9	3					29
20	1					30
45	2					31
25	1					32
6	3					33
25	1					34
80	2					35
45	2					36
20	1					37
10	3					38
9	2					39
55	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 2013/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	COOS RIVER SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
2	COQUILLE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
3	CREEK SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
4	CROOKED RIVER RANCH SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
5	CROWFOOT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
6	CULLY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
7	CULVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	DAIRY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	DALLAS SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
10	DALREED SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
11	DESCHUTES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	DEVILS LAKE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
13	DIXON SUB	DISTRIBUTION-UNATTEN	115.00	4.16	
14	DODGE BRIDGE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
15	DOWELL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
16	EASY VALLEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
17	EMPIRE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
18	ENTERPRISE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	FERN HILL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
20	FIELDER CREEK SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
21	FOOTHILLS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	FRALEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	GARDEN VALLEY SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
24	GAZLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	GLENDALE SUB	DISTRIBUTION-UNATTEN	230.00	12.47	
26	GLENEDEN SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
27	GLIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
28	GOLD HILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	GORDON HOLLOW SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	GOSHEN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
31	GRANT STREET SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
32	GRASS VALLEY SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
33	GREEN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	GRIFFIN CREEK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
35	HAMAKER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	HARRISBURG SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
37	HENLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	HERMISTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	HILLVIEW SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
40	HINKLE SUB	DISTRIBUTION-UNATTEN	69.00	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 2013/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.
20	1					1
40	2					2
5	1					3
25	2					4
20	1					5
25	1					6
13	1					7
25	1					8
50	2					9
75	3					10
25	1					11
50	2					12
7	1					13
12	1					14
20	1					15
45	2					16
20	1					17
19	2					18
12	1					19
25	1					20
21	4					21
5	3					22
20	1					23
8	4					24
25	2					25
5	1					26
12	1					27
11	3					28
6	1					29
20	1					30
45	2					31
1	4					32
25	1					33
20	1					34
8	3					35
13	1					36
6	3					37
40	1					38
45	2					39
20	1					40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	HOLLADAY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	HOLLYWOOD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
3	HOOD RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	HORNET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	HUMBUG CREEK SUB	DISTRIBUTION-UNATTEN	67.00	12.50	
6	HUNTERS CIRCLE TEMP SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	ILLAHEE FLATS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
8	INDEPENDENCE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
9	JACKSONVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
10	JEFFERSON SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
11	JEROME PRAIRIE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
12	JORDAN POINT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
13	JOSEPH SUB	DISTRIBUTION-UNATTEN	20.80	12.47	
14	JUNCTION CITY SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
15	KENWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	KILLINGWORTH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	KNAPPA SVENSEN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	LAKEPORT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	LANCASTER SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
20	LEBANON SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
21	LINCOLN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
22	LOCKHART SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
23	LYONS SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
24	MADRAS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	MALLORY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
26	MARYS RIVER SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
27	MEDCO SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
28	MEDFORD	DISTRIBUTION-UNATTEN	69.00	12.47	
29	MERLIN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
30	MERRILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	MINAM SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	MODOC SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	MORO SUB	DISTRIBUTION-UNATTEN	20.80	2.40	
34	MURDER CREEK SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
35	MYRTLE CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	MYRTLE POINT SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
37	NELSCOTT SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
38	NEW O'BRIEN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
39	OAK KNOLL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
40	OAKLAND SUB	DISTRIBUTION-UNATTEN	115.00	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)	
75	3					1
50	2					2
40	2					3
20	1					4
9	1					5
12	1					6
2	1					7
20	1					8
75	2					9
12	1					10
20	1					11
20	1					12
6	1	1				13
25	2					14
3	3					15
40	2					16
6	1					17
50	2					18
12	3					19
40	2					20
105	3					21
40	2					22
9	2					23
25	2					24
25	1					25
20	1					26
20	1					27
67	8					28
45	2					29
17	6					30
	1					31
6	3					32
2	3					33
100	4					34
14	1					35
9	1					36
4	1					37
9	1					38
45	2					39
8	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 2013/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	OREMET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	OVERPASS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	PALLETTE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
4	PARK STREET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
5	PARKROSE SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
6	PENDLETON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	PILOT ROCK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	POWELL BUTTE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
9	PRINEVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	PROVOLT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	QUEEN AVE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
12	RED BLANKET SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
13	REDMOND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	RIDDLE SUB	DISTRIBUTION-UNATTEN	116.00	69.00	
15	RIDDLE VENEER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
16	ROGUE RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	ROSEBURG SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
18	ROSS AVE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	ROXY ANN SUB	DISTRIBUTION-UNATTEN	115.00	12.50	
20	RUCH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	RUNNING Y SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
22	RUSSELLVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
23	SCENIC SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
24	SCIO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	SEASIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
26	SELMA SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
27	SHASTA WAY SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
28	SHEVLIN PARK SUB	DISTRIBUTION-UNATTEN	69.00	12.50	
29	SIMTAG BOOSTER PUMP	DISTRIBUTION-UNATTEN	34.50	4.16	
30	SOUTH DUNES SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
31	SOUTHGATE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
32	SPRAGUE RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	STATE STREET SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
34	STAYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	STEAMBOAT SUB	DISTRIBUTION-UNATTEN	115.00	7.20	
36	STEVENS ROAD SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
37	SUTHERLIN SUB	DISTRIBUTION-UNATTEN	115.00	12.00	
38	SWEET HOME SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
39	TAKELMA SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
40	TALENT SUB	DISTRIBUTION-UNATTEN	116.00	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.
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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.
75	2					1
45	2					2
1	1	1				3
40	2					4
39	2					5
46	7	1				6
22	2					7
6	1					8
50	2					9
11	3					10
50	2					11
2	3					12
50	2					13
75	2					14
25	1	1				15
25	2					16
50	2					17
9	3					18
25	1					19
9	1					20
9	1					21
45	2					22
70	3					23
8	1					24
40	2					25
9	1					26
2	3					27
25	1					28
19	2					29
9	1					30
20	1					31
7	3					32
40	2					33
55	2					34
	1					35
50	2					36
25	1					37
42	2					38
12	1					39
50	2					40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	TEXUM SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	TILLER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
3	TOLO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	TURKEY HILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	UMAPINE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	UMATILLA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	VERNON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	VILAS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
9	VILLAGE GREEN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
10	VINE STREET SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
11	WALLOWA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	WARM SPRINGS SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
13	WARRENTON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	WASCO SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
15	WECOMA BEACH SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
16	WESTERN KRAFT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
17	WESTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	WESTSIDE HYDRO/SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	WEYERHAUSER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	WHITE CITY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
21	WILLOW COVE SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
22	WINSTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	YEW AVENUE SUB	DISTRIBUTION-UNATTEN	115.00	12.50	
24	YOUNGS BAY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
25	Total		15524.27	2559.80	195.00
26	Number of Substations-180				
27					
28	ALBINA SUB	T/D-UNATTENDED	115.00	12.47	69.00
29	APPLEGATE SUB	T/D-UNATTENDED	115.00	69.00	12.47
30	ASHLAND MTN AVE SUB	T/D-UNATTENDED	115.00	69.00	12.47
31	BEND PLANT SUB	T/D-UNATTENDED	69.00	13.09	12.47
32	CAVE JUNCTION SUB	T/D-UNATTENDED	115.00	12.47	69.00
33	HAZELWOOD SUB	T/D-UNATTENDED	115.00	69.00	12.47
34	KNOTT SUB	T/D-UNATTENDED	115.00	12.47	57.00
35	MILE HI SUB	T/D-UNATTENDED	115.00	69.00	12.47
36	PILOT BUTTE SUB	T/D-UNATTENDED	230.00	69.00	12.47
37	SAGE ROAD SUB	T/D-UNATTENDED	115.00	12.47	
38	WINCHESTER SUB	T/D-UNATTENDED	115.00	12.47	69.00
39	Total		1334.00	420.44	338.82
40	Number of Substations-11				

