ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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

RECEIVED
2015 MAY 29 AM 9:43
IDAHO PUBLIC
UTILITIES COMMISSION

May 28, 2015

VIA ELECTRONIC FILING
AND 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, 2014.

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 / cm

Jeffrey K. Larsen
Vice President, Regulation

Enclosure

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

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

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 2014/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 2014/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 Street, 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 Street, Suite 1900, Portland, OR 97232	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(503) 813-5958	(1) [X] An Original (2) [ ] A Resubmission	/ /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Douglas K. Stuver	Doug K Stuver Douglas K. Stuver	04/17/2015
02 Title Senior VP & Chief Financial Officer		

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

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/Q4

LIST OF SCHEDULES (Electric Utility)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

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 2014/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 Street, 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. In March 2015, PacifiCorp reorganized its divisions to be comprised of Rocky Mountain Power, Pacific Power and PacifiCorp Transmission.

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

CONTROL OVER RESPONDENT

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

Berkshire Hathaway Inc.(a)
- Berkshire Hathaway Energy Company ("BHE") (100%)
  - PPW Holdings LLC (100% controlled by BHE)
    - PacifiCorp (100% of common stock held by PPW Holdings LLC)

(a) Berkshire Hathaway Inc. owns 89.9%, Walter Scott, Jr. (along with family members and related entities) owns 9.1% and Gregory E. Abel owns 1.0% of BHE's common stock.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Energy West Mining Company	Mining	100	
2	Fossil Rock Fuels, LLC	Mining	100	
3	Glenrock Coal Company	Mining	100	
4	Interwest Mining Company	Management Services	100	
5	Pacific Minerals, Inc.	Management Services	100	
6	Bridger Coal Company	Mining	66.67	
7	Trapper Mining Inc.	Mining	21.40	
8	PacifiCorp Foundation	Non-profit foundation		
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Schedule Page: 103 Line No.: 1 Column: a

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

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

Glenrock Coal Company ceased mining operations in October 1999.

Schedule Page: 103 Line No.: 5 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.: 6 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.: 7 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.: 8 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. As of December 31, 2014, 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 2014/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	Chairman of the Board of Directors		
2	and Chief Executive Officer	Gregory E. Abel	
3	Senior Vice President and Chief Financial Officer	Douglas K. Stuver	252,000
4	President and Chief Executive Officer, Pacific Power	R. Patrick Reiten	320,000
5	President and Chief Executive Officer, PacifiCorp Energy	Micheal G. Dunn	320,000
6	President and Chief Executive Officer,		
7	Rocky Mountain Power	Cindy A. Crane	224,538
8	Former President and Chief Executive Officer,		
9	Rocky Mountain Power	A. Richard Walje	379,034
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Schedule Page: 104 Line No.: 1 Column: c

PacifiCorp sets forth the salary information for its "named executive officers" for the year ended December 31, 2014, 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.: 2 Column: b

Mr. Abel receives no direct compensation from PacifiCorp. PacifiCorp reimburses Berkshire Hathaway Energy Company ("BHE")for the cost of Mr. Abel’s time spent on matters supporting PacifiCorp, including compensation paid to him by BHE, pursuant to an intercompany administrative services agreement among BHE and its subsidiaries. Please refer to BHE’s Annual Report on Form 10-K for the year ended December 31, 2014 (File No. 001-14881) for executive compensation information for Mr. Abel.

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

R. Patrick Reiten was elected President and Chief Executive Officer of PacifiCorp Transmission, a new division of PacifiCorp, effective March 10, 2015. Stefan A. Bird was elected President and Chief Executive Officer of Pacific Power effective March 10, 2015. Refer to Item 13 in Important Changes During the Quarter/Year of this Form 1.

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

Micheal G. Dunn resigned as a director and employee of PacifiCorp effective March 2015. Refer to Item 13 in Important Changes During the Quarter/Year of this Form 1.

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

Cindy A. Crane was appointed President and Chief Executive Officer of Rocky Mountain Power, a division of PacifiCorp, on November 1, 2014 and was elected to that position on December 18, 2014. Refer to Item 13 in Important Changes During the Quarter/Year of this Form 1.

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

A. Richard Walje was appointed President and Chief Executive Officer of Gateway Projects, PacifiCorp on November 1, 2014 and was elected to that position on December 18, 2014. Refer to Item 13 in Important Changes During the Quarter/Year of this Form 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 2014/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, 2014:	
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	(Former President and CEO, Rocky Mountain Power)	1407 West North Temple, Suite 270, Salt Lake City, Utah 84116
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	Natalie L. Hocken	
14	(SVP, Transmission and System Operations, PacifiCorp)	825 NE Multnomah, Suite 1600, Portland, Oregon 97232
15	Mark C. Moench	
16	(SVP, General Counsel and Corporate Secretary, PacifiCorp)	201 South Main, Suite 2400, Salt Lake City, Utah 84111
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Schedule Page: 105 Line No.: 6 Column: a

A. Richard Walje resigned as a director effective November 2014. Refer to Item 13 in Important Changes During the Quarter/Year of this Form 1.

Schedule Page: 105 Line No.: 9 Column: a

Brent E. Gale retired as a director and employee effective January 1, 2015. Refer to Item 13 in Important Changes During the Quarter/Year of this Form 1.

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

Micheal G. Dunn resigned as a director and employee effective March 2015. Refer to Item 13 in Important Changes During the Quarter/Year of this Form 1.

Schedule Page: 105 Line No.: 15 Column: a

Mark C. Moench retired as a director and employee effective February 2014. Refer to Item 13 in Important Changes During the Quarter/Year of this Form 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 2014/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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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 2014/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	20140401-5215	04/01/2014	ER14-1635		
2	20140515-5146	05/15/2014	ER11-3643		
3	20140723-5137	07/23/2014	ER11-3643		
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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 (Rev Depreciation Rates 2014) to be effective 6/1/2014 under ER 14-1635

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

Supplement to May 15, 2014 Transmission Formula Rate Annual Update Informational Filing of PacifiCorp under ER11-3643

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 2014/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

ITEM 1.

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

State	Effective Date	Expiration Date	Fee
California (1)			
None			
Idaho (2)			
None			
Oregon (3)			
Creswell	01/16/2014	01/16/2024	5.0%
Rogue River	05/24/2014	05/24/2024	7.0%
Butte Falls	07/15/2014	07/15/2024	5.0%
Utah (5)			
Juab County	03/07/2014	03/07/2034	-
Santaquin	05/28/2014	05/28/2029	-
Henefer	06/26/2014	06/26/2024	-
Lynndyl	06/26/2014	06/26/2029	-
Coalville	07/15/2014	07/15/2024	-
Wallsburg	10/23/2014	10/23/2034	-
Emery County	11/24/2014	11/24/2039	-
Leamington	12/02/2014	12/02/2039	-
Washington (5)			
Asotin County	06/20/2014	06/20/2039	-
Walla Walla	09/18/2014	09/18/2034	-
Wyoming (4)			
Shoshoni	03/25/2014	03/25/2039	2.0%
Worland	09/01/2014	09/01/2024	5.0%

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

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

(3) In Oregon, the first 3.5% of the franchise agreement fee is an expense to PacifiCorp and is embedded in rates. Any amount above the 3.5% is collected from customers and remitted directly to the applicable municipalities.

(4) 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.

(5) In Utah and Washington, PacifiCorp collects associated taxes from customers and remits them directly to the applicable municipalities.

ITEM 2.

None.

ITEM 3.

In December 2014, PacifiCorp entered into asset purchase and sale agreements to sell certain Utah mining assets, which are contingent upon regulatory approvals from certain state commissions. For further discussion, refer to Note 5 of Notes to Financial Statements in this Form No. 1.

In October 2014, PacifiCorp and Idaho Power Company ("Idaho Power") executed a Joint Purchase and Sale Agreement under which each party has agreed to transfer to the other party full or undivided joint ownership interests in specified transmission-related equipment and facilities with an estimated net book value of approximately $43 million. The Joint Purchase and Sale Agreement also provides for the termination and amendment of a number of legacy long-term transmission service agreements between PacifiCorp and Idaho Power. Contemporaneously with the Joint Purchase and Sale Agreement, PacifiCorp and Idaho Power executed a Joint Ownership and Operating Agreement applicable to the specified transmission-related equipment and facilities to be transferred. The closing of the transfer of the transmission-related equipment and facilities, the effectiveness of the two executed agreements, and the termination and amendment of the legacy long-term transmission service agreements are subject to approval by the Federal Energy Regulatory Commission ("FERC"), the Oregon Public Utility Commission ("OPUC"), the Wyoming Public Service Commission ("WPSC"), the Idaho Public Utilities Commission ("IPUC"), the Washington Utilities and Transportation Commission ("WUTC") and the California Public Utilities Commission. The required notice filing with the Utah Public Service Commission was submitted in December 2014.

In September 2014, PacifiCorp entered into an agreement for the sale of the Fountain Green hydroelectric generating facility in exchange for a transmission line corridor easement with the Utah Division of Wildlife Resources. The sale was approved by the WPSC in Docket No. 20000-459-EA-14 and the OPUC in Docket No. UP 312, Order No. 15-071 in January 2015 and March 2015, respectively. As a result of receiving the required regulatory approvals, PacifiCorp recorded the sale in account 102, Electric plant purchased or sold, in March 2015.

ITEM 4.

In February 2005, PacifiCorp entered into a long-term firm natural gas transportation service agreement with Questar Gas Company ("Questar") to provide firm natural gas transportation service to the Lake Side generating facility ("Lake Side") and construct a natural gas pipeline and facilities necessary to connect Lake Side to Questar's existing feeder line. PacifiCorp accounted for the agreement as a capital lease. During 2011, PacifiCorp began construction of the 631-MW Lake Side 2 combined-cycle combustion turbine natural gas-fueled generating facility ("Lake Side 2") adjacent to Lake Side, which was placed in service in May 2014. In February 2012, PacifiCorp entered into a second long-term agreement with Questar to provide firm natural gas transportation service to Lake Side 2 and construct facilities to provide the additional natural gas transportation service. As a result of the construction of the additional facilities, Questar is able to utilize the facilities to provide natural gas transportation service to customers other than PacifiCorp's Lake Side generating facilities. In March 2014, Questar notified PacifiCorp that the construction of the additional facilities was substantially complete and available for service. As a result of PacifiCorp entering into the second agreement with Questar and the ability for others to benefit from Questar's facilities located near the Lake Side generating facilities, the February 2005 firm natural gas transportation service agreement is no longer accounted for as a lease.

ITEM 5.

In April 2015, PacifiCorp and the California Independent System Operator Corporation ("California ISO") entered into a non-binding memorandum of understanding to explore the feasibility, costs and benefits of PacifiCorp joining the California ISO as a participating transmission owner. A comprehensive benefits study is underway and is expected to be completed this summer. Should PacifiCorp decide to take additional steps to pursue joining the California ISO, a stakeholder input and review process would be initiated and PacifiCorp would seek necessary regulatory approvals, including from its state regulatory commissions and the FERC.

PacifiCorp and the California ISO launched the regional energy imbalance market in November 2014, which allows PacifiCorp to participate in the California ISO's real-time energy markets to most cost-effectively manage short-term fluctuations in energy supply and demand. Joining the California ISO would extend that participation by PacifiCorp into the day-ahead energy market operated by the California ISO, in addition to unified planning and operation of PacifiCorp's transmission network.

ITEM 6.

Short-term Debt and Credit Facilities

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt. PacifiCorp had $20 million of short-term debt outstanding as of December 31, 2014 at a weighted average interest rate of 0.43%.

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

- OPUC – Docket No. UF-4120, Order No. 98-158, dated April 16, 1998.
- WUTC - Docket No. UE-980404, dated April 8, 1998.
- IPUC - Case No. PAC-E-11-09, Order No. 32221, dated April 8, 2011, effective through April 30, 2016.
- FERC - Docket No. ES14-5-000, dated November 26, 2013, letter order effective January 1, 2014 through December 31, 2015.

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 its 3.60% First Mortgage Bonds due April 2024. The net proceeds were 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 in March 2014 to PPW Holdings LLC, a wholly owned subsidiary of Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company. The OPUC and the IPUC authorizations for this issuance were as follows:

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

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $1.575 billion of long-term debt. PacifiCorp must make a notice filing with the WUTC prior to any future issuance. State commission authorizations for future issuances are as follows:

- OPUC – Docket No. UF-4288, Order No. 14-268, dated July 22, 2014.
- IPUC – Case No. PAC-E-14-05, Order No. 33083, dated July 29, 2014.

As of December 31, 2014, PacifiCorp had $451 million of letters of credit providing credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $444 million plus interest. These letters of credit were fully available as of December 31, 2014 and expire periodically through March 2017. 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, 2014, PacifiCorp estimated it would be able to issue up to $9.2 billion of new first mortgage bonds under the most restrictive issuance test in the mortgage. Any issuances are subject to market conditions and amounts may be further limited by regulatory authorizations or commitments or by covenants and tests contained in other financing agreements. PacifiCorp also has the ability to release property from the lien of the mortgage on the basis of property additions, bond credits or deposits of cash.

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

ITEM 7.

None.

ITEM 8.

For the year ended December 31, 2014, 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%	1/26/2014	$ 485,704
IBEW 57 Power Delivery (UT, ID & WY)	1.81%	1/26/2014	1,414,035
IBEW 57 Power Supply (UT, ID & WY)	1.86%	1/26/2014	731,827
IBEW 57 Combustion Turbine (UT)	2.23%	2/26/2014	68,816
IBEW 659 (OR, CA)	1.28%	4/26/2014	404,537
UWUA 197 (OR)	1.19%	5/26/2014	18,302
IBEW 57 Laramie (WY)	1.03%	6/26/2014	4,899
UWUA 127 (WY)	0.52%	9/26/2014	232,549
Total			$ 3,360,669

(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, 2014 other than preferred and common stock dividends declared and paid.

ITEM 11.

(Reserved.)

ITEM 12.

None.

ITEM 13.

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

Effective April 30, 2014, MidAmerican Energy Holdings Company was renamed Berkshire Hathaway Energy Company.

Cindy A. Crane was appointed President and Chief Executive Officer ("CEO"), Rocky Mountain Power, a division of PacifiCorp, on November 1, 2014 and was elected to that position on December 18, 2014. A. Richard Walje, the former President and CEO of Rocky Mountain Power, was appointed President and CEO, Gateway Projects, PacifiCorp on November 1, 2014 and was elected to that position on December 18, 2014. Mr. Walje resigned as a director effective November 8, 2014.

Brent E. Gale retired as a director and employee effective December 31, 2014.

In March 2015, PacifiCorp reorganized its divisions to be comprised of Rocky Mountain Power, Pacific Power and PacifiCorp Transmission. Stefan A. Bird was elected President and CEO of Pacific Power effective March 10, 2015. R. Patrick Reiten, the former President and CEO of Pacific Power, was elected President and CEO of PacifiCorp Transmission effective March 10, 2015.

Ms. Crane, Mr. Bird and Andrea L. Kelly, Senior Vice President, Strategic Business Performance, were elected directors of PacifiCorp effective March 10, 2015.

Michael G. Dunn resigned as a director and President and CEO of PacifiCorp Energy effective March 2015.

ITEM 14.

Not applicable.

Deloitte.

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Fax: +1 503 224 2172
www.deloitte.com

INDEPENDENT AUDITORS' REPORT

PacifiCorp
Portland, Oregon

We have audited the accompanying financial statements of PacifiCorp (the "Company"), which comprise the balance sheet—regulatory basis as of December 31, 2014, 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, 2014, and the results of its operations and its cash flows for the year then ended in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

Basis of Accounting

As discussed in Note 2 to the financial statements, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a basis of accounting other than accounting principles generally accepted in the United States of America. Our opinion is not modified with respect to this matter.

Restricted Use

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

Deloitte + Touche LLP

April 17, 2015

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 2014/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	26,026,444,483	24,810,145,362
3	Construction Work in Progress (107)	200-201	934,535,929	1,321,622,138
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		26,960,980,412	26,131,767,500
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	9,057,705,065	8,511,018,083
6	Net Utility Plant (Enter Total of line 4 less 5)		17,903,275,347	17,620,749,417
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)		17,903,275,347	17,620,749,417
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		13,345,624	14,388,489
19	(Less) Accum. Prov. for Depr. and Amort. (122)		2,556,976	2,937,770
20	Investments in Associated Companies (123)		69,928	69,928
21	Investment in Subsidiary Companies (123.1)	224-225	227,471,078	210,924,059
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		83,174,506	82,248,215
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		19,384,022	19,849,214
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		128,978	154,542
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		341,017,160	324,696,677
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		7,178,730	6,739,098
36	Special Deposits (132-134)		0	172,901
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		6,297,596	44,824,535
39	Notes Receivable (141)		52,493	72,137
40	Customer Accounts Receivable (142)		376,015,082	420,371,007
41	Other Accounts Receivable (143)		38,029,262	34,941,278
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		7,018,317	8,008,893
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		152,259,841	6,608,556
45	Fuel Stock (151)	227	198,515,639	240,980,677
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	223,638,201	212,544,115
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 2014/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)		54,470,840	48,954,180
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	14,382
60	Rents Receivable (172)		1,902,475	2,320,602
61	Accrued Utility Revenues (173)		243,252,000	258,009,000
62	Miscellaneous Current and Accrued Assets (174)		180,653	109,302
63	Derivative Instrument Assets (175)		18,078,275	10,279,567
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		128,978	154,542
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)		1,312,723,792	1,278,777,902
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		34,036,382	33,721,944
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	1,760,602
72	Other Regulatory Assets (182.3)	232	1,589,995,081	1,373,975,244
73	Prelim. Survey and Investigation Charges (Electric) (183)		3,103,498	3,615,224
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)		80,622	113,051
78	Miscellaneous Deferred Debits (186)	233	110,913,409	90,972,267
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)		7,184,006	8,089,941
82	Accumulated Deferred Income Taxes (190)	234	544,969,532	482,567,288
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,290,282,530	1,994,815,561
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		21,847,298,829	21,219,039,557

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

As of December 31, 2014, Account 146, Accounts receivable from associated companies, included $139,681,803 of income taxes receivable from Berkshire Hathaway Energy Company, PacifiCorp’s indirect parent company.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2014/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	3,417,945,896	3,417,945,896
3	Preferred Stock Issued (204)	250-251	2,397,600	2,397,600
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	1,102,063,956
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	41,101,061	41,101,061
11	Retained Earnings (215, 215.1, 216)	118-119	3,145,875,690	3,187,664,983
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	142,148,647	127,661,628
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)	-13,665,680	-9,091,505
16	Total Proprietary Capital (lines 2 through 15)		7,755,665,048	7,787,541,497
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	7,031,538,000	6,842,300,000
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)		80,126	91,152
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		13,185,043	13,958,237
24	Total Long-Term Debt (lines 18 through 23)		7,018,433,083	6,828,432,915
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		31,882,690	45,935,961
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		15,776,598	59,307,721
29	Accumulated Provision for Pensions and Benefits (228.3)		324,459,642	205,063,178
30	Accumulated Miscellaneous Operating Provisions (228.4)		37,861,624	38,745,810
31	Accumulated Provision for Rate Refunds (229)		1,879,732	0
32	Long-Term Portion of Derivative Instrument Liabilities		35,217,373	26,001,569
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		134,721,631	137,818,818
35	Total Other Noncurrent Liabilities (lines 26 through 34)		581,799,290	512,873,057
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		20,000,000	0
38	Accounts Payable (232)		436,531,636	472,746,697
39	Notes Payable to Associated Companies (233)		0	8,616,719
40	Accounts Payable to Associated Companies (234)		147,513,984	42,517,163
41	Customer Deposits (235)		39,692,452	36,794,115
42	Taxes Accrued (236)	262-263	39,025,536	53,535,702
43	Interest Accrued (237)		113,861,896	113,038,154
44	Dividends Declared (238)		40,475	40,476
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2014/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		19,834,847	19,668,643
48	Miscellaneous Current and Accrued Liabilities (242)		69,093,393	81,535,728
49	Obligations Under Capital Leases-Current (243)		1,986,489	2,772,497
50	Derivative Instrument Liabilities (244)		75,193,965	52,849,128
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		35,217,373	26,001,569
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)		927,557,300	858,113,453
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		31,403,438	24,877,489
57	Accumulated Deferred Investment Tax Credits (255)	266-267	27,213,937	32,306,325
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	303,969,379	308,485,444
60	Other Regulatory Liabilities (254)	278	71,012,945	91,533,914
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	252,151,842	226,880,978
63	Accum. Deferred Income Taxes-Other Property (282)		4,244,780,923	3,991,613,412
64	Accum. Deferred Income Taxes-Other (283)		633,311,644	556,381,073
65	Total Deferred Credits (lines 56 through 64)		5,563,844,108	5,232,078,635
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		21,847,298,829	21,219,039,557

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

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 the interest rate on the outstanding borrowings was 0.25%.

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

As of December 31, 2013, Account 236, Taxes accrued, included $18,691,010 of income taxes payable to Berkshire Hathaway Energy 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 2014/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	5,267,001,125	5,153,186,543		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,632,619,056	2,660,714,690		
5	Maintenance Expenses (402)	320-323	437,565,258	423,183,559		
6	Depreciation Expense (403)	336-337	663,171,827	600,829,680		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	40,709,374	45,434,666		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	4,834,296	5,211,112		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		1,760,602	2,365,947		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		415,224	294,983		
13	(Less) Regulatory Credits (407.4)		1,049,382			
14	Taxes Other Than Income Taxes (408.1)	262-263	171,415,396	169,647,183		
15	Income Taxes - Federal (409.1)	262-263	-2,889,557	74,343,217		
16	- Other (409.1)	262-263	9,721,676	15,767,344		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	1,071,119,870	826,690,640		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	760,877,449	625,812,453		
19	Investment Tax Credit Adj. - Net (411.4)	266	-5,019,198	-1,812,064		
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)		1,117	26,460		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		4,263,495,876	4,196,895,425		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,003,505,249	956,291,118		

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
5,267,001,125	5,153,186,543					2
						3
2,632,619,056	2,660,714,690					4
437,565,258	423,183,559					5
663,171,827	600,829,680					6
						7
40,709,374	45,434,666					8
4,834,296	5,211,112					9
1,760,602	2,365,947					10
						11
415,224	294,983					12
1,049,382						13
171,415,396	169,647,183					14
-2,889,557	74,343,217					15
9,721,676	15,767,344					16
1,071,119,870	826,690,640					17
760,877,449	625,812,453					18
-5,019,198	-1,812,064					19
						20
	63,381					21
1,117	26,460					22
						23
						24
4,263,495,876	4,196,895,425					25
1,003,505,249	956,291,118					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		1,003,505,249	956,291,118		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,742,323	1,154,351		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,612,424	1,395,781		
33	Revenues From Nonutility Operations (417)			389,833		
34	(Less) Expenses of Nonutility Operations (417.1)		46,644	127,665		
35	Nonoperating Rental Income (418)		164,280	122,658		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	14,581,067	13,397,403		
37	Interest and Dividend Income (419)		7,738,789	5,541,076		
38	Allowance for Other Funds Used During Construction (419.1)		50,655,904	57,244,026		
39	Miscellaneous Nonoperating Income (421)		353,146	1,000,254		
40	Gain on Disposition of Property (421.1)		224,256	306,494		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		73,800,697	77,632,649		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		11,056	342,145		
44	Miscellaneous Amortization (425)		1,342,957	1,298,969		
45	Donations (426.1)		2,522,386	2,516,950		
46	Life Insurance (426.2)		-6,393,772	-4,817,326		
47	Penalties (426.3)		1,814,037	2,337,066		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,583,944	1,763,417		
49	Other Deductions (426.5)		37,428,313	3,789,575		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		39,308,921	7,230,796		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	203,109	345,622		
53	Income Taxes-Federal (409.2)	262-263	-6,629,160	-2,396,204		
54	Income Taxes-Other (409.2)	262-263	-900,793	-325,603		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	102,052,978	70,283,900		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	105,466,318	67,854,963		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		691,070	928,426		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-11,431,254	-875,674		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		45,923,030	71,277,527		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		358,380,033	355,945,454		
63	Amort. of Debt Disc. and Expense (428)		4,073,420	3,888,848		
64	Amortization of Loss on Reaquired Debt (428.1)		905,935	1,421,460		
65	(Less) Amort. of Premium on Debt-Credit (429)		11,026	11,027		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		2,512	24,397		
68	Other Interest Expense (431)		13,513,332	13,394,876		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		25,295,555	29,258,693		
70	Net Interest Charges (Total of lines 62 thru 69)		351,568,651	345,405,315		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		697,859,628	682,163,330		
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)		697,859,628	682,163,330		

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, 2014 and 2013, depreciation expense associated with transportation equipment was $13,767,456 and $15,921,062, 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, 2014 and 2013, payroll taxes were $40,126,082 and $39,811,382, respectively.

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

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

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 2014/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		3,180,100,349	2,974,333,637
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)		683,278,561	668,765,927
17	Appropriations of Retained Earnings (Acct. 436)			
18	Appropriation of excess earnings at certain hydroelectric generating facilities	215.1	-3,096,169	(2,762,978)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-3,096,169	(2,762,978)
23	Dividends Declared-Preferred Stock (Account 437)			
24	Preferred Stock, various series and rates	238	-161,902	(1,493,811)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-161,902	(1,493,811)
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock	238	-725,000,000	(500,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-725,000,000	(500,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings	216.1	94,048	43,034,828
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		3,135,214,887	3,180,100,349
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		10,660,803	7,564,634
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		10,660,803	7,564,634
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		3,145,875,690	3,187,664,983
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		127,661,628	157,299,053
50	Equity in Earnings for Year (Credit) (Account 418.1)		14,581,067	13,397,403
51	(Less) Dividends Received (Debit)			
52	Transfers to/from Unappropriated Retained Earnings (Account 216)		-94,048	(43,034,828)
53	Balance-End of Year (Total lines 49 thru 52)		142,148,647	127,661,628

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, 2014 and dividends on preferred stock during the year ended December 31, 2014 were as follows:

		Shares	Dividend
6.00%	Serial Preferred	5,930	$ 35,580
7.00%	Serial Preferred	18,046	126,322
		23,976	$ 161,902

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

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.: 37 Column: c

In September 2014, Trapper Mining Inc., a subsidiary of PacifiCorp, paid a dividend of $94,048 to PacifiCorp.

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

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.: 46 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.: 46 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 2014/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)	697,859,628	682,163,330
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	678,784,159	623,158,412
5	Amortization:	46,983,824	52,239,730
6			
7			
8	Deferred Income Taxes (Net)	306,829,081	203,307,124
9	Investment Tax Credit Adjustment (Net)	-5,710,268	-2,740,490
10	Net (Increase) Decrease in Receivables	9,327,709	-10,007,750
11	Net (Increase) Decrease in Inventory	31,370,952	14,591,039
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	10,273,904	30,795,829
14	Net (Increase) Decrease in Other Regulatory Assets	-95,045,998	-23,882,915
15	Net Increase (Decrease) in Other Regulatory Liabilities	-10,169,717	-8,253,088
16	(Less) Allowance for Other Funds Used During Construction	50,655,904	57,244,026
17	(Less) Undistributed Earnings from Subsidiary Companies	14,487,019	-29,637,425
18	Amounts Due To/From Affiliates (Net)	-54,351,514	-33,476,313
19	Derivative Collateral (Net)	-16,500,000	42,900,000
20	Other Operating Acitivities:	21,671,928	21,056,199
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,556,180,765	1,564,244,506
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,115,501,291	-1,119,674,872
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	-50,655,904	-57,244,026
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,064,845,387	-1,062,430,846
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	1,069,188	277,539
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-2,060,000	-1,499,000
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

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:	1,624,874	6,064,789
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,064,211,325	-1,057,587,518
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	424,745,000	299,100,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	19,999,528	
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	444,744,528	299,100,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-235,762,000	-277,729,000
74	Preferred Stock		-40,095,281
75	Common Stock		
76	Other (provide details in footnote):	-12,032,497	-6,831,840
77	Repayment of Capital Lease Obligations	-1,844,876	-6,407,670
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock	-161,902	-1,965,797
81	Dividends on Common Stock	-725,000,000	-500,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-530,056,747	-533,929,588
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-38,087,307	-27,272,600
87			
88	Cash and Cash Equivalents at Beginning of Period	51,563,633	78,836,233
89			
90	Cash and Cash Equivalents at End of period	13,476,326	51,563,633

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

Includes depreciation expense associated with transportation equipment and capital lease assets of $15,612,332 and $22,328,732 during the years ended December 31, 2014 and 2013, respectively.

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

	Years Ended December 31, 2014	2013
Amortization of software development & other intangibles	$ 42,052,331	$ 46,733,635
Amortization of electric plant acquisition adjustments	4,834,296	5,211,112
Amortization of regulatory assets	97,197	294,983
	$ 46,983,824	$ 52,239,730

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

	Years Ended December 31, 2014	2013
Depreciation and depletion included in cost of fuel	$ 24,247,414	$ 12,456,145
Net(gain)/loss on sale of property	(310,850)	22,871
Write-off of assets under construction	362,850	10,483,484
Change in corporate owned life insurance cash surrender value	(6,374,744)	(4,880,695)
Amortization of debt issuance expenses and bond discount/premium	4,062,394	3,877,821
Other	(315,136)	(903,427)
	$ 21,671,928	$ 21,056,199

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, 2014	2013
Other investments/special funds	$ 1,174,723	$ 5,949,345
Temporary facilities	32,429	(66,153)
Restricted cash	417,722	181,597
	$ 1,624,874	$ 6,064,789

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

	Years Ended December 31, 2014	2013
Net repayments of affiliate borrowing from subsidiary company, Pacific Minerals, Inc.	$(8,615,195)	$ (2,492,611)
Long-term debt issuance and other deferred financing costs	(3,417,302)	(4,339,229)
	$(12,032,497)	$ (6,831,840)

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 Berkshire Hathaway Energy Company ("BHE"), a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. BHE 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 the FERC and 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

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):

	2014	2013
Cash (131)	$ 7	$ 7
Temporary cash investments (136)	6	45
Total cash and cash equivalents	$ 13	$ 52

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, 2014 and 2013, 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):

	2014	2013
Beginning balance	$ 8	$ 9
Charged to operating costs and expenses, net	11	13
Write-offs, net	(12)	(14)
Ending balance	$ 7	$ 8

Derivatives

PacifiCorp employs a number of different derivative contracts, which may include 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 FERC and 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 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 represent 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 and unbilled amounts. As of December 31, 2014 and 2013, unbilled revenue was $243 million and $258 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 $446 million and $461 million as of December 31, 2014 and 2013, respectively, and regulatory liabilities of $13 million and $21 million as of December 31, 2014 and 2013, respectively, and will be included in rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense 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 to be 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 May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-09, which creates FASB Accounting Standards Codification ("ASC") Topic 606, "Revenue from Contracts with Customers" and supersedes ASC Topic 605, "Revenue Recognition." The guidance replaces industry-specific guidance and establishes a single five-step model to identify and recognize revenue. The core principle of the guidance is that an entity should recognize revenue upon transfer of control of promised goods or services to customers in an amount that reflects the consideration to which an entity expects to be entitled in exchange for those goods or services. Additionally, the guidance requires the entity to disclose further quantitative and qualitative information regarding the nature and amount of revenues arising from contracts with customers, as well as other information about the significant judgments and estimates used in recognizing revenues from contracts with customers. This guidance is effective for interim and annual reporting periods beginning after December 15, 2016. Early application is not permitted. This guidance may be adopted retrospectively or under a modified retrospective method where the cumulative effect is recognized at the date of initial application. PacifiCorp is currently evaluating the impact of adopting this guidance on its financial statements and disclosures included within Notes to Financial Statements.

In February 2013, the FASB issued ASU No. 2013-04, which amends FASB 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. 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.

Subsequent Events

PacifiCorp has evaluated the impact of events occurring after December 31, 2014 up to February 27, 2015, the date that PacifiCorp’s GAAP financial statements were filed with the Securities and Exchange Commission and has updated such evaluation for disclosure purposes through April 17, 2015. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

(3) Net Utility Plant

The average depreciation and amortization rate applied to depreciable utility plant was 3.0% for the year ended December 31, 2014 and 2.8% for the year ended December 31, 2013.

Depreciation Study

As a result of PacifiCorp's depreciation study approved by its state regulatory commissions, PacifiCorp revised its depreciation rates effective January 1, 2014. The approved depreciation rates resulted in an increase in depreciation expense of $35 million for the year ended December 31, 2014 as compared to the year ended December 31, 2013.

(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, 2014 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4	67%	$ 1,134	$ 549	$ 116
Hunter No. 1	94	467	141	—
Hunter No. 2	60	290	86	1
Wyodak	80	450	178	5
Colstrip Nos. 3 and 4	10	231	127	1
Hermiston	50	175	66	1
Craig Nos. 1 and 2	19	323	206	7
Hayden No. 1	25	55	28	12
Hayden No. 2	13	33	18	3
Foote Creek	79	37	23	—
Transmission and distribution facilities	Various	347	79	—
Total		$ 3,542	$ 1,501	$ 146

(5) Regulatory Matters

Utah Mine Disposition

Due to quality issues with the coal reserves at PacifiCorp's Deer Creek mine in Utah and rising costs at PacifiCorp's wholly owned subsidiary, Energy West Mining Company, PacifiCorp believes the Deer Creek coal reserves are no longer able to be economically mined. As a result, in December 2014, PacifiCorp filed applications with the Utah Public Service Commission, the Oregon Public Utility Commission ("OPUC"), the Wyoming Public Service Commission and the Idaho Public Utilities Commission ("IPUC") seeking certain approvals, prudence determinations and accounting orders to close its Deer Creek mining operations, sell certain Utah mining assets, enter into a replacement coal supply agreement, amend an existing coal supply agreement, withdraw from the United Mine Workers of America ("UMWA") 1974 Pension Trust and settle PacifiCorp's other postretirement benefit obligation for UMWA participants (collectively, the "Utah Mine Disposition"). PacifiCorp also filed an advice letter with the California Public Utilities Commission ("CPUC"). The asset sales and coal supply agreements are contingent upon regulatory approvals for which orders are expected to be issued in the second quarter of 2015. PacifiCorp expects to transfer funds from its other postretirement plan assets to the UMWA in June 2015 to effectuate the settlement of the portion of the obligation related to UMWA participants.

Regulatory Assets

PacifiCorp had regulatory assets not earning a return on investment of $1.479 billion and $1.244 billion as of December 31, 2014 and 2013, respectively.

(6) Short-term Debt and Other Financing Agreements

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

2014:		
Credit facilities	$	1,200
Less:		
Short-term debt		(20)
Letters of credit and tax-exempt bond support		(398)
Net credit facilities	$	782
2013:		
Credit facilities	$	1,200
Less:		
Short-term debt		—
Letters of credit and tax-exempt bond support		(321)
Net credit facilities	$	879

PacifiCorp has a $600 million unsecured credit facility expiring in June 2017 and a $600 million unsecured credit facility expiring in March 2018. 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. As of December 31, 2014, the weighted average interest rate on commercial paper borrowings outstanding was 0.43%. 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, 2014, PacifiCorp was in compliance with the covenants of its credit facilities.

As of December 31, 2014 and 2013, PacifiCorp had $451 million and $559 million, respectively, of fully available letters of credit issued under committed arrangements, of which $270 million as of December 31, 2014 and 2013 were issued under the credit facilities. These letters of credit support PacifiCorp's variable-rate tax-exempt bond obligations and expire through March 2017.

As of December 31, 2014, 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, 2014 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 its 3.60% First Mortgage Bonds due April 2024. The net proceeds were 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 in March 2014 to PPW Holdings LLC, a wholly owned subsidiary of BHE and PacifiCorp's direct parent company ("PPW Holdings").

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $1.575 billion of long-term debt. PacifiCorp must make a notice filing with the Washington Utilities and Transportation Commission prior to any future issuance. PacifiCorp currently has an effective shelf registration statement filed with the United States Securities and Exchange Commission expected to provide for future first mortgage bond issuances through 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 $25 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2014.

PacifiCorp has entered into long-term agreements that qualify as capital leases and expire at various dates through March 2035 for transportation services, power purchase agreements and real estate. The transportation services agreements included as capital leases are for the right to use pipeline facilities to provide natural gas to two of PacifiCorp's generating facilities. Net capital lease assets of $34 million and $49 million as of December 31, 2014 and 2013, respectively, were included in net utility plant in the Comparative Balance Sheet.

As of December 31, 2014, the annual maturities of long-term debt and capital lease obligations, excluding unamortized discounts and including interest on capital lease obligations, for 2015 and thereafter are as follows (in millions):

	Long-term Debt	Capital Lease Obligations	Total
2015	$ 132	$ 5	$ 137
2016	57	5	62
2017	52	10	62
2018	586	6	592
2019	350	5	355
Thereafter	5,855	31	5,886
Total	7,032	62	7,094
Unamortized discount	(13)	—	(13)
Amounts representing interest	—	(28)	(28)
Total	$ 7,019	$ 34	$ 7,053

(8) Income Taxes

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

	2014	2013
Current:		
Federal	$ (10)	$ 72
State	9	16
Total	(1)	88
Deferred:		
Federal	264	177
State	43	26
Total	307	203
Investment tax credits	(6)	(3)
Total income tax expense	$ 300	$ 288

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:

	2014	2013
Federal statutory income tax rate	35%	35%
State income taxes, net of federal income tax benefit	3	3
Federal income tax credits(1)	(7)	(7)
Other	(1)	(1)
Effective income tax rate	30%	30%

(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):

	2014	2013
Deferred income tax assets:		
Employee benefits	$ 183	$ 99
Derivative contracts and unamortized contract values	79	76
State carryforwards	68	68
Loss contingencies	51	67
Asset retirement obligations	47	48
Regulatory liabilities	29	36
Other	88	89
	545	483
Deferred income tax liabilities:		
Property, plant and equipment	(4,497)	(4,219)
Regulatory assets	(611)	(526)
Other	(22)	(30)
	(5,130)	(4,775)
Net deferred income tax liability	$ (4,585)	$ (4,292)

The following table provides PacifiCorp's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2014 (in millions):

	State
Net operating loss carryforwards	$ 1,417
Deferred income taxes on net operating loss carryforwards	$ 52
Expiration dates	2015 - 2032
Tax credit carryforwards	$ 16
Expiration dates	2015 - 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, 2006, except for the December 31, 1995 and 1997 tax years in Utah and the March 31, 2004, 2005 and 2006 tax years in Colorado and 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 and froze future accruals for active participants as of December 31, 2014. 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.

Utah Mine Disposition and Labor Agreement

In conjunction with the Utah Mine Disposition described in Note 5, in December 2014, Energy West Mining Company reached a labor settlement with the UMWA covering union employees at PacifiCorp's Deer Creek mining operations. As a result of the labor settlement, the UMWA agreed to assume PacifiCorp's other postretirement benefit obligation associated with UMWA plan participants in exchange for PacifiCorp transferring $150 million to the UMWA. Transfer of the assets to the UMWA and settlement of this obligation is expected to occur in June 2015, which will result in a remeasurement of the other postretirement plan assets and benefit obligation. No curtailment accounting will be triggered as a result of the settlement due to an insignificant impact to the average remaining service lives in the plan.

As a result of the intended closure of the Deer Creek mining operations, withdrawal by Energy West Mining Company from the UMWA 1974 Pension Trust could be triggered as early as spring 2015. Refer to "Multiemployer and Joint Trustee Pension Plans" below for further information regarding the withdrawal.