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 2013/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
25	1					1
1	1					2
11	1					3
13	3					4
20	1					5
25	2					6
50	2					7
25	1					8
40	2					9
20	1					10
7	1					11
12	3					12
25	2					13
3	3					14
3	1					15
50	2					16
22	2					17
22	9					18
40	2					19
60	3					20
28	3					21
22	3					22
25	1					23
37	2					24
4619	346	6				25
						26
						27
177	9					28
65	2					29
70	2					30
31	3					31
70	2					32
132	4					33
163	5					34
39	4					35
400	4					36
40	2					37
75	5					38
1262	42					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	LEMOLO #1 HYDRO	TRANSMISSION-ATTENDE	11.30	12.50	
3	CALAPOOYA SUB	TRANSMISSION-UNATTEN	230.00	69.00	
4	CHILOQUIN SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
5	COLD SPRINGS SUB	TRANSMISSION-UNATTEN	230.00	69.00	2.40
6	COVE SUB	TRANSMISSION-UNATTEN	230.00	69.00	
7	DAYS CREEK SUB	TRANSMISSION-UNATTEN	115.00	69.00	
8	DIAMOND HILL SUB	TRANSMISSION-UNATTEN	230.00	69.00	
9	DIXONVILLE 115/230 SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
10	DIXONVILLE 500 SUB	TRANSMISSION-UNATTEN	500.00	230.00	
11	FISH HOLE SUB	TRANSMISSION-UNATTEN	115.00	69.00	
12	FRY SUB	TRANSMISSION-UNATTEN	230.00	115.00	
13	GRANTS PASS SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
14	GREEN SPRINGS PLANT/SUB	TRANSMISSION-UNATTEN	115.00	69.00	
15	HURRICANE SUB	TRANSMISSION-UNATTEN	230.00	69.00	2.40
16	ISTHMUS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
17	KENNEDY SUB	TRANSMISSION-UNATTEN	69.00	57.00	
18	KLAMATH FALLS SUB	TRANSMISSION-UNATTEN	230.00	69.00	
19	LONE PINE SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
20	MALIN SUB	TRANSMISSION-UNATTEN	500.00	230.00	69.00
21	MERIDIAN SUB	TRANSMISSION-UNATTEN	500.00	230.00	
22	MONPAC SUB	TRANSMISSION-UNATTEN	115.00	69.00	
23	NICKEL MOUNTAIN SUB	TRANSMISSION-UNATTEN	230.00	115.00	
24	PARRISH GAP SUB	TRANSMISSION-UNATTEN	230.00	69.00	12.47
25	PONDEROSA SUB	TRANSMISSION-UNATTEN	230.00	115.00	
26	PROSPECT CENTRAL SUB	TRANSMISSION-UNATTEN	115.00	69.00	
27	ROBERTS CREEK SUB	TRANSMISSION-UNATTEN	115.00	69.00	
28	TROUTDALE SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
29	TUCKER SUB	TRANSMISSION-UNATTEN	115.00	69.00	
30	Total		6065.30	2760.50	431.27
31	Number of Substations-28				
32					
33	UTAH				
34	106TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
35	118TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
36	23RD ST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	70TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
38	ALTAVIEW SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	AMALGA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	AMERICAN FORK SUB	DISTRIBUTION-UNATTEN	138.00	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 2013/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
2	3	1				2
75	1					3
119	4					4
66	2					5
67	3					6
50	1					7
75	1					8
343	6					9
650	3	1				10
7	3					11
500	2					12
473	5					13
19	3					14
29	2					15
250	1					16
33	1					17
251	6	1				18
733	10					19
775	4	1				20
1300	6	1				21
50	1					22
114	1					23
150	1					24
250	1					25
30	3					26
50	1					27
500	3					28
100	2					29
7061	80	5				30
						31
						32
						33
30	1					34
30	1					35
12	1					36
30	1					37
45	2					38
11	1					39
30	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 2013/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	ARAGONITE	DISTRIBUTION-UNATTEN	46.00	7.20	
2	AURORA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	BANGERTER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
4	BEAR RIVER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	BENJAMIN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	BINGHAM SUB	DISTRIBUTION-UNATTEN	46.00	7.62	
7	BLUE CREEK	DISTRIBUTION-UNATTEN	46.00	12.47	
8	BLUFF SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	BLUFFDALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	BOTHWELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	BRIAN HEAD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	BRICKYARD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	BRIGHTON SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
14	BROOKLAWN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	BRUNSWICK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	BURTON SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
17	BUSH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	CANNON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	CANYONLANDS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	CAPITOL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	CARBIDE SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
22	CARBONVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	CARLISLE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
24	CASTO SUBSTATION	DISTRIBUTION-UNATTEN	46.00	12.47	
25	CENTERVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	CENTRAL SUB	DISTRIBUTION-UNATTEN	43.80	12.47	
27	CHAPEL HILL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
28	CHERRYWOOD SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
29	CIRCLEVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	CLEAR CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	CLEAR LAKE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	CLEARFIELD SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
33	CLINTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
34	CLIVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	COALVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	COLD WATER CANYON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
37	COLEMAN SUB	DISTRIBUTION-UNATTEN	138.00	69.00	12.47
38	COLTON WELL SUB	DISTRIBUTION-UNATTEN	46.00	2.40	
39	COMMERCE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
40	COPPER HILLS SUB	DISTRIBUTION-UNATTEN	138.00	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.
1	1					1
3	1					2
50	2					3
17	2					4
2	1					5
25	1					6
2	3					7
1	3					8
9	1					9
4	1					10
14	1					11
9	1					12
29	2					13
6	1					14
60	3					15
11	3					16
9	1					17
12	1					18
1	1					19
20	1					20
3	1					21
6	1					22
30	1					23
25	1					24
22	1					25
9	1					26
30	1					27
50	2					28
3	1					29
4	1					30
	3					31
60	2					32
50	2					33
4	1					34
6	1					35
30	1					36
106	4					37
1	3					38
30	1					39
30	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 2013/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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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	CORINNE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	COVE FORT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	COZYDALE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
4	CROSS HOLLOW SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
5	CUDAHY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
6	DAMMERON VALLEY SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
7	DECKER LAKE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	DELLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	DELTA SUB	DISTRIBUTION-UNATTEN	46.00	69.00	
10	DESERET SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
11	DEWEYVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	DIMPLE DELL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
13	DIXIE DEER SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
14	DRAPER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	EAST BENCH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
16	EAST HYRUM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	EAST LAYTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
18	EAST MILLCREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	EDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	ELBERTA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	ELK MEADOWS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	ELSINORE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	EMERY CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	EMIGRATION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	ENOCH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
26	ENTERPRISE VALLEY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
27	EUREKA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	FARMINGTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
29	FAYETTE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	FERRON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	FIELDING SUB	DISTRIBUTION-UNATTEN	46.00	12.00	
32	FIFTH WEST SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
33	FLUX SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	FOOL CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	FORT DOUGLAS	DISTRIBUTION-UNATTEN	138.00	13.20	
36	FOUNTAIN GREEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	FREEDOM SUBSTATION	DISTRIBUTION-UNATTEN	46.00	7.20	
38	FRUIT HEIGHTS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	GARDEN CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	GATEWAY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	

SUBSTATIONS (Continued)

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3	1					1
2	3					2
30	1					3
22	1					4
30	1					5
42	1					6
55	2					7
6	1					8
48	3					9
2	1					10
4	1					11
60	2					12
2	1					13
23	2					14
30	1					15
6	1					16
60	2					17
20	1					18
19	2					19
5	1					20
3	1					21
2	1					22
3	3					23
25	1					24
14	1					25
10	1					26
3	1					27
30	1					28
1	2					29
5	1					30
6	1					31
50	2					32
4	1					33
2	1					34
40	1					35
7	1					36
	1					37
22	1					38
12	1					39
28	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 2013/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	GOLD RUSH SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
2	GORDON AVENUE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
3	GOSHEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	GRANGER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	GRANTSVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	GUNNISON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	HAMMER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	HAVASU SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	HELPER CITY SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
10	HENEFER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	HERRIMAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
12	HIGHLAND DIST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	HOGGARD SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
14	HOLDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	HOLLADAY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	HUNTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	HUNTINGTON CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	IRON MOUNTAIN SUB	DISTRIBUTION-UNATTEN	34.50	7.20	
19	IRONTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	IVINS SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
21	JORDAN NARROWS SUB	DISTRIBUTION-UNATTEN	46.00	2.40	
22	JORDAN PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
23	JORDANELLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
24	JUAB SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	JUNCTION SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	KAIBAB SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	KAMAS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	KEARNS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
29	KENSINGTON SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
30	LAKE PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
31	LARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	LAYTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	LEGRANDE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	LEWISTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	LINCOLN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	LINDON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	LISBON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	LOAFER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	LOGAN CANYON SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
40	LONE TREE SUB	DISTRIBUTION-UNATTEN	34.50	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 2013/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
30	1					1
30	1					2
2	1					3
50	2					4
23	1					5
11	2					6
60	2					7
3	1					8
3	3					9
4	1					10
30	1					11
25	1					12
50	2					13
4	1					14
32	2					15
22	1					16
12	2					17
1	1					18
2	1					19
22	1					20
13	2					21
30	1					22
30	1					23
2	3					24
2	1					25
5	1					26
7	1					27
60	2					28
7	1					29
53	2					30
6	1					31
40	2					32
2	1					33
14	1					34
20	1					35
20	1					36
4	1					37
	1					38
1	1					39
20	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 2013/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	LOWER BEAVER SUB	DISTRIBUTION-UNATTEN	46.00	6.60	
2	LYNNDYL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	MAESER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	MAGNA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
5	MANILA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	MANTUA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	MAPLETON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	MARRIOTT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	MARYSVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	MATHIS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	MCCORNICK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	MCKAY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	MEADOWBROOK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	46.00
14	MEDICAL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	MIDLAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
16	MIDVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	MILFORD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	MILFORD TV SUB	DISTRIBUTION-UNATTEN	46.00	13.20	
19	MINERSVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	MOAB CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	MONTEZUMA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	MOORE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	MORGAN SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
24	MORONI SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	MOSS JUNCTION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	MOUNTAIN DELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	MOUNTAIN GREEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	MYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	NEW HARMONY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	NEWGATE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	NEWTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	NIBLEY SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
33	NORTH BENCH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	NORTH FIELDS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	NORTH LOGAN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	NORTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	NORTH SALT LAKE SUB	DISTRIBUTION-UNATTEN	46.00	13.20	
38	NORTHEAST SUB	DISTRIBUTION-UNATTEN	46.00	12.50	
39	NORTHRIDGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	OAKLAND AVE 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 2013/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
1	1					1
4	1					2
12	1					3
30	1					4
22	1					5
2	1					6
14	1					7
20	1					8
3	1					9
9	1					10
6	1					11
20	1					12
42	2					13
57	4					14
30	1					15
25	1					16
14	1					17
	1					18
2	1					19
19	2					20
12	1					21
3	1					22
7	2					23
6	1					24
6	3					25
5	1					26
6	1					27
6	1					28
7	1					29
20	1					30
5	1					31
14	1					32
25	1					33
2	1					34
25	1					35
22	1					36
25	1					37
45	2					38
14	1					39
24	2					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 2013/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	OAKLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	OLYMPUS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	OPHIR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	ORANGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	ORANGEVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	OREM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	PACK CREEK RESERVOIR	DISTRIBUTION-UNATTEN	46.00	12.47	
8	PANGUITCH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	PARIETTE SUBSTATION	DISTRIBUTION-UNATTEN	69.00	24.90	
10	PARK CITY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	PARKWAY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
12	PARLEYS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	PELICAN POINT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	PINE CANYON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
15	PINE CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	PINNACLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	PLAIN CITY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
18	PLEASANT GROVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	PLEASANT VIEW SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	PORTER ROCKWELL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
21	PROMONTORY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	QUAIL CREEK SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
23	QUARRY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
24	QUICHAPA SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
25	RAINS SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
26	RANDOLPH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	RASMUSON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	RATTLESNAKE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
29	RED MOUNTAIN SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
30	RED ROCK SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
31	REDWOOD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	RESEARCH PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	RICH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	RICHFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	RICHMOND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	RIDGELAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
37	RITER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	ROCK CANYON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	ROCKVILLE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
40	ROCKY POINT	DISTRIBUTION-UNATTEN	138.00	13.20	