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	
	2014	2013	2014	2013
Service cost	$ 5	$ 6	$ 6	$ 9
Interest cost	57	54	28	25
Expected return on plan assets	(76)	(74)	(31)	(30)
Net amortization	29	48	2	8
Net periodic benefit cost	$ 15	$ 34	$ 5	$ 12

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	
	2014	2013	2014	2013
Plan assets at fair value, beginning of year	$ 1,171	$ 1,012	$ 486	$ 424
Employer contributions	10	63	1	8
Participant contributions	—	—	7	7
Actual return on plan assets	53	213	25	86
Benefits paid	(88)	(117)	(37)	(39)
Plan assets at fair value, end of year	$ 1,146	$ 1,171	$ 482	$ 486

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

	Pension		Other Postretirement	
	2014	2013	2014	2013
Benefit obligation, beginning of year	$ 1,230	$ 1,391	$ 598	$ 632
Service cost	5	6	6	9
Interest cost	57	54	28	25
Participant contributions	—	—	7	7
Actuarial loss (gain)	174	(104)	(63)	(36)
Benefits paid	(88)	(117)	(37)	(39)
Benefit obligation, end of year	$ 1,378	$ 1,230	$ 539	$ 598
Accumulated benefit obligation, end of year	$ 1,378	$ 1,229		

The actuarial gain associated with the other postretirement benefit obligation during the year ended December 31, 2014 includes a gain that reduced the benefit obligation resulting from the $150 million to be transferred to the UMWA in June 2015 as a result of the contractually binding labor settlement.

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	
	2014	2013	2014	2013
Plan assets at fair value, end of year	$ 1,146	$ 1,171	$ 482	$ 486
Less - Benefit obligation, end of year	1,378	1,230	539	598
Funded status	$ (232)	$ (59)	$ (57)	$ (112)
Amounts recognized on the Comparative Balance Sheet:				
Miscellaneous current and accrued liabilities	$ (4)	$ (4)	$ —	$ —
Accumulated provision for pensions and benefits	(228)	(55)	(57)	(112)
Amounts recognized	$ (232)	$ (59)	$ (57)	$ (112)

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 $51 million and $48 million as of December 31, 2014 and 2013, 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	
	2014	2013	2014	2013
Net loss	$ 520	$ 361	$ 41	$ 108
Prior service credit	(21)	(29)	(26)	(33)
Regulatory deferrals	(3)	(4)	2	2
Total	$ 496	$ 328	$ 17	$ 77

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2014 and 2013 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss	Total
Pension			
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
Net loss arising during the year	189	8	197
Net amortization	(28)	(1)	(29)
Total	161	7	168
Balance, December 31, 2014	$ 474	$ 22	$ 496

	Regulatory Asset
Other Postretirement	
Balance, December 31, 2012	$ 177
Net gain arising during the year	(92)
Net amortization	(8)
Total	(100)
Balance, December 31, 2013	77
Net gain arising during the year	(58)
Net amortization	(2)
Total	(60)
Balance, December 31, 2014	$ 17

The net loss, prior service credit and regulatory deferrals that will be amortized in 2015 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Regulatory Deferrals	Total
Pension	$ 50	$ (8)	$ (1)	$ 41
Other postretirement	2	(7)	1	(4)
Total	$ 52	$ (15)	$ —	$ 37

Plan Assumptions

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

	Pension		Other Postretirement	
	2014	**2013**	**2014**	**2013**
Benefit obligations as of December 31:				
Discount rate	4.00%	4.80%	3.90%	4.90%
Rate of compensation increase	2.75	3.00	N/A	N/A
Net periodic benefit cost for the years ended December 31:				
Discount rate	4.80%	4.05%	4.90%	4.10%
Expected return on plan assets	7.50	7.50	7.50	7.50
Rate of compensation increase	3.00	3.00	N/A	N/A

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

	2014	**2013**
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	2025	2019

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 for the year ended December 31, 2014	$ 3	$ (2)
Other postretirement benefit obligation as of December 31, 2014	—	—

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $4 million and $- million, respectively, during 2015. 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, subject to tax deductibility limitations and other considerations.

The expected benefit payments to participants in PacifiCorp's pension and other postretirement benefit plans for 2015 through 2019 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2015	$ 106	$ 184
2016	111	29
2017	108	28
2018	107	28
2019	109	27
2020 - 2024	465	126

Projected benefit payments for the other postretirement plan in 2015 include the $150 million to be transferred to the UMWA in June 2015 as a result of the contractually binding labor settlement with the UMWA.

Plan Assets

Investment Policy and Asset Allocations

PacifiCorp's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of debt securities, equity securities and other alternative investments. Maturities for debt securities are managed to targets consistent with prudent risk tolerances. The plans retain outside investment advisors to manage plan investments within the parameters outlined by the PacifiCorp Pension Committee. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments.

The target allocations (percentage of plan assets) for PacifiCorp's pension and other postretirement benefit plan assets are as follows as of December 31, 2014:

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

(1) PacifiCorp's Retirement Plan trust includes a separate account that is used to fund benefits for the other postretirement benefit plan. In addition to this separate account, the assets for the other postretirement benefit 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, 2014				
Cash equivalents	$ —	$ 8	$ —	$ 8
Debt securities:				
United States government obligations	15	—	—	15
Corporate obligations	—	53	—	53
Municipal obligations	—	8	—	8
Agency, asset and mortgage-backed obligations	—	48	—	48
Equity securities:				
United States companies	488	—	—	488
International companies	16	—	—	16
Investment funds(2)	217	223	—	440
Limited partnership interests(3)	—	—	70	70
Total	$ 736	$ 340	$ 70	$ 1,146
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

(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 2014 and 2013, and are invested in United States and international securities of approximately 43% and 57%, respectively, for 2014 and 42% and 58%, respectively, for 2013.

(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, 2014				
Cash and cash equivalents(2)	$ 139	$ —	$ —	$ 139
Debt securities:				
United States government obligations	8	—	—	8
Corporate obligations	—	18	—	18
Municipal obligations	—	2	—	2
Agency, asset and mortgage-backed obligations	—	16	—	16
Equity securities:				
United States companies	112	—	—	112
International companies	4	—	—	4
Investment funds(3)	84	94	—	178
Limited partnership interests(4)	—	—	5	5
Total	$ 347	$ 130	$ 5	$ 482
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(3)	173	120	—	293
Limited partnership interests(4)	—	—	6	6
Total	$ 350	$ 130	$ 6	$ 486

(1) Refer to Note 12 for additional discussion regarding the three levels of the fair value hierarchy.

(2) In December 2014, PacifiCorp began to migrate funds to cash and cash equivalents in anticipation of the $150 million to be transferred to the UMWA in June 2015 as a result of the other postretirement settlement. Remaining investments were rebalanced to align to target investment allocations.

(3) Investment funds are substantially comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 63% and 37%, respectively, for 2014 and 49% and 51%, respectively, for 2013, and are invested in United States and international securities of approximately 64% and 36%, respectively, for 2014 and 70% and 30%, respectively, for 2013.

(4) 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, 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
Actual return on plan assets still held at December 31, 2014	(1)	—
Purchases, sales, distributions and settlements	(15)	(1)
Balance, December 31, 2014	$ 70	$ 5

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 its subsidiary, Energy West Mining Company, contributes to the UMWA 1974 Pension Trust (plan number 002). Contributions to these pension plans are based on the terms of collective bargaining agreements.

As a result of the Utah Mine Disposition and UMWA labor settlement, PacifiCorp believes withdrawal by its subsidiary, Energy West Mining Company, from the UMWA 1974 Pension Trust is probable. As a result, the estimated withdrawal obligation was recorded in December 2014 and a regulatory asset established for the portion of the obligation considered probable of recovery. The most recent estimate of the withdrawal obligation provided by the UMWA 1974 Pension Trust is $97 million for a withdrawal occurring by July 1, 2015. In the event of withdrawal, Energy West Mining Company may elect to make a lump sum payment or annual installment payments to settle the withdrawal obligation. PacifiCorp is seeking recovery of the withdrawal obligation from its customers as part of the regulatory filings associated with the Utah Mine Disposition.

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. This is expected to occur upon Energy West Mining Company's withdrawal from the UMWA 1974 Pension Trust. If participating employers withdraw from a multiemployer 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.

The following table presents PacifiCorp's and Energy West Mining Company'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,				Contributions[1]		
Plan name	**Employer Identification Number**	**2014**	**2013**	**Funding improvement plan**	**Surcharge imposed under PPA**	**2014**	**2013**	**Year contributions to plan exceeded more than 5% of total contributions[2]**
UMWA Pension Plan	52-1050282	Critical	Seriously Endangered	Implemented	Yes	$ 2	$ 3	None
Local 57 Trust Fund	87-0640888	At least 80%	At least 80%	None	None	$ 9	$ 9	2013, 2012

(1) PacifiCorp's and Energy West Mining Company'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 1974 Pension Trust, respectively, subject to ERISA minimum funding requirements. As a result of the plan's critical status, Energy West Mining Company was required to begin paying a surcharge for hours worked on and after December 1, 2014.

(2) For the UMWA 1974 Pension Trust, information is for plan year beginning July 1, 2012. Information for the plan years beginning July 1, 2014 is not yet available. For the Local 57 Trust Fund, information is for plan years beginning July 1, 2013 and 2012. Information for the plan year beginning July 1, 2014 is not yet available.

The current collective bargaining agreements governing the Local 57 Trust Fund expire in January 2016. The current collective bargaining agreement governing the UMWA 1974 Pension Trust expires in June 2016.

Defined Contribution Plan

PacifiCorp's 401(k) Plan covers substantially all employees. PacifiCorp's contributions are based primarily on each participant's level of contribution and cannot exceed the maximum allowable for tax purposes. PacifiCorp's contributions to the 401(k) Plan were $34 million and $35 million for the years ended December 31, 2014 and 2013, 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 changes in laws and regulations, 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 $873 million and $843 million as of December 31, 2014 and 2013, respectively.

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

	2014	2013
Beginning balance	$ 138	$ 127
Change in estimated costs	(3)	3
Additions	—	8
Retirements	(6)	(6)
Accretion	6	6
Ending balance	$ 135	$ 138

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.

In December 2014, the Environmental Protection Agency released its final rule regulating the management and disposal of coal combustion byproducts resulting from the operation of coal-fueled generating facilities, including requirements for the operation and closure of surface impoundment and ash landfill facilities. The final rule will be effective 180 days after it is published in the Federal Register. Under the final rule, surface impoundments and landfills utilized for coal combustion byproducts may need to be closed unless they can meet the more stringent regulatory requirements. PacifiCorp is currently evaluating the requirements and costs of the new rule and cannot determine the impact on its ARO liabilities at this time.

(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 FERC and 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, 2014					
Not designated as hedging contracts[1]:					
Commodity assets	$ 28	$ —	$ 1	$ —	$ 29
Commodity liabilities	(10)	—	(55)	(49)	(114)
Total	18	—	(54)	(49)	(85)
Total derivatives	18	—	(54)	(49)	(85)
Cash collateral receivable	—	—	14	14	28
Total derivatives - net basis	$ 18	$ —	$ (40)	$ (35)	$ (57)
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)

(1) PacifiCorp's commodity derivatives are generally included in rates and as of December 31, 2014 and 2013, a regulatory asset of $85 million and $55 million, respectively, was recorded related to the net derivative liability of $85 million and $55 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):

	2014	2013
Beginning balance	$ 55	$ 121
Changes in fair value recognized in regulatory assets	45	15
Net (losses) gains reclassified to operating revenue	(4)	9
Net losses reclassified to energy costs	(11)	(90)
Ending balance	$ 85	$ 55

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	**2014**	**2013**
Electricity sales	Megawatt hours	(1)	(1)
Natural gas purchases	Decatherms	113	120
Fuel oil purchases	Gallons	3	15

Credit Risk

PacifiCorp is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent PacifiCorp's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, PacifiCorp analyzes the financial condition of each significant wholesale counterparty, 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 further mitigate wholesale counterparty credit risk, 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. 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, 2014, 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 $113 million and $68 million as of December 31, 2014 and 2013, respectively, for which PacifiCorp had posted collateral of $28 million and $12 million, respectively, in the form of cash deposits. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of December 31, 2014 and 2013, PacifiCorp would have been required to post $75 million and $51 million, respectively, of additional collateral.

In addition to derivative contracts in liability positions, PacifiCorp has non-derivative wholesale agreements with specified credit-risk-related contingent features that base certain collateral requirements on credit ratings. If all credit-risk-related contingent features or adequate assurance provisions for wholesale agreements, including non-derivative agreements and derivative contracts in liability positions, had been triggered as of December 31, 2014 and December 31, 2013, PacifiCorp would have been required to post $233 million and $236 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, 2014					
Assets:					
Commodity derivatives	$ —	$ 25	$ 4	$ (11)	$ 18
Money market mutual funds[2]	23	—	—	—	23
	$ 23	$ 25	$ 4	$ (11)	$ 41
Liabilities - Commodity derivatives	$ —	$ (114)	$ —	$ 39	$ (75)
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)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $28 million and $12 million as of December 31, 2014 and 2013, 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.

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):

	2014		**2013**	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
Long-term debt	$ 7,019	$ 8,358	$ 6,828	$ 7,626

(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 BHE'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 a May 2010 ruling on the Plaintiff's petition for reconsideration, the Utah Supreme Court reversed summary judgment and remanded the case back to the Third District Court for further consideration. In May 2012, a 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. 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. 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. 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 is vigorously pursuing all appellate measures. Both PacifiCorp and the Plaintiff filed appeals with the Utah Supreme Court. Briefing before the Utah Supreme Court is complete and oral arguments will most likely be held in 2015. As of December 31, 2014, PacifiCorp had accrued $119 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 expected insurance recovery. PacifiCorp believes it is reasonably possible it may incur additional loss beyond the amount accrued, but does not believe the potential additional loss will have a material impact on its financial results.

Environmental Laws and Regulations

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

Hydroelectric Relicensing

PacifiCorp's 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 May 2014, a bill was introduced in the United States Senate that, if passed by both houses of Congress, would enact the KHSA and companion agreements that seek to resolve other water-related conflicts and restore habitat in the Klamath basin. A hearing on the bill before a Senate Energy and Natural Resources subcommittee was held in June 2014, and the bill was voted out of committee and referred to the full Senate for consideration in November 2014. However, the bill was not passed by Congress prior to the end of the 2014 session. In January 2015, the bill was re-introduced into 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. Additional funding of up to $250 million for dam removal costs is to be provided by the State of California. California voters approved a water bond measure in November 2014 from which the State of California's contribution towards dam removal costs will be drawn. If dam removal costs exceed the combined funding that will be available from PacifiCorp's Oregon and California customers and the State of California, 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 and California customers for their share of dam removal costs, as approved by the OPUC and the CPUC, and is depositing the proceeds into trust accounts maintained by the OPUC and the CPUC, respectively. PacifiCorp is authorized to collect the surcharges through 2019.

As of December 31, 2014, PacifiCorp's assets included $92 million of costs associated with the Klamath hydroelectric system's mainstem dams and the associated relicensing and settlement costs, which are being depreciated and amortized in accordance with state regulatory approvals through either December 31, 2019 or 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 $203 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, 2014 are as follows (in millions):

	2015	2016	2017	2018	2019	2020 and Thereafter	Total
Contract type:							
Purchased electricity contracts - commercially operable	$ 167	$ 90	$ 65	$ 61	$ 58	$ 292	$ 733
Purchased electricity contracts - non-commercially operable	3	16	64	65	65	1,078	1,291
Fuel contracts	789	653	588	452	460	1,294	4,236
Construction commitments	231	53	12	8	2	8	314
Transmission	116	112	102	95	78	617	1,120
Operating leases and easements	5	5	4	4	4	46	68
Maintenance, service and other contracts	49	29	26	14	19	81	218
Total commitments	$ 1,360	$ 958	$ 861	$ 699	$ 686	$ 3,416	$ 7,980

Purchased Electricity Contracts - Commercially Operable

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 generating facilities that are not included in the table above as the payments are based on the amount of energy generated and there are no minimum payments. Included in the purchased electricity payments are any power purchase agreements that meet the definition of a lease. Rent expense related to those power purchase agreements that meet the definition of a lease totaled $15 million for 2014 and $24 million for 2013.

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 2014 and 2013 energy sources.

Purchased Electricity Contracts - Non-commercially Operable

PacifiCorp has several contracts for purchases of electricity from facilities that have not yet achieved commercial operation. To the extent any of these facilities do not achieve commercial operation, PacifiCorp has no obligation to the counterparty.

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 and distribution projects.

Transmission

PacifiCorp has contracts 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 each of the years ended December 31, 2014 and 2013.

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 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.

(15) Common Shareholder's Equity

In February 2015, PacifiCorp declared a dividend of $450 million, which was paid to PPW Holdings in March 2015.

Through PPW Holdings, BHE is the sole shareholder of PacifiCorp's common stock. The state regulatory orders that authorized BHE'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, 2014, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings or BHE 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 BHE as common equity. As of December 31, 2014, PacifiCorp's actual common equity percentage, as calculated under this measure, was 53.0%, and PacifiCorp would have been permitted to dividend $2.3 billion under this commitment.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings or BHE 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, 2014, 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):

	2014	2013
Interest paid, net of amounts capitalized	$ 340	$ 340
Income taxes paid, net(1)	$ 154	$ 124
Supplemental disclosure of non-cash investing and financing activities:		
Accounts payable related to utility plant additions	$ 140	$ 157

(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 BHE.

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 2014/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(12,003,821)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				498,291
3	Preceding Quarter/Year to Date Changes in Fair Value				2,414,025
4	Total (lines 2 and 3)				2,912,316
5	Balance of Account 219 at End of Preceding Quarter/Year				(9,091,505)
6	Balance of Account 219 at Beginning of Current Year				(9,091,505)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				346,579
8	Current Quarter/Year to Date Changes in Fair Value				(4,920,754)
9	Total (lines 7 and 8)				(4,574,175)
10	Balance of Account 219 at End of Current Quarter/Year				(13,665,680)

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			(12,003,821)	[redacted]	
2			498,291		
3			2,414,025		
4			2,912,316	682,163,330	685,075,646
5			(9,091,505)	[redacted]	
6			(9,091,505)		
7			346,579		
8			(4,920,754)		
9			(4,574,175)	697,859,628	693,285,453
10			(13,665,680)	[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 2014/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)	25,724,748,750	25,724,748,750
4	Property Under Capital Leases	33,869,179	33,869,179
5	Plant Purchased or Sold		
6	Completed Construction not Classified	101,339,366	101,339,366
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	25,859,957,295	25,859,957,295
9	Leased to Others		
10	Held for Future Use	23,319,217	23,319,217
11	Construction Work in Progress	934,535,929	934,535,929
12	Acquisition Adjustments	143,167,971	143,167,971
13	Total Utility Plant (8 thru 12)	26,960,980,412	26,960,980,412
14	Accum Prov for Depr, Amort, & Depl	9,057,705,065	9,057,705,065
15	Net Utility Plant (13 less 14)	17,903,275,347	17,903,275,347
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	8,395,189,232	8,395,189,232
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	555,584,757	555,584,757
22	Total In Service (18 thru 21)	8,950,773,989	8,950,773,989
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	106,931,076	106,931,076
33	Total Accum Prov (equals 14) (22,26,30,31,32)	9,057,705,065	9,057,705,065

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 2014/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
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					32
					33

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/Q4

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	207,652,388	67,385
4	(303) Miscellaneous Intangible Plant	649,633,440	32,977,923
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	857,285,828	33,045,308
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	93,604,532	932
9	(311) Structures and Improvements	1,011,284,474	9,947,043
10	(312) Boiler Plant Equipment	4,116,137,262	182,742,714
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	989,029,762	13,079,519
13	(315) Accessory Electric Equipment	480,444,603	12,097,029
14	(316) Misc. Power Plant Equipment	31,133,252	106,928
15	(317) Asset Retirement Costs for Steam Production	58,481,237	1,768,435
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	6,780,115,122	219,742,600
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	31,316,716	
28	(331) Structures and Improvements	192,276,703	58,529,867
29	(332) Reservoirs, Dams, and Waterways	471,289,781	11,420,487
30	(333) Water Wheels, Turbines, and Generators	120,766,696	7,507,493
31	(334) Accessory Electric Equipment	76,319,914	1,730,349
32	(335) Misc. Power PLant Equipment	2,359,453	19,746
33	(336) Roads, Railroads, and Bridges	19,882,202	619,445
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	914,211,465	79,827,387
36	D. Other Production Plant		
37	(340) Land and Land Rights	29,095,936	13,813,089
38	(341) Structures and Improvements	165,443,499	61,501,263
39	(342) Fuel Holders, Products, and Accessories	11,117,341	4,960,268
40	(343) Prime Movers	2,565,322,968	344,113,254
41	(344) Generators	313,142,611	158,064,197
42	(345) Accessory Electric Equipment	249,675,392	76,211,255
43	(346) Misc. Power Plant Equipment	12,138,583	3,004,061
44	(347) Asset Retirement Costs for Other Production	9,072,015	402,636
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	3,355,008,345	662,070,023
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	11,049,334,932	961,640,010

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
800,979			206,918,794		3
9,303,413		-31,619	673,276,331		4
10,104,392		-31,619	880,195,125		5
					6
					7
			93,605,464		8
2,082,194		-2,184,776	1,016,964,547		9
59,897,537		2,177,184	4,241,159,623		10
					11
5,830,000		-105,238	996,174,043		12
659,791		112,830	491,994,671		13
63,924			31,176,256		14
	-3,669,764		56,579,908		15
68,533,446	-3,669,764		6,927,654,512		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			31,316,716		27
3,254,733		-716,157	246,835,680		28
1,473,757		712,008	481,948,519		29
1,294,335			126,979,854		30
528,887			77,521,376		31
3,819			2,375,380		32
5,193		4,149	20,500,603		33
					34
6,560,724			987,478,128		35
					36
-635		108,159	43,017,819		37
27,289		-1,904	226,915,569		38
209,679		1,904	15,869,834		39
7,753,416		-1,845,837	2,899,836,969		40
1,410,829		1,845,837	471,641,816		41
279,476			325,607,171		42
40,532			15,102,112		43
			9,474,651		44
9,720,586		108,159	4,007,465,941		45
84,814,756	-3,669,764	108,159	11,922,598,581		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 2014/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	225,631,404	4,661,601
49	(352) Structures and Improvements	184,174,369	3,191,210
50	(353) Station Equipment	1,813,896,299	103,221,884
51	(354) Towers and Fixtures	1,218,917,978	2,631,301
52	(355) Poles and Fixtures	706,210,382	39,618,286
53	(356) Overhead Conductors and Devices	1,059,513,463	25,619,465
54	(357) Underground Conduit	3,340,104	-1,100
55	(358) Underground Conductors and Devices	7,499,460	
56	(359) Roads and Trails	11,922,795	14,405
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	5,231,106,254	178,957,052
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	62,028,583	1,318,226
61	(361) Structures and Improvements	97,377,014	2,458,813
62	(362) Station Equipment	906,249,058	30,807,276
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	1,052,968,133	38,012,995
65	(365) Overhead Conductors and Devices	693,804,415	16,695,558
66	(366) Underground Conduit	330,194,141	12,134,599
67	(367) Underground Conductors and Devices	776,602,508	20,568,877
68	(368) Line Transformers	1,200,818,543	41,991,053
69	(369) Services	654,161,585	26,466,667
70	(370) Meters	177,965,016	5,767,721
71	(371) Installations on Customer Premises	8,822,747	89,214
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	60,769,235	1,066,268
74	(374) Asset Retirement Costs for Distribution Plant	1,651,393	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	6,023,412,371	197,377,267
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	21,472,385	7,532
87	(390) Structures and Improvements	233,694,751	8,204,632
88	(391) Office Furniture and Equipment	87,147,440	12,215,804
89	(392) Transportation Equipment	105,016,260	4,986,063
90	(393) Stores Equipment	14,884,798	600,188
91	(394) Tools, Shop and Garage Equipment	63,129,288	1,714,310
92	(395) Laboratory Equipment	35,461,262	873,136
93	(396) Power Operated Equipment	158,392,929	9,677,000
94	(397) Communication Equipment	384,826,535	22,677,764
95	(398) Miscellaneous Equipment	8,030,164	394,660
96	SUBTOTAL (Enter Total of lines 86 thru 95)	1,112,055,812	61,351,089
97	(399) Other Tangible Property	305,657,640	874,375
98	(399.1) Asset Retirement Costs for General Plant	39,748	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	1,417,753,200	62,225,464
100	TOTAL (Accounts 101 and 106)	24,578,892,585	1,433,245,101
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	24,578,892,585	1,433,245,101

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
350,801		284,199	230,226,403		48
194,688		23,259,250	210,430,141		49
16,393,608		-24,935,844	1,875,788,731		50
461,152		209,892	1,221,298,019		51
1,725,675			744,102,993		52
1,674,110		-926,348	1,082,532,470		53
		180,562	3,519,566		54
		535,894	8,035,354		55
			11,937,200		56
					57
20,800,034		-1,392,395	5,387,870,877		58
					59
2,912		-208,464	63,135,433		60
372,676		4,791,897	104,255,048		61
5,998,675		-5,298,161	925,759,498		62
					63
5,536,608			1,085,444,520		64
2,626,188			707,873,785		65
1,097,827			341,230,913		66
1,647,111			795,524,274		67
8,093,637			1,234,715,959		68
788,577			679,839,675		69
2,830,608			180,902,129		70
80,009			8,831,952		71
					72
464,043			61,371,460		73
	-144,313		1,507,080		74
29,538,871	-144,313	-714,728	6,190,391,726		75
					76
					77
					78
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					84
					85
		-83,307	21,396,610		86
2,890,456		-2,898	239,006,029		87
16,626,390		13,986	82,750,840		88
2,946,426		15,148	107,071,045		89
626,447		51,661	14,910,200		90
1,656,334		-223,632	62,963,632		91
2,564,144		170,460	33,940,714		92
4,422,568		112,577	163,759,938		93
1,306,427		2,294,721	408,492,593		94
386,104			8,038,720		95
33,425,296		2,348,716	1,142,330,321		96
3,736,039		-134,238	302,661,738		97
			39,748		98
37,161,335		2,214,478	1,445,031,807		99
182,419,388	-3,814,077	183,895	25,826,088,116		100
					101
					102
					103
182,419,388	-3,814,077	183,895	25,826,088,116		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	43,927,215	4,334	1,225	-	-	43,930,324
39941	Surface-Plant Equipment	14,435,529	-	-	-	-	14,435,529
39944	Surface-Electric Power Facil	3,424,575	-	-	-	-	3,424,575
39945	Underground-Coal Mine Equip	74,986,010	-	3,601,104	-	-	71,384,906
39946	Longwall Shields	24,486,688	-	-	-	-	24,486,688
39947	Longwall Equipment	9,115,912	-	-	-	-	9,115,912
39948	Mainline Extension	20,274,157	-	-	-	-	20,274,157
39949	Section Extension	7,412,591	(25,749)	-	-	-	7,386,842
39951	Vehicles	1,321,430	-	-	-	-	1,321,430
39952	Heavy Construction Equip	6,158,245	-	32	-	(134,238)	6,023,975
39960	Miscellaneous General Equip	2,355,726	135,692	127,093	-	-	2,364,325
39961	Computers-Mainframe	470,996	3,306	6,585	-	-	467,717
39970	Mine Development and Road Ext	38,657,119	-	-	-	-	38,657,119
39915	Coal Mine ARO	3,445,884	756,792	-	-	-	4,202,676
		$305,657,640	$ 874,375	$ 3,736,039	$ -	$(134,238)	$302,661,738

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.

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 2014/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	2024	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	2021	396,020
11	Bend Service Center	2010	2022	3,507,838
12	Legacy Substation	2010	2025	562,276
13	Aeolus Substation	2011	2022	1,013,577
14	Anticline Substation	2011	2024	964,043
15	Populus Substation	2011	2024	254,753
16	Snyderville Substation	2011	2016	253,401
17	Lassen Substation	2012	2018	683,318
18	Old Mill Substation	2012	2020	1,838,281
19	Chimney Butte-Paradise 230-kV Transmission Line	2013	2025	598,457
20	Miscellaneous, each under $250,000:			912,001
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			23,319,217

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 2014/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	15,928,188
3	GIS - FastGate Replacement Project	3,034,862
4	Wallowa Falls Hydro Relicensing	2,164,106
5	Spectrum License Buildout	1,527,036
6	Customer Service Mobile Applications	1,157,673
7		
8	Production:	
9	Jim Bridger U3 Selective Catalytic Reduction System	57,730,063
10	Jim Bridger U4 Selective Catalytic Reduction System	37,229,315
11	Hayden U1 Selective Catalytic Reduction System	11,685,541
12	Lewis River System Relicensing Implementation	6,986,266
13	Craig U2 Selective Catalytic Reduction System	5,095,667
14	Wyodak Mercury Controls	4,353,322
15	Jim Bridger U4 Mercury Controls	3,973,947
16	Jim Bridger U1 Mercury Controls	3,916,631
17	Jim Bridger U2 Mercury Controls	3,916,257
18	Jim Bridger U3 Mercury Controls	3,915,114
19	Yale Upper Rock Block Stabilization	3,879,853
20	Jim Bridger U3 Replace Finishing Superheater	3,343,135
21	Hayden U2 Selective Catalytic Reduction System	2,994,372
22	Huntington U1 and U2 Submerged Drag Chain Conveyor	2,645,330
23	Dave Johnston U4 Mercury Controls	2,595,516
24	Dave Johnston U3 Mercury Controls	2,544,220
25	Dave Johnston U2 Mercury Controls	2,096,845
26	Dave Johnston U1 Mercury Controls	2,089,082
27	Naughton U1 Mercury Controls	1,299,133
28	Naughton U2 Mercury Controls	1,291,773
29		
30	Transmission:	
31	Sigurd - Red Butte - Crystal 345kV Line	314,444,993
32	Aeolus - Clover 500kV Line	61,248,993
33	Windstar - Populus 230 - 500kV Line	61,025,629
34	Populus - Hemingway 500kV Line	39,399,837
35	Boardman - Hemingway 500kV Line	38,148,609
36	Carbon Plant Replacement - Transmission	29,425,633
37	Whetstone 230 - 115kV Substation Phase 1	13,806,887
38	Vantage - Pomona Heights 230kV Line	13,334,864
39	Oquirrh - Terminal 345kV Line	10,114,858
40	Southwest WY - Silver Creek Build 138kV Line	8,847,470
41	West Point - New 138kV Line and 40 MVA Substation	8,028,832
42	Fry Substation Install 115kV Capacitor Bank	6,676,652
43	TOTAL	934,535,929

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 2014/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	Cameron - Milford 138kV Transmission 138 - 46kV Transformer	5,478,801
2	Standpipe Substation New 230kV Substation	4,880,942
3	Union Gap Substation Add 230 - 115kV Capacity	3,876,263
4	Utah Facility Rating Modifications	3,329,780
5	Lake Side 2 Spare Generator Step-Up Transformer	3,027,341
6	Wallula - McNary 230kV Line	2,877,584
7	Snow Goose 500 - 230kV Substation	2,092,314
8	Klamath Falls - Purchase Spare 230 - 69kV Auto-Transformer	2,004,504
9	Terminal - Horseshoe Relocate 138 and 46kV Lines	1,947,842
10	Two Elks Intercon at Tri County Switchyard	1,886,886
11	Pinto Substation Add 3rd Phase Shifting Transformer	1,826,068
12	Casper Outer Loop - Complete 115kV Loop	1,508,840
13	Bucking Horse 7.5 MW Load	1,355,097
14	Lyons Substation Increase Capacity	1,340,734
15	Chehalis U3 Generator Step-Up Transformer Replacement	1,077,071
16	Casper Substation Install 230 - 115kV 250 MVA Transformer	1,034,563
17		
18	Distribution:	
19	Pomona Heights Substation Add 115 - 12.47kV Capacity	4,253,006
20	Threemile Canyon Farms Irrigation Pumping 2,500 HP Increase	3,196,652
21	Bar Nunn New 115 - 12.5kV Substation and Transmission Line	2,055,104
22	Knott Substation Increase Capacity	1,374,254
23		
24	General:	
25	Non-Data Center Router and Switch Technology Obsolescence Management	2,460,306
26	Deer Creek - 2 Section Terminal Groups	1,547,357
27	F5 Hardware Load Balancer Blade Upgrade	1,291,324
28		
29	Miscellaneous Projects each under $1,000,000	86,916,792
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	934,535,929

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 2014/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	7,863,751,463	7,863,751,463		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	663,171,827	663,171,827		
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):	74,687,869	74,687,869		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	737,859,696	737,859,696		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	170,396,930	170,396,930		
13	Cost of Removal	46,586,700	46,586,700		
14	Salvage (Credit)	8,035,148	8,035,148		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	208,948,482	208,948,482		
16	Other Debit or Cr. Items (Describe, details in footnote):	2,526,555	2,526,555		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	8,395,189,232	8,395,189,232		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	2,822,999,224	2,822,999,224		
21	Nuclear Production				
22	Hydraulic Production-Conventional	302,834,825	302,834,825		
23	Hydraulic Production-Pumped Storage				
24	Other Production	777,090,296	777,090,296		
25	Transmission	1,432,003,537	1,432,003,537		
26	Distribution	2,479,873,031	2,479,873,031		
27	Regional Transmission and Market Operation				
28	General	580,388,319	580,388,319		
29	TOTAL (Enter Total of lines 20 thru 28)	8,395,189,232	8,395,189,232		

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	$	22,191,690
Account 143, Other accounts receivable, - depreciation expense billed to joint owners		205,655
Asset retirement obligation asset depreciation recorded as a regulatory asset or liability		4,284,437
Deferral of Carbon depreciation recorded as a regulatory asset		22,035,266
Deferral of increased depreciation, due to depreciation study rates, net of amortization, recorded as a regulatory asset		10,998,313
Transportation depreciation charged to operations and maintenance expense and construction work in progress based on usage activity		13,767,456
Account 503, Steam from other sources, - Blundell depletion		185,368
Account 503, Steam from other sources, - Blundell depreciation		1,019,684
Total Other Accounts	$	74,687,869

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	$	(1,526,419)
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		4,052,974
Total Other Debit or Cr. Items	$	2,526,555

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 2014/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.			
2	Common Stock			1
3	Paid-in Capital			47,960,000
4	Undistributed Subsidiary Earnings			121,361,852
5	SUBTOTAL			169,321,853
6				
7	ENERGY WEST MINING COMPANY	1990		
8	Common Stock			1,000
9	SUBTOTAL			1,000
10				
11	GLENROCK COAL COMPANY	1991		
12	Common Stock			1
13	SUBTOTAL			1
14				
15	INTERWEST MINING COMPANY	1992		
16	Common Stock			1,000
17	SUBTOTAL			1,000
18				
19	TRAPPER MINING INC.	1992		
20	Members' Equity			6,038,000
21	Undistributed Subsidiary Earnings			6,310,111
22	SUBTOTAL			12,348,111
23				
24	FOSSIL ROCK FUELS, LLC	2011		
25	Paid-in Capital			29,262,429
26	Undistributed Subsidiary Earnings			-10,335
27	SUBTOTAL			29,252,094
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 85,322,431		TOTAL	210,924,059

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 2014/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		1		2
		47,960,000		3
14,148,087		135,509,939		4
14,148,087		183,469,940		5
				6
				7
		1,000		8
		1,000		9
				10
				11
		1		12
		1		13
				14
				15
		1,000		16
		1,000		17
				18
				19
		6,038,000		20
436,318		6,652,381		21
436,318		12,690,381		22
				23
				24
		31,322,429		25
-3,338		-13,673		26
-3,338		31,308,756		27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
14,581,067		227,471,078		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.: 21 Column: g

In September 2014, Trapper Mining Inc., a subsidiary of PacifiCorp, paid a dividend of $94,048 to PacifiCorp.