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)	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)	
6	1					1
22	1					2
3	1					3
20	1					4
14	1					5
48	2					6
4	1					7
5	1					8
4	3					9
35	2					10
50	2					11
16	2					12
6	1					13
55	2					14
2	1					15
14	1					16
22	1					17
25	1					18
14	1					19
30	1					20
2	1					21
4	1					22
60	2					23
4	1					24
15	1					25
2	1					26
1	3					27
14	1					28
12	1					29
3	1					30
45	2					31
45	2					32
5	1					33
22	2					34
11	1					35
40	2					36
20	1					37
5	1					38
4	1					39
30	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 2013/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	ROSE PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	ROYAL SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
3	SALINA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	SANDY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
5	SARATOGA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
6	SCIPIO SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	SCOFIELD RESERVOIR SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
8	SCOFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	SECOND STREET SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	SEGO CANYON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	SEVEN MILE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	SHARON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	SHIVWITS SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
14	SHORELINE SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
15	SIXTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	SKULL VALLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	SKYPARK SUB	DISTRIBUTION-UNATTEN	138.00	12.50	12.50
18	SNARR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	SNOWVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	SNYDERVILLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
21	SOLDIER SUMMIT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	SOUTH JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
23	SOUTH MILFORD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	SOUTH MOUNTAIN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
25	SOUTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	SOUTH PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
27	SOUTH WEBER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
28	SOUTHWEST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	SPANISH VALLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	SPRINGDALE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
31	ST. JOHNS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	STANSBURY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	SUMMIT CREEK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
34	SUMMIT PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	SUNRISE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
36	SUPERIOR SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	SUTHERLAND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	TAMARISK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
39	TAYLOR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	THIEF CREEK SUB	DISTRIBUTION-UNATTEN	138.00	24.90	

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)	
24	3					1
	3					2
11	1					3
60	2					4
60	2					5
1	3					6
1	1					7
1	3					8
13	2					9
14	1					10
	1					11
20	1					12
6	1					13
60	2					14
20	1					15
2	1					16
40	1					17
40	2					18
5	1					19
60	2					20
12	1					21
60	2					22
20	2					23
60	2					24
25	1					25
30	1					26
22	1					27
22	2					28
6	1					29
4	1					30
4	1					31
20	1					32
14	1					33
7	1					34
60	2					35
8	1					36
6	1					37
20	1					38
14	1					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 (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	THIRD WEST SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
2	THIRTEENTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	TOOELE DEPOT SUB	DISTRIBUTION-UNATTEN	46.00	12.50	
4	TOQUERVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	34.50
5	UINTAH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	UNION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	VALLEY CENTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	VERMILLION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	VERNAL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	VICKERS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	VINEYARD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	WALLSBURG SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
13	WALNUT GROVE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
14	WARREN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
15	WASATCH STATE PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	WASHAKIE SUB	DISTRIBUTION-UNATTEN	138.00	4.16	
17	WELBY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	WELFARE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	WEST COMMERCIAL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	WEST JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
21	WEST OGDEN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
22	WEST ROY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	WEST TEMPLE SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
24	WESTWATER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	WHITE MESA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	WHITE ROCK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
27	WILLOWCREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	WILLOWRIDGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	WINCHESTER HILLS SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
30	WINKLEMAN SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
31	WOLF CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	WOOD CROSS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	WOODRUFF SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	Total		19616.80	3545.24	105.47
35	Number of Substations-280				
36					
37	90TH SOUTH SUB	T/D-UNATTENDED	345.00	138.00	12.47
38	ANGEL SUB	T/D-UNATTENDED	138.00	12.47	46.00
39	BDO SUBSTATION	T/D-UNATTENDED	138.00	12.47	
40	BUTLERVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
100	2					1
22	1					2
25	1					3
34	2					4
39	2					5
50	2					6
22	1					7
3	1					8
33	2					9
2	1					10
25	1					11
13	1					12
30	1					13
30	1					14
2	3					15
14	1					16
42	2					17
5	1					18
22	1					19
28	1					20
60	2					21
25	1					22
60	3					23
5	1					24
14	1					25
30	1					26
1	1					27
14	1					28
4	1					29
	1					30
6	1					31
20	1					32
2	1					33
5458	383	1				34
						35
						36
1572	5	1				37
135	3					38
30	1					39
205	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 2013/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	CENTENNIAL SUB	T/D-UNATTENDED	138.00	12.47	
2	COTTONWOOD SUB	T/D-UNATTENDED	138.00	12.47	46.00
3	DECADE SUB	T/D-UNATTENDED	138.00	12.50	
4	DUMAS SUB	T/D-UNATTENDED	138.00	12.47	
5	EMMA PARK SUBSTATION	T/D-UNATTENDED	138.00	12.47	
6	GROW SUB	T/D-UNATTENDED	138.00	12.47	46.00
7	HALE SUB	T/D-UNATTENDED	138.00	46.00	12.47
8	HIGHLAND SUB	T/D-UNATTENDED	138.00	12.47	46.00
9	JORDAN SUB	T/D-UNATTENDED	138.00	46.00	12.47
10	JUDGE SUB	T/D-UNATTENDED	46.00	12.47	
11	MCCLELLAND SUB	T/D-UNATTENDED	138.00	46.00	12.47
12	MORTON COURT SUB	T/D-UNATTENDED	138.00	12.47	
13	OQUIRRH SUB	T/D-UNATTENDED	345.00	46.00	138.00
14	PARRISH SUB	T/D-UNATTENDED	138.00	12.47	46.00
15	PIONEER PLANT	T/D-UNATTENDED	138.00	12.47	
16	RIVERDALE SUB	T/D-UNATTENDED	138.00	46.00	12.47
17	SEVIER SUB	T/D-UNATTENDED	138.00	46.00	12.47
18	SILVER CREEK SUB	T/D-UNATTENDED	138.00	12.47	46.00
19	SOUTHEAST SUB	T/D-UNATTENDED	138.00	12.47	46.00
20	SPHINX SUB	T/D-UNATTENDED	46.00	12.47	
21	SYRACUSE SUB	T/D-UNATTENDED	345.00	46.00	138.00
22	TAYLORSVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47
23	TERMINAL SUB	T/D-UNATTENDED	345.00	46.00	138.00
24	TIMP SUB	T/D-UNATTENDED	138.00	46.00	12.47
25	TOOELE SUB	T/D-UNATTENDED	138.00	46.00	12.47
26	TRI CITY SUB	T/D-UNATTENDED	138.00	12.47	
27	WEST VALLEY SUB	T/D-UNATTENDED	138.00	12.47	
28	WESTFIELD SUB	T/D-UNATTENDED	138.00	12.47	
29	Total		5060.00	926.96	860.70
30	Number of Substations-32				
31					
32	EMERY SUB	TRANSMISSION-ATTENDE	345.00	138.00	69.00
33	GADSBY SUB	TRANSMISSION-ATTENDE	138.00	46.00	
34	ABAJO SUB	TRANSMISSION-UNATTEN	138.00	69.00	
35	ASHLEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
36	BARNEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
37	BEN LOMOND SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
38	BLACK ROCK SUB	TRANSMISSION-UNATTEN	230.00	69.00	
39	BLACKHAWK SUB	TRANSMISSION-UNATTEN	138.00	69.00	46.00
40	CAMERON SUB	TRANSMISSION-UNATTEN	138.00	46.00	

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 2013/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.
40	2					1
289	7					2
60	2					3
60	2					4
8	1					5
72	3					6
114	2					7
97	2					8
164	2					9
22	1					10
340	3					11
65	2					12
835	4	1				13
97	2					14
30	1					15
180	3					16
34	4					17
100	2					18
50	2					19
3	1	3				20
600	5					21
358	4					22
1108	6	2				23
130	2					24
158	3					25
30	1					26
30	1					27
20	1					28
7036	84	7				29
						30
						31
783	13	1				32
318	2					33
67	1					34
133	2					35
100	1					36
1813	5					37
75	1					38
100	2					39
25	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 2013/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	CAMP WILLIAMS SUB	TRANSMISSION-UNATTEN	345.00	138.00	12.47
2	CLOVER SUB	TRANSMISSION-UNATTEN	345.00	138.00	14.40
3	COLUMBIA SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
4	CRANER FLAT SUB	TRANSMISSION-UNATTEN	138.00	12.47	
5	CUTLER SUB	TRANSMISSION-UNATTEN	138.00	46.00	
6	EL MONTE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
7	GARKANE SUB	TRANSMISSION-UNATTEN	69.00	46.00	
8	GREEN CANYON SUB	TRANSMISSION-UNATTEN	138.00	46.00	
9	GRINDING SUB	TRANSMISSION-UNATTEN	138.00	13.80	
10	HELPER SUB	TRANSMISSION-UNATTEN	138.00	46.00	
11	HONEYVILLE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
12	HORSESHOE SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
13	HUNTINGTON SUB	TRANSMISSION-UNATTEN	345.00	138.00	
14	JERUSALEM SUB	TRANSMISSION-UNATTEN	138.00	46.00	
15	LAMPO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
16	MATHINGTON SUB	TRANSMISSION-UNATTEN	138.00	46.00	13.20
17	MCFADDEN SUB	TRANSMISSION-UNATTEN	138.00	46.00	
18	MIDDLETON SUB	TRANSMISSION-UNATTEN	138.00	69.00	34.50
19	MIDVALLEY SUB	TRANSMISSION-UNATTEN	345.00	138.00	
20	MIDWAY CITY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
21	MINERAL PRODUCTS SUB	TRANSMISSION-UNATTEN	69.00	46.00	
22	MOAB SUB	TRANSMISSION-UNATTEN	138.00	69.00	
23	NEBO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
24	PAROWAN VALLEY SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
25	PAVANT SUB	TRANSMISSION-UNATTEN	230.00	46.00	
26	PINTO SUB	TRANSMISSION-UNATTEN	345.00	138.00	69.00
27	RED BUTTE SUB	TRANSMISSION-UNATTEN	230.00	138.00	
28	SIGURD SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
29	SMITHFIELD SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
30	SPANISH FORK SUB	TRANSMISSION-UNATTEN	345.00	138.00	46.00
31	ST GEORGE SUB	TRANSMISSION-UNATTEN	138.00	16.50	
32	THREE PEAKS SUB	TRANSMISSION-UNATTEN	345.00	138.00	
33	WEST CEDAR SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
34	Total		8188.00	3331.77	686.98
35	Number of Substations-42				
36					
37	WASHINGTON				
38	ATTALIA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	BOWMAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	CASCADE KRAFT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	4.16