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

In January 2014, PacifiCorp contributed $2,060,000 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 2014/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)	240,980,677	198,515,639	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)	91,333,148	111,221,100	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	101,171,275	94,012,733	Electric
8	Transmission Plant (Estimated)	678,432	490,752	Electric
9	Distribution Plant (Estimated)	12,375,512	12,319,645	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	6,985,748	5,593,971	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	212,544,115	223,638,201	
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)	453,524,792	422,153,840	

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

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

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

Mining materials and supplies	$	5,512,384
General plant materials and supplies		81,587
	$	5,593,971

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 2014/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)	2015 No. (d)	2015 Amt. (e)
1	Balance-Beginning of Year	347,437.00		136,466.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	40,554.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	306,883.00		136,466.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	2,259.00		2,259.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	2,259.00			
40	Balance-End of Year			2,259.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2016		2017		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
149,627.00		151,733.00		4,067,537.00		4,852,800.00		1
								2
								3
				156,643.00		156,643.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						40,554.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
149,627.00		151,733.00		4,224,180.00		4,968,889.00		29
								30
								31
								32
								33
								34
								35
2,259.00		2,259.00		110,921.00		119,957.00		36
				4,528.00		4,528.00		37
								38
				2,269.00		4,528.00		39
2,259.00		2,259.00		113,180.00		119,957.00		40
								41
								42
								43
								44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	1,205,416		407	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	555,186		407	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	1,760,602			1,760,602	

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 2014/Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Q1789	3,879	561.6	3,879	456
3	Q1799	47,663	561.6	47,663	456
4	Q1802	103	561.6	103	456
5	Q1803	4,312	561.6	4,312	456
6	Q1827	359	561.6	359	456
7	AREF 78351080	860	561.6		
8	AREF 78834184	215	561.6		
9	AREF 78926238	180	561.6		
10	AREF 79272901	716	561.6		
11	AREF 79428812	10,489	561.6		
12	AREF 79456228	11,477	561.6		
13	AREF 79486154	409	561.6		
14	AREF 79611263	654	561.6		
15	AREF 79648694	2,755	561.6		
16	AREF 79648850	2,216	561.6		
17	AREF 79648886	363	561.6		
18	AREF 79648900	363	561.6		
19	AREF 79651319	903	561.6		
20	AREF 79656579	2,062	561.6		
21	**Generation Studies**				
22	GIQ0252	142	561.7	142	456
23	GIQ0255	1,232	561.7	1,232	456
24	GIQ0316	2,799	561.7	2,799	456
25	GIQ0332	155	561.7	155	456
26	GIQ0397	5,575	561.7	5,575	456
27	GIQ0403	1,232	561.7	1,232	456
28	GIQ0409	602	561.7	602	456
29	GIQ0420	1,346	561.7	1,346	456
30	GIQ0425	771	561.7	771	456
31	GIQ0426	4,022	561.7	4,022	456
32	GIQ0427	142	561.7	142	456
33	GIQ0429	719	561.7	719	456
34	GIQ0438	2,384	561.7	2,384	456
35	GIQ0443	744	561.7	744	456
36	GIQ0450	1,480	561.7	1,480	456
37	GIQ0451	248	561.7	248	456
38	GIQ0453	2,081	561.7	2,081	456
39	GIQ0456	213	561.7	213	456
40	GIQ0460	3,601	561.7	3,601	456

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	AREF 79656649	1,802	561.6		
3	AREF 79656693	4,442	561.6		
4	AREF 79656740	252	561.6		
5	AREF 79656769	1,995	561.6		
6	AREF 79656794	4,943	561.6		
7	AREF 79656841	1,711	561.6		
8	AREF 79656858	1,787	561.6		
9	AREF 79656968	2,039	561.6		
10	AREF 79656996	1,715	561.6		
11	AREF 79657047	1,715	561.6		
12	AREF 79657068	2,045	561.6		
13	AREF 79657086	287	561.6		
14	AREF 79675896	287	561.6		
15	AREF 79675996	449	561.6		
16	AREF 79857385	2,058	561.6		
17	AREF 79857389	1,586	561.6		
18	AREF 79857395	725	561.6		
19	AREF 79857400	840	561.6		
20	AREF 79887230	593	561.6		
21	**Generation Studies**				
22	GIQ0463	744	561.7	744	456
23	GIQ0464	2,109	561.7	2,109	456
24	GIQ0465	31,187	561.7	31,187	456
25	GIQ0471	567	561.7	567	456
26	GIQ0472	496	561.7	496	456
27	GIQ0473	496	561.7	496	456
28	GIQ0475	2,472	561.7	2,472	456
29	GIQ0488	1,630	561.7	1,630	456
30	GIQ0489	1,564	561.7	1,564	456
31	GIQ0491	1,927	561.7	1,927	456
32	GIQ0492	2,265	561.7	2,265	456
33	GIQ0493	1,856	561.7	1,856	456
34	GIQ0495	284	561.7	284	456
35	GIQ0496	3,064	561.7	3,064	456
36	GIQ0500	106	561.7	106	456
37	GIQ0501	35	561.7	35	456
38	GIQ0502	1,760	561.7	1,760	456
39	GIQ0503	2,661	561.7	2,661	456
40	GIQ0504	2,991	561.7	2,991	456

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 79887233	410	561.6		
3	AREF 80031241	2,263	561.6		
4	AREF 80039313	1,393	561.6		
5	AREF 80039416	2,135	561.6		
6	AREF 80149329	2,221	561.6		
7	AREF 80243374	1,778	561.6		
8	AREF 788834184	(11,756)	561.6		
9	AREF 788834184	11,756	107		
10	AREF 78764672	284	107		
11	AREF 78849614	981	107		
12	AREF 78984295	1,481	107		
13	AREF 79341660	2,369	107		
14	Q0568	2,519	107		
15	Q0569	2,524	107		
16	Customer Studies Accruals	(43,668)	561.6		
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20					
21	**Generation Studies**				
22	GIQ0509	17,883	561.7	17,883	456
23	GIQ0510	13,424	561.7	13,424	456
24	GIQ0511	2,788	561.7	2,788	456
25	GIQ0512	2,918	561.7	2,918	456
26	GIQ0513	23,812	561.7	23,812	456
27	GIQ0514	28,471	561.7	28,471	456
28	GIQ0515	22,780	561.7	22,780	456
29	GIQ0516	16,453	561.7	16,453	456
30	GIQ0517	9,554	561.7	9,554	456
31	GIQ0518	16,830	561.7	16,830	456
32	GIQ0519	15,156	561.7	15,156	456
33	GIQ0520	11,685	561.7	11,685	456
34	GIQ0521	14,111	561.7	14,111	456
35	GIQ0522	523	561.7	523	456
36	GIQ0523	23,928	561.7	23,928	456
37	GIQ0524	15,235	561.7	15,235	456
38	GIQ0525	13,845	561.7	13,845	456
39	GIQ0526	1,873	561.7	1,873	456
40	GIQ0527	1,686	561.7	1,686	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	GIQ0528	1,369	561.7	1,369	456
23	GIQ0529	2,644	561.7	2,644	456
24	GIQ0530	3,669	561.7	3,669	456
25	GIQ0531	2,220	561.7	2,220	456
26	GIQ0532	33,344	561.7	33,344	456
27	GIQ0533	6,849	561.7	6,849	456
28	GIQ0534	15,390	561.7	15,390	456
29	GIQ0535	409	561.7	409	456
30	GIQ0536	409	561.7	409	456
31	GIQ0537	409	561.7	409	456
32	GIQ0539	33,442	561.7	33,442	456
33	GIQ0540	630	561.7	630	456
34	GIQ0541	1,835	561.7	1,835	456
35	GIQ0542	41,186	561.7	41,186	456
36	GIQ0543	21,681	561.7	21,681	456
37	GIQ0544	15,728	561.7	15,728	456
38	GIQ0545	4,606	561.7	4,606	456
39	GIQ0546	2,924	561.7	2,924	456
40	GIQ0547	22,134	561.7	22,134	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	GIQ0548	22,142	561.7	22,142	456
23	GIQ0549	5,208	561.7	5,208	456
24	GIQ0550	370	561.7	370	456
25	GIQ0551	17,778	561.7	17,778	456
26	GIQ0552	7,245	561.7	7,245	456
27	GIQ0553	1,439	561.7	1,439	456
28	GIQ0554	6,343	561.7	6,343	456
29	GIQ0555	20,617	561.7	20,617	456
30	GIQ0556	20,650	561.7	20,650	456
31	GIQ0557	6,126	561.7	6,126	456
32	GIQ0558	44,962	561.7	44,962	456
33	GIQ0559	1,295	561.7	1,295	456
34	GIQ0560	6,051	561.7	6,051	456
35	GIQ0561	471	561.7	471	456
36	GIQ0564	20,459	561.7	20,459	456
37	GIQ0565	2,581	561.7	2,581	456
38	GIQ0566	16,208	561.7	16,208	456
39	GIQ0567	13,299	561.7	13,299	456
40	GIQ0570	2,535	561.7	2,535	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	GIQ0571	9,600	561.7	9,600	456
23	GIQ0572	13,157	561.7	13,157	456
24	GIQ0573	23,352	561.7	23,352	456
25	GIQ0574	1,596	561.7	1,596	456
26	GIQ0575	1,220	561.7	1,220	456
27	GIQ0576	1,051	561.7	1,051	456
28	GIQ0577	19,553	561.7	19,553	456
29	GIQ0578	15,284	561.7	15,284	456
30	GIQ0579	12,162	561.7	12,162	456
31	GIQ0580	8,556	561.7	8,556	456
32	GIQ0581	3,852	561.7	3,852	456
33	GIQ0582	24,438	561.7	24,438	456
34	GIQ0585	8,731	561.7	8,731	456
35	GIQ0586	7,331	561.7	7,331	456
36	GIQ0587	9,563	561.7	9,563	456
37	GIQ0588	938	561.7	938	456
38	GIQ0589	7,620	561.7	7,620	456
39	GIQ0590	1,483	561.7	1,483	456
40	GIQ0591	2,051	561.7	2,051	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	GIQ0592	11,139	561.7	11,139	456
23	GIQ0593	12,600	561.7	12,600	456
24	GIQ0594	9,684	561.7	9,684	456
25	GIQ0595	5,816	561.7	5,816	456
26	GIQ0596	179	561.7	179	456
27	GIQ0597	4,967	561.7	4,967	456
28	GIQ0598	4,770	561.7	4,770	456
29	GIQ0599	1,513	561.7	1,513	456
30	GIQ0600	7,666	561.7	7,666	456
31	GIQ0601	1,161	561.7	1,161	456
32	GIQ0602	926	561.7	926	456
33	GIQ0603	1,592	561.7	1,592	456
34	GIQ0604	5,595	561.7	5,595	456
35	GIQ0605	3,911	561.7	3,911	456
36	GIQ0606	4,023	561.7	4,023	456
37	GIQ0607	3,365	561.7	3,365	456
38	GIQ0608	6,688	561.7	6,688	456
39	GIQ0609	7,014	561.7	7,014	456
40	GIQ0610	1,874	561.7	1,874	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 2014/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	GIQ0611	5,530	561.7	5,530	456
23	GIQ0612	8,243	561.7	8,243	456
24	GIQ0613	3,477	561.7	3,477	456
25	GIQ0614	3,719	561.7	3,719	456
26	GIQ0615	1,912	561.7	1,912	456
27	GIQ0616	6,711	561.7	6,711	456
28	GIQ0617	1,295	561.7	1,295	456
29	GIQ0618	1,445	561.7	1,445	456
30	GIQ0619	2,329	561.7	2,329	456
31	GIQ0620	1,998	561.7	1,998	456
32	GIQ0621	2,089	561.7	2,089	456
33	GIQ0622	3,572	561.7	3,572	456
34	GIQ0623	2,782	561.7	2,782	456
35	GIQ0624	4,722	561.7	4,722	456
36	GIQ0625	3,703	561.7	3,703	456
37	GIQ0626	1,237	561.7	1,237	456
38	GIQ0627	1,377	561.7	1,377	456
39	GIQ0628	1,306	561.7	1,306	456
40	GIQ0629	4,987	561.7	4,987	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	GIQ0630	2,520	561.7	2,520	456
23	GIQ0631	1,200	561.7	1,200	456
24	GIQ0632	974	561.7	974	456
25	Pre-Application Studies - East	2,173	561.7	2,173	456
26	Pre-Application Studies - West	3,535	561.7	3,535	456
27	Q0568	9,661	561.7		
28	Q0569	8,722	561.7		
29	Q0583	1,710	561.7		
30		1,140	561.7		
31	Customer Studies Accruals	12,083	561.7		
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Schedule Page: 231.8 Line No.: 30 Column: a

Large Generation Interconnect Agreement Modification

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 2014/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 Balancing Account - CA	1,001,435	2,273,447	908,431	2,108,072	1,166,810
2	DSM Balancing Account - ID		3,378,301	908,431	2,633,413	744,888
3	DSM Balancing Account - UT		77,771,033	908	59,356,900	18,414,133
4	DSM Balancing Account - WA		11,671,120	908	10,593,061	1,078,059
5	Deferred Excess Net Power Costs - CA	4,791,326	3,925,666	555	1,622,261	7,094,731
6	Deferred Excess Net Power Costs - ID	24,493,966	14,252,129	555	13,140,236	25,605,859
7	Deferred Excess Net Power Costs - UT	71,218,625	25,362,814	555	33,496,987	63,084,452
8	Deferred Excess Net Power Costs - WY	38,359,894	11,351,465	555	23,547,981	26,163,378
9	Deferred Excess RECs in Rates - UT	16,140,769	5,968,926	456	3,107,779	19,001,916
10	Deferred Excess RECs/SO2 in Rates - WY	5,405,889	94,826	456	3,293,278	2,207,437
11	Deferred Excess RECs in Rates - OR	248,555		456	248,555	
12	Deferred Excess RECs in Rates - WA		4,917,237			4,917,237
13	Income Tax Reg. Asset - WA Flow Through		4,119,790	254	3,865,030	254,760
14	Deferred Income Tax Electric	461,454,531	3,654,003	282,283	19,091,517	446,017,017
15	Solar ITC Basis Adjustment Regulatory Asset		87,620	282,283	5,307	82,313
16	Tax Adj on Postretirement Benefits - CA (3)	2		410.1,283	2	
17	Tax Adj on Postretirement Benefits - ID (4)	204,997		410.1	204,997	
18	Tax Adj on Postretirement Benefits - OR (5)	3,577,313		410.1	894,329	2,682,984
19	Tax Adj on Postretirement Benefits - UT (4)	1,178,250		410.1	1,178,250	
20	Tax Adj on Postretirement Benefits - WY (4)	559,135		410.1	559,134	1
21	Tax Revenue Requirement Adjustment - WY (4)	39,674			17,633	22,041
22	Pension	312,870,952	189,381,576		28,705,712	473,546,816
23	Other Postretirement	76,812,296			60,054,286	16,758,010
24	Postemployment Costs	7,734,798	1,848,944		1,222,297	8,361,445
25	Powerdale Decommissioning - ID (10)	182,578		407.3	26,216	156,362
26	Powerdale Decommissioning - WA (3)	70,982		407.3	70,982	
27	Carbon Plant Regulatory Asset - ID		2,106,371			2,106,371
28	Carbon Plant Regulatory Asset - UT		14,599,216			14,599,216
29	Carbon Plant Regulatory Asset - WY		5,329,679			5,329,679
30	Depreciation Study Deferral - ID		1,589,451			1,589,451
31	Depreciation Study Deferral - UT (17)		2,201,576	403	88,864	2,112,712
32	Depreciation Study Deferral - WY (17)		7,532,200	403	236,050	7,296,150
33	Generating Plant Liquidated Damages - WY	1,461,568		930.2	54,288	1,407,280
34	Generating Plant Liquidated Damages - UT	700,000		930.2	35,000	665,000
35	Chehalis Generating Facility Deferral - WA (6)	6,000,000			3,000,000	3,000,000
36	Klamath Hydroelectric Relicensing Costs - UT (10)	32,014,114	1,639,813	404	4,483,442	29,170,485
37	Cholla Plant Transaction Costs (26)	3,363,432		557	938,633	2,424,799
38	Washington Colstrip Unit No. 3 (22)	369,695		456	52,188	317,507
39	Naughton Unit No. 3 Environmental Costs - CA (2)	102,043		407	51,022	51,021
40	Naughton Unit No. 3 Environmental Costs - ID (2)	478,988		407	239,494	239,494
41	Environmental Costs (10)	37,043,065	5,586,014	925,253	2,555,190	40,073,889
42	Asset Retirement Obligations Regulatory Difference	51,025,640	318,625			51,344,265
43	Unamortized Contract Values	145,804,625		242	22,789,829	123,014,796

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 2014/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	Unrealized Loss on Derivative Contracts	54,369,561	31,046,129			85,415,690
2	Greenhouse Gas Allowance Compliance Costs - CA	7,099,190	5,565,676	555	7,554,206	5,110,660
3	Solar Feed-In Tariff Deferral - OR (1)	4,105,556	4,555,405		3,639,844	5,021,117
4	Renewable Portfolio Standards Compliance - OR (1)	180,906		555	180,906	
5	Deferred Intervenor Funding Grants - OR	802,926	266,643			1,069,569
6	Deferred Intervenor Funding Grants - CA	40,307	40			40,347
7	Deferred Intervenor Funding Grants - ID (2)	55,462		928	16,431	39,031
8	Schedule 203 - Black Cap Solar - OR (1)		30,491		18,919	11,572
9	Schedule 94 - Distribution Safety Surcharge - OR	6,945		588	6,945	
10	Deferred Overburden Cost - ID	184,683	1,150,243	501	1,080,904	254,022
11	Deferred Overburden Cost - WY	493,553	3,067,014	501	2,883,221	677,346
12	BPA Balancing Account - WA		316,957			316,957
13	BPA Balancing Account - OR		1,468,531			1,468,531
14	Excess Gain on Sale of Assets in Rates - OR (1)	275,610	3,764		136,985	142,389
15	GRC Invest. In Emission Control Equip. - OR (1)		418,227			418,227
16	Injuries & Damages Reserve - OR	886,570		925	886,570	
17	Property Insurance Reserve - WY	702,183	118,495	924	349,810	470,868
18	Misc. Regulatory Assets/Liabilities - OR	62,655			6,250	56,405
19	Utah Mine Disposition		86,357,715			86,357,715
20	Preferred Stock Redemption Loss - WY		261,901			261,901
21	Preferred Stock Redemption Loss - UT (10)		787,480	407.3	27,510	759,970
22						
23						
24						
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43						
44	**TOTAL :**	1,373,975,244	536,376,553		320,356,716	1,589,995,081

Schedule Page: 232 Line No.: 5 Column: a
Weighted average remaining life is approximately one year for deferred excess net power cost mechanisms being amortized.

Schedule Page: 232 Line No.: 6 Column: a
Weighted average remaining life is approximately one year for deferred excess net power cost mechanisms being amortized, including Monsanto and Agrium net power cost components.

Schedule Page: 232 Line No.: 7 Column: a
Weighted average remaining life is approximately one year for deferred excess net power cost mechanisms being amortized.

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

Schedule Page: 232 Line No.: 9 Column: a
Weighted average remaining life is approximately two years for deferred excess renewable energy credits in rates being amortized.

Schedule Page: 232 Line No.: 10 Column: a
Weighted average remaining life is approximately one year for deferred excess renewable energy credits and sulfur dioxide revenues in rates being amortized.

Schedule Page: 232 Line No.: 14 Column: a
Weighted average remaining life is 26 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.: 21 Column: d
Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

Schedule Page: 232 Line No.: 22 Column: a
Weighted average remaining life is eight 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.: 22 Column: d
Pensions are associated with labor and generally charged to operations and maintenance expense and construction work in progress.

Schedule Page: 232 Line No.: 23 Column: a
Weighted average remaining life is eight 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.: 23 Column: d
Other benefits are associated with labor and generally charged to operations and maintenance expense, construction work in progress and Account 228.3, Accumulated provision for pensions and benefits.

Schedule Page: 232 Line No.: 24 Column: a
Weighted average remaining life is six years.

Schedule Page: 232 Line No.: 24 Column: d
Other benefits are associated with labor and generally charged to operations and maintenance expense and construction work in progress.

Schedule Page: 232 Line No.: 33 Column: a
Weighted average remaining life is 28 years.

Schedule Page: 232 Line No.: 34 Column: a
Weighted average remaining life is 19 years.

Schedule Page: 232 Line No.: 35 Column: d
Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

Schedule Page: 232 Line No.: 43 Column: a

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

Schedule Page: 232.1 Line No.: 1 Column: a

Weighted average remaining life is four years.

Schedule Page: 232.1 Line No.: 3 Column: d

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

Schedule Page: 232.1 Line No.: 8 Column: d

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

Schedule Page: 232.1 Line No.: 14 Column: d

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

Schedule Page: 232.1 Line No.: 18 Column: d

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

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)	560,971		557	137,381	423,590
2						
3	Lacomb Irrigation (24)	369,570		557	45,720	323,850
4						
5	Bogus Creek (41)	1,076,720		557	41,280	1,035,440
6						
7	Mead Phoenix Availability and					
8	Transmission Charge (50)	12,623,480		565	377,760	12,245,720
9						
10	TGS Buyout (23)	94,130		557	15,474	78,656
11						
12	Point-to-Point Transmission	1,603,678	289,103	142	838,404	1,054,377
13						
14	Jim Boyd Hydro Buyout (11)	6,905		557	6,905	
15						
16	Hermiston Swap (40)	3,877,405		557	171,694	3,705,711
17						
18	Oregon Prepaid REC Purchases					
19	for RPS Compliance (1)	188,367	8,570	555	98,664	98,273
20						
21	Deferred Longwall Costs	1,288,250	1,526,148	151	2,787,566	26,832
22						
23	Deferred Coal Costs - Wyodak					
24	Settlement (22)	3,016,636		151	335,182	2,681,454
25						
26	Deferred Coal Costs - Naughton					
27	Settlement (7)	4,128,461		151	1,376,154	2,752,307
28						
29	Deferred Coal Costs - Jim					
30	Bridger Plant	2,916,673				2,916,673
31						
32	Deferred Colstrip Plant					
33	Costs (5)	625,000		501	300,000	325,000
34						
35	Deferred Royalty Reduction -					
36	Craig Plant	20,728		151	20,728	
37						
38	LT Lease Commissions					
39	Prepaids (10)	432,574		931	99,515	333,059
40						
41	Lake Side Maintenance Prepaid	19,523,667	6,902,416			26,426,083
42						
43	Lake Side 2 Maintenance Prepaid		5,281,592			5,281,592
44						
45	Chehalis Maintenance Prepaid	13,717,203	8,121,711			21,838,914
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	90,972,267				110,913,409

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 2014/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	Currant Creek Maint. Prepaid	7,272,782	6,723,326			13,996,108
2						
3	Lease Incentives (10)	649,871		454	157,229	492,642
4						
5	Credit Agreement Costs (5)	2,885,523		427,431	744,271	2,141,252
6						
7	PCRB LOC/SBBPA Costs	346,216		427	258,190	88,026
8						
9	PCRB Mode Conversion Costs	259,606	103,411	427	117,173	245,844
10						
11	'94 Series Restruct. Costs (16)	673,998		427	62,215	611,783
12						
13	LT Prepaid IBEW 57 Pension					
14	Contribution	6,230,810	293,688		1,736,591	4,787,907
15						
16	BPA LT Transmission Prepaid	5,658,577	162,690	565	1,104,072	4,717,195
17						
18	Emission Reduction Credits	306,510				306,510
19						
20	Unamortized Contract Values	312,267		174	180,653	131,614
21						
22	Sales of Electric Utility					
23	Facilities & Properties	276,000	1,569,747			1,845,747
24						
25	Other Deferred Charges	29,689	20,048	181	48,487	1,250
26						
27						
28						
29						
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32						
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39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	90,972,267				110,913,409

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

Weighted average life is three years.

Schedule Page: 233.1 Line No.: 9 Column: a

Weighted average life is seven years.

Schedule Page: 233.1 Line No.: 14 Column: d

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

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 2014/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	98,584,009	182,825,392
3	Derivative contracts and unamortized contract values	76,128,093	79,219,960
4	State carryforwards	68,472,715	68,037,070
5	Loss contingencies	66,767,632	51,188,383
6	Asset retirement obligations	47,989,295	47,023,073
7	Other	124,625,544	116,675,654
8	TOTAL Electric (Enter Total of lines 2 thru 7)	482,567,288	544,969,532
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)	482,567,288	544,969,532

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	$ 36,289,678	$ 28,575,535
Other	88,335,866	88,100,119
	$124,625,544	$116,675,654

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 2014/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	Berkshire Hathaway Energy 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	Authorized and Unissued Capital Stock			
21				
22				
23				
24				
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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
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						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.: 20 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, 2014, PacifiCorp had regulatory approval from the aforementioned commissions for the issuance of an additional 30,000,000 shares of common stock out of the 750,000,000 authorized (357,060,915 outstanding) by PacifiCorp's articles of incorporation.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 211 Miscellaneous Paid-in Capital	
2	Additional Paid-in Capital	
3	Share based payments	1,973,218
4	Tax benefit from stock option exercises	14,422,979
5	Benefit plan separation	-3,575,760
6	Capital contributions	1,089,950,000
7	Gain on sale of ScottishPower plc stock	136,208
8	Qualified production activity tax deduction	-1,275,241
9	Contribution of Intermountain Geothermal	432,552
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
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40	TOTAL	1,102,063,956

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

Represents the fair value of stock options granted by ScottishPower 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 ScottishPower 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 ScottishPower plc.

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

Represents capital contributions to PacifiCorp (with no shares of stock issued) from its indirect parent Berkshire Hathaway Energy Company ("BHE"). No capital contributions were made by BHE to PacifiCorp during the year ended December 31, 2014.

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

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

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 2014/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Bonds: (Account 221)		
2	First Mortgage Bonds:		
3			
4	4.95% Series due August 15, 2014	200,000,000	1,442,365
5			728,000 D
6	8.734% Series due October 1, 2014	28,218,000	
7	8.294% Series due October 1, 2015	46,946,000	
8	8.635% Series due October 1, 2016	18,750,000	
9	8.470% Series due October 1, 2017	19,609,000	
10	5.65% Series due July 15, 2018	500,000,000	3,067,221
11			905,000 D
12	5.50% Series due January 15, 2019	350,000,000	2,515,793
13			2,292,500 D
14	3.85% Series due June 15, 2021	400,000,000	3,007,139
15			744,000 D
16	2.95% Series due February 1, 2022	350,000,000	2,424,350
17			308,000 D
18	2.95% Series due February 1, 2022	100,000,000	254,129
19			-81,000 P
20	2.95% Series due June 1, 2023	300,000,000	1,859,352
21			900,000 D
22	3.60% Series due April 1, 2024	425,000,000	3,345,164
23			255,000 D
24	7.70% Series due November 15, 2031	300,000,000	2,874,150
25			864,000 D
26	5.90% Series due August 15, 2034	200,000,000	1,892,365
27			722,000 D
28	5.25% Series due June 15, 2035	300,000,000	2,912,021
29			1,080,000 D
30	6.10% Series due August 1, 2036	350,000,000	2,907,881
31			1,141,000 D
32	5.75% Series due April 1, 2037	600,000,000	589,216
33	TOTAL	7,417,018,000	79,444,237

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
08/24/2004	08/15/2014	08/24/2004	08/15/2014		6,187,500	4
						5
04/15/1992	10/01/2014	04/15/1992	10/01/2014		171,820	6
04/15/1992	10/01/2015	04/15/1992	10/01/2015	4,178,000	586,386	7
04/15/1992	10/01/2016	04/15/1992	10/01/2016	3,241,000	372,535	8
04/15/1992	10/01/2017	04/15/1992	10/01/2017	4,779,000	490,667	9
07/17/2008	07/15/2018	07/17/2008	07/15/2018	500,000,000	28,250,000	10
						11
01/08/2009	01/15/2019	01/08/2009	01/15/2019	350,000,000	19,250,000	12
						13
05/12/2011	06/15/2021	05/12/2011	06/15/2021	400,000,000	15,400,000	14
						15
01/06/2012	02/01/2022	01/06/2012	02/01/2022	350,000,000	10,325,000	16
						17
03/06/2012	02/01/2022	03/06/2012	02/01/2022	100,000,000	2,950,000	18
						19
06/06/2013	06/01/2023	06/06/2013	06/01/2023	300,000,000	8,850,000	20
						21
03/13/2014	04/01/2024	03/13/2014	04/01/2024	425,000,000	12,240,000	22
						23
11/21/2001	11/15/2031	11/21/2001	11/15/2031	300,000,000	23,100,000	24
						25
08/24/2004	08/15/2034	08/24/2004	08/15/2034	200,000,000	11,800,000	26
						27
06/13/2005	06/15/2035	06/13/2005	06/15/2035	300,000,000	15,750,000	28
						29
08/10/2006	08/01/2036	08/10/2006	08/01/2036	350,000,000	21,350,000	30
						31
03/14/2007	04/01/2037	03/14/2007	04/01/2037	600,000,000	34,500,000	32
				7,031,538,000	358,380,033	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			24,000 D
2	6.25% Series due October 15, 2037	600,000,000	5,127,281
3			750,000 D
4	6.35% Series due July 15, 2038	300,000,000	2,290,333
5			1,671,000 D
6	6.00% Series due January 15, 2039	650,000,000	6,134,687
7			6,175,000 D
8	4.10% Series due February 1, 2042	300,000,000	2,737,911
9			987,000 D
10	8.53% Series C Medium-Term Notes due Dec. 16, 2021	15,000,000	115,202
11	8.375% Series C Medium-Term Notes due Dec. 31, 2021	5,000,000	38,400
12	8.26% Series C Medium-Term Notes due Jan. 7, 2022	5,000,000	33,243
13	8.27% Series C Medium-Term Notes due Jan. 10, 2022	4,000,000	30,594
14	8.05% Series E Medium-Term Notes due Sept. 1, 2022	15,000,000	131,471
15	8.07% Series E Medium-Term Notes due Sept. 9, 2022	8,000,000	70,118
16	8.12% Series E Medium-Term Notes due Sept. 9, 2022	50,000,000	438,238
17	8.11% Series E Medium-Term Notes due Sept. 9, 2022	12,000,000	105,177
18	8.05% Series E Medium-Term Notes due Sept. 14, 2022	10,000,000	87,648
19	8.08% Series E Medium-Term Notes due Oct. 14, 2022	26,000,000	208,198
20	8.08% Series E Medium-Term Notes due Oct. 14, 2022	25,000,000	200,190
21	8.23% Series E Medium-Term Notes due Jan. 20, 2023	5,000,000	37,914
22	8.23% Series E Medium-Term Notes due Jan. 20, 2023	4,000,000	30,331
23			-81,560 P
24	7.26% Series F Medium-Term Notes due July 21, 2023	27,000,000	246,981
25	7.26% Series F Medium-Term Notes due July 21, 2023	11,000,000	100,622
26	7.23% Series F Medium-Term Notes due Aug. 16, 2023	15,000,000	137,211
27	7.24% Series F Medium-Term Notes due Aug. 16, 2023	30,000,000	274,423
28	6.75% Series F Medium-Term Notes due Sept. 14, 2023	5,000,000	38,250
29	6.75% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
30	6.72% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
31	6.75% Series F Medium-Term Notes due Oct. 26, 2023	20,000,000	152,326
32	6.75% Series F Medium-Term Notes due Oct. 26, 2023	16,000,000	121,861
33	TOTAL	7,417,018,000	79,444,237

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 2014/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
10/03/2007	10/15/2037	10/03/2007	10/15/2037	600,000,000	37,500,000	2
						3
07/17/2008	07/15/2038	07/17/2008	07/15/2038	300,000,000	19,050,000	4
						5
01/08/2009	01/15/2039	01/08/2009	01/15/2039	650,000,000	39,000,000	6
						7
01/06/2012	02/01/2042	01/06/2012	02/01/2042	300,000,000	12,300,000	8
						9
12/16/1991	12/16/2021	12/16/1991	12/16/2021	15,000,000	1,279,500	10
12/31/1991	12/31/2021	12/31/1991	12/31/2021	5,000,000	418,750	11
01/08/1992	01/07/2022	01/08/1992	01/07/2022	5,000,000	413,000	12
01/09/1992	01/10/2022	01/09/1992	01/10/2022	4,000,000	330,800	13
09/18/1992	09/01/2022	09/18/1992	09/01/2022	15,000,000	1,207,500	14
09/09/1992	09/09/2022	09/09/1992	09/09/2022	8,000,000	645,600	15
09/11/1992	09/09/2022	09/11/1992	09/09/2022	50,000,000	4,060,000	16
09/11/1992	09/09/2022	09/11/1992	09/09/2022	12,000,000	973,200	17
09/14/1992	09/14/2022	09/14/1992	09/14/2022	10,000,000	805,000	18
10/15/1992	10/14/2022	10/15/1992	10/14/2022	26,000,000	2,100,800	19
10/15/1992	10/14/2022	10/15/1992	10/14/2022	25,000,000	2,020,000	20
01/20/1993	01/20/2023	01/20/1993	01/20/2023	5,000,000	411,500	21
01/29/1993	01/20/2023	01/29/1993	01/20/2023	4,000,000	329,200	22
						23
07/22/1993	07/21/2023	07/22/1993	07/21/2023	27,000,000	1,960,200	24
07/22/1993	07/21/2023	07/22/1993	07/21/2023	11,000,000	798,600	25
08/16/1993	08/16/2023	08/16/1993	08/16/2023	15,000,000	1,084,500	26
08/16/1993	08/16/2023	08/16/1993	08/16/2023	30,000,000	2,172,000	27
09/14/1993	09/14/2023	09/14/1993	09/14/2023	5,000,000	337,500	28
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	135,000	29
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	134,400	30
10/26/1993	10/26/2023	10/26/1993	10/26/2023	20,000,000	1,350,000	31
10/26/1993	10/26/2023	10/26/1993	10/26/2023	16,000,000	1,080,000	32
				7,031,538,000	358,380,033	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	12,000,000	91,396
2	6.71% Series G Medium-Term Notes due Jan. 15, 2026	100,000,000	904,467
3	Subtotal - First Mortgage Bonds	6,762,523,000	68,390,159
4			
5	Pollution Control Obligations - Secured by Pledged First Mortgage Bonds:		
6			
7	Poll Ctrl Rev Refunding Bonds, Moffat County, CO, Series 1994	40,655,000	874,159
8	Poll Ctrl Rev Refunding Bonds, Sweetwater County, WY, Series 1994	21,260,000	510,479
9	Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1994	8,190,000	209,777
10	Poll Ctrl Rev Refunding Bonds, Emery County, UT, Series 1994	121,940,000	3,274,246
11	Poll Ctrl Rev Refunding Bonds, Carbon County, UT, Series 1994	9,365,000	206,519
12	Poll Ctrl Rev Refunding Bonds, Lincoln County, WY, Series 1994	15,060,000	422,858
13	Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1988	17,000,000	155,970
14	Poll Ctrl Rev Refunding Bonds, Lincoln Cnty, WY, Series 1991	45,000,000	771,836
15	Poll Ctrl Revenue Bonds, Sweetwater County, WY, Series 1984	15,000,000	122,887
16			105,000 D
17	Poll Ctrl Revenue Bonds, City of Forsyth, MT, Series 1986	8,500,000	304,824
18	Environ. Imprvmnt Rev Bonds, Converse County, WY, Series 1995	5,300,000	132,043
19	Environ. Imprvmnt Rev Bonds, Lincoln County, WY, Series 1995	22,000,000	404,262
20	Subtotal Pollution Control Obligations - Secured by Pledged First Mortgage Bonds	329,270,000	7,494,860
21			
22			
23	Pollution Control Obligations - Unsecured:		
24			
25	Poll Ctrl Rev Refndng Bonds, Emery County, UT, Series 1991	45,000,000	872,505
26	Poll Ctrl Rev Refndng Bonds, City of Forsyth, MT, Series 1988	45,000,000	380,198
27	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Series 1988A	50,000,000	422,443
28	Poll Ctrl Rev Refndng Bonds, City of Gillette, WY, Ser. 1988	41,200,000	351,905
29	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1988B	11,500,000	84,822
30	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1990A	70,000,000	660,750
31	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992A	9,335,000	167,524
32	Poll Ctrl Rev Refndng Bonds, Converse County, WY, Series 1992	22,485,000	242,163
33	TOTAL	7,417,018,000	79,444,237

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	12,000,000	810,000	1
01/23/1996	01/15/2026	01/23/1996	01/15/2026	100,000,000	6,710,000	2
				6,461,198,000	350,990,958	3
						4
						5
						6
11/17/1994	05/01/2013	11/17/1994	05/01/2013		-14	7
11/17/1994	11/01/2024	11/17/1994	11/01/2024	21,260,000	354,378	8
11/17/1994	11/01/2024	11/17/1994	11/01/2024	8,190,000	138,873	9
11/17/1994	11/01/2024	11/17/1994	11/01/2024	121,940,000	2,022,029	10
11/17/1994	11/01/2024	11/17/1994	11/01/2024	9,365,000	157,772	11
11/17/1994	11/01/2024	11/17/1994	11/01/2024	15,060,000	270,718	12
01/01/1988	01/01/2014	01/01/1988	01/01/2014		-2,222	13
01/17/1991	01/01/2016	01/17/1991	01/01/2016	45,000,000	555,933	14
12/01/1984	12/01/2014	12/01/1984	12/01/2014		105,523	15
						16
12/01/1986	12/01/2016	12/01/1986	12/01/2016	8,500,000	57,157	17
11/17/1995	11/01/2025	11/17/1995	11/01/2025	5,300,000	29,792	18
11/17/1995	11/01/2025	11/17/1995	11/01/2025	22,000,000	145,889	19
				256,615,000	3,835,828	20
						21
						22
						23
						24
05/23/1991	07/01/2015	05/23/1991	07/01/2015	45,000,000	733,375	25
01/01/1988	01/01/2018	01/01/1988	01/01/2018	45,000,000	728,648	26
01/01/1988	01/01/2017	01/01/1988	01/01/2017	50,000,000	430,234	27
01/01/1988	01/01/2018	01/01/1988	01/01/2018	41,200,000	338,987	28
01/01/1988	01/01/2014	01/01/1988	01/01/2014		-4,896	29
07/25/1990	07/01/2015	07/25/1990	07/01/2015	70,000,000	703,610	30
09/29/1992	12/01/2020	09/29/1992	12/01/2020	9,335,000	92,762	31
09/29/1992	12/01/2020	09/29/1992	12/01/2020	22,485,000	220,054	32
				7,031,538,000	358,380,033	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 2014/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. 1992B	6,305,000	151,908
2	Environ. Imprvmnt Rev Bonds, Sweetwater County, WY, Series 1995	24,400,000	225,000
3	Subtotal - Pollution Control Obligations - Unsecured	325,225,000	3,559,218
4			
5			
6	TOTAL ACCOUNT 221	7,417,018,000	79,444,237
7			
8	Reacquired Bonds: (Account 222)		
9			
10	Advances from Associated Companies: (Account 223)		
11			
12	Other Long-Term Debt: (Account 224)		
13			
14			
15	Long-Term Debt Authorized but Unissued		
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	7,417,018,000	79,444,237

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.
09/29/1992	12/01/2020	09/29/1992	12/01/2020	6,305,000	63,432	1
12/14/1995	11/01/2025	12/14/1995	11/01/2025	24,400,000	247,041	2
				313,725,000	3,553,247	3
						4
						5
				7,031,538,000	358,380,033	6
						7
						8
						9
						10
						11
						12
						13
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						24
						25
						26
						27
						28
						29
						30
						31
						32
				7,031,538,000	358,380,033	33

Schedule Page: 256 Line No.: 22 Column: a

In March 2014, PacifiCorp issued $425 million of its 3.60% First Mortgage Bonds due April 2024. 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.: 7 Column: i

Interest refund received.

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

Interest refund received.

Schedule Page: 256.2 Line No.: 29 Column: i

Interest refund received.

Schedule Page: 256.3 Line No.: 6 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.: 6 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 all such interest was accrued on amounts included in Account 233, Notes payable to associated companies.

Schedule Page: 256.3 Line No.: 15 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 ($1.575 billion authorized; $1.575 billion available as of December 31, 2014), 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, 2014) 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, 2014) 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 2014/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)	697,859,628
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8	Other	92,436,304
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13	Other	1,325,973,022
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18	Other	57,848,632
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25	Other	1,828,618,654
26	State Tax Deductions	-7,579,764
27	Federal Tax Net Income	222,221,904
28	Show Computation of Tax:	
29		
30	Federal Income Tax at 35.00%	77,777,666
31	Provision to Return Adjustment	-19,317,309
32	Tax Reserve Changes	16,580
33	Renewable Energy Production Tax Credits	-67,845,972
34	Other Federal Tax Credits	-149,682
35		
36	Federal Income Tax Accrual	-9,518,717
37		
38		
39		
40		
41		
42		
43		
44		

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

Particulars (Details)	Amounts
Contribution in Aid of Construction	74,536,326
Deferred Revenue - Lease Incentives	279,558
Regulatory Asset - REC Sales Deferral - OR - Current	414,385
Regulatory Asset - REC Sales Deferral - OR - Noncurrent	15,076
Regulatory Asset - REC Sales Deferral - UT - Noncurrent	1,199,664
Regulatory Asset - REC Sales Deferral - WY - Current	1,470,421
Regulatory Asset - REC Sales Deferral - WY - Noncurrent	1,728,031
Regulatory Asset - WA Colstrip #3	52,188
Reimbursements	1,879,476
Regulatory Liability - BPA Balancing Account - ID	1,392,822
Regulatory Liability - Deferred Excess NPC - OR - Noncurrent	6,025,257
Regulatory Liability - Depreciation Decrease - OR	854,995
Regulatory Liability - Depreciation Decrease - WA	668,497
Regulatory Liability - Sale of REC - OR - Current	404,974
Regulatory Liability - UT Home Energy Lifeline	1,048,013
Regulatory Liability - WA Low Energy Program	186,554
Transmission Service Deposit	200,763
Trapper Mining Stock Basis	50,479
Unearned Joint Use Pole Contact Revenue	28,825
Total	$ 92,436,304

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

Particulars (Details)	Amounts
Fed/State Tax Expense	300,420,980
Fed/State Tax Expense-Interest	1,010,061
50% Meals and Entertainment	868,859
Accrued Bonus	84,982
Accrued Final Reclamation	2,440,579
Accrued Royalties	38,339
Accrued Severance	1,044,553
Avoided Costs	39,260,939
Bear River Settlement Agreement	239,318
Book Cost Depletion	1,167,298
Book Depreciation	784,239,359
Book Depreciation Allocated to Medicare and M&E	70,328
Capitalization of Test Energy	9,961,641
Deferred Coal Costs - Naughton Contract Settlement	1,376,154
Deferred Compensation - Noncurrent	516,674
FAS 112 Book Reserve - Postemployment Benefits	2,031,113
FAS 158 Post-Retirement Liability	2,560,420
Fuel Cost Adjustment	1,250,016
Hermiston Swap	171,693
Hydro Relicensing Obligation	1,342,957
Income Tax Interest	33,464
Injuries and Damages Accrual - Cash Basis	6,566,251
Joseph Settlement	137,381
Lewis River Settlement Agreement	66,619
Lobbying Expenses	1,863,970
LT Incentive Plan - Noncurrent	6,935,250
LT Prepaid IBEW 57 Pension Contribution	5,642,903
Medicare Subsidy	5,538,043
Mine Rescue Training Credit Addback	38,764
Miscellaneous Current and Accrued Liability	3,223,493
Oregon Regulatory Asset/Regulatory Liability Consolidation	6,250
Other Environmental Liabilities	10,472
Penalties	1,639,702

Pension/Retirement Accrual	118,135
Prepaid Aircraft Maintenance	86,725
Regulatory Asset - Chehalis Generating Facility Deferral - WA	3,000,000
Regulatory Asset - Cholla Plant Transaction Costs	1,122,425
Regulatory Asset - Deferred Excess NPC - ID - Noncurrent	4,676,756
Regulatory Asset - Deferred Excess NPC - WY - Current	1,494,117
Regulatory Asset - Deferred Excess NPC - WY '09 & After - Noncurrent	10,702,399
Regulatory Asset - Deferred Intervenor Funding Grants - ID	16,431
Regulatory Asset - DSM Balance Reclass	25,255,409
Regulatory Asset - Environmental Costs - WA	351,452
Regulatory Asset - FAS 158 Pension Liability	29,529,090
Regulatory Asset - FAS 158 Post Retirement Liability	1,946,135
Regulatory Asset - GHG Allowances - CA - Current	1,988,530
Regulatory Asset - Goodnoe Hills Settlement - WY	21,250
Regulatory Asset - Klamath Hydroelectric Relicensing Costs - UT	2,843,628
Regulatory Asset - Lake Side Settlement - WY	27,331
Regulatory Asset - Liquidation Damages - N2 - WY	5,708
Regulatory Asset - Naughton Unit #3 Costs - CA	51,021
Regulatory Asset - Naughton Unit #3 Costs - ID	239,494
Regulatory Asset - Naughton Unit #3 Costs - UT	1,205,417
Regulatory Asset - Naughton Unit #3 Costs - WY	555,186
Regulatory Asset - OR Asset Sale Gain GB - Current	140,166
Regulatory Asset - OR Sch94 Distribution Safety Surcharge	375,629
Regulatory Asset - Pension MMT - UT	283,176
Regulatory Asset - Post Merger Loss - Reacquired Debt	905,935
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	26,216
Regulatory Asset - Powerdale Decommissioning - WA	70,981
Regulatory Asset - Tax Revenue Requirement Adj - WY	17,633
Regulatory Asset - UT Liquidation Damages	35,000
Regulatory Asset - Utah ECAM	27,889,661
Regulatory Liability - ARO/Reg Diff - Trojan - WA Portion	8,242
Regulatory Liability - Blue Sky - CA	45,601
Regulatory Liability - Blue Sky - ID	32,279
Regulatory Liability - Blue Sky - OR	91,771
Regulatory Liability - Blue Sky - UT	233,319
Regulatory Liability - Blue Sky - WA	16,222
Regulatory Liability - Blue Sky - WY	64,230
Regulatory Liability - Deferred Excess NPC - WA - Current	9,513
Regulatory Liability - Injuries & Damages Reserve - OR	2,971,603
Regulatory Liability - Property Insurance Reserve - ID	66,424
Regulatory Liability - Property Insurance Reserve - OR	590,939
Regulatory Liability - Property Insurance Reserve - UT	1,175,615
Regulatory Liability - Property Insurance Reserve - WY	231,315
Regulatory Liability - Solar Feed-in Tariff Deferral - CA - Current	821,873
Regulatory Liability - Solar Incentive Program - UT - Current	4,134,727
Regulatory Liability - Trojan Decommissioning	154,870
TGS Buyout	15,474
USA Power Litigation	2,480,165
Utah Mine Disposition	14,524,828
Western Coal Carrier Retiree Medical Accrual	602,000
Intercompany adjustment	432,980
Total	$ 1,325,973,022

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

Particulars (Details)	Amounts
Dividend Received Deduction - Deferred Compensation	(97,316)

Foote Creek Contract	(137,640)
Investment Gain/Loss - Current	(6,597)
MCI F.O.G. Wire Lease	(77)
Officer's Life Insurance	(6,143,752)
Redding Contract	(549,996)
Regulatory Asset - BPA Balancing Account - OR	(1,468,531)
Regulatory Asset - BPA Balancing Account - WA	(316,957)
Regulatory Asset - REC Sales Deferral - UT - Current	(4,060,810)
Regulatory Asset - REC Sales Deferral - WA - Current	(1,843,964)
Regulatory Asset - REC Sales Deferral - WA - Noncurrent	(3,073,273)
Regulatory Liability - Alt Rate for Energy Program (CARE) - CA - Current	(221,063)
Regulatory Liability - BPA Balancing Account - OR	(211,995)
Regulatory Liability - BPA Balancing Account - WA	(149,739)
Regulatory Liability - GHG Allowance Revenues - CA - Current	(6,201,433)
Regulatory Liability - OR 2012 GRC Giveback - Noncurrent	(1,181,807)
Regulatory Liability - Sale of REC - UT - Current	(1,521,547)
Regulatory Liability - Sale of REC - WA - Current	(14,121,277)
Regulatory Liability - SMUD Revenue Imputation - UT	(1,823,147)
Unrealized Gain/Loss from Trading Securities	(136,644)
Equity Earnings in Subsidiaries	(14,581,067)
Total	$ (57,848,632)

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

Particulars (Details)	Amounts
Accrued Vacation	(8,896,278)
Amortization NOPAs 99-00 RAR	(50,796)
Basis Intangible Difference	(164,861)
Book Fixed Asset Gain/Loss	(310,850)
Capitalized Depreciation	(5,051,360)
Capitalized labor and benefit costs	(2,662,821)
Cholla SHL NOPA (Lease Amortization)	(162,147)
Coal Pile Inventory Adjustment	(7,672,640)
Cost of Removal	(46,586,700)
CWIP Reserve	(3,721,441)
Debt AFUDC	(25,240,671)
Deferred Revenue - Citibank	(154,403)
Deseret Settlement Receivable	(104,502)
Environmental Liability - Non-regulated	(316,833)
Environmental Liability - Regulated	(2,129,561)
Equity AFUDC-Temp	(50,545,926)
FAS 158 Pension Liability	(17,063,795)
FAS 158 SERP Liability	(1,146,920)
Federal Tax Depreciation	(1,246,168,964)
Federal Tax Fixed Asset Gain/Loss	(4,980,604)
Insurance Reserve - Current	(50,097,374)
Inventory Reserve	(618,500)
MEHC Insurance Services - Receivable	(69,076)
N Umpqua Settlement Agreement	(188,658)
Non-deductible Post-Retirement Costs	(5,538,043)
Pre-1943 Preferred Stock Dividend - Deduction	(64,760)
Prepaid IBEW 57 Pension Contribution - Current	(4,200,000)
Prepaid Membership Fees	(3,460,390)
Prepaid Surety Bond	(158,745)
Prepaid Taxes - ID PUC	(51,552)
Prepaid Taxes - OR PUC	(57,637)
Prepaid Taxes - Property Taxes	(404,491)
Prepaid Taxes - UT PUC	(40,515)
Prepaid Water Rights	(689,556)

Regulatory Asset - Carbon Unrecovered Plant - ID	(2,106,371)
Regulatory Asset - Carbon Unrecovered Plant - UT	(14,599,216)
Regulatory Asset - Carbon Unrecovered Plant - WY	(5,329,679)
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	(1,209,396)
Regulatory Asset - Deferred Excess NPC - CA - Noncurrent	(1,094,009)
Regulatory Asset - Deferred Excess NPC - ID - Current	(5,788,650)
Regulatory Asset - Deferred Excess NPC - UT - Current	(7,203,350)
Regulatory Asset - Deferred Excess NPC - UT - Noncurrent	(12,552,136)
Regulatory Asset - Deferred Independent Evaluator Fee - UT	(62,151)
Regulatory Asset - Deferred Intervenor Funding Grants - CA	(40)
Regulatory Asset - Deferred Intervenor Funding Grants - OR	(266,642)
Regulatory Asset - Deferred Overburden Costs - ID	(69,339)
Regulatory Asset - Deferred Overburden Costs - WY	(183,793)
Regulatory Asset - Demand Side Management - Current	(20,402,455)
Regulatory Asset - Demand Side Management - Noncurrent	(25,255,409)
Regulatory Asset - Depreciation Increase - ID	(1,589,451)
Regulatory Asset - Depreciation Increase - UT	(2,112,712)
Regulatory Asset - Depreciation Increase - WY	(7,296,150)
Regulatory Asset - Environmental Costs	(3,382,277)
Regulatory Asset - OR Asset Sale Gain GB - Noncurrent	(6,945)
Regulatory Asset - OR Sch 203 Black Cap Solar	(11,572)
Regulatory Asset - Post Employment Costs	(626,647)
Regulatory Asset - Pref Stock Redemption - WY	(261,901)
Regulatory Asset - Pref Stock Redemption Loss - UT	(759,970)
Regulatory Asset - Solar Feed-In Tariff Deferral - OR - Current	(823,055)
Regulatory Asset - Solar Feed-in Tariff Deferral - OR - Noncurrent	(92,506)
Repairs Deduction	(156,673,269)
Reserve for Bad Debts	(1,338,678)
Regulatory Liability - Contra-Carbon Decommissioning - ID	(966,650)
Regulatory Liability - Contra-Carbon Decommissioning - UT	(6,743,936)
Regulatory Liability - Contra-Carbon Decommissioning - WY	(2,460,237)
Regulatory Liability - Deferred Excess NPC - OR - Current	(2,273,466)
Regulatory Liability - Demand Side Management - Current	(4,852,954)
Regulatory Liability - OR Energy Conservation Charge	(432,204)
Rogue River - Habitat Enhancement Liability	(7,201)
Sec. 481a Adjustment - Repair Deduction	(43,322,360)
Tax Depletion-SRC	(174,980)
Tax Percentage Depletion - Blundell Steam Field	(482,315)
Tax Percentage Depletion - Deer Creek	(5,491,852)
Wasatch Workers Comp Reserve	(251,014)
Total	$ (1,828,618,654)

Schedule Page: 261 Line No.: 36 Column: b

Berkshire Hathaway Inc. includes PacifiCorp in its United States Federal Income Tax Return. PacifiCorp's provision for income taxes has been computed on a stand-alone basis.

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

Under Berkshire Hathaway Energy ("BHE"):
PPW Holdings LLC Sub-Group:
PacifiCorp
PPW Holdings LLC

PacifiCorp Sub-Group:
Energy West Mining Company
Glenrock Coal Company
Interwest Mining Company
Pacific Minerals, Inc

BHE Sub-Group:
Alaska Gas Transmission Company, LLC
American Pacific Finance Company
American Pacific Finance Company II
AVSP 1B, LLC
AVSP 2B, LLC
Berkshire Hathaway Energy Company
BG Energy Holding Company LLC
BG Energy LLC
BHE AC Holding, LLC
BHE America Transco, LLC
BHE California Utility Holdco, LLC
BHE Canada, LLC
BHE Geothermal, LLC
BHE Hydro, LLC
BHE Renewables, LLC
BHE Solar, LLC
BHE Texas Transco, LLC
BHE U.K. Electric, Inc
BHE U.K. Inc
BHE U.K. Power, Inc
BHE U.S. Transmission, LLC
BHE Wind, 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
CE Administrative Services, Inc
CE Black Rock Holdings LLC
CE Butte Energy Holdings LLC
CE Butte Energy LLC
CE Electric (NY), Inc
CE Exploration Company
CE Geothermal, Inc.
CE Indonesia Geothermal, Inc
CE International Investments, Inc
CE Obsidian Energy LLC
CE Obsidian Holding LLC
CE Red Island Energy Holdings LLC
CE Red Island Energy LLC
Cordova Energy Company, LLC
Cordova Funding Corporation
IES Holding LLC
Intelligent Energy Solutions LLC
Jumbo Road Holdings, LLC

M & M Ranch Acquisition Company LLC
M & M Ranch Holding Company LLC
MEHC Insurance Services Ltd.
MEHC Investment, Inc
MEHC Merger Sub Inc
MidAmerican Central California Transco LLC
MidAmerican Energy Machining Services LLC
MidAmerican Funding, LLC
MidAmerican Geothermal Development Corp
MidAmerican Nuclear Energy Company LLC
Midwest Power Transmission Illinois LLC
Midwest Power Transmission Iowa LLC
NNGC Acquisition LLC
Northern Aurora Inc
Pinyon Pines I Holding Company, LLC
Pinyon Pines II Holding Company, LLC
Pinyon Pines Wind I, LLC
Pinyon Pines Wind II, LLC
Quad Cities Energy Company
S.W. Hydro, Inc.
Salton Sea Minerals Corporation
Solar Star 3, LLC
Solar Star California XIX, LLC
Solar Star California XX, LLC
Solar Star Funding, LLC
Solar Star Projects Holdings, LLC
SSC XIX, LLC
SSC XX, LLC
Topaz Solar Farms, LLC
TPZ Holding, LLC
TX Jumbo Road Wiind, LLC
Wailuku Holding Company LLC
Wailuku Investment LLC
Wailuku River Hydroelectric Power Co, Inc.
Kern River Funding Corporation
KR Acquisition 1, LLC
KR Acquisition 2, LLC
KR Holding, LLC
Cimmred Leasing Company
Dakota Dunes Development Company
DCCO, Inc
MEC Construction Services Company
MHC Investment Company
MHC, Inc
MidAmerican Energy Company
Midwest Capital Group, Inc
MWR Capital, Inc
Two Rivers, Inc
Northern Natural Gas Company
Commonsite, Inc.
GPSF-B
Lands of Sierra, Inc.
Nevada Electric Investment Company
Nevada Power Company d/b/a NV Energy
NV Energy, Inc. fka Sierra Pacific Resources
NVE Holdings, LLC
NVE Insurance Co, Inc.
Pinon Pine Corporation

Pinon Pine Investment Company
Sierra Gas Holding Company
Sierra Pacific Power Company d/b/a NV Energy
Big Spring Pipeline Company
CalEnergy Operating Corporation
California Energy Development Corporation
California Energy Management Company
California Energy Yuma Corporation
CE Gen Oil Company
CE Gen Pipeline Corporation
CE Gen Power Corporation
CE Generation LLC
CE Leathers Company
CE Salton Sea Inc
CE Texas Energy, LLC
CE Texas Fuel LLC
CE Texas Pipeline LLC
CE Texas Power LLC
CE Texas Resources LLC
CE Turbo LLC
Conejo Energy Company
Del Ranch Company
Desert Valley Company
Elmore Company
Falcon Power Operating Company
FSRI Holdings, Inc
Imperial Magma LLC
Magma Land Company I
Magma Power Company
Niguel Energy Company
Norcon Holdings, Inc
Northern Consolidated Power, Inc
Salton Sea Brine Processing Company
Salton Sea Funding Corporation
Salton Sea Power Company
Salton Sea Power Generation Company
Salton Sea Power LLC
Salton Sea Royalty Company
San Felipe Energy Company
Saranac Energy Company, Inc
SECI Holdings, Inc
VPC Geothermal LLC
Vulcan Power Company
Vulcan/BN Geothermal Power Company
Arizona HomeServices, LLC
BHH KC Real Estate, LLC
California Title Company
Capitol Title Company
CBSHome Commerical, LLC
CBSHome Real Estate Company
CBSHome Real Estate of Iowa, Inc
CBSHome Relocation Services, Inc
Champion Realty, Inc
Chancellor Title Services, Inc
Columbia Title of Florida, Inc
Connecticut Referral Group, L.L.C.
CTHM, L.L.C.
CTRE, L.L.C.

Edina Financial Services, Inc
Edina Realty Referral Network, Inc
Edina Realty Relocation, Inc
Edina Realty Title, Inc
Edina Realty, Inc
Esslinger-Wooten-Maxwell, Inc
E-W-M Referral Services, Inc.
F&R/T LLC
FFR, Inc
First Realty, Ltd
First Reserve Insurance, Inc
For Rent, Inc
FRTC, LLC
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
HomeServcies Lending, LLC
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 Illinois Holdings, LLC
HomeServices of Illinois Holdings, LLC
HomeServices of Iowa, Inc
HomeServices of Kentucky, Inc
HomeServices of MOKAN, LLC
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
Intero Franchise Services, Inc.
Intero Real Estate Holdings, Inc.
Intero Real Estate Services, Inc.
Intero Referral Services, Inc.
Iowa Realty Company, Inc
Iowa Realty Insurance Agency, Inc
Iowa Title Company
J.S. White Associates, Inc
JBRC, Inc
Jim Huff Realty, Inc.

JRHBW Realty, Inc d/b/a RealtySouth
Kansas City Title, Inc
Kentucky Residential Referral, LLC
Larabee School of Real Estate & Insurance, Inc
Mid-America Referral Network, Inc.
Midland Escrow Services, Inc
Midwest Realty Ventures, LLC
Nebraska Land Title & Abstract Company
Nebraska Referral, Inc.
NMA, LLC
NRS Referral Services, LLC
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
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
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
San Diego PCRE, Inc
Semonin Realtors, Inc
Southwest Relocation, LLC
Sterling Title Services, LLC
The Escrow Firm
The Referral Company
TIAC LLC
TitleSouth, LLC
TLTC LLC
TRMC LLC
Wm Broughton, LLC

With respect to members of the BHE Sub-Group, BHE requires all subsidiaries to pay or receive from BHE 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:

Berkshire Hathaway Inc.
Berkshire Hathaway Automotive Inc.
Berkshire Hathaway Credit Corporation
BH Columbia Inc.
Berkshire Hathaway Finance Corporation
Railsplitter Holdings Corporation
Acme Brick Company
Acme Brick DFW, Inc.
Acme Brick Sales Company
Acme Ochs Brick and Stone, Inc.
American Tile and Stone, Inc
Innovative Building Products, Inc
Alpha Cargo Motor Express, Inc
Acme Brick Tile & Stone, Inc. (fka Brick Acquisition Company)
Acme Building Brands, Inc
Acme Investment Company
Acme Management Company
Acme Services Company, L.P.
Denver Brick Company
Edmonds Material and Equipment Co.
Justin Industries, Inc.
AEG Processing Center No. 35, Inc.
AEG Processing Center No. 58, Inc.
Applied Processing Center No. 60, Inc.
American Employers Group, Inc.
Applied Group Insurance Holdings, Inc.
Applied Investigations Inc.
Applied Logistics, Inc.
Applied Premium Finance, Inc.
Applied Risk Services of New York, Inc.
Applied Risk Services, Inc.
AU Holding Company, Inc.
Applied Underwriters, Inc.
AU Captive Risk Assurance Co.
BH, LLC
Berkshire Indemnity Group Inc.
Combined Claims Services, Inc.
Coverage Dynamics Group, Inc.
Commercial General Indemnity, Inc.
California Insurance Company
Continental Indemnity Company
Applied Underwriters Captive Risk Assurance Company, Inc.
Illinois Insurance Company
North American Casualty Co.
Promesa Health, Inc.
Pennsylvania Insurance Company
Strategic Staff Management, Inc.
Texas Insurance Company
The Ben Bridge Corporation
Ben Bridge Jeweler, Inc.
Benjamin Moore & Co.
Complementary Coatings Corporation
Eco Color Company
The Indecor Group, Inc.
Burlington Northern Santa Fe, LLC
FreightWise, Inc.
Burlington Northern Santa Fe Insurance Company, Ltd.
BNSF Logistics International, Inc.

Royal Cargo Lines
Albacor Shipping (USA) Inc.
BNSF Railway Company
Bayport Systems, Inc.
Burlington Northern Santa Fe Manitoba, Inc.
Los Angeles Junction Railway Company
Star Lake Railroad Company
The BN and SF Railway de Mexico, S.A. de C.V.
The Zia Company
Santa Fe Pacific Pipeline Holdings, Inc.
Burlington Northern Santa Fe British Columbia, Ltd.
Pine Canyon Land Company
Santa Fe Pacific Insurance Company
Santa Fe Pacific Railroad Company
Western Fruit Express Company
Burlington Northern Railroad Holdings, Inc.
Winona Bridge Railroad Company
BNSF Railway International Services, Inc.
BN Leasing Corporation
Midwest Northwest Properties, Inc.
Santa Fe Pacific Pipelines, Inc.
BNSF Communications, Inc.
BNSF Spectrum, Inc.
Borsheim Jewelry Company, Inc
Brooks Sports, Inc.
Total Quality Apparel Resources
The Buffalo News, Inc.
Business Wire, Inc.
Charter Brokerage Holdings Corp.
DL Trading Holdings I, Inc.
Clayton Commercial Buildings, Inc.
CMH Hodgenville, Inc.
CMH Manufacturing, Inc.
CMH Set and Finish, Inc.
CMH Manufacturing West, Inc.
AL/TEX Homes, Inc.
BR Agency, Inc.
Giles Industries, Inc.
Southern Energy Homes, Inc.
CMH Transport, Inc.
Cavalier Homes, Inc.
Fontana Wood Products, Inc.
Fontana Wood Products of Oregon, Inc.
CMH Homes, Inc.
CMH of KY, Inc.
CMH Parks, Inc.
Chatwell, Inc.
Freedom Warehouse Corp.
Vanderbilt ABS Corp.
Vanderbilt Mortgage and Finance, Inc.
Vanderbilt SPC, Inc.
Vanderbilt Property&Casualty Insurance Co., Ltd.
Homefirst Agency, Inc.
21st Communities, Inc.
21st Mortgage Corporation
Henley Holdings, LLC
21 SPC, Inc.
Clayton Homes, Inc.

CMH Capital, Inc.
CMH Services, Inc.
Clayton Education Corp.
Cort Business Services Corporation
Central States of Omaha Companies, Inc.
Central States Indemnity Co. of Omaha
CSI Life Insurance Company
Roxell USA, Inc. (fka Agile Manufacturing Inc.)
CTB Credit Corp
CTB Inc.
CTB International Corp
Ironwood Plastics Inc
CTB IW INC
CTB Midwest
CTB MN Investments
Meyn LLC
International Dairy Queen, Inc.
American Dairy Queen Corporation
DQF, Inc.
DQGC, Inc.
Unified Supply Chain, Inc.
DQ Funding Corporation
Dairy Queen Of Georgia, Inc.
Golden Skillet International, Inc.
Karmelkorn Shoppes, Inc.
Orange Julius Of America
Dairy Queen Corporate Stores, Inc.
DQ Managed Stores, Inc.
DQ Wholly-Owned Stores, Inc.
DQ Joint Venture Stores, Inc.
PJR Management, Inc.
All Bilt Uniforms
Commonwealth Uniforms Inc.
Crowley Garment Mfg Co Inc.
Crowley Shirt Mfg Co Inc.
The Eagle Company
Farriors, Inc.
The Fechheimer Brothers Co.
Fulton Manufacturing Company
Great Plains Uniforms
Griffey Uniforms
Harris Uniforms
Martin Manufacturing Company
McCain Uniform Company Inc.
Metro Uniforms
Nick Bloom Uniforms
Nationwide Uniforms
Roberts Men's Shop
Silver State Uniforms
Simon's Incorporated
Sol Frank Uniforms Inc.
Uniforms of Texas
Universal Uniforms
Waynesburg Shirt Company Inc.
Zuckerbergs Uniforms
Fruit of the Loom, Inc.
Union Underwear Co., Inc
Cumberland Asset Management, Inc.

Fruit of the Loom Direct, Inc.
Vanity Fair, Inc.
VFI-Mexico, Inc.
The BVD Licensing Corporation
Russell Athletic Corporation
Martin Mills, Inc.
Camp Manufacturing Company
Leesburg Yarn Mills, Inc.
Rabun Apparel, Inc.
FTL Regional Sales Co., Inc.
Union Sales, Inc.
Fruit of the Loom Trading Company
Fruit of the Loom, Inc. (Sub)
Forest River Financial Services, Inc.
Forest River Housing, Inc.
Forest River, Inc.
Forest River Manufacturing LLC
Mapletree Transportation, Inc.
Priority One Financial Services, Inc.
Veritas Insurance Group, Inc.
FlightSafety Capital Corp.
FlightSafety Development Corp.
FlightSafety International Inc.
FlightSafety New York, Inc.
FlightSafety Properties, Inc.
FlightSafety Services Corporation
Garan Central America Corp.
Garan Incorporated
Garan Manufacturing Corp.
Garan Services Corp
Criterion Insurance Agency
GEICO Corporation
Government Employees Financial Corp.
GEICO Insurance Agency
GEICO Products, Inc.
International Insurance Underwriters, Inc.
Maryland Ventures, Inc..
Plaza Financial Services Co.
Plaza Resources Co.
Top Five Club, Inc.
GEICO Advantage Insurance Company
GEICO Casualty Co.
GEICO Choice Insurance Company
GEICO General Insurance Co.
Government Employees Insurance Co.
GEICO Indemnity Co.
GEICO Secure Insurance Company
General Re Corporation
Elm Street Corporation
GRD Holdings Corporation
Gen Re Intermediaries Corporation
General Re New England Asset Management
Genesis Management and Insurance Services Corporation
General Star Management Company
United States Aviation Underwriters, Incorporated
General Re Financial Products Corporation
General Reinsurance Corporation
Faraday Capital Limited

Genesis Insurance Company
General Star Indemnity Company
General Star National Insurance Company
Helzberg's Diamond Shops, Inc.
HDS Redevelopment Corporation
H. H. Brown Shoe Company, Inc.
BH Shoe Holdings, Inc.
Vision Retailing, Inc.
American All Risk Insurance Services Inc.
American Commercial Claims Administrators Inc
Brookwood Insurance Company
Berkshire Hathaway Homestate Insurance Company
Continental Divide Insurance Company
Cypress Insurance Company
Oak River Insurance Company
Redwood Fire and Casualty Insurance Company
D.I. Properties Inc.
IMC Group USA Holdings, Inc.
Ingersoll Cutting Tool Company
IMC Investment Holding Inc
Iscar Metals Inc.
Taegutec Inc.
Tool-Flo Manufacturing, Inc.
Boot Royalty Company
Chippewa Shoe Company
Footwear Investment Company
H.J. Justin & Sons, Inc.
Justin Belt Company, Inc.
Justin Brands, Inc.
Justin Boot Company
J.S Justin, Inc.
Nocona Boot Company
Tony Lama Company
Johns Manville Corporation
Johns Manville, Inc.
Seventeenth Street Realty, Inc.
Johns Manville China, Ltd.
Jordan's Furniture, Inc.
Albecca, Inc.
Active Organics, Inc.
Lubrizol Inter-Americas Corporation
Lubrizol Advanced Materials China, Inc.
The Lubrizol Corporation
Chemtool Incorporated
Lubrizol Advanced Materials FCC, Inc.
Lubrizol Specialty Products, Inc. FKA Phillips Specialty Products, Inc
Lubrizol Advanced Materials Holding Corporation
Lubrizol Advanced Materials International, Inc.
Lipotec Group Corp.
Lubrizol Enterprises, Inc.
Lubrizol International Management Corporation
Lubrizol Overseas Trading Corporation
LSP Holding, Inc.
MPP Pipeline Corporation
Noveon Hilton Davis, Inc.
Lubrizol Advanced Materials, Inc.
Lubrizol Oilfield Solutions, Inc.
P Chem, Inc.

Lubrizol Advanced Materials Gibraltar, Inc.
Syrgis Holdings, Inc.
Vesta Funding, Inc.
Vesta Intermediate Funding, Inc.
ExtruMed, Inc.
SSP-SiMatrix Inc.
Lubricant Investments, Inc.
Warwick Chemicals USA, Inc.
Marmon Water, Inc.
Marmon Crane Services, Inc.
Marmon Electrical & Plumbing Distribution Products, Inc.
Marmon Engineered Components Company
Marmon Retail Technologies Company
Marmon Wire & Cable, Inc.
Lockwood Street Urban Renewal Corporation
Ecodyne Corporation
J.L. Mining Company
Fontaine Truck Equipment Company
Marmon Retail Products, Inc.
Morgantown-National Supply, Inc.
Procrane Holdings, Inc.
RCP Investment, Inc.
Tucker Safety Products, Inc.
Artform International Inc.
DCI Marketing Inc.
Marmon Merchandising Holdings, Inc.
Marmon Beverage Technologies, Inc.
Cornelius Renew, Inc.
3Wire Group Inc.
Cornelius Inc.
HG-Power Plant. Inc.
Marmon Energy Services Company
UTLX Company
Penn Coal Land, Inc.
Penn Pocahontas Coal Co.
TRH Holding Corp.
Precision Millwork Settings LLC
Marmon Holdings, Inc.
Webb Wheel Products, Inc.
Perfection Hy-Test Company
Marathon Suspension Systems, Inc.
Fontaine Trailer Company
Fontaine Modification Company
Fontaine Fifth Wheel Company
Fontaine Commercial Trailer, Inc.
Fontaine Engineered Products, Inc.
Marmon-Herrington Company
Triangle Suspension Systems, Inc.
Fontaine Spray Suppression Company
TSE Brakes, Inc.
Union Tank Car Company
Uni-Form Components Co.
Marmon Distribution Services, Inc.
Railserve, Inc.
Tiger-Sunbelt Industries, Inc.
Worldwide Containers, Inc.
Exsif Worldwide, Inc.
Marmon Beverage Technologies Espana, S.A. (fka IMI Cornelius Expana SA)

McLane Southern, Inc.
McLane Western, Inc.
McLane Beverage Distribution, Inc.
McLane Beverage Holding, Inc.
McLane Minnesota, Inc.
McLane Express, Inc.
JDS Properties, Inc.
Intrepid JSB, Inc.
International Traders, Inc.
First American Carriers, Inc.
Meadowbrook Meat Company, Inc.
McLane New Jersey, Inc.
Kahn Ventures, Inc.
Empire Distributors, Inc.
Empire Distributors of North Carolina, Inc.
Horizon Wine & Spirits - Nashville, Inc.
Horizon Wine & Spirits - Chattanooga, Inc.
Delta Wholesale Liquors, Inc.
Salado Sales, Inc.
McLane Foodservice, Inc.
McCarty-Hull Cigar Company, Inc.
Professional Datasolutions, Inc.
Claims Services, Inc.
M & C Products, Inc.
Transco, Inc.
McLane Company, Inc.
McLane Eastern, Inc.
McLane Midwest, Inc.
McLane Suneast, Inc.
McLane Mid-Atlantic, Inc.
C & R Insurance Services, Inc.
Medical Protective Finance Corporation
The Medical Protective Company
Medical Protective Insurance Services, Inc.
Princeton Advertising & Marketing Group, Inc.
Alexander Road Insurance Agency, Inc.
Princeton Insurance Company
Medical Protective Corporation
Princeton Risk Protection, Inc.
MedPro Risk Retention Services, Inc.
Somerset Services, Inc
Accurate Installations, Inc.
Benson, Ltd.
Benson Industries, Inc.
Cubic Designs, Inc.
Hohmann & Barnard, Inc.
MiTek Holdings, Inc.
HeatPipe Technology, Inc.
Kova Solutions, Inc.
MiTek Industries, Inc.
Miller-Sage, Inc.
Rush Air Inc
SidePlate Systems, Inc.
SSS Acquisition Inc.
TBS USA, Inc.
TMI Climate Solutions, Inc.
MiTek USA, Inc.
121 Acquisition Co., LLC

Floors, Inc.
NFM of Kansas, Inc.
LMG Ventures, LLC
Nebraska Furniture Mart, Inc.
NFM SERVICES, LLC
Homemakers Plaza, Inc.
TXFM, Inc.
WMC Corp.
First Berkshire Hathaway Life Insurance Company
Berkshire Hathaway Life Insurance Company of Nebraska
BHG Life Insurance Company
Ringwalt & Liesche Co.
Brilliant National Services, Inc.
Soco West, Inc.
Whittaker, Clark & Daniels, Inc.
L.A. Terminals, Inc.
Boat America Corporation
Boat/U.S, Inc.
BHG Structured Settlements, Inc.
Resolute Management Inc.
International American Group Inc.
International American Management Company
Northern States Agency, Inc.
Finial Holdings, Inc.
CLAL U.S. Holdings, Inc.
GUARD Financial Group, Inc.
GUARD Insurance Group, Inc.
GUARDco, Inc.
Affiliated Agency Operations Co.
InterGUARD, Ltd.
Hartford Life International, Ltd.
Consolidated Health Plans Inc.
Affordable Housing Partners, Inc.
Berkshire Hathaway Specialty Concierge, LLC
Boat Owners Association of the United States
VT Insurance Acquisition Sub Inc.
VT Real Estate Acquisition Sub Inc
American Centennial Insurance Company
WestGUARD Insurance Company
Berkshire Hathaway Assurance Corporation
EastGUARD Insurance Company
National Liability & Fire Insurance Company
National Indemnity Company of Mid-America
National Fire & Marine Insurance Company
National Indemnity Company
Atlanta International Insurance Company
Berkshire Hathaway Specialty Insurance Company
Columbia Insurance Company
NorGUARD Insurance Company
Commercial Casualty Insurance Company
Unione Italiana Reinsurance Company of America, Inc.
Seaworthy Insurance Company
Finial Reinsurance Company
National Indemnity Company of the South
AmGUARD Insurance Company
BNJ NetJets, Inc.
Executive Jet Management, 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.
NJE Holdings, LLC
NJI Sales, Inc.
Marquis Jet Partners, Inc.
Marquis Jet Holdings, Inc.
Brainy Toys, Inc.
OTC Brands, Inc.
OTC Direct, Inc.
Mindware Corporation
MW Wholesale, Inc.
Oriental Trading Company, Inc.
OTC Worldwide Holdings, Inc.
Smilemakers, Inc.
Smilemakers Canada Inc.
Ace Mailing Services, Inc.
BH Media Group, Inc.
BH Media Group Holdings, Inc.
LEE Distributing Services, Inc.
Mail Tech, LTD.
Omaha World-Herald Company
World Investments, Inc.
World Marketing, Inc.
World Publishing Enterprises, Inc.
World Technologies, Inc.
TPC European Holdings, LTD.
TPC North America, Ltd.
The Pampered Chef, Ltd.
Precision Steel Warehouse - Charlotte
Precision Steel Warehouse, Inc.
Precision Brand Products, Inc.
R.C. Willey Home Furnishings
Richline Group, Inc
Hallmark Sweet, Inc.
Stern/Leach Company
Rio Grande, Inc.
See's Candies, Inc
Sees Candy Shops, Incorporated
BHSF, Inc.
Ambucor Health Solutions, Inc.
ScottCare Corporation
The Scott Fetzer Company
Campbell Hausfeld/Scott Fetzer Company
Adalet/Scott Fetzer Company
Western/Scott Fetzer Company
Halex/Scott Fetzer Company
Stahl/Scott Fetzer Company
France/Scott Fetzer Company
Wayne/Scott Fetzer Company
Carefree/Scott Fetzer Company
Scott Fetzer Financial Group, Inc.
UCFS Europe Company
BH Finance, Inc.

United Consumer Financial Services Company
United Direct Finance, Inc.
World Book, Inc.
World Book Encyclopedia, Inc.
World Book/Scott Fetzer Company
SHX Leasing, Inc.
SHX Flooring, Inc.
Shaw International Services, Inc.
Pro Installations, Inc.
Shaw Contract Flooring Installation Services, Inc.
Shaw Contract Flooring Services, Inc.
Spectra Contract Flooring Puerto Rico, Inc.
Shaw Industries Group, Inc.
Shaw Industries, Inc.
Shaw Diversified Services, Inc.
Shaw Transport, Inc.
Queen Carpet Corporation
Shaw Floors, Inc.
Shaw Retail Properties, Inc.
Shaw Funding Company
Star Furniture Company
CJE II
Mouser Electronics, Inc.
Sager Electrical Supply Co. Inc
Astrex Holding Company
Astrex Electronics, Inc
TTI, Inc.
Gateway Underwriters Agency, Inc.
U.S. Investment Corporation
United States Liability Insurance Company
Mount Vernon Fire Insurance Company
Mount Vernon Specialty Insurance Company
U.S. Underwriters Insurance Co.
Blue Chip Stamps, Inc.
Montana Retail Properties, Inc.
MS Property Company
AJF Warehouse Distributors, Inc.
XTRA Finance Corporation
XTRA Intermodal, Inc.
RENTCO Trailer Corporation
X-L-Co., Inc.
XTRA Corporation
XTRA Companies, Inc.

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 2014/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	14,281,052		-9,518,717	132,869,369	-128,255,990
3	FICA	645,661	10,234	36,493,634	36,469,676	
4	Unemployment	4,601		243,208	242,552	
5	Excise Tax - Coal	101,364		2,187,559	2,281,538	
6	Subtotal	15,032,678	10,234	29,405,684	171,863,135	-128,255,990
7						
8	State:					
9						
10	Arizona:					
11	Property	1,619,025		3,782,928	3,510,489	
12	Income	615,630		-349,018	538,000	-271,388
13	Subtotal	2,234,655		3,433,910	4,048,489	-271,388
14						
15	California:					
16	Property			2,253,386	2,253,386	
17	Unemployment	1,236	45	32,086	31,070	
18	Franchise-Income	-350,643		1,823,050	1,817,546	-345,139
19	Use	12,710		28,440	38,509	
20	Local Franchise	1,265,469		1,229,045	1,215,654	
21	Subtotal	928,772	45	5,366,007	5,356,165	-345,139
22						
23	Colorado:					
24	Property	2,060,000		2,264,499	2,134,499	
25	Income	6,236		-5,885		351
26	Subtotal	2,066,236		2,258,614	2,134,499	351
27						
28	Idaho:					
29	Property	3,351,464		3,244,612	4,189,309	
30	Income	-36,280		1,465,328	1,896,252	-467,204
31	KWh	15,087		34,818	32,889	
32	Unemployment	1,836		43,560	43,973	
33	Use	20,867		195,941	202,347	
34	Subtotal	3,352,974		4,984,259	6,364,770	-467,204
35						
36	Montana:					
37	Property	1,967,726		4,314,789	4,126,597	
38	Corporate License-Income	10,969		56,847	124,797	-56,981
39	Unemployment			1,056	1,056	
40	Energy License	40,000		203,996	181,996	
41	TOTAL	53,535,702	12,025,243	234,971,158	389,765,588	-139,933,468

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 2014/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
148,956		-2,889,557			-6,629,160	2
664,385	5,000				36,493,634	3
5,257					243,208	4
7,385					2,187,559	5
825,983	5,000	-2,889,557			32,295,241	6
						7
						8
						9
						10
1,891,464		3,782,928				11
		-334,552			-14,466	12
1,891,464		3,448,376			-14,466	13
						14
						15
		2,135,662			117,724	16
2,207					32,086	17
		1,871,103			-48,053	18
2,641					28,440	19
1,278,860		1,229,045				20
1,283,708		5,235,810			130,197	21
						22
						23
2,190,000		2,091,449			173,050	24
		-5,855			-30	25
2,190,000		2,085,594			173,020	26
						27
						28
2,406,767		3,238,480			6,132	29
		1,525,336			-60,008	30
17,016		34,818				31
1,423					43,560	32
14,461					195,941	33
2,439,667		4,798,634			185,625	34
						35
						36
2,155,918		4,314,789				37
		62,554			-5,707	38
					1,056	39
62,000		203,996				40
39,025,536	12,376,039	178,247,515			56,723,643	41

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 2014/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	30,000		143,304	129,304	
2	Subtotal	2,048,695		4,719,992	4,563,750	-56,981
3						
4	Nebraska:					
5	Unemployment			359	359	
6	Subtotal			359	359	
7						
8	New Mexico:					
9	Property			21,695	21,695	
10	Income	77,025		-57,603	50	19,372
11	Subtotal	77,025		-35,908	21,745	19,372
12						
13	Oregon:					
14	Property		11,539,928	23,740,607	24,051,822	
15	Unemployment	50,661	110	1,525,204	1,521,854	
16	Wilsonville Payroll	776		9	785	
17	Excise-Income	-53,716		1,439,332	7,458,278	-6,072,662
18	City of Portland-Income	15,131		-81,063	-53,404	-12,528
19	Department of Energy		474,926	994,823	1,039,793	
20	Tri-Met	411,201		1,069,137	1,053,217	
21	Lane County			1,973	1,973	
22	Franchise	4,526,794		29,046,878	28,951,795	
23	Subtotal	4,950,847	12,014,964	57,736,900	64,026,113	-6,085,190
24						
25	Utah:					
26	Property	704,212		68,915,491	69,060,666	
27	Income	489,524		4,529,895	9,490,718	-4,471,299
28	Unemployment	5,925		321,658	320,003	
29	Navajo Nation			1,284	1,284	
30	Use	409,248		4,612,972	4,619,062	
31	Subtotal	1,608,909		78,381,300	83,491,733	-4,471,299
32						
33	Washington:					
34	Property	10,090,000		10,228,150	10,028,150	
35	Unemployment	2,563		74,051	74,693	
36	Business & Occupation	3,657		27,907	28,850	
37	Public Utility	1,200,000		12,593,513	12,468,513	
38	Natural Gas Use Tax	124,916		3,894,859	3,665,607	
39	Use	57,636		579,222	546,755	
40	Subtotal	11,478,772		27,397,702	26,812,568	
41	TOTAL	53,535,702	12,025,243	234,971,158	389,765,588	-139,933,468

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 2014/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
44,000		143,304				1
2,261,918		4,724,643			-4,651	2
						3
						4
					359	5
					359	6
						7
						8
		21,695				9
		-55,974			-1,629	10
		-34,279			-1,629	11
						12
						13
	11,851,143	23,296,416			444,191	14
53,901					1,525,204	15
					9	16
		1,809,646			-370,314	17
		-80,037			-1,026	18
	519,896	994,823				19
427,121					1,069,137	20
					1,973	21
4,621,877		29,046,878				22
5,102,899	12,371,039	55,067,726			2,669,174	23
						24
						25
559,037		58,897,363			10,018,128	26
		4,929,455			-399,560	27
7,580					321,658	28
		1,284				29
403,158					4,612,972	30
969,775		63,828,102			14,553,198	31
						32
						33
10,290,000		9,898,234			329,916	34
1,921					74,051	35
2,714		27,907				36
1,325,000		12,593,513				37
354,168					3,894,859	38
90,103					579,222	39
12,063,906		22,519,654			4,878,048	40
39,025,536	12,376,039	178,247,515			56,723,643	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 2014/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1						
2	Wyoming:					
3	Property	7,459,081		14,978,109	14,948,136	
4	Wind Generation Tax	1,830,847		2,075,142	1,878,035	
5	Unemployment	10,441		320,147	325,431	
6	Franchise	283,100		1,954,276	1,952,076	
7	Use	132,962		1,450,821	1,435,020	
8	Annual Report			71,948	71,948	
9	Subtotal	9,716,431		20,850,443	20,610,646	
10						
11	State Other	20,512				
12						
13	Miscellaneous:					
14	Goshute Possessory			24,288	24,288	
15	Sho-Ban Possessory			235,663	235,663	
16	Navajo Possessory	19,196		38,951	38,671	
17	Ute Possessory			37,776	37,776	
18	Crow Possessory			69,444	69,444	
19	Umatilla Possessory			65,774	65,774	
20	Subtotal	39,708		471,896	471,616	
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	53,535,702	12,025,243	234,971,158	389,765,588	-139,933,468

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
						2
7,489,054		14,889,550			88,559	3
2,027,954		2,075,142				4
5,157					320,147	5
285,300		1,954,276				6
148,763					1,450,821	7
		71,948				8
9,956,228		18,990,916			1,859,527	9
						10
20,512						11
						12
						13
		24,288				14
		235,663				15
19,476		38,951				16
		37,776				17
		69,444				18
		65,774				19
39,988		471,896				20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
39,025,536	12,376,039	178,247,515			56,723,643	41

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

Represents a reclassification of a portion of the balance at end of year to Account 146, Accounts receivable from associated companies.