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)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
169	2					1
448	1					2
71	2					3
40	2					4
50	1					5
312	3					6
33	1					7
67	2					8
225	3					9
142	2					10
35	1					11
80	2					12
270	4					13
67	1					14
75	1					15
75	1					16
45	1					17
141	4					18
900	2					19
67	1					20
12	1					21
67	1					22
67	1					23
138	2					24
133	2					25
258	3					26
400	1					27
1124	6					28
63	2					29
1017	5					30
100	3	1				31
450	1					32
262	3					33
10817	99	2				34
						35
						36
						37
25	1					38
45	2					39
118	6					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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	CLINTON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	DAYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	DODD ROAD SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
4	GRANDVIEW SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
5	HOPLAND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
6	NACHES	DISTRIBUTION-UNATTEN	115.00	12.47	
7	NOB HILL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
8	NORTH PARK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
9	ORCHARD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	PACIFIC SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
11	POMEROY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	PROSPECT POINT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	PUNKIN CENTER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	RIVER ROAD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
15	SELAH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
16	SULPHUR CREEK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
17	SUNNYSIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	TIETON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	34.50
19	TOPPENISH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
20	TOUCHET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	VOELKER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
22	WAITSBURG SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	WAPATO SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
24	WENAS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
25	WHITE SWAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
26	WILEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
27	Total		2921.00	369.96	107.66
28	Number of Substations-29				
29					
30	CENTRAL SUB	T/D-UNATTENDED	69.00	12.47	
31	MILL CREEK SUB	T/D-UNATTENDED	69.00	12.47	
32	UNION GAP SUB	T/D-UNATTENDED	230.00	115.00	12.47
33	Total		368.00	139.94	12.47
34	Number of Substations-3				
35					
36	OUTLOOK SUB	TRANSMISSION-UNATTEN	230.00	115.00	
37	PASCO SUB	TRANSMISSION-UNATTEN	115.00	69.00	7.20
38	POMONA HEIGHTS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
39	WALLA WALLA 230KV SUB	TRANSMISSION-UNATTEN	230.00	69.00	
40	WALLULA SUB	TRANSMISSION-UNATTEN	230.00	69.00	

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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)	
25	1					1
23	2					2
25	4					3
42	2					4
50	2					5
20	1					6
42	2					7
45	2					8
50	2					9
28	3					10
9	1					11
40	2					12
20	2					13
51	4					14
45	2					15
25	1					16
45	2					17
29	2					18
50	2					19
6	1					20
25	1					21
9	1					22
45	2					23
25	2					24
22	2					25
45	2					26
1029	59					27
						28
						29
14	1					30
45	2					31
348	5					32
407	8					33
						34
						35
125	1					36
39	9					37
300	2					38
300	2					39
120	2					40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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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	WINE COUNTRY SUB	TRANSMISSION-UNATTEN	230.00	115.00	
2	Total		1265.00	552.00	7.20
3	Number of Substations-6				
4	WYOMING				
5	ANTELOPE MINE SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
6	ASTLE STREET	DISTRIBUTION-UNATTEN	34.50	13.20	
7	BAILEY DOME SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
8	BAR X SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
9	BIG MUDDY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	BIG PINEY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
11	BLACKS FORK SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
12	BRIDGER PUMP SUB	DISTRIBUTION-UNATTEN	230.00	34.50	13.20
13	BRYAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	BUFFALO TOWN SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
15	BYRON SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
16	CASSA SUB	DISTRIBUTION-UNATTEN	57.00	20.80	12.47
17	CENTER STREET SUB	DISTRIBUTION-UNATTEN	115.00	4.16	
18	CHAPMAN SUBSTATION	DISTRIBUTION-UNATTEN	46.00	12.47	
19	CHUKAR SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
20	CHURCH AND DWIGHT SUB	DISTRIBUTION-UNATTEN	34.50	0.48	
21	COKEVILLE SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
22	COLUMBIA-GENEVA SUB	DISTRIBUTION-UNATTEN	230.00	13.80	
23	COMMUNITY PARK SUB	DISTRIBUTION-UNATTEN	116.00	13.20	
24	CROOKS GAP SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
25	DEER CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	DJ COAL MINE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
27	DOUGLAS SUB	DISTRIBUTION-UNATTEN	57.00	2.30	
28	DRY FORK SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
29	ELK BASIN SUB	DISTRIBUTION-UNATTEN	34.50	7.20	
30	EMIGRANT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
31	EVANS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
32	EVANSTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
33	FORT CASPER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	FORT SANDERS SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
35	FRANNIE SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
36	FRONTIER SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
37	GARLAND SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
38	GLENDO SUB	DISTRIBUTION-UNATTEN	57.00	4.16	
39	GRASS CREEK SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
40	GREAT DIVIDE SUB	DISTRIBUTION-UNATTEN	115.00	34.50	

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)	
250	1					1
1134	17					2
						3
						4
25	1					5
12	1					6
2	1					7
25	1					8
7	1					9
14	1					10
150	2					11
72	4					12
25	1					13
2	3					14
2	3					15
2	6	1				16
12	1					17
4	1					18
1	3					19
3	2					20
4	1					21
45	2					22
45	2					23
5	3					24
9	1					25
12	1					26
6	3					27
9	1					28
5	1					29
12	1					30
9	1					31
40	2					32
28	1					33
20	1					34
50	2					35
6	1					36
45	2					37
3	4					38
25	1					39
20	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 2013/Q4