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: f

Represents a reclassification of the balance at end of year to Account 143, Other accounts receivable.

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

$111,629	Account 408.2, Taxes other than income taxes, other income and deductions
1,569	Account 589, Rents
4,526	Account 107, Construction work in progress
$117,724	

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

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

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

Represents a reclassification of the balance at end of year to Account 146, Accounts receivable from associated companies.

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

$ 826	Account 408.2, Taxes other than income taxes, other income and deductions
172,224	Account 107, Construction work in progress
$173,050	

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

Represents a reclassification of the balance at end of year to Account 143, Other accounts receivable.

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

$1,183	Account 408.2, Taxes other than income taxes, other income and deductions
4,949	Account 107, Construction work in progress
$6,132	

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

Represents a reclassification of the balance at end of year to Account 146, Accounts receivable from associated companies.

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: f

Represents a reclassification of the balance at end of year to Account 146, Accounts receivable from associated companies.

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: f

Represents a reclassification of the balance at end of year to Account 143, Other accounts receivable.

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

$ 18,268	Account 408.2, Taxes other than income taxes, other income and deductions
134,418	Account 589, Rents
291,505	Account 107, Construction work in progress
$444,191	

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: f

Represents a reclassification of the balance at end of year to Account 146, Accounts receivable from associated companies.

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: f

Represents a reclassification of the balance at end of year to Account 146, Accounts receivable from associated companies.

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.: 20 Column: l

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

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.: 26 Column: l

$ 35,798 Account 408.2, Taxes other than income taxes, other income and deductions
530 Account 589, Rents
7,955,390 Account 107, Construction work in progress
2,026,410 Account 151, Fuel stock
$10,018,128

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

Represents a reclassification of the balance at end of year to Account 146, Accounts receivable from associated companies.

Schedule Page: 262.1 Line No.: 27 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.: 28 Column: l

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

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

Charged to same account as related goods.

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

$(30,415) Account 408.2, Taxes other than income taxes, other income and deductions
360,331 Account 107, Construction work in progress
$329,916

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

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

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

Account 151, Fuel stock

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

Charged to same account as related goods.

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

$ 1,960 Account 408.2, Taxes other than income taxes, other income and deductions
15,382 Account 589, Rents
71,217 Account 107, Construction work in progress
$88,559

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

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

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

Charged to same account as related goods.

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%	31,144,100			411.4, 420	5,705,998	
6	30%	168,013	420	110,915	420	9,770	
7	Idaho	133,626			411.4, 420	9,632	
8	TOTAL	31,445,739		110,915		5,725,400	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	Idaho	860,586	190	538,320	420	95,783	79,560
12	Total Nonutility	860,586		538,320		95,783	79,560
13							
14							
15							
16							
17							
18							
19							
20							
21							
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46							
47							
48							

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
25,438,102	38.82 and 30		5
269,158	24		6
123,994	38.82 and 30		7
25,831,254			8
			9
			10
1,382,683	30		11
1,382,683			12
			13
			14
			15
			16
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			21
			22
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			45
			46
			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%	$29,765,829	-	-	411.4(1)	$5,012,746	$ -	$24,753,083	38.82
10%	1,378,271	-	-	420(2)	693,252	-	685,019	30
	$31,144,100		-		$5,705,998	$ -	$25,438,102	

(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	$ 66,539	-	-	411.4(1)	$ 6,452	$ -	$ 60,087	38.82
Idaho	67,087	-	-	420(2)	3,180	-	63,907	30
	$ 133,626		-		$ 9,632	$ -	$ 123,994	

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

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

Represents an adjustment to the balance at beginning of year debited to Account 190, Accumulated deferred income taxes.

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/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	6,686,727	131	31,000	148,474	6,804,201
2						
3	Reclamation Costs - Trapper Mine	5,466,807			150,697	5,617,504
4						
5	Reclamation Costs - Deseret Mine	451,406	131,182.3	451,406		
6						
7	Western Coal Carriers Benefits					
8	Obligation	11,815,000	131,232	790,520	1,392,520	12,417,000
9						
10	Program Incentives	423,276	921	154,403		268,873
11						
12	Deferred Compensation Plans	9,205,162	131,232,241	622,473	1,139,146	9,721,835
13						
14	Long-Term Incentive Plan				6,935,250	6,935,250
15						
16	Redding Contract (20)	1,100,092	456	549,996		550,096
17						
18	Foote Creek Contract (15)	154,742	456	137,640		17,102
19						
20	Environmental Liabilities	26,273,100		8,674,454	6,238,532	23,837,178
21						
22	Unearned Joint Use Pole					
23	Contact (1)	2,886,601	454	6,239,788	6,268,613	2,915,426
24						
25	Misc. Security Deposits	2,200	131	300		1,900
26						
27	Lease Incentives (9)		931	12,942	292,500	279,558
28						
29	Cowlitz/Lewis River O&M (1)	117,115	539	283,450	285,146	118,811
30						
31	Employee Housing Security Deposits	18,275	131	1,469	1,000	17,806
32						
33	Cogeneration Bonds-Sunnyside	413,417				413,417
34						
35	Transmission Security Deposits	681,500	131	26,893	450,000	1,104,607
36						
37	Transmission Service Deposits	153,225	131	9,446	210,208	353,987
38						
39	MCI F.O.G. Wire Lease (1)	557,890	454	3,346,955	3,346,878	557,813
40						
41	Unamortized Contract Values	123,327,063	242	13,123,502		110,203,561
42						
43	Loss Contingency - USA Power	116,623,436			2,480,165	119,103,601
44						
45	Accrued Right-of-Way Obligations	1,648,357			601,443	2,249,800
46						
47	TOTAL	308,485,444		34,456,637	29,940,572	303,969,379

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 2014/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	Navajo Tribal Utility Authority					
2	Escrow	480,053				480,053
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
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21						
22						
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24						
25						
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31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	308,485,444		34,456,637	29,940,572	303,969,379

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

The weighted average life is four 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

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 2014/Q4

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	226,880,978	27,797,857	2,526,993
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	226,880,978	27,797,857	2,526,993
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)	226,880,978	27,797,857	2,526,993
18	Classification of TOTAL			
19	Federal Income Tax	199,739,675	23,331,892	1,084,136
20	State Income Tax	27,141,303	4,465,965	1,442,857
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 2014/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
						252,151,842	4
							5
							6
							7
						252,151,842	8
							9
							10
							11
							12
							13
							14
							15
							16
						252,151,842	17
							18
						221,987,431	19
						30,164,411	20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	3,991,613,412	757,539,035	501,658,642
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	3,991,613,412	757,539,035	501,658,642
6	Nonutility			
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	3,991,613,412	757,539,035	501,658,642
10	Classification of TOTAL			
11	Federal Income Tax	3,546,947,138	617,557,067	394,790,406
12	State Income Tax	444,666,274	139,981,968	106,868,236
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (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
			14,265,314		11,552,432	4,244,780,923	2
							3
							4
			14,265,314		11,552,432	4,244,780,923	5
							6
							7
							8
			14,265,314		11,552,432	4,244,780,923	9
							10
			11,106,181		8,717,828	3,767,325,446	11
			3,159,133		2,834,604	477,455,477	12
							13

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) X An Original (2) _ A Resubmission	/ /	2014/Q4

FOOTNOTE DATA

Schedule Page: 274 Line No.: 2 Column: g

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

Schedule Page: 274 Line No.: 2 Column: i

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

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 2014/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Regulatory Assets	526,062,074	156,269,401	119,064,278
4	Other	30,318,999	25,060,716	23,796,286
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	556,381,073	181,330,117	142,860,564
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)	556,381,073	181,330,117	142,860,564
20	Classification of TOTAL			
21	Federal Income Tax	489,857,428	159,784,161	125,916,651
22	State Income Tax	66,523,645	21,545,956	16,943,913
23	Local Income Tax			

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
45,935,084	42,801,732		39,979,807		84,377,673	610,798,415	3
7,601,957	10,150,102	190, 282	9,597,664	190, 282	3,075,609	22,513,229	4
							5
							6
							7
							8
53,537,041	52,951,834		49,577,471		87,453,282	633,311,644	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
53,537,041	52,951,834		49,577,471		87,453,282	633,311,644	19
							20
46,692,890	46,177,693		43,007,009		76,351,810	557,584,936	21
6,844,151	6,774,141		6,570,462		11,101,472	75,726,708	22
							23

NOTES (Continued)

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

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

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

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

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	DSM Balancing Account - ID	2,053		2,053		
2	DSM Balancing Account - UT	6,191,038		6,191,038		
3	DSM Balancing Account - WA	367,062		367,062		
4	DSM Balancing Account - WY	183,406		4,852,032	6,559,232	1,890,606
5	Oregon Energy Conservation Charge	3,062,696	131,232	26,652,465	26,220,261	2,630,492
6	Deferred Excess Net Power Costs - WA Hydro	112,448			9,513	121,961
7	Deferred Excess RECs in Rates - UT	1,521,547	456	1,521,547		
8	Deferred Excess RECs in Rates - OR				300,002	300,002
9	Deferred Excess RECs in Rates - WA	14,121,277	456	14,121,277		
10	Income Tax Reg. Liab. - WA Flow Through	4,787,240	182.3,411.1	4,787,240		
11	Investment Tax Credit Regulatory Liability	16,068,451	190	2,703,477	359	13,365,333
12	Solar Feed-In Tariff Deferral - CA	123,782		135,623	957,497	945,656
13	Solar Incentive Program - UT	5,982,150		2,677,911	6,812,638	10,116,877
14	Renewable Portfolio Standards Compliance - OR (1)		555,431	91,428	196,400	104,972
15	Deferred Independent Evaluator Fee - UT (1)	124,303	923	62,152		62,151
16	Alternative Rate for Energy (CARE) - CA	896,054		221,815	751	674,990
17	Utah Home Energy Lifeline	1,448,684	142	20,891	1,068,904	2,496,697
18	Washington Low Income Program	1,116,234	142	300,688	487,243	1,302,789
19	Schedule 94-Distribution Safety Surcharge - OR		923	610,415	979,099	368,684
20	2013 FERC Rate True-up - OR	2,273,466			3,751,791	6,025,257
21	Greenhouse Gas Allowance Revenues - CA	9,106,055	456,909	14,726,605	8,525,172	2,904,622
22	Asset Retirement Obligations Reg. Difference	10,657,389	230	713,401		9,943,988
23	BPA Balancing Account - WA	149,742	440,442	149,742		
24	BPA Balancing Account - OR	211,990	440,442	211,990		
25	BPA Balancing Account - ID	922,145			1,392,822	2,314,967
26	SMUD Revenue Imputation (11)	1,823,145	440,442	1,823,556	411	
27	GRC Invest. In Emission Control Equip. - OR (1)	763,580		763,580		
28	Blue Sky - OR	2,732,953	440,442	1,674,572	1,766,343	2,824,724
29	Blue Sky - WA	330,282	440,442	161,685	177,907	346,504
30	Blue Sky - CA	87,852	440,442	23,573	69,175	133,454
31	Blue Sky - UT	2,929,746	440,442	2,612,963	2,846,281	3,163,064
32	Blue Sky - ID	91,282	440,442	20,316	52,595	123,561
33	Blue Sky - WY	287,012	440,442	150,710	214,941	351,243
34	Injuries & Damages Reserve - OR		925	397,575	2,482,608	2,085,033
35	Property Insurance Reserve - OR	445,516	924	6,483,405	7,074,343	1,036,454
36	Property Insurance Reserve - ID	315,300	924	47,120	113,544	381,724
37	Property Insurance Reserve - UT	2,298,034	924	976,622	2,152,236	3,473,648
38	Depreciation Deferral - OR				854,995	854,995
39	Depreciation Deferral - WA				668,497	668,497
40						
41	TOTAL	91,533,914		96,256,529	75,735,560	71,012,945

Schedule Page: 278 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 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

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

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

Schedule Page: 278 Line No.: 4 Column: c

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

Schedule Page: 278 Line No.: 11 Column: a

Weighted average remaining life is 39 years.

Schedule Page: 278 Line No.: 12 Column: c

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

Schedule Page: 278 Line No.: 13 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.: 16 Column: c

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

Schedule Page: 278 Line No.: 27 Column: c

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

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 2014/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	1,732,822,429	1,773,896,154
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,517,907,746	1,467,851,627
5	Large (or Ind.) (See Instr. 4)	1,430,453,424	1,365,175,755
6	(444) Public Street and Highway Lighting	20,446,444	20,047,674
7	(445) Other Sales to Public Authorities	17,499,523	17,101,922
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	4,719,129,566	4,644,073,132
11	(447) Sales for Resale	360,600,595	325,520,827
12	TOTAL Sales of Electricity	5,079,730,161	4,969,593,959
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	5,079,730,161	4,969,593,959
15	Other Operating Revenues		
16	(450) Forfeited Discounts	9,670,249	9,906,509
17	(451) Miscellaneous Service Revenues	5,956,286	6,310,584
18	(453) Sales of Water and Water Power		1,577
19	(454) Rent from Electric Property	17,827,613	17,887,016
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	65,097,066	63,993,962
22	(456.1) Revenues from Transmission of Electricity of Others	88,719,750	85,492,936
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	187,270,964	183,592,584
27	TOTAL Electric Operating Revenues	5,267,001,125	5,153,186,543

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ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
15,567,753	16,339,122	1,545,529	1,522,173	2
				3
17,073,151	17,057,194	200,454	207,690	4
21,933,602	21,831,865	33,373	33,561	5
143,147	142,585	3,534	3,557	6
281,624	292,107	3	3	7
				8
				9
54,999,277	55,662,873	1,782,893	1,766,984	10
10,270,247	10,206,135			11
65,269,524	65,869,008	1,782,893	1,766,984	12
				13
65,269,524	65,869,008	1,782,893	1,766,984	14

Line 12, column (b) includes $ 243,252,000 of unbilled revenues.

Line 12, column (d) includes 3,131,082 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:

	2014	2013
Account service charges - disconnects/reconnects/returned check charges	$ 4,450,910	$ 4,737,594
Customer contract flat rate billings	1,464,397	1,525,594

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:

	2014	2013
Renewable energy credit sales, including amortization and deferrals	$ 23,779,972	$ 32,904,131
Amortization of California greenhouse gas allowance revenue	14,673,226	-
Wind-based ancillary services	10,678,814	12,114,934
Energy exchange credits	9,010,784	10,700,944
Flyash/by-product sales	4,998,296	3,264,830
Revenue from generation interconnection and transmission service request studies	1,162,487	905,164
Steam sales	988,645	2,029,668
Power sale and exchange agreements	685,320	1,091,292
Phase shifting equipment fee from Western Electricity Coordinating Council	656,040	1,062,518
Maintenance charges for work on transmission facilities	606,542	727,226
Timber sales	426,135	-
Net profit on sales of materials and supplies inventory	381,251	356,039
Service territory fixed cost recovery fee	302,725	276,016
Indemnity revenues	(a)	346,845
Deferral of Oregon retail customers' allocated share of the incremental Open Access Transmission Tariff revenues associated with FERC Docket No. ER11-3643-000	(3,442,129)	(2,220,863)

(a) The 2014 amount is less than $250,000.

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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 - RES NET MTR	789	64,299	141	5,596	0.0815
6	06OALT015R-OUTD AR LGT SR	308	83,085	327	942	0.2698
7	06RESD000D-RES SRVC	164,540	17,925,280	17,379	9,468	0.1089
8	06RESDDL06-CA LOW INCOME	114,930	12,622,348	10,791	10,651	0.1098
9	06RGNSV025-CA SMALL GEN	1,082	224,722	427	2,534	0.2077
10	06RESD0DM9 - MULTI FAMILY	186	15,159	7	26,571	0.0815
11	06RESD0DS8-MULT FAM SBMET	1,117	51,839	16	69,813	0.0464
12	06UPPL000R-BASE SCH FALL			2		
13	UNBILLED REV - UNCOLLECTIBLE		3,000			
14	REVENUE_ACCT ADJ		-1,320,292			
15	SMUD REVENUE IMPUTATIONS		29,027			
16	06RESD00DN - RES SVC DEL NO	77,562	8,721,123	7,135	10,871	0.1124
17	DSM REVENUE-RESIDENTIAL		1,025,229			
18	BLUE SKY REV RESIDENTIAL		20,458			
19	SOLAR FEED-IN REVENUE		64,434			
20	UNBILLED REVENUE	-8,694	-805,000			0.0926
21						
22	IDAHO					
23	07LNX00010-MNTHLY 80%GUAR		1,460			
24	07LNX00035-ADV 80%MO GUAR		1,869			
25	07NETMT135 - ID RES NET MTR	1,545	158,461	104	14,856	0.1026
26	07OALCO007-CUST OWN LIGHT	10	3,825	1	10,000	0.3825
27	07OALT07AR-SECURITY AR LG	87	36,897	123	707	0.4241
28	07RESD0001-RES SRVC	436,720	49,550,473	46,174	9,458	0.1135
29	07RESD0036-RES SRVC-OPTIO	231,669	22,512,773	13,354	17,348	0.0972
30	07RGNSV23A-SM GEN SVC-R	6,767	773,802	869	7,787	0.1143
31	07ZZMERGCR-MERGER CREDITS		5			
32	UNBILLED REV - UNCOLLECTIBLE		7,000			
33	SMUD REVENUE IMPUTATIONS		45,392			
34	UNBILLED REVENUE	-11,454	-1,175,000			0.1026
35	DSM REVENUE-RESIDENTIAL		1,392,294			
36	BLUE SKY REV RESIDENTIAL		18,150			
37						
38	OREGON					
39	01CHCK000R-RES CHECK MTR			1		
40	01COST0004 - 01RESD0004	4,950,084	286,737,427			0.0579
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
43	TOTAL	54,999,277	4,817,264,361	1,782,893	30,848	0.0876

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	01COSTR023 RES GEN SRV CST	68,401	4,076,112			0.0596
2	01COSTR028, OR RES GEN SVC	19,524	1,158,185			0.0593
3	01FXRENEWR - FIXED		-2			
4	01HABIT004 - 01RESD0004	38,255	2,171,891			0.0568
5	01HABTR023-RES GEN SVC HAB	102	6,266			0.0614
6	01LNX00102-LINE EXT 80% G		8,803			
7	01LNX00109-REF/NREF ADV +		5,484			
8	01LNX00300 - LINE EXT 80% GTY		26			
9	01NETMT135-NET METERING		1,226,621	2,710		
10	01NMTOU135-TOU NET METERING		9,533	18		
11	01OALTB15R-OUTD AR LGT RE	2,317	371,065	2,640	878	0.1601
12	01PTOU0004 - 01RESD0004	16,887	1,007,762			0.0597
13	01RENEW004 - 01RESD0004	276,939	15,529,866			0.0561
14	01RENWR023-RENEW USAGE	305	18,588			0.0609
15	01RESD0004-RES SRVC		283,129,141	477,485		
16	01RESD004T - RES TIME OPT		862,946	1,169		
17	01RGNSB023-SMALL GENERAL		5,478,529	13,808		
18	01RGNSB028 -GEN SVC > 30 KW		601,571	164		
19	01RNETM023-NET METER RES		34,803	15		
20	01UPPL000R-BASE SCH FALL			2		
21	01VIR04136-OR RES VOL INC		284,648	361		
22	OR GAIN ON SALE OF ASSET		-15,286			
23	REVENUE ADJ - DEF NPC		-243,749			
24	REVENUE_ACCT ADJ		-1,716,610			
25	SMUD REVENUE IMPUTATIONS		359,986			
26	SOLAR FEED-IN REVENUE		1,293,279			
27	UNBILLED REV - UNCOLLECTIBLE		26,000			
28	UNBILLED REVENUE	-63,519	-6,038,000			0.0951
29	DSM REVENUE-RESIDENTIAL		15,198,990			
30	BLUE SKY REV-RESIDENTIAL		482,286			
31						
32	UTAH					
33	08ACTSETUP-NEW SRVC SETUP			1		
34	08BLSKY01R-BLUESKY ENERGY		-3			
35	08CFR00001-MTH FACILITY S		838			
36	08CHCK000R-UT RES CHECK M			1		
37	08COOLKPRR -COOL KEEPER			91,379		
38	08LNX00001-MTHLY 80% GUAR		4,411			
39	08LNX00005-MTHLY MIN GUAR		396			
40	08LNX00013-80% MNTHLY MIN		23,379			
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
43	TOTAL	54,999,277	4,817,264,361	1,782,893	30,848	0.0876

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SALES OF ELECTRICITY BY RATE SCHEDULES

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4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	08LNX00108-ANN COST MTHLY		2,574			
2	08MHTP0006-MOBILE HOME &	11,215	845,910	8	1,401,875	0.0754
3	08MHTP0023-MOBILE HOME &	282	26,416	2	141,000	0.0937
4	08NETMT135 - NET MTR	15,117	1,696,352	2,495	6,059	0.1122
5	08OALT007R-SECURITY AR LG	2,686	767,153	2,894	928	0.2856
6	08PTLD000R-POST TOP LIGHT	2	131	3	667	0.0655
7	08RESD0001-RES SRVC	6,241,612	677,726,573	707,396	8,823	0.1086
8	08RESD0002-RES SRVC-OPTIO	3,090	329,135	371	8,329	0.1065
9	08RESD0003-LIFELINE PRGRM	201,030	21,403,238	26,798	7,502	0.1065
10	08RGNSV006-GEN SRVC-RES	84,775	6,545,358	225	376,778	0.0772
11	08RGNSV023-GEN SRVC-RES	91,740	10,219,952	12,324	7,444	0.1114
12	08RGNSV06A-UT SM GEN SVC	15,085	1,242,804	23	655,870	0.0824
13	08RGNSV06B-UT SM GEN SVC	22	1,992	1	22,000	0.0905
14	08RNM06135 - UT NET MTR, GEN	287	30,422	4	71,750	0.1060
15	08RNM23135 - UT NET MTR, GEN	234	25,819	29	8,069	0.1103
16	08UPPL000R-BASE SCH FALL			4		
17	REVENUE_ACCOUNTING		-2,406,676			
18	REVENUE ADJ - DEF NPC		13,190,462			
19	SOLAR FEED-IN REVENUE		1,017,606			
20	UNBILLED REV - UNCOLLECTIBLE		48,000			
21	UNBILLED REVENUE	-62,038	-5,058,000			0.0815
22	DSM REVENUE-RESIDENTIAL		25,798,568			
23	BLUE SKY REV-RESIDENTIAL		1,995,804			
24						
25	WASHINGTON					
26	02LNX00109-REF/NREF ADV +		904			
27	02NETMT135 - WA RES NET MTR	2,411	219,080	161	14,975	0.0909
28	02OALTB15R-WA OUTD AR LGT	1,033	148,519	1,118	924	0.1438
29	02RESD0016-WA RES SRVC	1,500,324	131,844,971	99,277	15,113	0.0879
30	02RESD0017-BILL ASSISTANCE	80,814	7,043,752	5,400	14,966	0.0872
31	02RESD0018-WA 3 PHASE RES	2,259	216,923	83	27,217	0.0960
32	02RESD018X-WA 3 PHASE RES	428	39,959	18	23,778	0.0934
33	02RGNSB024-WA SM GEN SVC	19,359	2,120,558	3,044	6,360	0.1095
34	02UPPL000R-BASE SCH FALL			1		
35	REVENUE ADJ- DEF NPC		-311,259			
36	REVENUE_ACCT ADJUSTMENTS		-4,547,120			
37	SMUD REVENUE IMPUTATIONS		105,830			
38	WASHINGTON - CHEHALIS DEF		-1,320,000			
39	UNBILLED REV - UNCOLLECTIBLE		3,000			
40	UNBILLED REVENUE	-11,884	-751,000			0.0632
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
43	TOTAL	54,999,277	4,817,264,361	1,782,893	30,848	0.0876

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1	DSM REVENUE-RESIDENTIAL		4,676,006			
2	BLUE SKY REV-RESIDENTIAL		126,825			
3						
4	WYOMING					
5	05LNX00102-LINE EXT 80% G		753			
6	05NETMT135 - EXP PARTIALREQ	1,421	163,454	127	11,189	0.1150
7	05OALT015R-OUTD AR LGT SR	890	143,381	1,041	855	0.1611
8	05RESD0002-WY RES SRVC	919,330	97,988,436	100,120	9,182	0.1066
9	05RGNSV025-WY SM GEN SVC	8,294	992,423	1,220	6,798	0.1197
10	REVENUE ADJUSTMENT -		243,423			
11	REVENUE_ACCT ADJUSTMENTS		-2,962			
12	SMUD REVENUE IMPUTATIONS		56,842			
13	UNBILLED REV - UNCOLLECTIBLE		12,000			
14	UNBILLED REVENUE	-7,487	-685,000			0.0915
15	DSM REVENUE-RESIDENTIAL		1,442,805			
16	DSM REVENUE-RESIDENTIAL GEN		14,494			
17	BLUE SKY REV-RESIDENTIAL		116,728			
18	05LNX00109-REF/NREF ADV +		825			
19	05RESD0002-WY RES SRVC	118,783	12,852,318	12,508	9,497	0.1082
20	05RGNSV025- SM GEN SVC-R	398	65,612	121	3,289	0.1649
21	09OALT207R-SECURITY AR LG	75	21,834	89	843	0.2911
22	05NETMT135 - EXP PARTIAL REQ	241	27,382	14	17,214	0.1136
23	09RES00002			2		
24	09RESD0002			4		
25	UNBILLED REVENUE	-534	-55,000			0.1030
26	DSM REVENUE-RESIDENTIAL		185,079			
27	DSM REVENUE-RES GEN SVC		1,925			
28	BLUE SKY REV-RESIDENTIAL		19,893			
29						
30	LESS MULTIPLE BILLINGS			-118,001		
31						
32	TOTAL RESIDENTIAL SALES	15,567,753	1,732,822,429	1,545,529	10,073	0.1113
33						
34	COMMERCIAL SALES					
35	CALIFORNIA					
36	06CHCK000N-CA NRES CHECK			1		
37	06GNSV0025-CA GEN SRVC	53,397	8,878,328	6,457	8,270	0.1663
38	06GNSV025F-GEN SRVC-< 20	873	160,013	85	10,271	0.1833
39	06GNSV0A32-GEN SRVC-20 KW	81,380	11,951,341	1,022	79,628	0.1469
40	06LGSV048T-LRG GEN SERV	28,466	2,730,670	5	5,693,200	0.0959
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
43	TOTAL	54,999,277	4,817,264,361	1,782,893	30,848	0.0876

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1	06NMT48135-CA GEN SVC NET	2,691	261,910	1	2,691,000	0.0973
2	06LGSV0A36-LRG GEN SRVC-O	68,270	8,499,700	162	421,420	0.1245
3	06LNX00102-LINE EXT 80% GTY		7,998			
4	06LNX00105-CNTRCT $ MIN G		4,953			
5	06LNX00109-REF/NREF ADV +		76,943			
6	06LNX00300 - 80% MTHLY MIN		4,759			
7	06LNX00311 - LINE EXT 80% GTY		11,120			
8	06NMT36135-G SVC NT ->100	2,315	290,998	4	578,750	0.1257
9	06OALT015N-OUTD AR LGT SR	695	189,765	491	1,415	0.2730
10	06RCFL0042-AIRWAY & ATHLE	176	37,857	36	4,889	0.2151
11	06NMT25135-CA GEN SVC NET	81	13,073	8	10,125	0.1614
12	06NMT32135-CA GEN SVC NET	475	82,111	10	47,500	0.1729
13	REVENUE_ACCT ADJUSTMENTS		-974,465			
14	SMUD REVENUE IMPUTATIONS		19,485			
15	06LNX00110-REF/NREF ADV +		6,602			
16	SOLAR FEED-IN REVENUE		54,047			
17	UNBILLED REVENUE	-1,608	-77,000			0.0479
18	DSM REVENUE-COMMERCIAL		632,637			
19	BLUE SKY REV-COMMERCIAL		3,017			
20						
21	IDAHO					
22	07CISH0019-COMM & IND SPA	5,094	441,181	101	50,436	0.0866
23	07GNSV0006-GEN SRVC-LRG P	213,973	17,526,970	932	229,585	0.0819
24	07GNSV0009-GEN SRVC-HI VO	43,654	2,673,086	2	21,827,000	0.0612
25	07GNSV0023-GEN SRVC-SML P	139,863	13,749,621	6,260	22,342	0.0983
26	07GNSV0035-GEN SRVCOPTION	875	55,969	2	437,500	0.0640
27	07GNSV006A-GEN SRVC-LRG P	26,883	2,335,614	189	142,238	0.0869
28	07GNSV023A-GEN SRVC-SML P	24,780	2,440,529	1,278	19,390	0.0985
29	07GNSV023F-GEN SRVC SML P	7	1,951	5	1,400	0.2787
30	07LNX00010-MNTHLY 80%GUAR		8,987			
31	07LNX00035-ADV 80%MO GUAR		207,261			
32	07LNX00040-ADV+REFCHG+80%		47,913			
33	07OALT007N-SECURITY AR LG	243	93,311	176	1,381	0.3840
34	07OALT07AN-SECURITY AR LG	11	4,429	12	917	0.4026
35	07LNX00312 - ID LINE EXT		11,134			
36	07NMT06135 - NET MTR - LG GEN	1,681	144,948	4	420,250	0.0862
37	07NMT23135 - NET MTR - SM GEN	717	60,967	17	42,176	0.0850
38	07LNX00015-ANNUAL 80%GUAR		211			
39	07LNX00311 - LINE EXT 80% GTY		23,473			
40	07LNX00300 - 80% MTHLY MIN		10,072			
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
43	TOTAL	54,999,277	4,817,264,361	1,782,893	30,848	0.0876

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1	SMUD REVENUE IMPUTATIONS		28,043			
2	UNBILLED REVENUE	-2,942	-279,000			0.0948
3	DSM REVENUE-COMMERCIAL		720,858			
4	BLUE SKY REV-COMMERCIAL		2,136	1		
5						
6	OREGON					
7	01COST0023, OR GEN SRV, COST	977,448	55,943,107			0.0572
8	01COST0048 - 01LGSV0048	862,794	42,047,669			0.0487
9	01COST023F - GEN SRV COST	3,034	185,180			0.0610
10	01COSTB023 - OR GEN SRV,	38,730	2,266,327			0.0585
11	01COSTL030 - OR LRG GEN SRV,	1,108,862	56,434,545			0.0509
12	01COSTS028, OR GEN SERV	1,918,139	113,675,844			0.0593
13	01GNSV0023, GEN SRV < 30 KW		51,888,496	55,095		
14	01GNSV0028, GEN SRV > 30 KW		55,678,970	8,893		
15	01GNSV023F - GEN SRV - FLAT RA	10,219	1,618,934	781	13,085	0.1584
16	01GNSV023M - GEN SRV, MANUAL	78	8,112	1	78,000	0.1040
17	01GNSV023T, OR GEN SRV, TOU		169,370	204		
18	01HABT0023, OR HABITAT BLEND	2,500	146,925			0.0588
19	01HABTB023 - OR HABITAT BLEND	69	4,191			0.0607
20	01LGSB0030, GEN DEL SRV, > 200		1,061,780	22		
21	01LGSV0030 - LG GEN SRV > 1000		27,838,472	617		
22	01LGSV0048-1000KW AND OVR		15,185,516	92		
23	01LGSV048M-LRG GEN SRVC 1	63,518	4,084,862	1	63,518,000	0.0643
24	01LNX00100-LINE EXT 60% G		3,406			
25	01LNX00102-LINE EXT 80% G		320,010			
26	01LNX00103-LINE EXT 80% G		5,383			
27	01LNX00105-CNTRCT $ MIN G		14,004			
28	01LNX00109-REF/NREF ADV +		1,123,757			
29	01LNX00110-REF/NREF ADV +		8,342			
30	01LNX00311 - LINE EXT 80% GTY		133,264			
31	01LNX00120 - LINE EXT 60% GTY		294			
32	01LNX00300 - LINE EXT 80% GTY		192,390			
33	01LNX00310-LINE EXTENSION		636			
34	01LPRS047M-PART REQ SRVC	48,149	4,494,139	5	9,629,800	0.0933
35	01NMT23135 - NET MTR GEN < 30		174,593	204		
36	01NMT28135 - NET MTR GEN > 30		834,349	115		
37	01NMT30135 -NET MTR GEN > 200		1,024,606	23		
38	01NMT48135-NET MTR GEN SVC =		393,768	4		
39	01OALT015N-OUTD AR LGT NR	5,620	819,409	2,906	1,934	0.1458
40	01OALTB15N-OUTD AR LGT NR	1,497	247,369	1,091	1,372	0.1652
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
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1	01PTOU0023, OR GEN SRV, TOU	3,050	177,076			0.0581
2	01PTOUB023, OR GEN SRV, TOU	470	28,102			0.0598
3	01RCFL0054-REC FIELD LGT	1,405	137,250	107	13,131	0.0977
4	01RENW0023, OR RENW USAGE	8,171	478,253			0.0585
5	01RENWB023 - OR RENEWABLE	198	11,873			0.0600
6	01STDAY023 - DAY STD OFR SCH	2,833	193,073			0.0682
7	01STDAY028 - DAY STD OFF SCH	13,756	950,975			0.0691
8	01STDAY030 - STD DAY OFF SCH	4,829	301,016			0.0623
9	01VIR23136-VOL INC <=30KW		121,061	80		
10	01VIR28136-VOL INC >30KW		547,135	84		
11	01VIR30136-VOL INC >200KW		219,403	5		
12	01VIR48136-VOL INC >1000KW		127,100	1		
13	01LGSB0048 - LG GSVC > 1000		84,743	1		
14	01LGSV028M - LGSV, <1000 kW, M	466	42,586	1	466,000	0.0914
15	01GNSV030M - GEN SRV, 200 KW	145	23,270	1	145,000	0.1605
16	01GNSV0728 - GEN SVC DIR ACC		250,417	15		
17	01GNSV0730 -GEN SVC DIR ACC		2,174,244	16		
18	01GNSV0748 LG GEN SVC DIR		2,099,603	4		
19	01ZZ MERGCR-MERGER CREDITS		-2			
20	OR GAIN ON SALE OF ASSET		-13,728			
21	REVENUE ADJ - DEF NPC		-183,213			
22	REVENUE_ACCT ADJUSTMENTS		-1,290,514			
23	SMUD REVENUE IMPUTATIONS		331,311			
24	SOLAR FEED-IN REVENUE		1,089,606			
25	UNBILLED REVENUE	10,260	2,170,000			0.2115
26	DSM REVENUE-COMMERCIAL		9,857,491			
27	BLUE SKY REV-COMMERCIAL		727,145	109		
28	01GNSB0023, OR GEN SRV, BPA		2,657,473	4,812		
29	01GNSB0028, OR GEN SRV, BPA		2,873,018	411		
30	01GNSB023T - OR GEN SRV - TOU		30,295	55		
31						
32	UTAH					
33	08ABL-NRES - APPLICANT BUILT		7,654			
34	08BLSKY01N-BLUESKY ENERGY		-1			
35	08CFR00051-MTH FAC SRVCHG		38,907			
36	08CFR00052-ANN FAC SVCCHG		2			
37	08COOLKPRN - A/C DIRECT LOAD			2,881		
38	08GNSV0006-GEN SRVC-DISTR	4,938,734	411,142,588	10,904	452,929	0.0832
39	08GNSV0009-GEN SRVC-HI VO	676,042	40,462,935	26	26,001,615	0.0599
40	08GNSV0023-GEN SRVC-DISTR	1,197,924	118,608,752	65,953	18,163	0.0990
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
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1	08GNSV006A-GEN SRVC-ENERG	237,223	28,023,955	2,050	115,719	0.1181
2	08GNSV006B-GEN SRVC-DEM&	2,271	260,319	29	78,310	0.1146
3	08GNSV006M-MNL DIST VOLTG	1,538	116,926	6	256,333	0.0760
4	08GNSV009A-GEN SRVC HI VO	23,096	1,528,199	2	11,548,000	0.0662
5	08GNSV009M-MANL HIGH VOLT	4,033	290,743	1	4,033,000	0.0721
6	08GNSV023F-GEN SRVC FIXED	1,307	187,525	127	10,291	0.1435
7	08GNSV023M-GNSV DIST VOLT	101	9,689	4	25,250	0.0959
8	08GNSV06AM-MNL ENERGY TOD	582	59,022	1	582,000	0.1014
9	08GNSV06MN-GNSV DIST VOLT	35,335	2,714,908	524	67,433	0.0768
10	08LNX00002-MTHLY 80% GUAR		229,822			
11	08LNX00004-ANNUAL 80%GUAR		17,166			
12	08LNX00006-FIXD MTHLY MIN		4,476			
13	08LNX00008-ANNUALMIN GUAR		10,757			
14	08LNX00014-80% MIN MNTHLY		1,456,844			
15	08LNX00017-ADV/REF&80%ANN		153,901			
16	08LNX00158-ANNUALCOST MTH		32,125			
17	08LNX00300 - LINE EXT 80% PLUS		100,545			
18	08LNX00310 - IRR 80% ANN MIN		50,649			
19	08LNX00312 UT IRG LINE EXT		4,924			
20	08NMT06135-NET MTR GEN SV	60,904	5,282,497	126	483,365	0.0867
21	08NMT08135 -NET MTR GEN SVC	60,584	4,061,468	5	12,116,800	0.0670
22	08NMT23135 - UT NET MTR, GEN	3,302	343,308	190	17,379	0.1040
23	08NMT6A135-NET MTR GEN SVC T	1,936	236,429	13	148,923	0.1221
24	08OALT007N-SECURITY AR LG	8,143	1,894,612	4,259	1,912	0.2327
25	08POLE0075-POLES W/LIGHT		230	2		
26	08PRSV031M-BKUP MNT&SUPPL	24,290	1,762,247	3	8,096,667	0.0726
27	08PTLD000N-POST TOP LIGHT	6	452	2	3,000	0.0753
28	08TOSS015F-TRAFFIC SIG NM	167	15,592	20	8,350	0.0934
29	08TOSS0015-TRAF & OTHER S	2,193	241,435	855	2,565	0.1101
30	08MONL0015-MTR OUTDONIGHT	17,789	1,248,743	461	38,588	0.0702
31	REVENUE_ACCT ADJUSTMENTS		-1,672,573			
32	REVENUE ADJ - DEF NPC		13,699,555			
33	SOLAR FEED-IN REVENUE		707,504			
34	08LNX00311 - LINE EXT 80% GTY		267,510			
35	08GNSV0008 -GEN SVC TOU	970,917	71,667,899	149	6,516,221	0.0738
36	08GNSV008M -GEN SVC TOU	29,441	2,340,606	5	5,888,200	0.0795
37	UNBILLED REVENUE	-30,279	-2,064,000			0.0682
38	DSM REVENUE-COMMERCIAL		24,842,117			
39	BLUE SKY REV-COMMERCIAL		434,725			
40						
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
43	TOTAL	54,999,277	4,817,264,361	1,782,893	30,848	0.0876

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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	WASHINGTON					
2	02GNSB0024-WA GEN SRVC DO	33,078	3,030,551	1,773	18,657	0.0916
3	02GNSB024F-GEN SRVC DOM/F	154	18,731	6	25,667	0.1216
4	02GNSB24FP-WA GEN SVC	185	82,969	84	2,202	0.4485
5	02GNSV0024-WA GEN SRVC	479,723	41,734,253	13,549	35,407	0.0870
6	02GNSV024F-WA GEN SRVC-FL	1,116	144,572	111	10,054	0.1295
7	02LGSB0036-LRG GEN SVC IRG	71,510	5,403,808	113	632,832	0.0756
8	02LGSV0036-WA LRG GEN SRV	744,523	54,743,597	845	881,092	0.0735
9	02LGSV048T-LRG GEN SRVC 1	183,063	12,335,935	34	5,384,206	0.0674
10	02LNX00102-LINE EXT 80% G		29,002			
11	02LNX00103-LINE EXT 80% G		7,237			
12	02LNX00105-CNTRCT $ MIN G		1,754			
13	02LNX00109-REF/NREF ADV +		255,524			
14	02LNX00110-REF/NREF ADV +		13,532			
15	02LNX00112-YR INCURRED CH		669			
16	02LNX00300-LINE EXT 80% G		11,101			
17	02LNX00310 - IRG, 80% ANNUAL		1,741			
18	02LNX00311 - LINE EXT 80% GTY		72,584			
19	02LNX00312 - WA IRG LINE EXT		2,922			
20	02OALT015N-WA OUTD AR LGT	1,532	208,736	802	1,910	0.1363
21	02OALTB15N-WA OUTD AR LGT	557	80,992	491	1,134	0.1454
22	02RCFL0054-WA REC FIELD L	267	23,346	30	8,900	0.0874
23	02NMT24135, NET MTR, WA	1,125	93,684	24	46,875	0.0833
24	02NMT36135-NET METER LG SVC	3,111	231,906	4	777,750	0.0745
25	02NMT48135-WA LG SVC NET	5,138	327,238	1	5,138,000	0.0637
26	REVENUE ADJ - DEF NPC		-244,702			
27	REVENUE_ACCT ADJUSTMENTS		-3,884,429			
28	SMUD REVENUE IMPUTATIONS		97,430			
29	WASHINGTON - CHEHALIS DEF		-1,020,000			
30	UNBILLED REVENUE	11,391	1,139,000			0.1000
31	DSM REVENUE-COMMERCIAL		4,004,906			
32	BLUE SKY REV-COMMERCIAL		34,752	5		
33						
34	WYOMING					
35	05CHCK000N-WY NRES CHECK			1		
36	05GNSV0025-WY GEN SRVC	228,493	22,715,976	17,509	13,050	0.0994
37	05GNSV0028-GEN SVC > 15 KW	912,076	76,976,356	3,384	269,526	0.0844
38	05GNSV025F-GEN SRVC-FL RA	1,013	163,412	180	5,628	0.1613
39	05LGSV0046-WY LRG GEN SRV	214,848	14,973,247	19	11,307,789	0.0697
40	05LGSV048T-LRG GENSRV TIM	11,578	888,516	1	11,578,000	0.0767
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
43	TOTAL	54,999,277	4,817,264,361	1,782,893	30,848	0.0876

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1	05LNX00100-LINE EXT 60% G		451			
2	05LNX00102-LINE EXT 80% G		561,536			
3	05LNX00103-LINE EXT 80% G		7,799			
4	05LNX00105-CNTRCT $ MIN G		6,005			
5	05LNX00109-REF/NREF ADV +		615,241			
6	05LNX00110-REF/NREF ADV +		5,915			
7	05LNX00114-TEMP SVC 12MO>		787			
8	05NMT25135 - NET MTR, GEN	255	24,955	19	13,421	0.0979
9	05NMT28135-NET MTR SM GEN	6,747	649,697	18	374,833	0.0963
10	05OALT015N-OUTD AR LGT SR	2,764	448,371	1,681	1,644	0.1622
11	05RCFL0054-WY REC FIELD L	765	63,511	51	15,000	0.0830
12	05RFNDCENT-CENTRALIA RFND		1			
13	09OALT207N-SECURITY AR LG		152	1		
14	05LNX00300 - LINE EXT 80% GTY		50,285			
15	05LNX00311 - LINE EXT 80% GTY		84,149			
16	05LNX00312 - WY IRG LINE EXT		2,225			
17	REVENUE ADJ - DEF NPC		348,447			
18	REVENUE_ACCT ADJUSTMENTS		-3,509			
19	SMUD REVENUE IMPUTATIONS		80,756			
20	UNBILLED REVENUE	-15,923	-1,071,000			0.0673
21	DSM REVENUE-SMALL		1,207,456			
22	DSM REVENUE-LARGE		53,176			
23	BLUE SKY		5,624			
24	05GNSV0025-WY GEN SRVC	31,186	3,077,215	2,311	13,495	0.0987
25	05GNSV0028-GEN SVC > 15 KW	96,539	8,187,915	415	232,624	0.0848
26	05GNSV025F-GEN SRVC-FL RA	209	26,747	33	6,333	0.1280
27	05LNX00102-LINE EXT 80% G		8,640			
28	05LNX00109-REF/NREF ADV +		186,285			
29	05LNX00110-REF/NREF ADV +		1,691			
30	05LNX00114-TEMP SVC 12MO>		488			
31	05NMT25135 - WY NET MTR, GEN	5	914	2	2,500	0.1828
32	05NMT28135-NET MTR SM GEN	521	48,620	4	130,250	0.0933
33	09OALT207N-SECURITY AR LG	275	69,829	138	1,993	0.2539
34	09MONL0213-WY MTR OUTDOOR	409	20,551	11	37,182	0.0502
35	05LNX00300 - LINE EXT 80%		711			
36	05LNX00311 - LINE EXT 80%		3,063			
37	UNBILLED REVENUE	-951	-64,000			0.0673
38	DSM REVENUE-SMALL		251,935			
39	BLUE SKY REV-COMMERCIAL		969			
40						
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
43	TOTAL	54,999,277	4,817,264,361	1,782,893	30,848	0.0876

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1	LESS MULTIPLE BILLINGS			-24,811		
2						
3	TOTAL COMMERCIAL SALES	17,073,151	1,517,907,746	200,454	85,172	0.0889
4						
5	INDUSTRIAL SALES					
6	CALIFORNIA					
7	06GNSV0025-CA GEN SRVC	704	119,533	92	7,652	0.1698
8	06GNSV0A32-GEN SRVC-20 KW	1,778	309,329	23	77,304	0.1740
9	06LGSV048T-LRG GEN SERV	46,895	4,737,861	10	4,689,500	0.1010
10	06LGSV0A36-LRG GEN SRVC-O	4,778	642,554	12	398,167	0.1345
11	REVENUE_ACCT ADJUSTMENTS		-164,914			
12	SMUD REVENUE IMPUTATIONS		2,905			
13	SOLAR FEED-IN REVENUE		7,303			
14	UNBILLED REVENUE	500	91,000			0.1820
15	DSM REVENUE-INDUSTRIAL		107,433			
16	BLUE SKY REVENUE-INDUSTRIAL		75			
17						
18	IDAHO					
19	07CFR00001-MTH FACILITY S		2,217			
20	07CISH0019-COMM & IND SPA	47	4,524	2	23,500	0.0963
21	07GNSV0006-GEN SRVC-LRG P	88,944	6,369,347	106	839,094	0.0716
22	07GNSV0009-GEN SRVC-HI VO	78,074	5,024,006	15	5,204,933	0.0643
23	07GNSV0023-GEN SRVC-SML P	13,335	1,264,065	328	40,655	0.0948
24	07GNSV0035-GEN SRVCOPTION	1,029	68,920	1	1,029,000	0.0670
25	07GNSV006A-GEN SRVC LG P	3,846	326,745	24	160,250	0.0850
26	07GNSV023A-GEN SRVC-SML P	2,170	226,142	166	13,072	0.1042
27	07GNSV023S-IDAHO TRAFFIC	5	609	1	5,000	0.1218
28	07LNX00108-ANN COST MTHLY		1,996			
29	07OALT007N-SECURITY AR LG	12	4,767	16	750	0.3973
30	07OALT07AN-SECURITY AR LG		238	1		
31	07SPCL0001	1,441,000	89,205,252	1	1,441,000,000	0.0619
32	07SPCL0002	107,327	6,345,346	1	107,327,000	0.0591
33	SMUD REVENUE IMPUTATIONS		112,240			
34	UNBILLED REVENUE	-301	240,000			-0.7973
35	DSM REVENUE-INDUSTRIAL		234,190			
36						
37	OREGON					
38	01COST0023, GEN SRV CST BSD	20,169	1,157,777			0.0574
39	01COST0048 - 01LGSV0048	1,730,907	83,849,862			0.0484
40	01COST023F - GEN SRV CST-BSD	1	63			0.0630
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
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1	01COSTB023 - GEN SRV, CST-BSD	234	13,060			0.0558
2	01COSTL030 - LRG GEN SRV, CST	220,008	11,231,660			0.0511
3	01COSTS028, OR GEN SERV	93,365	5,515,819			0.0591
4	01GNSV0023, OR GEN SRV, < 30		1,121,615	1,081		
5	01GNSV0028, OR GEN SRV > 30		3,522,412	461		
6	01GNSV023F - GEN SRV - FLT	2	688	2	1,000	0.3440
7	01GNSV023M - OR GEN SRV			1		
8	01GNSV023T, GEN SRV, TOU OPT		2,346	3		
9	01GNSV0728 -GEN SVC DIR		7,469	1		
10	01GNSV0730 -GEN SVC DIR		39,989	3		
11	01GNSV0748 LG GEN SVC DIR		1,723,866	2		
12	01LGSV0030 - LG G SRV > 1000		7,779,630	150		
13	01LGSV0048-1000KW AND OVR		28,485,668	88		
14	01LGSV048M-LRG GEN SRVC 1	87,763	6,623,196	3	29,254,333	0.0755
15	01LNX00102-LINE EXT 80% G		45,792			
16	01LNX00109-REF/NREF ADV +		2,256			
17	01LNX00300 - LINE EXT 80% GTY		22,656			
18	01LPRS047M-PART REQ SRVC	18,604	1,554,677	2	9,302,000	0.0836
19	01NMT23135 - NET MTR GEN < 30		1,454	2		
20	01NMT28135 - NET MTR GEN > 30		27,928	4		
21	01NMT30135 - NET MTR GEN > 200		39,491	1		
22	01OALT015N-OUTD AR LGT NR	285	40,624	128	2,227	0.1425
23	01OALTB15N-OR OUTD AR LGT	1	127	4	250	0.1270
24	01PTOU0023, GEN SRV, TOU ENG	31	1,936			0.0625
25	01RENW0023, RENW USAGE SPLY	96	5,314			0.0554
26	01RENWB023 - OR RENEWABLE		2			
27	01STDAY023 - DAY STD OFR SCH	16	1,116			0.0698
28	01STDAY028 - DAY STD OFF SCH	537	37,355			0.0696
29	01STDAY030 - STD DAY OFF SCH	728	46,138			0.0634
30	01VIR23136-VOL INC <=30KW		1,047	1		
31	01VIR30136-VOL INC >200KW		36,487	1		
32	OR GAIN ON SALE OF ASSET		-9,488			
33	REVENUE ADJ - DEF NPC		-60,536			
34	REVENUE_ACCT ADJUSTMENTS		-780,844			
35	SMUD REVENUE IMPUTATIONS		141,188			
36	SOLAR FEED-IN REVENUE		723,370			
37	UNBILLED REVENUE	-956	191,000			-0.1998
38	DSM REVENUE-INDUSTRIAL		873,524			
39	BLUE SKY REVENUE-INDUSTRIAL		464,643	34		
40	01GNSB0023, OR GEN SRV, BPA		15,302	22		
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
43	TOTAL	54,999,277	4,817,264,361	1,782,893	30,848	0.0876

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1	01GNSB0028, OR GEN SRV, BPA		9,200	2		
2						
3	UTAH					
4	08CFR00051-MTH FAC SRVCHG		18,725			
5	08EFOP0021-ELEC FURNACE O	1,960	208,099	2	980,000	0.1062
6	08EFOP021M-ELEC FURNACE O	1,229	164,840	3	409,667	0.1341
7	08GNSV0006-GEN SRVC-DISTR	667,128	57,986,225	1,097	608,139	0.0869
8	08GNSV0009-GEN SRVC-HI VO	3,587,791	193,621,203	116	30,929,233	0.0540
9	08GNSV0023-GEN SRVC-DISTR	54,959	5,543,230	3,347	16,420	0.1009
10	08GNSV006A-GEN SRVC-ENERG	60,045	7,139,984	255	235,471	0.1189
11	08GNSV006B-GEN SRVC-DEM&	1,951	138,237	2	975,500	0.0709
12	08GNSV009A-GEN SRVC HI VO	17,076	1,466,883	6	2,846,000	0.0859
13	08GNSV009M-MANL HIGH VOLT	488,858	26,344,251	9	54,317,556	0.0539
14	08GNSV023F-GEN SRVC FIXED	4	2,569	1	4,000	0.6423
15	08GNSV06MN-GNSV DIST VOLT	1,194	106,255	25	47,760	0.0890
16	08GNSV09AM-MAN TOD HIVOLT	1,087	117,879	1	1,087,000	0.1084
17	08LNX00002-MTHLY 80% GUAR		482,057			
18	08LNX00014-80% MIN MNTHLY		7,582			
19	08LNX00311 - LINE EXT 80% GTY		1,708			
20	08LNX00300 - LINE EXT 80% PLUS		30,640			
21	08LNX00310 - IRR 80% ANN MIN		3,493			
22	08OALT007N-SECURITY AR LG	1,210	259,489	453	2,671	0.2145
23	08TOSS0015-TRAF & OTHER S	10	1,398	9	1,111	0.1398
24	08MONL0015-MTR OUTDONIGHT	14	2,757	7	2,000	0.1969
25	08NMT06135-NET MTR GEN SV	2,492	291,762	8	311,500	0.1171
26	08NMT23135 -NET MTR G <25	173	15,723	6	28,833	0.0909
27	08NMT6A135-NET MTR GEN SVC T	2,939	347,946	3	979,667	0.1184
28	08PRSV031M-BKUP MNT&SUPPL	6,541	695,654	1	6,541,000	0.1064
29	08SPCL0001	605,019	29,957,097	1	605,019,000	0.0495
30	08SPCL0002	911,562	40,226,507	1	911,562,000	0.0441
31	08SPCL0003	1,176,612	53,533,831	1	1,176,612,000	0.0455
32	REVENUE_ACCT ADJUSTMENTS		-2,087,301			
33	REVENUE ADJ - DEF NPC		8,463,673			
34	08GNSV06AM-MNL ENERGY TOD	325	41,337	2	162,500	0.1272
35	08GNSV0008 - GEN SVC TOU	1,021,842	76,659,982	105	9,731,829	0.0750
36	08GNSV008M - GEN SVC TOU	60,639	4,600,454	7	8,662,714	0.0759
37	SOLAR FEED-IN REVENUE		882,372			
38	UNBILLED REVENUE	-47,474	-1,160,000			0.0244
39	DSM REVENUE-INDUSTRIAL		13,361,539			
40	BLUE SKY REVENUE-INDUSTRIAL		105,703	7		
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
43	TOTAL	54,999,277	4,817,264,361	1,782,893	30,848	0.0876

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1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	WASHINGTON					
2	02GNSB0024-WA GEN SRVC DO	1,312	126,570	49	26,776	0.0965
3	02GNSB24FP-WA GEN SVC	6	2,214	1	6,000	0.3690
4	02GNSV0024-WA GEN SRVC	16,746	1,450,848	345	48,539	0.0866
5	02GNSV024F-WA GEN SRVC-FL	33	7,930	4	8,250	0.2403
6	02LGSV0036-WA LRG GEN SRV	102,051	7,784,835	104	981,260	0.0763
7	02LGSV048T-LRG GEN SRVC 1	679,498	39,753,291	31	21,919,290	0.0585
8	02OALT015N-WA OUTD AR LGT	121	15,363	41	2,951	0.1270
9	02OALTB15N-WA OUTD AR LGT	29	4,028	15	1,933	0.1389
10	02PRSV47TM-LRG PART REQMT	1,996	293,874	1	1,996,000	0.1472
11	02LGSB0036-LRG GEN SVC IRG	1,880	236,627	14	134,286	0.1259
12	REVENUE ADJ - DEF NPC		-113,560			
13	REVENUE_ACCT ADJUSTMENTS		-1,648,227			
14	SMUD REVENUE IMPUTATIONS		52,367			
15	WASHINGTON - CHEHALIS		-510,000			
16	UNBILLED REVENUE	-3,800	-44,000			0.0116
17	DSM REVENUE-INDUSTRIAL		1,700,460			
18						
19	WYOMING					
20	05GNSV0025-WY GEN SRVC	28,048	2,506,415	1,141	24,582	0.0894
21	05GNSV0028-GEN SVC > 15 KW	258,078	19,105,345	481	536,545	0.0740
22	05GNSV025F-GEN SRVC-FL RA	26	4,302	8	3,250	0.1655
23	05LGSV0046-WY LRG GEN SRV	1,702,965	111,811,653	57	29,876,579	0.0657
24	05LGSV046M-WY LRG GEN SRV	19,709	1,392,451	1	19,709,000	0.0707
25	05LGSV048M-TOU>1000KW MAN	287,448	16,256,612	1	287,448,000	0.0566
26	05LGSV048T-LRG GENSRV TIM	1,574,638	92,566,416	10	157,463,800	0.0588
27	05LNX00100-LINE EXT 60% G		36,161			
28	05LNX00102-LINE EXT 80% G		406,293			
29	05LNX00105-CNTRCT $ MIN G		36,851			
30	05LNX00109-REF/NREF ADV +		238,170			
31	05OALT015N-OUTD AR LGT SR	83	12,113	41	2,024	0.1459
32	05PRSV033M-PART SERV REQ	1,371,276	88,855,668	8	171,409,500	0.0648
33	REVENUE ADJ - DEF NPC		1,633,205			
34	REVENUE_ACCT ADJUSTMENTS		-11,109			
35	SMUD REVENUE IMPUTATIONS		360,754			
36	05LNX00300 - LINE EXT 80%		30,798			
37	05LNX00311 - LINE EXT 80%		22,578			
38	UNBILLED REVENUE	6,762	1,019,000			0.1507
39	DSM REVENUE-SMALL		228,545			
40	DSM REVENUE-LARGE		966,948			
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
43	TOTAL	54,999,277	4,817,264,361	1,782,893	30,848	0.0876

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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	BLUE SKY REVENUE-INDUSTRIAL		7,474	1		
2	05GNSV0025-WY GEN SRVC	3,660	367,246	288	12,708	0.1003
3	05GNSV0028-GEN SVC > 15 KW	56,472	4,260,213	77	733,403	0.0754
4	05GNSV028M-GEN SVC > 15 KW	3,407	208,024	3	1,135,667	0.0611
5	05LGSV0046-WY LRG GEN SRV	45,999	3,192,808	4	11,499,750	0.0694
6	05LGSV048M-TOU>1000KW MAN	235,847	13,816,600	4	58,961,750	0.0586
7	05LGSV048T-LRG GENSRV TIM	1,310,835	81,609,106	12	109,236,250	0.0623
8	05LNX00102-LINE EXT 80% G		46,001			
9	05LNX00109-REF/NREF ADV +		1,640,760			
10	05LNX00300 - LINE EXT 80%		1,668			
11	05PRSV033M-PART SERV REQ	97,095	6,284,861	2	48,547,500	0.0647
12	09OALT207N-SECURITY AR LG	4	940	2	2,000	0.2350
13	UNBILLED REVENUE	-817	-83,000			0.1016
14	DSM REVENUE-SMALL		106,661			
15	DSM REVENUE-LARGE		421,189			
16	BLUE SKY REVENUE-INDUSTRIAL		23			
17						
18	LESS MULTIPLE BILLINGS			-962		
19						
20	TOTAL INDUSTRIAL SALES	20,388,527	1,287,846,708	10,054	2,027,902	0.0632
21						
22	IRRIGATION SALES					
23	CALIFORNIA					
24	06APSV0020-AG PMP SRVC	13,728	1,790,015	879	15,618	0.1304
25	06APSV020L-AG PMP SRVC-NO	61,142	8,461,322	579	105,599	0.1384
26	06LGSV048T-LRG GEN SERV	934	126,297	1	934,000	0.1352
27	06LNX00103-LINE EXT 80% G		3,934			
28	06LNX00109-REF/NREF ADV +		104			
29	06LNX00110-REF/NREF ADV +		21,790			
30	06LNX00312 - CA IRG LINE EXT		3,345			
31	06NML20135-AGRI PUMP-NET MTR	641	107,517	7	91,571	0.1677
32	06NMT20135-AGRI PUMP-NET	5	802	4	1,250	0.1604
33	06USBR0020-KLAM IRG ONPRJ	4,570	652,962	348	13,132	0.1429
34	06USBR020L-KLAM IRG PRJ-NO	27,160	4,057,061	370	73,405	0.1494
35	SOLAR FEED-IN REVENUE		9,124			
36	IRRIGATION UNBILLED	-22	-21,000			0.9545
37	DSM REVENUE-IRRIGATION		333,182			
38	BLUE SKY REVENUE-IRRIGATION		23			
39	REVENUE_ACCT ADJUSTMENTS		-591,320			
40						
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
43	TOTAL	54,999,277	4,817,264,361	1,782,893	30,848	0.0876

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 2014/Q4

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1	IDAHO					
2	07APSA010L - IRG & PUMP LG	392,904	35,466,958	2,676	146,825	0.0903
3	07APSA010S - IRG & PUMP SM	4,476	502,010	346	12,936	0.1122
4	07APSAL10X - IRG & PUMP - LG	205,238	18,170,839	1,456	140,960	0.0885
5	07APSAS10X - IRG & PUMP - SM	3,701	431,317	359	10,309	0.1165
6	07APSV006A-LRG POWER OPT		148	2		
7	07APSV023A-SM POWER OPT S	5	539	3	1,667	0.1078
8	07APSVCNLL-LG LOAD CANAL	27,526	2,229,602	64	430,094	0.0810
9	07APSVCNLS-SM LOAD CANAL	366	34,870	16	22,875	0.0953
10	07LNX00015-ANNUAL 80%GUAR		730			
11	07LNX00035-ADV 80%MO GUAR		242			
12	07LNX00040-ADV+REFCHG+80%		126,037			
13	07LNX00310 80% ANNUAL GTY		432			
14	07LNX00311 - LINE EXT 80% GTY		1,755			
15	07LNX00312 - ID LINE EXT		35,574			
16	07APSN010L - ID LG IRR & PUMP	2,273	220,301	26	87,423	0.0969
17	07APSN010S - IRRIGATION SM	59	7,316	5	11,800	0.1240
18	07APSNS10X - IRRIGATION SM	261	28,055	12	21,750	0.1075
19	UNBILLED REV - IRRIGATION	23	7,000			0.3043
20	DSM REVENUE-IRRIGATION		675,443			
21	BLUE SKY REV-IRRIGATION		30	1		
22						
23	OREGON					
24	01APSV0041-AG PMP SRVC		2,118,801	3,833		
25	01APSV0215-OR IRR TOU PILO		1,471	3		
26	01APSV041L-PUMP SERV >30KW		2,795,795	841		
27	01APSV041T - AGR PUMP SRV		29,902	55		
28	01APSV041X-AG PMP SRVC		773,982	1,195		
29	01COST0041 -01APSV0041	137,787	7,897,519			0.0573
30	01COST0048 - 01LGSV0048	118,510	5,860,447			0.0495
31	01COST0215-OR TOU PILOT COST	409	16,856			0.0412
32	01COSTS028 G SERV CST > 30	583	34,620			0.0594
33	01CSTUSB41-USBR IRR CONTRA	94,869	5,424,571			0.0572
34	01GNSB0028-OR GENL SVC > 30		9,754	2		
35	01GNSV0028, OR GEN SRV > 30		16,112	2		
36	01HABIT041 - 01APSV0041 AG	8	445			0.0556
37	01LGSB0048 - LG GEN SVC > 1000		614,870	2		
38	01LGSV0048-1000KW AND OVR		1,661,291	4		
39	01LNX00103-LINE EXT 80% G		36,255			
40	01LNX00110-REF/NREF ADV +		210,904			
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
43	TOTAL	54,999,277	4,817,264,361	1,782,893	30,848	0.0876

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1	01LNX00310-LINE EXTENSION		11,273			
2	01PTOU0041 - 01APSV0041 AG	583	32,487			0.0557
3	01RENEW041 - 01APSV0041 AG	149	8,651			0.0581
4	01STDAY041 - DAILY STD OFFER	148	9,737			0.0658
5	01USBR0215-OR IRG TOU PILOT		17,377	3		
6	01USBRGV41-IRG TOU W/O BPA		41,213	9		
7	01USBROF41-KLAMATH BASIN		1,986,068	565		
8	01USBRON41-KLAMATH BASIN		2,221,687	1,221		
9	01VIR41136-OR VOLUME INC		39,733	15		
10	01VRU41136-VOL INC USB		313,444	81		
11	SOLAR FEED-IN REVENUE		25,734			
12	IRRIGATION UNBILLED	-160	-42,000			0.2625
13	DSM REVENUE-IRRIGATION		585,964			
14	BLUE SKY REVENUE-IRRIGATION		498			
15	01LNX00312 - OR IRG LINE EXT		23,678			
16	01NMT41135 - NETMTR AG PMP		4,087	5		
17	01NMU41135 -NET MTR <PRJ		3,580	3		
18	OR GAIN ON SALE OF ASSET		-716			
19	REVENUE ADJ - DEF NPC		8,115			
20	REVENUE_ACCT ADJUSTMENTS		-54,820			
21	01APSV41XL-OR Pumping Serv		1,194,471	221		
22						
23	UTAH					
24	08APSV0010-IRR & SOIL DRA	214,373	15,849,826	2,866	74,799	0.0739
25	08APSV10NS- LG SOIL DRAIN	35,312	2,382,786	192	183,917	0.0675
26	08LNX00004-ANNUAL 80%GUAR		4,127			
27	08LNX00014-80% MIN MNTHLY		14,195			
28	08LNX00017-ADV/REF&80%ANN		189,517			
29	08LNX00310 - IRR, 80% ANN MIN		9,439			
30	08LNX00311 - LINE EXT 80% GTY		173			
31	08LNX00312 UT IRG LINE EXT		28,370			
32	08NMT10135-UT IRR_SOIL DRNG	103	9,720	4	25,750	0.0944
33	REVENUE_ACCT ADJUSTMENTS		-48,758			
34	SOLAR FEED-IN REVENUE		20,620			
35	UNBILLED REV - IRRIGATION	160	5,000			0.0313
36	DSM REVENUE-IRRIGATION		597,897			
37	BLUE SKY REVENUE-IRRIGATION		30			
38						
39	WASHINGTON					
40	02APSV0040-WA AG PMP SRVC	134,082	11,033,682	4,010	33,437	0.0823
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
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1	02APSV040X-WA AG PMP SRVC	40,863	3,463,324	1,214	33,660	0.0848
2	02LNX00103-LINE EXT 80% G		6,067			
3	02LNX00105-CNTRCT $ MIN G		79			
4	02LNX00109-REF/NREF ADV +		5,923			
5	02LNX00110-REF/NREF ADV +		172,588			
6	02LNX00310 - IRG 80% ANN MIN		10,695			
7	02LNX00311 - LINE EXT 80%		180			
8	02LNX00312 - WA IRG LINE EXT		37,516			
9	02NMT40135-WA NET MTR -IRG	70	6,030	3	23,333	0.0861
10	REVENUE_ACCT ADJUSTMENTS		-485,911			
11	WASHINGTON - CHEHALIS DEF		-120,000			
12	IRRIGATION UNBILLED	-38	11,000			-0.2895
13	DSM REVENUE-IRRIGATION		492,680			
14	BLUE SKY REVENUE-IRRIGATION		107	5		
15						
16	WYOMING					
17	05APS00040-AG PUMPING SVC	18,040	1,583,791	689	26,183	0.0878
18	05LNX00103-LINE EXT 80% G		7,130			
19	05LNX00109-REF/NREF ADV +		714			
20	05LNX00110-REF/NREF ADV +		67,817			
21	05LNX00310-LINE EXTCONTRAC		96			
22	05LNX00312 - WY IRG LINE EXT		8,278			
23	IRRIGATION UNBILLED	-10	1,000			-0.1000
24	DSM REVENUE-IRRIGATION		26,098			
25	05LNX00103-LINE EXT 80% G		1,220			
26	05LNX00110-REF/NREF ADV +		10,299			
27	05LNX00312 - WY IRG LINE EXT		1,023			
28	09APSV0210-IRR & SOIL DRA	4,244	366,043	88	48,227	0.0862
29	DSM REVENUE-IRRIGATION		8,093			
30						
31	LESS MULTIPLE BILLINGS			-966		
32						
33	TOTAL IRRIGATION SALES	1,545,075	142,606,716	23,319	66,258	0.0923
34						
35	PUBLIC STREET & HWY LIGHTING					
36	CALIFORNIA					
37	06CUSL053E-SPECIAL CUST O	1,415	237,749	108	13,102	0.1680
38	06CUSL058F-CUST OWND STR	237	44,331	22	10,773	0.1871
39	06HPSV0051-HI PRESSURE SO	669	204,661	79	8,468	0.3059
40	DSM REVENUE-PUB ST & HWY LT		9,366			
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
43	TOTAL	54,999,277	4,817,264,361	1,782,893	30,848	0.0876

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 2014/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	REVENUE_ACCT ADJUSTMENTS		-14,352			
2	SOLAR FEED-IN REVENUE		715			
3	UNBILLED REVENUE	-17	-2,000			0.1176
4						
5	IDAHO					
6	07GNSV023S-IDAHO TRAFFIC	141	17,226	24	5,875	0.1222
7	07SLCO0011-STR LGT CO-OWN	88	40,365	37	2,378	0.4587
8	07SLCU012E-ENGY STR LGT	364	40,418	28	13,000	0.1110
9	07SLCU012F-FULL MNT STR	1,891	374,337	191	9,901	0.1980
10	07SLCU012P-PART MNT STR LGT	195	28,262	16	12,188	0.1449
11	DSM REVENUE-PUB ST & HWY LT		8,882			
12	UNBILLED REVENUE	-7	-1,000			0.1429
13						
14	OREGON					
15	01COSL0052-STR LGT SRVC C	411	61,152	35	11,743	0.1488
16	01CUSL0053-CUS-OWNED MTRD	762	55,908	72	10,583	0.0734
17	01CUSL053E-STR LGT SVC	8,927	658,889	167	53,455	0.0738
18	01CUSL053F-STR LGT SRVC C	123	11,637	9	13,667	0.0946
19	01HPSV0051-HI PRESSURE SO	19,716	4,134,931	725	27,194	0.2097
20	01LEDSL051-OR LED PILOT	45	15,940	20	2,250	0.3542
21	01MVSL0050-MERC VAPSTR LG	7,969	1,048,894	238	33,483	0.1316
22	01OALT015N-OUTD AR LGT NR	2	312	2	1,000	0.1560
23	01OALTB15N-OR OUTD AR LGT	2	265	1	2,000	0.1325
24	DSM REVENUE-PUB ST & HWY LT		136,498			
25	OR GAIN ON SALE OF ASSET		-118			
26	REVENUE ADJ - DEF NPC		1,695			
27	REVENUE_ACCT ADJUSTMENTS		-12,092			
28	SOLAR FEED-IN REVENUE		6,277			
29	UNBILLED REVENUE	565	100,000			0.1770
30						
31	UTAH					
32	08CFR00012-STR LGTS (CONV		54			
33	08CFR00051-MTH FAC SRVCHG		4,529			
34	08CFR00062-STREET LIGHTS		79			
35	08OALT007N-SECURITY AR LG	3	1,034	3	1,000	0.3447
36	08TOSS015F-TRAFFIC SIG NM	1,141	104,793	123	9,276	0.0918
37	08SLCO0011-STR LGT CO-OWN	15,377	4,702,714	792	19,415	0.3058
38	08TOSS0015-TRAF & OTHER S	3,072	360,580	1,533	2,004	0.1174
39	08MONL0015-MTR OUTDONIGHT	714	58,762	65	10,985	0.0823
40	08SLCU012P-STR LGT CUST-O	4,927	630,951	204	24,152	0.1281
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
43	TOTAL	54,999,277	4,817,264,361	1,782,893	30,848	0.0876

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1	08SLCU012F-STR LGT CUST-O	1,070	148,685	86	12,442	0.1390
2	08SLCU012E-DECOR CUST-OWN	50,742	3,333,456	614	82,642	0.0657
3	DSM REVENUE-PSHL		335,335			
4	REVENUE_ACCT ADJUSTMENTS		-48,163			
5	SOLAR FEED-IN REVENUE		20,352			
6	UNBILLED REVENUE	-1,221	-147,000			0.1204
7						
8	WASHINGTON					
9	02CFR00012-STR LGTS (CONV		91			
10	02COSL0052-WA STR LGT SRV	207	34,676	15	13,800	0.1675
11	02CUSL053F-WA STR LGT SRV	3,672	252,176	111	33,081	0.0687
12	02CUSL053M-WA STR LGT SRV	1,149	81,429	105	10,943	0.0709
13	02SLCO0051-WA COMPANY	3,871	747,076	159	24,346	0.1930
14	02MVSL0057-WA MERC VAPSTR	1,742	214,458	40	43,550	0.1231
15	WASHINGTON - CHEHALIS		-30,000			
16	DSM REVENUE-PSHL		27,982			
17	REVENUE_ACCT ADJUSTMENTS		-27,376			
18	UNBILLED REVENUE	942	121,000			0.1285
19						
20	WYOMING					
21	05COSL0057-CO-OWND STR LG	273	60,081	18	15,167	0.2201
22	05CUSL058M-CUST OWND STR	84	5,790	11	7,636	0.0689
23	05CUSL0E58-CUST OWNED STR	1,098	75,883	30	36,600	0.0691
24	05CUSL0M58-CUST OWNED STR	44	3,595	3	14,667	0.0817
25	05HPSV0051-HI PRESSURE SO	5,453	1,224,114	174	31,339	0.2245
26	05MVS00053-MERCURY VAPOR	3,854	531,376	254	15,173	0.1379
27	05OALT015N-OUTD AR LGT SR	24	2,921	1	24,000	0.1217
28	DSM REVENUE-PSHL		15,367			
29	REVENUE_ACCT ADJUSTMENTS		-53			
30	UNBILLED REVENUE	-200	-33,000			0.1650
31	09MONL0213-WY MTR OUTDOOR	26	2,457	1	26,000	0.0945
32	09SLCO0211-STR LGT CO-OWN	1,490	402,387	51	29,216	0.2701
33	09SLCUP212-CUST OWNED	34	5,959	5	6,800	0.1753
34	09TOSS0213-TRAFFIC & OTHER	56	2,663	14	4,000	0.0476
35	DSM REVENUE-PSHL		9,083			
36	UNBILLED REVENUE	5	1,000			0.2000
37						
38	LESS MULTIPLE BILLINGS			-2,652		
39						
40	TOTAL PUBLIC SREET & HWY	143,147	20,446,444	3,534	40,506	0.1428
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
43	TOTAL	54,999,277	4,817,264,361	1,782,893	30,848	0.0876