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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	GREYBULL SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
2	HANNA SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
3	JACKALOPE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	KEMMERER SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
5	KIRBY CREEK PUMPING STATION	DISTRIBUTION-UNATTEN	34.50	2.40	
6	KIRBY CREEK SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
7	LANDER SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
8	LARAMIE SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
9	LATHAM SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
10	LINCH SUB	DISTRIBUTION-UNATTEN	69.00	13.80	
11	LITTLE MOUNTAIN SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
12	LOVELL SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
13	MILL IRON SUB	DISTRIBUTION-UNATTEN	34.50	13.80	
14	MILLS SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
15	MURPHY DOME SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
16	NUGGETT SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
17	OPAL SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
18	ORIN SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
19	ORPHA SUB	DISTRIBUTION-UNATTEN	57.00	7.20	
20	PARADISE SUB	DISTRIBUTION-UNATTEN	69.00	25.00	
21	PARCO SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
22	PINEDALE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
23	PITCHFORK SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
24	POISON SPIDER SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
25	POLECAT SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
26	RAINBOW SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
27	RAVEN SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
28	RED BUTTE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	REFINERY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
30	SAGE HILL SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
31	SHOSHONI SUB	DISTRIBUTION-UNATTEN	34.50	2.40	
32	SLATE CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	SOUTH CODY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
34	SOUTH ELK BASIN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
35	SOUTH TRONA SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
36	SPRING CREEK SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
37	SVILAR SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
38	TEN MILE STEP DOWN SUB	DISTRIBUTION-UNATTEN	34.50	12.50	
39	TEN MILE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
40	THERMOPOLIS TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	

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 2013/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.
3	1					1
6	1					2
25	1					3
10	1					4
3	3					5
2	3					6
25	2					7
50	2					8
25	1					9
12	1					10
20	1					11
4	1					12
12	1	1				13
1	3					14
5	1					15
	1					16
8	1					17
2	3					18
3	3					19
30	1					20
5	1					21
8	1					22
17	9	2				23
3	1					24
1	3					25
12	1					26
200	2					27
20	1					28
45	2					29
6	1					30
2	3					31
1	1					32
14	3	1				33
2	6					34
150	2					35
25	1					36
2	3					37
5	1					38
12	1					39
5	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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	THUNDER CREEK SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
2	VETERANS SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
3	WELCH SUB	DISTRIBUTION-UNATTEN	57.00	2.40	
4	WERTZ-SINCLAIR SUB	DISTRIBUTION-UNATTEN	57.00	4.16	12.50
5	WEST ADAMS SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
6	WESTVACO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
7	WORLAND TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
8	WYOPO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
9	WYUTA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	Total		7494.24	1311.37	38.17
11	Number of Substations-85				
12					
13	BUFFALO SUB	T/D-UNATTENDED	230.00	20.80	
14	ELK HORN SUB	T/D-UNATTENDED	115.00	12.50	
15	FIREHOLE SUB	T/D-UNATTENDED	230.00	34.50	
16	HILLTOP SUB	T/D-UNATTENDED	115.00	34.50	20.80
17	LABARGE SUB	T/D-UNATTENDED	69.00	24.90	
18	POINT OF ROCKS SUB	T/D-UNATTENDED	230.00	34.50	
19	RIVERTON 230 SUB	T/D-UNATTENDED	230.00	12.47	34.50
20	YELLOWCAKE SUB	T/D-UNATTENDED	230.00	34.50	
21	Total		1449.00	208.67	55.30
22	Number of Substations-8				
23					
24	DAVE JOHNSTON PLANT/SUB	TRANSMISSION-ATTENDE	230.00	115.00	69.00
25	JIM BRIDGER 345KV SUB	TRANSMISSION-ATTENDE	345.00	230.00	34.50
26	NAUGHTON SUB	TRANSMISSION-ATTENDE	230.00	138.00	69.00
27	BAIROIL SUB	TRANSMISSION-UNATTEN	115.00	34.50	57.00
28	CASPER SUB	TRANSMISSION-UNATTEN	230.00	115.00	13.20
29	CHAPPELL CREEK SUB	TRANSMISSION-UNATTEN	230.00	69.00	
30	CHIMNEY BUTTE SUB	TRANSMISSION-UNATTEN	230.00	69.00	
31	FOOTE CREEK WIND FARM	TRANSMISSION-UNATTEN	230.00	34.50	
32	GLENDO AUTO SUB	TRANSMISSION-UNATTEN	69.00	57.00	
33	MANSFACE SUB	TRANSMISSION-UNATTEN	230.00	34.50	
34	MIDWEST SUB	TRANSMISSION-UNATTEN	230.00	69.00	34.50
35	MINERS SUB	TRANSMISSION-UNATTEN	230.00	34.50	9.70
36	MUSTANG SUB	TRANSMISSION-UNATTEN	230.00	115.00	
37	OREGON BASIN SUB	TRANSMISSION-UNATTEN	230.00	34.50	69.00
38	PLATTE SUB	TRANSMISSION-UNATTEN	230.00	115.00	34.50
39	RAILROAD SUB	TRANSMISSION-UNATTEN	230.00	138.00	
40	ROCK SPRINGS 230 SUB	TRANSMISSION-UNATTEN	230.00	34.50	