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1						
2	OTHER SALES TO PUBLIC AUTH					
3	UTAH					
4	08PRSV031M-BKUP MNT&SUPPL	35,786	2,853,146	1	35,786,000	0.0797
5	DSM REVENUE-OSPA		612,481			
6	REVENUE_ACCT ADJUSTMENTS		-69,636			
7	SOLAR FEED-IN REVENUE		29,457			
8	UNBILLED REVENUE	-5,272	-297,000			0.0563
9	08GNSV009M-MANL HIGH VOLT	251,110	14,371,075	2	125,555,000	0.0572
10						
11	TOTAL OTHER SALES TO PUBLIC	281,624	17,499,523	3	93,874,667	0.0621
12						
13	FORFEITED DISCOUNTS					
14	CALIFORNIA					
15	06LPAY0300-LATEFEE		283,123			
16						
17	IDAHO					
18	07LPAY0300-LATEFEE		452,358			
19						
20	OREGON					
21	01LPAY0300-LATEFEE		3,979,745			
22						
23	UTAH					
24	08LPAY0300-LATEFEE		3,550,834			
25	OTHER		1,964			
26						
27	WASHINGTON					
28	02LPAY0300-LATEFEE		676,553			
29						
30	WYOMING					
31	05LPAY0300-RES-LATEFEE		459,852			
32	05LPAY0300-COM-LATEFEE		145,733			
33	05LPAY0300-IND-LATEFEE		120,062			
34	05LPAY0300-OTHER-LATEFEE		25			
35						
36	TOTAL FORFEITED DISCOUNTS		9,670,249			
37						
38	MISCELLANEOUS SERVICE REV					
39	CALIFORNIA					
40	06CFR00003-MTH MAINTENANC		1,454			
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
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1	06CONN0300-CA RECONNECTIO		26,835			
2	06FCBUYOUT		50,273			
3	06RCHK0300-CA RET CHK CHR		10,464			
4	06TAMP0300-CA TAMP & UNAU		1,200			
5	06TEMP0300-CA TEMP SRVC C		1,105			
6	06XMTRTAMP-TMPRING - UNAU		298			
7	HOME COMFORT		225			
8						
9	IDAHO					
10	07CFR00001-MTH FAC SRVCHG		1,682			
11	07CONN0300-ID RECONNECTIO		44,155			
12	07FCBUYOUT - FAC CHG BUYOUT		14,438			
13	07RCHK0300-ID RET CHK CHR		29,640			
14	07TAMP0300		225			
15	07TEMP0014-TEMP SRVC CONN		18,505			
16	OTHER		-5			
17						
18	OREGON					
19	01CFR00001-MTH FACILITY S		137,462			
20	01CFR00003-MTH MAINTENANC		25,984			
21	01CFR00004-MTH MAINTENANC		25,753			
22	01CFR00005-INTERMTNT SRVC		37,401			
23	01CFR00013-MTH MISC CHRG		2,284			
24	01CFR00014-YR MISC CHRG		5			
25	01CONN0300-RECONNECTION C		374,310			
26	01CONTSERV-OR 3RD PARTY		8,677			
27	01ESSC0600 - ESS CHARGES		6,774			
28	01FCBUYOUT-FAC CHG BUYOUT		317,420			
29	01RCHK0300-RETURNED CHECK		295,700			
30	01TAMP0300-TAMP & UNAUTH		14,700			
31	01TEMP0300-TEMP SRVC CHRG		143,500			
32	01XMTRTAMP-TAMPRING - UNAU		3,425			
33	OTHER		-47,410			
34						
35	UTAH					
36	08CFR00013-MTH MISC CHRG		147,885			
37	08CFR00051-MTH FAC SRVCHG		87,747			
38	08CFR00052-ANN FAC SVCCHG		424			
39	08CFR00053-MTHLY MAINTFEE		11,633			
40	08CFR00054-NRES EMERGENCY		4,976			
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
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1	08CFR00063-MTH MISC CHARG		2,343			
2	08CFR00064-ANN MISC CHARG		6,660			
3	08CONN0300-RECONN&DISCONN		457,930			
4	08CONTSERV-3RD PARTY O/S		82,012			
5	08FCBUYOUT-FAC CHG BUYOUT		289,656			
6	08NCON0300-UT FEE NRES RE		8,050			
7	08NSMTR300-NON STAN MTR		1,415			
8	08PRINT300-SCREEN PRINT FOR		366			
9	08RCHK0300-UT RET CHK CHR		470,000			
10	08RCON0001-CONNECT FEE		1,641,530			
11	08RESD0001-RES SRVC		2,311			
12	08TAMP0300-TAMPERING&UNAU		8,175			
13	08TEMP0014-TEMP SRVC CONN		462,950			
14	08XMTRTAMP-TMPRING - UNAU		1,904			
15	ENERGY FINANSWER NEW COM		5,592			
16	08VISIT300 - UT VISIT, SERVICE		48,655			
17	OTHER		-4,765			
18						
19	WASHINGTON					
20	02CFR00003-MTH MAINTENANC		1,320			
21	02CFR00004-EMRGNCY ST&BY		5,892			
22	02CFR00005-INTERMTNT SRVC		4,302			
23	02CONN0300-WA RECONNECTIO		93,380			
24	02FCBUYOUT - FAC CHG BUYOUT		13,610			
25	02RCHK0300-WA RET CHK CHR		58,160			
26	02TAMP0300-WA TAMP & UNAU		3,150			
27	02TEMP0300-WA TEMP SRVC C		21,005			
28	02XMTRTAMP-TMPRING - UNAU		344			
29	ENERGY FINANSWER NEW COM		11			
30	HOME COMFORT		611			
31	OTHER		-38,445			
32						
33	WYOMING					
34	05CFR00003-MTH MAINTENANC		1,768			
35	05CFR00004-EMRGNCY ST&BY		18,416			
36	05CFR00005-INTERMTNT SRVC		10,133			
37	05CFR00013-MTH MISC CHRG		3,186			
38	05CONN0300-WY RECONNECTIO		94,593			
39	05FCBUYOUT - FAC CHG BUYOUT		205,684			
40	05RCHK0300-WY RET CHK CHR		74,970			
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
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1	05TAMP0300		825			
2	05TEMP0300-WY TEMP SRVC C		39,630			
3	05XMTRTAMP-TMPRING - UNAU		52			
4	09CFR00005-INTERMTNT SRVC		339			
5	OTHER		4,799			
6	05CONN0300-WY RECONNECTIO		16,898			
7	05FCBUYOUT - FAC CHG BUYOUT		26,427			
8	05RCHK0300-WY RET CHK CHR		8,160			
9	05TAMP0300		150			
10	05TEMP0300-WY TEMP SRVC C		285			
11	05XMTRTAMP-TAMP - UNAUTH		88			
12	09CFR00001-MTH FAC SRVCHG		5,025			
13	09CFR00014-YR MISC CHRG		3			
14	ENERGY FINANSWER 12,000		4			
15	OTHER		-2,417			
16						
17	TOTAL MISC SERVICE REV		5,956,286			
18						
19	RENT FROM ELEC PROPERTIES					
20	CALIFORNIA					
21	06CFR00006-MTH RNTAL CHRG		1,710			
22	RENT REVENUE-HYDRO		1,200			
23	RENT REVENUE - SUBLEASES		19,200			
24	JOINT USE		520,750			
25						
26	IDAHO					
27	07CFR00009-YR LSE CHRG-EQ		788			
28	07INVCHG00-INVEST MNT CHG		150			
29	07POLE0075-STEEL POLES US		276			
30	RENT REVENUE-HYDRO		66,535			
31	RENT REV-TRANSMISS		250			
32	RENT REV-DISTRIBUT		300			
33	RENT REVENUE - SUBLEASES		2,216			
34	JOINT USE		147,819			
35						
36	OREGON					
37	01CFR00006-MTH RNTAL CHRG		811,575			
38	RENTS - COMMON		670,588			
39	RENTS - NON COMMON		25			
40	MCI FOGWIRE REVENUE		3,346,955			
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4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RENT REV - SUBLEASES		36,292			
2	RENT REVENUE-HYDRO		23,721			
3	RENT REV-TRANSMISS		262,156			
4	RENT REV-DISTRIBUT		64,141			
5	RENT REV-GEN(COMM)		56,559			
6	JOINT USE		2,725,516			
7						
8	UTAH					
9	08CFR00056-MTH EQUIP RENT		33			
10	08CFR00058-MTH EQUIP LEAS		534,384			
11	08INVCHG0N-INVEST MNT CHG		4,403			
12	08INVCHG0R-INVEST MNT CHG		242			
13	08POLE0075-STEEL POLES US		54,832			
14	RENTS - NON COMMON		11,100			
15	RENT REVENUE-STEAM		124,465			
16	RENT REVENUE-HYDRO		71,196			
17	RENT REV-TRANSMISS		1,014,098			
18	RENT REV-DISTRIBUT		543,048			
19	RENT REV-GEN(COMM)		13,384			
20	RENT REVENUE - SUBLEASES		2,793,143			
21	JOINT USE		2,116,411			
22						
23	WASHINGTON					
24	02CFR00001-MTH FACILITY S		2,086			
25	02CFR00006-MTH RNTAL CHRG		9,073			
26	RENT REVENUE-HYDRO		342,580			
27	RENT REV-DISTRIBUT		20,558			
28	RENT REV-GEN(COMM)		39,942			
29	RENT REV-TRANSMISS		17,974			
30	JOINT USE		874,037			
31						
32	WYOMING					
33	05CFR00001-MTH FACILITY S		11,524			
34	05CFR00006-MTH RNTAL CHRG		2,482			
35	RENT REVENUE-STEAM		34,241			
36	RENT REVENUE-HYDRO		20,982			
37	RENT REV-TRANSMISS		14,230			
38	RENT REV-DISTRIBUT		150			
39	RENT REV-GEN(COMM)		27,838			
40	RENT REVENUE - SUBLEASES		1,467			
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
43	TOTAL	54,999,277	4,817,264,361	1,782,893	30,848	0.0876

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 2014/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	JOINT USE		346,652			
2	09POLE0075-STEEL POLES US		18,313			
3	RENT REVENUE-STEAM		3,880			
4	JOINT USE		143			
5						
6	TOTAL RENT FROM ELEC PROP		17,827,613			
7						
8	OTHER ELECTRIC REVENUE					
9	WIND BASED ANCILLARY SVC		11,521,257			
10	FERC TRANSMISSION REFUND		-3,442,129			
11	OTH ELEC ESTIMATE		-127,236			
12	RENEW ENERGY CRDT SALES		10,144,970			
13	GREEN CREDIT SALES		5,572,977			
14	CA GHG ALLOW REV AMORT		14,673,226			
15	NON-WHEELING SYSTEM		9,065,100			
16	OTHER ELEC (EXCLUDE WHEEL)		16,000			
17	REC SALES-WIND WAKE LOSS		8,174			
18	RENEWABLE ENERGY CR AMORT		8,053,851			
19						
20	CALIFORNIA					
21	3RD PARTY TRANS		9,581			
22	FISH, WILDLIFE, RECR		7,679			
23	OTHER ELEC (EXCLUDE WHEELI)		-11			
24						
25	IDAHO					
26	3RD PARTY TRANS O&M		133,191			
27						
28	OREGON					
29	3RD PARTY TRANS O&M		141,624			
30	I/C TRANS O&M REV - SIERRA		-10,244			
31	M&S INV REVENUE		1,199			
32	OTHER ELEC (EXCLUDE WHEELI)		1,845,579			
33						
34	UTAH					
35	08XTRN0011-SALES ORDERS		931			
36	ELEC INC-OTHR		97,060			
37	FLYASH SALES		2,105,993			
38	3RD PARTY TRANS O&M		196,351			
39	FISH, WILDLIFE, RECR		2,240			
40	I/C TRANS O&M REV - SIERRA		19,244			
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
43	TOTAL	54,999,277	4,817,264,361	1,782,893	30,848	0.0876

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 2014/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	OTHER ELEC (EXCLUDE WHEEL)		-30			
2	M&S INVENTORY REVENUE		939,493			
3	WASHINGTON					
4	TIMBER SALES - UTILITY PROP		426,135			
5	FISH, WILDLIFE, RECR		6,975			
6	OTHER ELEC (EXCLUDE WHEELI)		-33			
7	WASH COLSTRIP 3		-52,188			
8						
9	WYOMING					
10	05XTRN0011-SALES ORDERS		11,854			
11	ELEC INC-OTHR		15			
12	FLYASH SALES		2,892,303			
13	WY REG RECOVERY FEE		302,725			
14	3RD PARTY TRANS		116,795			
15	OTHER ELEC (EX WHEEL)		-4			
16						
17	TOTAL OTHER ELEC REV		64,680,647			
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	55,246,277	4,832,021,361	1,782,893	30,987	0.0875
42	Total Unbilled Rev.(See Instr. 6)	-247,000	-14,757,000	0	0	0.0597
43	TOTAL	54,999,277	4,817,264,361	1,782,893	30,848	0.0876

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 2014/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Requirement Sales					
2	Brigham City Corporation	RQ	T-12	21.0	20.0	19.0
3	Deaver, Town of	RQ	T-4	0.2	0.1	0.1
4	Helper City	RQ	T-6	1.0	1.0	0.9
5	Helper City Annex	RQ	T-6	0.6	0.6	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	1.0	1.0	1.0
8	Portland General Electric Company	RQ	147	NA	NA	NA
9	Price City Corporation	RQ	T-12	24.0	12.0	11.0
10	Accrual	RQ	NA	NA	NA	NA
11						
12	Nonrequirement Sales					
13	Arizona Public Service Company	SF	T-12	NA	NA	NA
14	Avista Corporation	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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
123,953	2,868,386	3,586,164		6,454,550	2
681	10,987	12,209		23,196	3
6,010	111,213	106,275		217,488	4
3,637	69,461	64,319		133,780	5
920	17,762	16,037		33,799	6
8,651	132,339	150,710		283,049	7
11,440		1,155,439		1,155,439	8
69,473	1,658,233	2,003,819		3,662,052	9
732			13,523	13,523	10
					11
					12
93,364		3,518,994		3,518,994	13
110,082		3,330,072		3,330,072	14
225,497	4,868,381	7,094,972	13,523	11,976,876	
10,044,750	11,767,897	490,410,575	-153,554,753	348,623,719	
10,270,247	**16,636,278**	**497,505,547**	**-153,541,230**	**360,600,595**	

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 2014/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Avista Corporation	SF	T-13	NA	NA	NA
2	Avista Corporation	SF	WSPP - Q	NA	NA	NA
3	BP Energy Company	AD	T-12	NA	NA	NA
4	BP Energy Company	SF	T-12	NA	NA	NA
5	Basin Electric Power Cooperative	SF	T-11	NA	NA	NA
6	Basin Electric Power Cooperative	SF	T-12	NA	NA	NA
7	Black Hills Power, Inc.	LF	441	50	56	51
8	Black Hills Power, Inc.	SF	T-12	NA	NA	NA
9	Black Hills Wyoming, Inc.	SF	T-11	NA	NA	NA
10	Bonneville Power Administration	AD	T-12	NA	NA	NA
11	Bonneville Power Administration	LF	368	NA	NA	NA
12	Bonneville Power Administration	LF	T-11	NA	NA	NA
13	Bonneville Power Administration	LU	519	NA	NA	NA
14	Bonneville Power Administration	SF	T-11	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/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			716	716	1
400		17,400		17,400	2
14			371	371	3
229,200		7,151,715		7,151,715	4
173			6,436	6,436	5
139,965		4,660,591		4,660,591	6
343,081	7,371,697	6,561,184		13,932,881	7
204,744		6,871,319		6,871,319	8
39			794	794	9
			226,265	226,265	10
2,748			88,475	88,475	11
16,022			553,546	553,546	12
38,882		2,921,593		2,921,593	13
13			471	471	14
225,497	4,868,381	7,094,972	13,523	11,976,876	
10,044,750	11,767,897	490,410,575	-153,554,753	348,623,719	
10,270,247	**16,636,278**	**497,505,547**	**-153,541,230**	**360,600,595**	

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 2014/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Bonneville Power Administration	SF	T-12	NA	NA	NA
2	Bonneville Power Administration	SF	T-13	NA	NA	NA
3	British Columbia Hydro and Power	SF	T-13	NA	NA	NA
4	Brookfield Energy Marketing L.P.	SF	T-12	NA	NA	NA
5	California Independent System Operator	SF	T-12	NA	NA	NA
6	Calpine Energy Services, L.P.	SF	T-12	NA	NA	NA
7	Cargill Power Markets, LLC	AD	T-12	NA	NA	NA
8	Cargill Power Markets, LLC	SF	T-11	NA	NA	NA
9	Cargill Power Markets, LLC	SF	T-12	NA	NA	NA
10	Cargill Power Markets, LLC	SF	WSPP - Q	NA	NA	NA
11	City of Anaheim	SF	T-12	NA	NA	NA
12	City of Burbank	SF	T-12	NA	NA	NA
13	City of Glendale	SF	T-12	NA	NA	NA
14	City of Redding	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 2014/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.
151,803		4,973,781		4,973,781	1
61			1,823	1,823	2
63			2,352	2,352	3
39,088		1,488,481		1,488,481	4
47,538		1,787,553		1,787,553	5
71,587		2,302,519		2,302,519	6
			7	7	7
1,706			64,176	64,176	8
921,868		33,135,641		33,135,641	9
196		6,468		6,468	10
2,309		96,347		96,347	11
152,420		5,058,817		5,058,817	12
65,613		2,261,618		2,261,618	13
15,368		436,909		436,909	14
225,497	4,868,381	7,094,972	13,523	11,976,876	
10,044,750	11,767,897	490,410,575	-153,554,753	348,623,719	
10,270,247	**16,636,278**	**497,505,547**	**-153,541,230**	**360,600,595**	

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	Clatskanie People's Utility District	SF	T-12	NA	NA	NA
2	ConocoPhillips Company	SF	T-12	NA	NA	NA
3	Constellation Energy Commodities Group	SF	T-11	NA	NA	NA
4	Constellation Energy Commodities Group	SF	T-11	NA	NA	NA
5	Coral Power, LLC	SF	T-11	NA	NA	NA
6	Deseret Generation & Transmission	SF	T-11	NA	NA	NA
7	EDF Trading North America, LLC	SF	T-12	NA	NA	NA
8	EDF Trading North America, LLC	SF	WSPP - Q	NA	NA	NA
9	El Paso Electric Company	SF	T-12	NA	NA	NA
10	Eugene Water & Electric Board	SF	T-12	NA	NA	NA
11	Exelon Generation Company, LLC	SF	T-12	NA	NA	NA
12	Gila River Power LLC	AD	T-12	NA	NA	NA
13	Gila River Power LLC	SF	T-12	NA	NA	NA
14	Gridforce Energy Management, LLC	AD	T-13	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
2,867		129,469		129,469	1
800		36,400		36,400	2
122			5,240	5,240	3
26			1,031	1,031	4
7,367			227,620	227,620	5
273			9,257	9,257	6
584,339		22,120,148		22,120,148	7
20,761		820,060		820,060	8
42,627		1,596,994		1,596,994	9
34,344		1,048,315		1,048,315	10
1,535,176		55,586,831		55,586,831	11
250			7,475	7,475	12
98,400		3,574,736		3,574,736	13
37			1,320	1,320	14
225,497	4,868,381	7,094,972	13,523	11,976,876	
10,044,750	11,767,897	490,410,575	-153,554,753	348,623,719	
10,270,247	**16,636,278**	**497,505,547**	**-153,541,230**	**360,600,595**	

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 2014/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	Gridforce Energy Management, LLC	SF	T-13	NA	NA	NA
2	Iberdrola Renewables, LLC	LF	T-11	NA	NA	NA
3	Iberdrola Renewables, LLC	SF	T-11	NA	NA	NA
4	Iberdrola Renewables, LLC	SF	T-11	NA	NA	NA
5	Iberdrola Renewables, LLC	SF	T-12	NA	NA	NA
6	Iberdrola Renewables, LLC	SF	WSPP - Q	NA	NA	NA
7	Idaho Power Company	LF	T-11	NA	NA	NA
8	Idaho Power Company	SF	T-11	NA	NA	NA
9	Idaho Power Company	SF	T-12	NA	NA	NA
10	Idaho Power Company	SF	T-13	NA	NA	NA
11	J. Aron & Company	SF	T-12	NA	NA	NA
12	J.P. Morgan Ventures Energy Corporation	SF	T-11	NA	NA	NA
13	J.P. Morgan Ventures Energy Corporation	SF	T-11	NA	NA	NA
14	Los Angeles Dept. of Water and Power	LU	301	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.
219			6,517	6,517	1
3,787			130,569	130,569	2
14,435			480,087	480,087	3
34			2,265	2,265	4
1,021,064		35,035,427		35,035,427	5
10,000		434,500		434,500	6
2,737			94,158	94,158	7
2,468			86,513	86,513	8
5,593		175,684		175,684	9
73			1,744	1,744	10
317,414		10,879,278		10,879,278	11
997			33,113	33,113	12
224			7,088	7,088	13
542,628		26,706,775		26,706,775	14
225,497	4,868,381	7,094,972	13,523	11,976,876	
10,044,750	11,767,897	490,410,575	-153,554,753	348,623,719	
10,270,247	**16,636,278**	**497,505,547**	**-153,541,230**	**360,600,595**	

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 2014/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
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LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
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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	Los Angeles Dept. of Water and Power	SF	T-11	NA	NA	NA
2	Los Angeles Dept. of Water and Power	SF	T-12	NA	NA	NA
3	Macquarie Energy LLC	SF	T-11	NA	NA	NA
4	Macquarie Energy LLC	SF	T-12	NA	NA	NA
5	Metro Water Dist. of S. California	SF	T-12	NA	NA	NA
6	Modesto Irrigation District	SF	T-12	NA	NA	NA
7	Morgan Stanley Capital Group Inc.	SF	T-11	NA	NA	NA
8	Morgan Stanley Capital Group Inc.	SF	T-12	NA	NA	NA
9	Municipal Energy Agency of Nebraska	SF	T-12	NA	NA	NA
10	NaturEner Power Watch, LLC	SF	T-13	NA	NA	NA
11	Nevada Power Company	SF	T-11	NA	NA	NA
12	Nevada Power Company	SF	WSPP - Q	NA	NA	NA
13	NextEra Energy Power Marketing, LLC	OS	T-11	NA	NA	NA
14	NextEra Energy Power Marketing, LLC	SF	T-11	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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)
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7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
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10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
186			6,340	6,340	1
49,084		1,727,435		1,727,435	2
525			3,058	3,058	3
120,000		4,301,341		4,301,341	4
31,167		1,004,447		1,004,447	5
44,759		1,587,904		1,587,904	6
6,959			217,440	217,440	7
408,833		12,492,902		12,492,902	8
96,950		2,691,785		2,691,785	9
10			304	304	10
234			9,408	9,408	11
166,872		4,542,803		4,542,803	12
9,697			289,188	289,188	13
47			1,149	1,149	14
225,497	4,868,381	7,094,972	13,523	11,976,876	
10,044,750	11,767,897	490,410,575	-153,554,753	348,623,719	
10,270,247	**16,636,278**	**497,505,547**	**-153,541,230**	**360,600,595**	

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 2014/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	NextEra Energy Power Marketing, LLC	SF	T-11	NA	NA	NA
2	NextEra Energy Power Marketing, LLC	SF	T-12	NA	NA	NA
3	Noble Americas Energy Solutions LLC	LF	T-11	NA	NA	NA
4	NorthWestern Corporation	SF	T-12	NA	NA	NA
5	NorthWestern Corporation	SF	T-13	NA	NA	NA
6	Northern California Power Agency	SF	T-12	NA	NA	NA
7	Northpoint Energy Solutions Inc.	AD	T-12	NA	NA	NA
8	PPL EnergyPlus, LLC	SF	T-11	NA	NA	NA
9	PPL EnergyPlus, LLC	SF	T-12	NA	NA	NA
10	Pacific Gas & Electric Company	SF	T-11	NA	NA	NA
11	Portland General Electric Company	SF	T-11	NA	NA	NA
12	Portland General Electric Company	SF	T-12	NA	NA	NA
13	Portland General Electric Company	SF	T-13	NA	NA	NA
14	Powerex Corporation	LF	T-11	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
7			193	193	1
800		25,200		25,200	2
923			27,836	27,836	3
12,915		387,027		387,027	4
370			11,919	11,919	5
6,397		114,229		114,229	6
			-2	-2	7
427			16,131	16,131	8
25,672		945,269		945,269	9
22			1,131	1,131	10
475			11,955	11,955	11
253,763		7,314,693	9,250	7,323,943	12
131			5,364	5,364	13
28,390			876,125	876,125	14
225,497	4,868,381	7,094,972	13,523	11,976,876	
10,044,750	11,767,897	490,410,575	-153,554,753	348,623,719	
10,270,247	**16,636,278**	**497,505,547**	**-153,541,230**	**360,600,595**	

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 2014/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-12	NA	NA	NA
8	PUD #1 of Chelan County	SF	T-13	NA	NA	NA
9	PUD #1 of Clark County	SF	T-12	NA	NA	NA
10	PUD #1 of Douglas County	SF	T-12	NA	NA	NA
11	PUD #1 of Douglas County	SF	T-13	NA	NA	NA
12	PUD #1 of Snohomish County	SF	T-12	NA	NA	NA
13	PUD #2 of Grant County	SF	T-12	NA	NA	NA
14	PUD #2 of Grant County	SF	T-13	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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.
22,426			654,319	654,319	1
443,363		11,234,614	8,900	11,243,514	2
34			530	530	3
27			1,004	1,004	4
119,166		3,878,580		3,878,580	5
244,997		9,053,039		9,053,039	6
7,150		214,050		214,050	7
5			166	166	8
17,818		662,327		662,327	9
120		5,900		5,900	10
7			168	168	11
21,821		887,732		887,732	12
25,079		1,033,728		1,033,728	13
3			120	120	14
225,497	4,868,381	7,094,972	13,523	11,976,876	
10,044,750	11,767,897	490,410,575	-153,554,753	348,623,719	
10,270,247	**16,636,278**	**497,505,547**	**-153,541,230**	**360,600,595**	

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 2014/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Puget Sound Energy, Inc.	SF	T-11	NA	NA	NA
2	Puget Sound Energy, Inc.	SF	T-12	NA	NA	NA
3	Puget Sound Energy, Inc.	SF	T-13	NA	NA	NA
4	Rainbow Energy Marketing Corporation	SF	T-11	NA	NA	NA
5	Rainbow Energy Marketing Corporation	SF	T-12	NA	NA	NA
6	Sacramento Municipal Utility District	AD	250	NA	NA	NA
7	Sacramento Municipal Utility District	LF	250	NA	NA	NA
8	Sacramento Municipal Utility District	LF	T-11	NA	NA	NA
9	Sacramento Municipal Utility District	SF	T-12	NA	NA	NA
10	Salt River Project	LF	T-11	NA	NA	NA
11	Salt River Project	SF	T-11	NA	NA	NA
12	Salt River Project	SF	T-12	NA	NA	NA
13	Seattle City Light	SF	T-12	NA	NA	NA
14	Seattle City Light	SF	T-13	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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.
84			4,234	4,234	1
71,286		2,423,344		2,423,344	2
71			1,810	1,810	3
759			29,100	29,100	4
190,280		5,673,880		5,673,880	5
			762,981	762,981	6
569,398		15,800,795		15,800,795	7
5,027			161,698	161,698	8
116,001		3,542,317		3,542,317	9
5,655			190,444	190,444	10
188			5,859	5,859	11
240,870		7,962,328		7,962,328	12
46,725		1,424,148		1,424,148	13
23			711	711	14
225,497	4,868,381	7,094,972	13,523	11,976,876	
10,044,750	11,767,897	490,410,575	-153,554,753	348,623,719	
10,270,247	**16,636,278**	**497,505,547**	**-153,541,230**	**360,600,595**	

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 2014/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	Sempra Generation, LLC	SF	T-12	NA	NA	NA
2	Shell Energy North America (US), L.P.	IF	T-12	NA	NA	NA
3	Shell Energy North America (US), L.P.	SF	T-12	NA	NA	NA
4	Shell Energy North America (US), L.P.	SF	WSPP - Q	NA	NA	NA
5	Sierra Pacific Power Company	SF	T-11	NA	NA	NA
6	Sierra Pacific Power Company	SF	T-13	NA	NA	NA
7	Sierra Pacific Power Company	SF	WSPP - Q	NA	NA	NA
8	Southern California Edison Company	SF	T-11	NA	NA	NA
9	Southern California Edison Company	SF	T-11	NA	NA	NA
10	Southern California Edison Company	SF	T-12	NA	NA	NA
11	Southern California Public Power Auth.	SF	T-11	NA	NA	NA
12	Southwestern Public Service Company	SF	T-12	NA	NA	NA
13	Tacoma Power	SF	T-12	NA	NA	NA
14	Tacoma Power	SF	T-13	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,067,740		35,557,196		35,557,196	1
213,171		8,646,268		8,646,268	2
203,816		7,215,625		7,215,625	3
1,895		66,107		66,107	4
12			189	189	5
232			8,516	8,516	6
875		20,125		20,125	7
13,694			462,275	462,275	8
9			174	174	9
217,159		7,256,460		7,256,460	10
49			1,465	1,465	11
3,075		104,375		104,375	12
32,025		891,310		891,310	13
16			411	411	14
225,497	4,868,381	7,094,972	13,523	11,976,876	
10,044,750	11,767,897	490,410,575	-153,554,753	348,623,719	
10,270,247	**16,636,278**	**497,505,547**	**-153,541,230**	**360,600,595**	

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 2014/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	Tenaska Power Services Co.	SF	T-11	NA	NA	NA
2	Tenaska Power Services Co.	SF	T-12	NA	NA	NA
3	Tenaska Power Services Co.	SF	WSPP - Q	NA	NA	NA
4	The Energy Authority, Inc.	AD	T-12	NA	NA	NA
5	The Energy Authority, Inc.	SF	T-11	NA	NA	NA
6	The Energy Authority, Inc.	SF	T-12	NA	NA	NA
7	Thermo No. 1 BE-01, LLC	LF	T-11	NA	NA	NA
8	TransAlta Energy Marketing (U.S.) Inc.	SF	T-11	NA	NA	NA
9	TransAlta Energy Marketing (U.S.) Inc.	SF	T-12	NA	NA	NA
10	TransCanada Energy Sales Ltd.	SF	T-12	NA	NA	NA
11	Tri-State Gen. and Trans.	LF	T-11	NA	NA	NA
12	Tri-State Gen. and Trans.	SF	T-11	NA	NA	NA
13	Tri-State Gen. and Trans.	SF	T-12	NA	NA	NA
14	Tucson Electric Power Company	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 2014/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.
3,857			124,761	124,761	1
325,715		9,659,251		9,659,251	2
1,200		34,000		34,000	3
-55			-2,090	-2,090	4
146			3,504	3,504	5
58,232		2,111,757		2,111,757	6
2,510			83,555	83,555	7
2,624			80,515	80,515	8
445,425		13,543,810		13,543,810	9
850		45,700		45,700	10
1,257			34,113	34,113	11
631			17,939	17,939	12
339,115		10,057,019		10,057,019	13
590,689		19,619,702		19,619,702	14
225,497	4,868,381	7,094,972	13,523	11,976,876	
10,044,750	11,767,897	490,410,575	-153,554,753	348,623,719	
10,270,247	**16,636,278**	**497,505,547**	**-153,541,230**	**360,600,595**	

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 2014/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	Turlock Irrigation District	SF	T-12	NA	NA	NA
2	Turlock Irrigation District	SF	T-13	NA	NA	NA
3	UNS Electric, Inc.	SF	T-12	NA	NA	NA
4	Utah Associated Municipal Power Systems	SF	T-11	NA	NA	NA
5	Utah Associated Municipal Power Systems	SF	T-12	NA	NA	NA
6	Utah Municipal Power Agency	LF	433	34	34	34
7	Utah Municipal Power Agency	LF	637	NA	NA	NA
8	Utah Municipal Power Agency	SF	T-11	NA	NA	NA
9	Utah Municipal Power Agency	SF	T-12	NA	NA	NA
10	Vitol Inc.	SF	T-12	NA	NA	NA
11	Western Area Power Administration	SF	T-11	NA	NA	NA
12	Western Area Power Administration	SF	T-12	NA	NA	NA
13	Western Area Power Administration	SF	T-13	NA	NA	NA
14	Test generation		NA	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
4,430		137,450		137,450	1
1			39	39	2
196,913		6,628,546		6,628,546	3
288			10,178	10,178	4
4,173		120,525		120,525	5
223,852	4,396,200	5,202,320		9,598,520	6
3,876			107,315	107,315	7
2			64	64	8
8,042		233,453		233,453	9
11,800		404,800		404,800	10
40			1,188	1,188	11
461,770		17,197,340		17,197,340	12
1			42	42	13
-426,743			-9,961,642	-9,961,642	14
225,497	4,868,381	7,094,972	13,523	11,976,876	
10,044,750	11,767,897	490,410,575	-153,554,753	348,623,719	
10,270,247	**16,636,278**	**497,505,547**	**-153,541,230**	**360,600,595**	

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 2014/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Netting - Bookouts		NA	NA	NA	NA
2	Netting - Trading		NA	NA	NA	NA
3	Line Loss Accrual		NA	NA	NA	NA
4	Accrual		NA	NA	NA	NA
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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.
-4,273,034			-151,199,671	-151,199,671	1
			-243,458	-243,458	2
			148,624	148,624	3
-8,054			1,418,979	1,418,979	4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
225,497	4,868,381	7,094,972	13,523	11,976,876	
10,044,750	11,767,897	490,410,575	-153,554,753	348,623,719	
10,270,247	**16,636,278**	**497,505,547**	**-153,541,230**	**360,600,595**	

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

This footnote applies to all occurrences of "Navajo Tribal Util. Auth. (Mexican Hat)" on pages 310-311. Complete name is Navajo Tribal Utility Authority (Mexican Hat).

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

This footnote applies to all occurrences of "Navajo Tribal Util. Auth. (Red Mesa)" on pages 310-311. Complete name is Navajo Tribal Utility Authority (Red Mesa).

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

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

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

Reserve share.

Schedule Page: 310.1 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 310.1 Line No.: 3 Column: j

Settlement adjustment.

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

Transmission losses.

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

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

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

Transmission losses.

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

Settlement adjustment.

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

Settlement adjustment.

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

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

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

Transmission losses.

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

Bonneville Power Administration - FERC T-11 [Network and Point-to-Point Services under the Open Access Transmission Tariff] - Contracts terminate September 30, 2025 through August 31, 2030.

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

Transmission losses.

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

Transmission losses.

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

Reserve share.

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

Reserve share.

Schedule Page: 310.2 Line No.: 5 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.: 7 Column: b

Settlement adjustment.

Schedule Page: 310.2 Line No.: 7 Column: j

Settlement adjustment.

Schedule Page: 310.2 Line No.: 8 Column: j
Transmission losses.
Schedule Page: 310.3 Line No.: 3 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.: 3 Column: j
Transmission losses.
Schedule Page: 310.3 Line No.: 4 Column: j
Unauthorized use charges.
Schedule Page: 310.3 Line No.: 5 Column: j
Transmission losses.
Schedule Page: 310.3 Line No.: 6 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.: 6 Column: j
Transmission losses.
Schedule Page: 310.3 Line No.: 12 Column: b
Settlement adjustment.
Schedule Page: 310.3 Line No.: 12 Column: j
Settlement adjustment.
Schedule Page: 310.3 Line No.: 14 Column: b
Settlement adjustment.
Schedule Page: 310.3 Line No.: 14 Column: j
Settlement adjustment.
Schedule Page: 310.4 Line No.: 1 Column: j
Reserve share.
Schedule Page: 310.4 Line No.: 2 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.: 2 Column: j
Transmission losses.
Schedule Page: 310.4 Line No.: 3 Column: j
Transmission losses.
Schedule Page: 310.4 Line No.: 4 Column: j
Unauthorized use charges.
Schedule Page: 310.4 Line No.: 7 Column: b
Idaho Power Company - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (8th revised S.A. 212)] - Contract termination date: May 31, 2019.
Schedule Page: 310.4 Line No.: 7 Column: j
Transmission losses.
Schedule Page: 310.4 Line No.: 8 Column: j
Transmission losses.
Schedule Page: 310.4 Line No.: 10 Column: j
Reserve share.
Schedule Page: 310.4 Line No.: 12 Column: j
Transmission losses.
Schedule Page: 310.4 Line No.: 13 Column: j
Unauthorized use charges.
Schedule Page: 310.4 Line No.: 14 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.: 1 Column: j
Transmission losses.

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

Schedule Page: 310.5 Line No.: 5 Column: a
This footnote applies to all occurrences of "Metro Water Dist. of S. California" on pages 310-311. Complete name is Metropolitan Water District of Southern California.

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

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

Schedule Page: 310.5 Line No.: 11 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 Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

Schedule Page: 310.5 Line No.: 11 Column: j
Transmission losses.

Schedule Page: 310.5 Line No.: 13 Column: b
NextEra Energy Power Marketing, LLC - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (2nd revised S.A. 733)] - Contract termination date: November 17, 2017.

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

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

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

Schedule Page: 310.6 Line No.: 3 Column: b
Noble Americas Energy Solutions LLC - FERC T-11 [Network Transmission Service under the Open Access Transmission Tariff (6th Revised Service Agreement 299)]- Contract termination upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 310.6 Line No.: 3 Column: j
Transmission losses.

Schedule Page: 310.6 Line No.: 5 Column: j
Reserve share.

Schedule Page: 310.6 Line No.: 7 Column: b
Settlement adjustment.

Schedule Page: 310.6 Line No.: 7 Column: j
Settlement adjustment.

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

Schedule Page: 310.6 Line No.: 10 Column: j
Transmission losses.

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

Schedule Page: 310.6 Line No.: 12 Column: j
Pond sales.

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

Schedule Page: 310.6 Line No.: 14 Column: b
Powerex Corporation - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (8th revised S.A. 169)] - Contract termination date: October 31, 2020.

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

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

Transmission losses.

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

Pond sales.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 310.7 Line No.: 4 Column: j

Transmission losses.

Schedule Page: 310.7 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: 310.7 Line No.: 8 Column: j

Reserve share.

Schedule Page: 310.7 Line No.: 9 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: 310.7 Line No.: 10 Column: a

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

Schedule Page: 310.7 Line No.: 11 Column: j

Reserve share.

Schedule Page: 310.7 Line No.: 12 Column: a

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

Schedule Page: 310.7 Line No.: 13 Column: a

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

Schedule Page: 310.7 Line No.: 14 Column: j

Reserve share.

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

Transmission losses.

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

Reserve share.

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

Transmission losses.

Schedule Page: 310.8 Line No.: 6 Column: b

Settlement adjustment.

Schedule Page: 310.8 Line No.: 6 Column: j

Settlement adjustment.

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

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

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

Sacramento Municipal Utility District - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (Service Agreement 751)] - Contract termination date: September 30, 2018.

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

Transmission losses.

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

Salt River Project - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (Service Agreement 765)] - Contract termination date: November 30, 2018.

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

Transmission losses.

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

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

Schedule Page: 310.9 Line No.: 5 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 Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

Schedule Page: 310.9 Line No.: 5 Column: j
Transmission losses.

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

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

Schedule Page: 310.9 Line No.: 9 Column: j
Unauthorized use charges.

Schedule Page: 310.9 Line No.: 11 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: 310.9 Line No.: 11 Column: j
Unauthorized use charges.

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

Schedule Page: 310.10 Line No.: 1 Column: j
Transmission losses.

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

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

Schedule Page: 310.10 Line No.: 5 Column: j
Transmission losses.

Schedule Page: 310.10 Line No.: 7 Column: b
Thermo No. 1 BE-01, LLC - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (3rd Revised Service Agreement 568)] - Contract termination date: April 30, 2029.

Schedule Page: 310.10 Line No.: 7 Column: j
Transmission losses.

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

Schedule Page: 310.10 Line No.: 11 Column: a
This footnote applies to all occurrences of "Tri-State Gen. and Trans." on pages 310-311. Complete name is Tri-State Generation and Transmission Association, Inc.

Schedule Page: 310.10 Line No.: 11 Column: b
Tri-State Generation and Transmission Association, Inc. - FERC T-11 [Network Transmission Service under the Open Access Transmission Tariff (3rd Revised Service Agreement 628)] - Contract termination date: June 30, 2021.

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

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

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

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

Transmission losses.

Schedule Page: 310.11 Line No.: 6 Column: b

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

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

Utah Municipal Power Agency - Legacy contract [Transmission Service over agreed upon facilities (5th Revised Rate Schedule 637)] - Subject to termination upon mutual agreement and replacement agreements are in effect.

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.: 11 Column: j

Transmission losses.

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

Reserve share.

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

The negative revenue reported on this line reflects test energy generated at the Lake Side II power plant that was transferred to construction. Energy generated during testing was delivered to PacifiCorp’s electric system for sale, as required by the guidance in 18 CFR Electric Plant Instructions 18(a), is a component of construction and is the fair value of the energy delivered.

Schedule Page: 310.12 Line No.: 1 Column: j

Reflects transactions that did not physically settle.

Schedule Page: 310.12 Line No.: 2 Column: j

Reflects transactions that did not physically settle.

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

Transmission losses.