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	1					1
25	2					2
3	3					3
2	6					4
3	1					5
25	1					6
5	1					7
20	1	1				8
	1					9
1629	157	6				10
						11
						12
20	1					13
25	1					14
50	2					15
45	2	1				16
8	6					17
25	1					18
74	4					19
25	1					20
272	18	1				21
						22
						23
336	4					24
703	7					25
599	4					26
53	3					27
517	5					28
67	1					29
75	1					30
196	2					31
15	2					32
20	1					33
91	4					34
20	1					35
100	1					36
65	2					37
140	3					38
400	1					39
50	2					40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SAGE SUB	TRANSMISSION-UNATTEN	69.00	46.00	
2	THERMOPOLIS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
3	Total		4048.00	1598.00	390.40
4	Number of Substations-19				
5					
6	CALIFORNIA				
7	Distribution - 42				
8	T/D - 2				
9	Transmission - 6				
10					
11	IDAHO				
12	Distribution - 65				
13	T/D - 5				
14	Transmission - 16				
15					
16	MONTANA				
17	Transmission - 3				
18					
19	OREGON				
20	Distribution - 180				
21	T/D - 11				
22	Transmission - 28				
23					
24	UTAH				
25	Distribution - 280				
26	T/D - 32				
27	Transmission - 42				
28					
29	WASHINGTON				
30	Distribution - 29				
31	T/D - 3				
32	Transmission - 6				
33					
34	WYOMING				
35	Distribution - 85				
36	T/D - 8				
37	Transmission - 19				
38					
39	ALL STATES				
40	Distribution - 681				

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)	
22	1					1
175	2					2
3644	47					3
						4
						5
						6
323						7
126						8
762						9
						10
						11
721						12
374						13
3804						14
						15
						16
200						17
						18
						19
4619						20
1262						21
7061						22
						23
						24
5458						25
7036						26
10817						27
						28
						29
1029						30
407						31
1134						32
						33
						34
1629						35
272						36
3644						37
						38
						39
13779						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 2013/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	T/D - 61				
2	Transmission - 120				
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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.
9477						1
27422						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426.3 Line No.: 38 Column: a

The Broadview 500kV Substation is jointly owned by PacifiCorp, NorthWestern Energy, Puget Sound Energy, Inc., Portland General Electric Company and Avista Corporation. Ownership and operations and maintenance costs vary by type of asset as defined in the Transmission Agreement.

Schedule Page: 426.3 Line No.: 39 Column: a

The Colstrip 500kV Substation is jointly owned by PacifiCorp, NorthWestern Energy, Puget Sound Energy, Inc., Portland General Electric Company and Avista Corporation. Ownership and operations and maintenance costs vary by type of asset as defined in the Transmission Agreement.

Schedule Page: 426.9 Line No.: 10 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.: 20 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.: 21 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: 426.22 Line No.: 24 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: 426.22 Line No.: 25 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%.

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 2013/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		158,550,835
4				
5	Coal mining services	Energy West Mining Company	151	70,633,989
6				
7	Coal purchases	Trapper Mining Inc.	151	14,232,252
8				
9	Administrative support services	Interwest Mining Company		1,168,072
10				
11	Administrative services under the IASA	MEHC		11,193,188
12	Administrative services under the IASA	MEC		4,723,795
13	Administrative services under the IASA	MHC, Inc.	426.5, 923	421,420
14	Administrative services under the IASA	Kern River Gas Transmission Company	107, 923	217,785
15				
16	Gas transportation services	Kern River Gas Transmission Company	501, 547	3,261,037
17				
18	Relocation services	HomeServices of America, Inc.		1,647,548
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Information technology and administrative			
22	support services	Bridger Coal Company	146	960,187
23				
24	Financial support services and employee benefits	Interwest Mining Company	146	629,055
25				
26	Information technology and administrative			
27	support services	Energy West Mining Company	146	502,281
28				
29	Administrative services under the IASA	MEHC	146	3,415,067
30	Administrative services under the IASA	MEC	146	1,750,416
31	Administrative services under the IASA	MidAmerican Transmission, LLC	146	1,520,264
32	Administrative services under the IASA	MEHC Canada Transmission	146	562,243
33	Administrative services under the IASA	Northern Natural Gas Company	146	357,164
34	Administrative services under the IASA	HomeServices of America, Inc.	146	260,300
35	Administrative services under the IASA	Kern River Gas Transmission Company	146	176,273
36				
37	Easement and relocation of utility facilities	Kern River Gas Transmission Company	107, 454	99,344
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2				

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 2013/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	31,801,205
4				
5	Banking services	Wells Fargo & Company		2,262,901
6				
7	Computer hardware and software and computer			
8	systems consulting and maintenance services	International Business Machines Corp		4,592,665
9				
10	Rating agency fees	Moody's Investors Service	181, 186, 930.2	416,415
11				
12	Surety bond premium	National Indemnity Company	165	427,920
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, 501, 502, 513 and 935.

Schedule Page: 429 Line No.: 3 Column: d

Non-power goods or services provided by Bridger Coal Company are as follows:

Coal purchases	$ 158,490,560
Support services	60,275
	$ 158,550,835

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, 512, 557, 923, 928 and 929.

Schedule Page: 429 Line No.: 9 Column: d

Interwest Mining Company manages PacifiCorp's mining operations and charges management services to Bridger Coal Company and Energy West Mining Company. Interwest Mining Company also charges PacifiCorp for administrative support services. All costs incurred by Interwest Mining Company are absorbed by PacifiCorp, Bridger Coal Company and Energy West Mining Company.

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: 107, 143, 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 payments related to wages and benefits associated with transferred employees.

The convenience payments, the LTIP reimbursements and the reimbursements 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 and 923.

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.: 14 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.: 184, 501, 506, 535, 548, 549, 553, 557, 560, 561.2, 569.3, 580, 581, 590, 593, 597, 902, 903, 908 and 921.

Schedule Page: 429 Line No.: 24 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 Bridger Coal Company and Energy West Mining Company.

Schedule Page: 429 Line No.: 29 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.: 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 Line No.: 31 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.: 32 Column: b

Complete name is MEHC Canada Transmission GP Corporation.

Schedule Page: 429 Line No.: 32 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.: 33 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	$ 31,747,908
Right-of-way fees	53,297
	$ 31,801,205

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.: 5 Column: c

Accounts charged for Wells Fargo & Company: 181, 186, 228.3, 419, 427, 431, 501, 557, 560, 588, 903, 921 and 928.

Schedule Page: 429.1 Line No.: 8 Column: b

This footnote applies to all occurrences of “International Business Machines Corp” on page 429. Complete name is International Business Machines Corporation.

Schedule Page: 429.1 Line No.: 8 Column: c

Accounts charged for International Business Machines Corp: 107, 165, 921 and 935.

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