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	18,509,642	18,091,723
5	(501) Fuel	860,709,193	836,194,561
6	(502) Steam Expenses	43,153,691	43,916,579
7	(503) Steam from Other Sources	4,303,809	4,312,439
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	3,921,304	3,949,096
10	(506) Miscellaneous Steam Power Expenses	41,560,988	55,018,295
11	(507) Rents	379,252	496,045
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	972,537,879	961,978,738
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	6,742,774	7,331,481
16	(511) Maintenance of Structures	28,711,998	29,996,120
17	(512) Maintenance of Boiler Plant	114,942,694	103,206,206
18	(513) Maintenance of Electric Plant	44,711,216	31,091,746
19	(514) Maintenance of Miscellaneous Steam Plant	11,939,661	14,777,438
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	207,048,343	186,402,991
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	1,179,586,222	1,148,381,729
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	7,346,206	7,551,949
45	(536) Water for Power	200,374	197,600
46	(537) Hydraulic Expenses	4,387,105	4,009,780
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	16,721,432	15,446,587
49	(540) Rents	921,405	1,075,124
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	29,576,522	28,281,040
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	388	506
54	(542) Maintenance of Structures	797,907	1,156,074
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,890,427	2,292,070
56	(544) Maintenance of Electric Plant	1,991,634	2,907,970
57	(545) Maintenance of Miscellaneous Hydraulic Plant	3,739,521	4,284,443
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	8,419,877	10,641,063
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	37,996,399	38,922,103

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 2014/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	353,767	448,713
63	(547) Fuel	396,700,941	321,290,415
64	(548) Generation Expenses	17,772,523	14,406,401
65	(549) Miscellaneous Other Power Generation Expenses	9,084,850	10,582,172
66	(550) Rents	4,187,040	4,649,553
67	TOTAL Operation (Enter Total of lines 62 thru 66)	428,099,121	351,377,254
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	2,279,301	3,029,122
71	(553) Maintenance of Generating and Electric Plant	17,425,171	17,613,519
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,986,641	3,121,555
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	22,691,113	23,764,196
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	450,790,234	375,141,450
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	603,201,899	666,554,057
77	(556) System Control and Load Dispatching	1,262,603	1,439,706
78	(557) Other Expenses	53,534,340	66,410,600
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	657,998,842	734,404,363
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,326,371,697	2,296,849,645
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	5,651,643	6,231,709
84			
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	8,490,351	7,218,959
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	824,276	292,567
89	(561.5) Reliability, Planning and Standards Development	1,111,085	1,114,579
90	(561.6) Transmission Service Studies	76,025	89,710
91	(561.7) Generation Interconnection Studies	1,139,487	861,392
92	(561.8) Reliability, Planning and Standards Development Services	5,545,389	
93	(562) Station Expenses	3,333,301	3,029,593
94	(563) Overhead Lines Expenses	488,475	353,289
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	151,335,724	137,182,304
97	(566) Miscellaneous Transmission Expenses	4,350,698	4,162,643
98	(567) Rents	1,917,195	2,755,216
99	TOTAL Operation (Enter Total of lines 83 thru 98)	184,263,649	163,291,961
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,369,666	1,608,159
102	(569) Maintenance of Structures	-46,352	181,944
103	(569.1) Maintenance of Computer Hardware	111,446	247,522
104	(569.2) Maintenance of Computer Software	448,520	318,385
105	(569.3) Maintenance of Communication Equipment	3,573,267	3,584,282
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	7,895,835	10,141,753
108	(571) Maintenance of Overhead Lines	15,744,941	18,707,537
109	(572) Maintenance of Underground Lines	100,695	72,498
110	(573) Maintenance of Miscellaneous Transmission Plant	-1,477,863	516,090
111	TOTAL Maintenance (Total of lines 101 thru 110)	27,720,155	35,378,170
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	211,983,804	198,670,131

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	9,856,256	13,049,994
135	(581) Load Dispatching	11,105,285	12,422,223
136	(582) Station Expenses	4,646,431	4,264,228
137	(583) Overhead Line Expenses	5,735,189	6,083,986
138	(584) Underground Line Expenses	128	496
139	(585) Street Lighting and Signal System Expenses	231,729	202,145
140	(586) Meter Expenses	7,226,408	7,072,984
141	(587) Customer Installations Expenses	10,081,874	11,097,401
142	(588) Miscellaneous Expenses	5,691,371	4,751,998
143	(589) Rents	2,539,539	3,698,889
144	TOTAL Operation (Enter Total of lines 134 thru 143)	57,114,210	62,644,344
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	5,882,500	6,186,943
147	(591) Maintenance of Structures	2,239,835	1,710,762
148	(592) Maintenance of Station Equipment	12,488,442	11,897,335
149	(593) Maintenance of Overhead Lines	95,268,142	89,950,166
150	(594) Maintenance of Underground Lines	21,417,732	21,363,704
151	(595) Maintenance of Line Transformers	872,964	1,024,257
152	(596) Maintenance of Street Lighting and Signal Systems	3,389,842	3,591,531
153	(597) Maintenance of Meters	5,985,723	6,666,726
154	(598) Maintenance of Miscellaneous Distribution Plant	1,977,891	3,403,630
155	TOTAL Maintenance (Total of lines 146 thru 154)	149,523,071	145,795,054
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	206,637,281	208,439,398
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	2,621,299	2,441,991
160	(902) Meter Reading Expenses	17,785,403	19,662,071
161	(903) Customer Records and Collection Expenses	53,283,660	52,388,395
162	(904) Uncollectible Accounts	11,444,958	12,924,355
163	(905) Miscellaneous Customer Accounts Expenses	156,938	117,514
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	85,292,258	87,534,326

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 2014/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	150,177	331,132
168	(908) Customer Assistance Expenses	132,017,498	112,671,756
169	(909) Informational and Instructional Expenses	3,745,519	3,484,752
170	(910) Miscellaneous Customer Service and Informational Expenses	99,133	117,029
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	136,012,327	116,604,669
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	75,687,733	76,754,883
182	(921) Office Supplies and Expenses	8,332,848	8,363,743
183	(Less) (922) Administrative Expenses Transferred-Credit	33,980,836	29,238,955
184	(923) Outside Services Employed	14,156,752	16,481,262
185	(924) Property Insurance	15,633,179	13,818,764
186	(925) Injuries and Damages	-23,490,203	36,151,606
187	(926) Employee Pensions and Benefits		
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	24,280,590	22,768,237
190	(929) (Less) Duplicate Charges-Cr.	7,469,667	4,347,767
191	(930.1) General Advertising Expenses	6,832	1,546
192	(930.2) Miscellaneous General Expenses	2,426,050	7,526,075
193	(931) Rents	6,140,970	6,318,601
194	TOTAL Operation (Enter Total of lines 181 thru 193)	81,724,248	154,597,995
195	Maintenance		
196	(935) Maintenance of General Plant	22,162,699	21,202,085
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	103,886,947	175,800,080
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	3,070,184,314	3,083,898,249

Schedule Page: 320 Line No.: 102 Column: b

Represents the difference between actual expense for the period and the accruals charged to Account 569, Maintenance of Structures, during the period.

Schedule Page: 320 Line No.: 110 Column: b

Amount includes reinstatement of a construction work in progress balance for which the construction was previously expected to be canceled.

Schedule Page: 320 Line No.: 186 Column: b

Amount includes expected insurance recovery related to the Sanpete County, Utah rangeland fire. Refer to footnote 13, Commitments and Contingencies, in Notes to Financial Statements of this Form 1.

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, 2014 and 2013, pensions and benefits expense was $126,017,454 and $145,750,552, 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 2014/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		0.02	0.02	0.02
8	Barclays Bank PLC	SF		NA	NA	NA
9	Basin Electric Power Cooperative	SF		NA	NA	NA
10	Beaver City Corporation	LF		NA	NA	NA
11	Bell Mountain Hydro, LLC	LU		NA	NA	NA
12	Big Top, LLC	LU		NA	NA	NA
13	Biomass One, L.P.	LU		NA	NA	NA
14	Birch Power Company, Inc.	LU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
200				6,600		6,600	2
104,264				3,616,329		3,616,329	3
161,453				6,551,536	354,565	6,906,101	4
101,514				4,134,979	10,088	4,145,067	5
102,090				4,440,340	-180,239	4,260,101	6
150			1,637	5,869		7,506	7
					-610,073	-610,073	8
2,480				87,965		87,965	9
75				6,157		6,157	10
637				49,807		49,807	11
3,886				272,136		272,136	12
195,149				13,811,713	1,290,790	15,102,503	13
13,210				794,736		794,736	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Black Cap Solar, LLC	LU		NA	NA	NA
2	Black Hills Power, Inc.	SF		NA	NA	NA
3	Bonneville Power Administration	AD		NA	NA	NA
4	Bonneville Power Administration	LF		NA	NA	NA
5	Bonneville Power Administration	OS		NA	NA	NA
6	Bonneville Power Administration	SF		NA	NA	NA
7	Box Canyon Limited Partnership	LU		1.1	2	0.7
8	Brookfield Energy Marketing L.P.	SF		NA	NA	NA
9	Butter Creek Power, LLC	LU		NA	NA	NA
10	C Drop Hydro, LLC	LU		NA	NA	NA
11	CDM Hydroelectric Company	LU		NA	NA	NA
12	California Independent System Operator	AD		NA	NA	NA
13	California Independent System Operator	SF		NA	NA	NA
14	Calpine Energy Services, L.P.	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 2014/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)	
597				20,797		20,797	1
1,550				85,604		85,604	2
					1	1	3
					35,240	35,240	4
					25,331	25,331	5
265,415				8,930,656	77,970	9,008,626	6
8,188			103,609	1,033,288		1,136,897	7
4,800				382,200		382,200	8
13,236				919,315		919,315	9
2,152				153,658		153,658	10
32,046				1,925,673		1,925,673	11
-776					22,623	22,623	12
195,865				6,327,022		6,327,022	13
94,919				4,647,519		4,647,519	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Cameron A. Curtiss	LU		NA	NA	NA
2	Cargill Power Markets, LLC	AD		NA	NA	NA
3	Cargill Power Markets, LLC	SF		NA	NA	NA
4	Cargill, Incorporated	LU		NA	NA	NA
5	Central Oregon Irrigation District	LU		3.5	4.3	2.9
6	Chevron U.S.A. Inc.	LU		NA	NA	NA
7	City of Albany	LU		NA	NA	NA
8	City of Burbank	SF		NA	NA	NA
9	City of Glendale	SF		NA	NA	NA
10	City of Hurricane	LF		NA	NA	NA
11	City of Lehi	AD		NA	NA	NA
12	City of Lehi	IF		NA	NA	NA
13	City of Pasadena	SF		NA	NA	NA
14	City of Portland, Water Bureau	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 2014/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)	
44				3,157		3,157	1
					-43	-43	2
378,414				14,243,799	738,032	14,981,831	3
7,688				539,531		539,531	4
39,535			577,297	3,754,003		4,331,300	5
42,376				2,655,660		2,655,660	6
1,063				75,641		75,641	7
11,472				855,096		855,096	8
165				4,125		4,125	9
1,928				125,307		125,307	10
21					2,056	2,056	11
7				761		761	12
188				4,770		4,770	13
127				9,086		9,086	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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 2014/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	City of Preston Idaho	LU		NA	NA	NA
2	Clatskanie People's Utility District	SF		NA	NA	NA
3	Commercial Energy Management Inc.	LU		NA	NA	NA
4	ConocoPhillips Company	OS		NA	NA	NA
5	ConocoPhillips Company	SF		NA	NA	NA
6	Cottonwood Hydro, LLC	IU		NA	NA	NA
7	Crook County Solar 1, LLC	RQ		NA	NA	NA
8	Deschutes Valley Water District	LU		4.7	4.2	3.2
9	Deseret Generation & Transmission Coop	LF		100	100	95
10	Dorena Hydro, LLC	LU		NA	NA	NA
11	Douglas County	LU		0.4	0.5	0.3
12	Douglas County, Inc.	AD		NA	NA	NA
13	Douglas County, Inc.	LU		NA	NA	NA
14	Draper Irrigation Company	IU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2,741				152,140		152,140	1
547				15,666		15,666	2
1,303				71,775		71,775	3
					13,948	13,948	4
2,400				124,400		124,400	5
3,596				236,172		236,172	6
1,096				37,928		37,928	7
26,920			460,721	3,214,281		3,675,002	8
697,852			15,870,020	14,119,817	4,136,234	34,126,071	9
538				38,407		38,407	10
2,708			39,727	362,649		402,376	11
267					10,562	10,562	12
3,053				100,949		100,949	13
9				426		426	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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 2014/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	Dry Creek LLC	LU		NA	NA	NA
2	EDF Trading North America, LLC	SF		NA	NA	NA
3	eBay Inc.	LU		NA	NA	NA
4	El Paso Electric Company	SF		NA	NA	NA
5	Eugene Water & Electric Board	OS		NA	NA	NA
6	Eugene Water & Electric Board	SF		NA	NA	NA
7	Eurus Combine Hills I, LLC	LU		NA	NA	NA
8	Evergreen BioPower, LLC	LU		NA	NA	NA
9	Exelon Generation Company, LLC	IF		NA	NA	NA
10	Exelon Generation Company, LLC	SF		NA	NA	NA
11	Falls Creek H.P. Limited Partnership	LU		3.5	3.5	1.4
12	Farm Power Misty Meadow, LLC	LU		NA	NA	NA
13	Farmers Irrigation District	LU		NA	NA	NA
14	Fillmore 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)	
7,719				425,150		425,150	1
407,936				15,752,755		15,752,755	2
795				42,614		42,614	3
6,963				250,955	17,027	267,982	4
				-819,190		-819,190	5
8,432				283,693		283,693	6
107,568				4,554,379		4,554,379	7
54,926				3,616,903		3,616,903	8
122,811				5,791,248		5,791,248	9
497,720				19,225,879		19,225,879	10
16,830			223,600	2,023,021		2,246,621	11
3,674				264,317		264,317	12
22,998				1,601,266		1,601,266	13
182				19,680		19,680	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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	Finley BioEnergy, LLC	LU		NA	NA	NA
2	Flathead Electric Cooperative, Inc.	LF		NA	NA	NA
3	Foote Creek II, LLC	LU		NA	NA	NA
4	Foote Creek III, LLC	LU		NA	NA	NA
5	Four Corners Windfarm, LLC	LU		NA	NA	NA
6	Four Mile Canyon Windfarm, LLC	LU		NA	NA	NA
7	George DeRuyter & Sons Dairy	LU		0.6	0.8	0.6
8	Georgetown Irrigation Company	LU		NA	NA	NA
9	Gila River Power LLC	SF		NA	NA	NA
10	Grand Valley Power	LF		NA	NA	NA
11	Gridforce Energy Management	SF		NA	NA	NA
12	Harold Foster & Robert Walker	LU		NA	NA	NA
13	Hermiston Generating Company, L.P.	AD		NA	NA	NA
14	Hermiston Generating Company, L.P.	LU		211	211	169
	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 2014/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)	
33,886				2,410,770		2,410,770	1
447					14,013	14,013	2
2,991				52,009		52,009	3
32,679				652,259		652,259	4
29,057				2,015,952		2,015,952	5
25,406				1,774,767		1,774,767	6
5,010			19,467	170,680		190,147	7
1,899				111,933		111,933	8
71,931				3,879,043		3,879,043	9
62				12,453		12,453	10
41					2,038	2,038	11
877				33,852		33,852	12
					206	206	13
1,162,637			36,916,842	49,889,760	329,240	87,135,842	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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	Iberdrola Renewables, LLC	SF		NA	NA	NA
2	Idaho Falls, City of	AD		NA	NA	NA
3	Idaho Falls, City of	LU		NA	NA	NA
4	Idaho Power Company	SF		NA	NA	NA
5	Intermountain Power Agency	LU		NA	NA	NA
6	J Bar 9 Ranch, Inc.	LU		NA	NA	NA
7	Jake Amy	LU		NA	NA	NA
8	Joseph Community Solar LLC	LU		NA	NA	NA
9	Kennecott Utah Copper LLC	LU		NA	NA	NA
10	Lacomb Irrigation District	LU		NA	NA	NA
11	Los Angeles Dept. of Water & Power	SF		NA	NA	NA
12	Lower Valley Energy, Inc.	IU		NA	NA	NA
13	Lower Valley Energy, Inc.	LU		NA	NA	NA
14	Loyd Fery	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 2014/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.
1,315,878				43,908,209	1,171,916	45,080,125	1
					-62,539	-62,539	2
52,354					3,030,682	3,030,682	3
23,492				866,793	2,217	869,010	4
542,628				26,706,775		26,706,775	5
66				3,888		3,888	6
1,200				66,956		66,956	7
740				25,106		25,106	8
78,586				2,537,238		2,537,238	9
4,496				160,444	37,919	198,363	10
18,470				1,025,020	12,749	1,037,769	11
5,939				351,411		351,411	12
1,529				94,261		94,261	13
330				11,615		11,615	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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 2014/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	Macquarie Energy LLC	SF		NA	NA	NA
2	Marsh Valley Hydro Electric Company	AD		NA	NA	NA
3	Marsh Valley Hydro Electric Company	LU		NA	NA	NA
4	Meadow Creek Project Company LLC	LU		NA	NA	NA
5	Metropolitan Water District of S. CA	SF		NA	NA	NA
6	Middle Fork Irrigation District	LU		NA	NA	NA
7	Mink Creek Hydro LLC	LU		NA	NA	NA
8	Monsanto Company	IU		NA	NA	NA
9	Morgan City Corporation	LF		NA	NA	NA
10	Morgan Stanley Capital Group Inc.	AD		NA	NA	NA
11	Morgan Stanley Capital Group Inc.	SF		NA	NA	NA
12	Mountain Energy, Inc.	LU		NA	NA	NA
13	Mountain Wind Power II, LLC	LU		NA	NA	NA
14	Mountain Wind Power, LLC	LU		NA	NA	NA
	Total					

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
86,096				3,843,146		3,843,146	1
122					7,254	7,254	2
3,661				219,983		219,983	3
375,128				23,774,146		23,774,146	4
200				7,400		7,400	5
26,290				1,728,532		1,728,532	6
7,758				449,887		449,887	7
					20,003,760	20,003,760	8
15				1,236		1,236	9
-33					1,853	1,853	10
283,273				13,120,000		13,120,000	11
61				4,339		4,339	12
255,545				16,309,431		16,309,431	13
191,634				10,583,909		10,583,909	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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 2014/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Municipal Energy Agency of Nebraska	SF		NA	NA	NA
2	NaturEner Power Watch, LLC	SF		NA	NA	NA
3	Nevada Power Company	AD		NA	NA	NA
4	Nevada Power Company	SF		NA	NA	NA
5	NextEra Energy Power Marketing, LLC	SF		NA	NA	NA
6	Nichols Gap Limited Partnership	LU		0.8	0.5	0.4
7	Nicholson's Sunny Bar Ranch	IF		NA	NA	NA
8	NorthWestern Corporation	SF		NA	NA	NA
9	Nucor Corporation	IF		NA	NA	NA
10	O.J. Power Company	LU		NA	NA	NA
11	Obsidian Renewables, LLC	LU		NA	NA	NA
12	OneEnergy, Inc.	OS		NA	NA	NA
13	Oregon Environmental Industries, LLC	LU		NA	NA	NA
14	Oregon Institute of Technology	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)	
655				33,655		33,655	1
4					100	100	2
					-152,075	-152,075	3
41,753				2,114,476	39,395	2,153,871	4
560				18,433		18,433	5
3,049			42,062	384,325		426,387	6
1,300				77,036		77,036	7
990				18,815	9,219	28,034	8
					6,055,400	6,055,400	9
289				13,765		13,765	10
865				30,084		30,084	11
					40,515	40,515	12
22,322				1,463,702		1,463,702	13
95				2,126		2,126	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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 2014/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Oregon State University	LU		NA	NA	NA
2	Oregon Trail Windfarm, LLC	LU		NA	NA	NA
3	PPL EnergyPlus, LLC	SF		NA	NA	NA
4	Pacific Canyon Windfarm, LLC	LU		NA	NA	NA
5	Paul Luckey	LU		NA	NA	NA
6	Platte River Power Authority	SF		NA	NA	NA
7	Portland General Electric Company	AD		NA	NA	NA
8	Portland General Electric Company	LF		NA	NA	NA
9	Portland General Electric Company	SF		NA	NA	NA
10	Power County Wind Park North, LLC	LU		NA	NA	NA
11	Power County Wind Park South, LLC	LU		NA	NA	NA
12	Powerex Corporation	OS		NA	NA	NA
13	Powerex Corporation	SF		NA	NA	NA
14	Provo City Corporation	LF		NA	NA	NA
	Total					

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				53		53	1
25,949				1,805,149		1,805,149	2
41,780				1,611,829		1,611,829	3
19,108				1,337,876		1,337,876	4
245				8,700		8,700	5
2,843					108,809	108,809	6
					-84,958	-84,958	7
12,024					307,000	307,000	8
58,015				2,213,795	12,083	2,225,878	9
72,267				4,329,172		4,329,172	10
65,970				4,046,252		4,046,252	11
50				3,250		3,250	12
638,320				33,061,386		33,061,386	13
35				3,357		3,357	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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 2014/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	Public Service Company of Colorado	SF		NA	NA	NA
2	Public Service Company of New Mexico	SF		NA	NA	NA
3	PUD No. 1 of Chelan County	SF		NA	NA	NA
4	PUD No. 1 of Clark County	SF		NA	NA	NA
5	PUD No. 1 of Cowlitz County	OS		NA	NA	NA
6	PUD No. 1 of Douglas County	AD		NA	NA	NA
7	PUD No. 1 of Douglas County	AD		NA	NA	NA
8	PUD No. 1 of Douglas County	LF		NA	NA	NA
9	PUD No. 1 of Douglas County	LU		NA	NA	NA
10	PUD No. 1 of Douglas County	OS		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					

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 2014/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.
1,932				70,576		70,576	1
61,760				2,183,324	12,695	2,196,019	2
5,334				201,100	4,595	205,695	3
8,334				266,982		266,982	4
					479,694	479,694	5
					528	528	6
					-92,951	-92,951	7
73,291				2,144,732		2,144,732	8
239,142					3,401,377	3,401,377	9
					34,723	34,723	10
7,943				309,430	1,086	310,516	11
22,750				741,030		741,030	12
					-24,689	-24,689	13
84,664					-8,143,703	-8,143,703	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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	SF		NA	NA	NA
5	Riverside, City of	SF		NA	NA	NA
6	Rock River 1, LLC	LU		NA	NA	NA
7	Roseburg Forest Products Company	LU		NA	NA	NA
8	Roseburg LFG Energy, LLC	LU		NA	NA	NA
9	Roush Hydro Inc.	LU		NA	NA	NA
10	Sacramento Municipal Utility District	AD		NA	NA	NA
11	Sacramento Municipal Utility District	LF		NA	NA	NA
12	Sacramento Municipal Utility District	SF		NA	NA	NA
13	Salt River Project	SF		NA	NA	NA
14	Sand Ranch Windfarm, LLC	LU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
30,707				993,848	4,962	998,810	1
109,668				4,199,324	14,482	4,213,806	2
475				35,452		35,452	3
29,020				1,018,021		1,018,021	4
680				5,920		5,920	5
155,833				5,528,938		5,528,938	6
80,306				4,229,402		4,229,402	7
10,604				756,057		756,057	8
205				7,263		7,263	9
					182,445	182,445	10
218,989				4,454,236		4,454,236	11
2,400				102,600		102,600	12
99,049				4,598,172	93,178	4,691,350	13
24,872				1,737,748		1,737,748	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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 2014/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	Santiam Water Control District	LU		0.2	0.2	0.2
2	Seattle City Light	SF		NA	NA	NA
3	Sempra Generation, LLC	SF		NA	NA	NA
4	Shell Energy North America (US), L.P.	SF		NA	NA	NA
5	Shiloh Warm Springs Ranch, LLC	LU		NA	NA	NA
6	Shoshone Irrigation District	LU		2.4	1.3	1.2
7	Sierra Pacific Power Company	AD		NA	NA	NA
8	Sierra Pacific Power Company	SF		NA	NA	NA
9	Sierra Pacific Power Company	SF		NA	NA	NA
10	Slate Creek Hydro Company, Inc.	LU		2.1	1.3	0.5
11	Solwatt LLC	LU		NA	NA	NA
12	South Utah Valley Electric	LF		NA	NA	NA
13	Southern California Edison Company	AD		NA	NA	NA
14	Southern California Edison Company	SF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
1,561			13,632	166,240		179,872	1
63,484				2,406,922	6,198	2,413,120	2
464,282				15,716,619		15,716,619	3
197,975				7,137,007	64,256	7,201,263	4
879				52,859		52,859	5
9,285			187,507	419,875		607,382	6
					-45,156	-45,156	7
305					8,789	8,789	8
392				11,426	4,285	15,711	9
4,427			69,023	503,199		572,222	10
665				23,202		23,202	11
44				3,102		3,102	12
14					350	350	13
6,212				158,030		158,030	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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 2014/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	Spanish Fork Wind Park 2, LLC	LU		NA	NA	NA
2	Sprague Hydro LLC	LU		0.6	0.6	0.2
3	St. Anthony Hydro, LLC	LU		NA	NA	NA
4	Stahlbush Island Farms, Inc.	IU		NA	NA	NA
5	Sunnyside Cogeneration Associates	AD		NA	NA	NA
6	Sunnyside Cogeneration Associates	LU		52	53	47
7	Swalley Irrigation District	LU		NA	NA	NA
8	TMF Biofuels, LLC	LU		NA	NA	NA
9	Tacoma Power	SF		NA	NA	NA
10	Tata Chemicals (Soda Ash) Partners	AD		NA	NA	NA
11	Tata Chemicals (Soda Ash) Partners	LU		NA	NA	NA
12	Tenaska Power Services Co.	SF		NA	NA	NA
13	Tesoro Refining & Marketing Co, LLC	LU		NA	NA	NA
14	Thayn Hydro LLC	AD		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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)	
47,368				2,542,259		2,542,259	1
2,812			50,567	351,448		402,015	2
932				37,577		37,577	3
2,870				171,209		171,209	4
					20,385	20,385	5
419,649			10,803,672	17,043,240		27,846,912	6
2,351				167,423		167,423	7
34,040				2,286,547		2,286,547	8
65,541				2,063,969	2,991	2,066,960	9
2,984					44,461	44,461	10
3,246				89,418		89,418	11
6,490				281,573		281,573	12
36,819				1,262,102		1,262,102	13
					-25,875	-25,875	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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	Thayn Hydro LLC	LU		0.4	0.4	0.4
2	The Confederated Tribe of Warm Springs	LU		NA	NA	NA
3	The Energy Authority, Inc.	SF		NA	NA	NA
4	The Town of the City of Buffalo	LU		0.2	0.2	0.2
5	Three Buttes Windpower, LLC	LU		NA	NA	NA
6	Three Sisters Irrigation District	LU		NA	NA	NA
7	Threemile Canyon Wind I, LLC	AD		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.	SF		NA	NA	NA
11	TransCanada Energy Sales Ltd.	SF		NA	NA	NA
12	Tri-State Generation and Transmission	LF		25	24	18
13	Tri-State Generation and Transmission	SF		NA	NA	NA
14	Tuana Springs Energy, LLC	AD		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,103			100,394	264,962		365,356	1
218				7,680		7,680	2
70,606				2,425,630		2,425,630	3
1,882			37,020	204,399		241,419	4
331,586				21,141,685		21,141,685	5
902				32,703		32,703	6
-363					-24,298	-24,298	7
23,075				1,639,809		1,639,809	8
640,986				42,305,091		42,305,091	9
486,651				20,401,577		20,401,577	10
400				13,200		13,200	11
112,850			6,117,000	3,409,198		9,526,198	12
5,560				141,159	62,072	203,231	13
					-77,340	-77,340	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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	Turlock Irrigation District	SF		NA	NA	NA
4	U.S. Dept 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	Vitol Inc.	SF		NA	NA	NA
9	Wagon Trail, LLC	LU		NA	NA	NA
10	Ward Butte Windfarm, LLC	LU		NA	NA	NA
11	Wasatch Integrated Waste Mgmt District	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					

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.
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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)	
					327,969	327,969	1
19,077				611,013	183,656	794,669	2
50				1,600		1,600	3
16				966		966	4
3,371				166,791		166,791	5
					6,367,389	6,367,389	6
13,945				673,718		673,718	7
21,600				1,099,800		1,099,800	8
7,518				525,515		525,515	9
17,696				1,228,590		1,228,590	10
361				20,758		20,758	11
3,963				195,608		195,608	12
35,277					1,528,501	1,528,501	13
2,360				49,098	197	49,295	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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.

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	Western Area Power Administration	SF		NA	NA	NA
2	Wolverine Creek Energy, LLC	LU		NA	NA	NA
3	Yakima-Tieton Irrigation District	LU		1.5	1.4	1
4	Oregon Solar Incentive	LU		NA	NA	NA
5	Settlements/Reserves			NA	NA	NA
6	Netting-Trading			NA	NA	NA
7	Netting-Bookouts			NA	NA	NA
8	CA Greenhouse Gas Allowance Purchases			NA	NA	NA
9	Net Power Cost Deferrals			NA	NA	NA
10	Accrual			NA	NA	NA
11						
12	Power Exchanges:					
13	Arizona Public Service Company	EX	307	NA	NA	NA
14	Avista Corporation	EX	T-13	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)	
16,971					722,035	722,035	1
183,793				10,544,211		10,544,211	2
7,881			23,970	274,566		298,536	3
8,531				290,386		290,386	4
					2,273,073	2,273,073	5
					-243,458	-243,458	6
-4,272,938					-151,199,670	-151,199,670	7
					884,031	884,031	8
					20,321,005	20,321,005	9
					7,266,834	7,266,834	10
							11
							12
	566,750	571,431			-203,000	-203,000	13
	2,005						14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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 2014/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Basin Electric Power Cooperative	EX	T-11	NA	NA	NA
2	Bonneville Power Administration	AD	237	NA	NA	NA
3	Bonneville Power Administration	AD	T-12	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	T-13	NA	NA	NA
8	Bonneville Power Administration	EX	T-11	NA	NA	NA
9	Bonneville Power Administration	EX	T-12	NA	NA	NA
10	California Independent System Operator	EX	T-11	NA	NA	NA
11	California Independent System Operator	EX	T-12	NA	NA	NA
12	Cargill Power Markets, LLC	EX	T-11	NA	NA	NA
13	City of Redding	EX	364	NA	NA	NA
14	Constellation Energy Commodities Group	EX	T-11	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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)	
	8,533	61			290,845	290,845	1
	61,870				154,676	154,676	2
	-253				4,297	4,297	3
		82,666			-206,666	-206,666	4
	53,125	50,000			76,938	76,938	5
	108,456	111,622			-37,304	-37,304	6
	235,092	9,788					7
	9,141	6,704			78,690	78,690	8
	15,157				500,537	500,537	9
					-4,526,444	-4,526,444	10
	28,078	180,898			-1,359,495	-1,359,495	11
	356	857			-3,058	-3,058	12
	114,230	109,431			235,898	235,898	13
	3,329	3,512			-7,769	-7,769	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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 2014/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	Deseret Generation & Transmission Coop	AD	280	NA	NA	NA
2	Deseret Generation & Transmission Coop	EX	280	NA	NA	NA
3	Emerald People's Utility District	EX	351	NA	NA	NA
4	Eugene Water & Electric Board	EX	T-12	NA	NA	NA
5	Iberdrola Renewables, LLC	EX	T-11	NA	NA	NA
6	Idaho Power Company	EX	380	NA	NA	NA
7	Idaho Power Company	EX	T-11	NA	NA	NA
8	J.P. Morgan Ventures Energy Corp	EX	T-11	NA	NA	NA
9	Los Angeles Dept. of Water & Power	EX	OV-1	NA	NA	NA
10	Macquarie Energy LLC	EX	T-11	NA	NA	NA
11	Milford Wind Corridor Phase I, LLC	EX	OV-1	NA	NA	NA
12	Milford Wind Corridor Phase II, LLC	EX	OV-1	NA	NA	NA
13	Morgan Stanley Capital Group Inc.	EX	T-11	NA	NA	NA
14	Nevada Power Company	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.
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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)	
	4,227	-898			238,835	238,835	1
	61,610	51,984			8,538	8,538	2
		674			-16,854	-16,854	3
	19,384	19,752			-14,308	-14,308	4
	12,069	18,744			-217,427	-217,427	5
	365,057	220,923					6
	2,354	2,552			45	45	7
	63,027	22,206			1,048,764	1,048,764	8
	4,311				282,127	282,127	9
	-16						10
		2,698			-203,249	-203,249	11
		1,613			-120,398	-120,398	12
	35,578	34,635			-12,601	-12,601	13
	1,015	1,015			-189	-189	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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 2014/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	NextEra Energy Power Marketing, LLC	EX	T-11	NA	NA	NA
2	Noble Americas Energy Solutions LLC	EX	T-11	NA	NA	NA
3	NorthWestern Corporation	EX	160	NA	NA	NA
4	PPL EnergyPlus, LLC	EX	T-11	NA	NA	NA
5	Portland General Electric Company	EX	T-13	NA	NA	NA
6	Portland General Electric Company	EX	T-11	NA	NA	NA
7	Powerex Corporation	EX	T-11	NA	NA	NA
8	Public Service Company of Colorado	AD	T-12	NA	NA	NA
9	Public Service Company of Colorado	EX	319	NA	NA	NA
10	Public Service Company of Colorado	EX	334	NA	NA	NA
11	Public Service Company of Colorado	EX	T-12	NA	NA	NA
12	PUD No. 1 of Cowlitz County	EX	554	NA	NA	NA
13	Sacramento Municipal Utility District	EX	T-11	NA	NA	NA
14	Seattle City Light	EX	554	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.
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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)	
	89,266	62,948			801,344	801,344	1
	8,142	3,619			132,689	132,689	2
	2,075						3
	11,004	11,004			24	24	4
	157,676	156,494					5
	468	470			302	302	6
	23,073	25,840			27,720	27,720	7
	-1				-55	-55	8
	3,100						9
	1,313,875	1,310,382			5,400,000	5,400,000	10
	48,845	68,821			-649,641	-649,641	11
	236,756	253,349					12
	367	90					13
	357,430	357,724			-478,383	-478,383	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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 2014/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Shell Energy North America (US), L.P.	EX	T-11	NA	NA	NA
2	Southern California Edison Company	AD	T-11	NA	NA	NA
3	Southern California Edison Company	EX	T-11	NA	NA	NA
4	Southern CA Public Power Authority	EX	T-11	NA	NA	NA
5	The Energy Authority, Inc.	EX	T-11	NA	NA	NA
6	Thermo No. 1 BE-01, LLC	EX	T-11	NA	NA	NA
7	TransAlta Energy Marketing (U.S.) Inc.	EX	T-11	NA	NA	NA
8	Tri-State Generation and Transmission	AD	319	NA	NA	NA
9	Tri-State Generation and Transmission	EX	319	NA	NA	NA
10	Tri-State Generation and Transmission	EX	T-11	NA	NA	NA
11	Utah Associated Municipal Power	AD	T-11	NA	NA	NA
12	Utah Associated Municipal Power	EX	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)	
	334	513			-3,995	-3,995	1
	-68	107			-7,007	-7,007	2
	86,504	77,320			262,366	262,366	3
	1,427	2,594			-39,522	-39,522	4
	522	477			1,727	1,727	5
	1,860	2,024			-13,509	-13,509	6
	6,282	7,644			7,922	7,922	7
					34,882	34,882	8
	3,100				31,220	31,220	9
	5,034	4,288			14,429	14,429	10
	3,224	-2,355			180,013	180,013	11
	152,033	86,471			2,190,683	2,190,683	12
	33,758	9,007			747,327	747,327	13
	10,057	1,367			296,682	296,682	14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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 2014/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	Western Area Power Administration	EX	OATT	NA	NA	NA
4	Imbalance Energy Accrual	EX	T-11	NA	NA	NA
5	System Deviation	NA		NA	NA	NA
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	84	2,783			-87,525	-87,525	1
	94	22,284			-713,650	-713,650	2
		55					3
					632,983	632,983	4
18,257							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
9,846,352	4,330,806	3,968,188	71,657,767	605,511,668	-73,967,536	603,201,899	

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: l
Financial swap.

Schedule Page: 326 Line No.: 10 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326 Line No.: 13 Column: l
Non-generation agreement.

Schedule Page: 326.1 Line No.: 1 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.: 3 Column: b
Settlement adjustment.

Schedule Page: 326.1 Line No.: 3 Column: l
Reserve share.

Schedule Page: 326.1 Line No.: 4 Column: b
Bonneville Power Administration - contract termination date: 30 days written notice.

Schedule Page: 326.1 Line No.: 4 Column: l
Ancillary services.

Schedule Page: 326.1 Line No.: 5 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.1 Line No.: 5 Column: l
Imbalance energy.

Schedule Page: 326.1 Line No.: 6 Column: l
Reserve share.

Schedule Page: 326.1 Line No.: 12 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: 326.1 Line No.: 12 Column: b
Settlement adjustment.

Schedule Page: 326.1 Line No.: 12 Column: l
Settlement adjustment.

Schedule Page: 326.2 Line No.: 2 Column: b
Settlement adjustment.

Schedule Page: 326.2 Line No.: 2 Column: l
Settlement adjustment.

Schedule Page: 326.2 Line No.: 3 Column: l
Financial swap.

Schedule Page: 326.2 Line No.: 10 Column: b
City of Hurricane - contract termination date: August 31, 2017.

Schedule Page: 326.2 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 326.2 Line No.: 11 Column: l
Settlement adjustment.

Schedule Page: 326.2 Line No.: 14 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.: 4 Column: b

Secondary, economy and/or non-firm.

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

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

Schedule Page: 326.3 Line No.: 9 Column: a

This footnote applies to all occurrences of "Deseret Generation & Transmission Coop" on pages 326-327. Complete name is Deseret Generation and Transmission Co-operative.

Schedule Page: 326.3 Line No.: 9 Column: b

Deseret Generation and Transmission Co-operative - contract termination date: September 30, 2024.

Schedule Page: 326.3 Line No.: 9 Column: l

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

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

Settlement adjustment.

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

Settlement adjustment.

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

Line loss.

Schedule Page: 326.4 Line No.: 5 Column: b

Settlement for costs of replacement power resulting from wind turbine failure.

Schedule Page: 326.4 Line No.: 14 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.5 Line No.: 2 Column: b

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

Schedule Page: 326.5 Line No.: 2 Column: l

Line loss.

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

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.5 Line No.: 11 Column: l

Reserve share.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 326.5 Line No.: 14 Column: l

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

Schedule Page: 326.6 Line No.: 1 Column: l

Financial swap.

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

Settlement adjustment.

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

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

Schedule Page: 326.6 Line No.: 3 Column: l

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

Schedule Page: 326.6 Line No.: 4 Column: l
Reserve share.
Schedule Page: 326.6 Line No.: 10 Column: l
Fixed annual payment.
Schedule Page: 326.6 Line No.: 11 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: 326.6 Line No.: 11 Column: l
Line loss.
Schedule Page: 326.7 Line No.: 2 Column: b
Settlement adjustment.
Schedule Page: 326.7 Line No.: 2 Column: l
Settlement adjustment.
Schedule Page: 326.7 Line No.: 5 Column: a
This footnote applies to all occurrences of "Metropolitan Water District of S. CA" on pages 326-327. Complete name is Metropolitan Water District of Southern California.
Schedule Page: 326.7 Line No.: 8 Column: l
Compensation for interruptible service and operating reserves.
Schedule Page: 326.7 Line No.: 9 Column: b
Under Electric Service Agreement subject to termination upon timely notification.
Schedule Page: 326.7 Line No.: 10 Column: b
Settlement adjustment.
Schedule Page: 326.7 Line No.: 10 Column: l
Settlement adjustment.
Schedule Page: 326.8 Line No.: 2 Column: l
Reserve share.
Schedule Page: 326.8 Line No.: 3 Column: a
This footnote applies to all occurrences of "Nevada Power Company" on pages 326-327. Nevada Power Company is a principal subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.
Schedule Page: 326.8 Line No.: 3 Column: b
Settlement adjustment.
Schedule Page: 326.8 Line No.: 3 Column: l
Line loss.
Schedule Page: 326.8 Line No.: 4 Column: l
Line loss.
Schedule Page: 326.8 Line No.: 8 Column: l
Reserve share.
Schedule Page: 326.8 Line No.: 9 Column: l
Ancillary services.
Schedule Page: 326.8 Line No.: 12 Column: b
Secondary, economy and/or non-firm.
Schedule Page: 326.8 Line No.: 12 Column: l
Purchase of renewable energy credit certificates for Oregon renewable portfolio standard requirements.
Schedule Page: 326.9 Line No.: 6 Column: l
Line loss.
Schedule Page: 326.9 Line No.: 7 Column: b
Settlement adjustment.
Schedule Page: 326.9 Line No.: 7 Column: l
Operation expense plus amortization of unrecovered costs of Cove Project.
Schedule Page: 326.9 Line No.: 8 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: 326.9 Line No.: 8 Column: l

Operation expense plus amortization of unrecovered costs of Cove Project.

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

Reserve share.

Schedule Page: 326.9 Line No.: 12 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.9 Line No.: 14 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

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

Line loss.

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

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

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

Reserve share.

Schedule Page: 326.10 Line No.: 4 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: 326.10 Line No.: 5 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: 326.10 Line No.: 5 Column: b

Secondary, economy and/or non-firm.

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

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

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

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

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

Operating expense, bond interest, amortization and taxes.

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

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

Schedule Page: 326.10 Line No.: 9 Column: l

Operating expense, bond interest, amortization and taxes.

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

Secondary, economy and/or non-firm.

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

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

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

Reserve share.

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

Schedule Page: 326.10 Line No.: 13 Column: l
Operating expense, bond interest, amortization and taxes.

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

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

Schedule Page: 326.11 Line No.: 2 Column: l
Reserve share.

Schedule Page: 326.11 Line No.: 10 Column: b
Settlement adjustment.

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

Schedule Page: 326.11 Line No.: 11 Column: b
Sacramento Municipal Utility District - contract termination date: December 31, 2014.

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

Schedule Page: 326.12 Line No.: 2 Column: l
Reserve share.

Schedule Page: 326.12 Line No.: 4 Column: l
Financial swap.

Schedule Page: 326.12 Line No.: 7 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 Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

Schedule Page: 326.12 Line No.: 7 Column: b
Settlement adjustment.

Schedule Page: 326.12 Line No.: 7 Column: l
Line loss.

Schedule Page: 326.12 Line No.: 8 Column: l
Line loss.

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

Schedule Page: 326.12 Line No.: 12 Column: a
This footnote applies to all occurrences of "South Utah Valley Electric" on pages 326-327. Complete company name is South Utah Valley Electric Service District.

Schedule Page: 326.12 Line No.: 12 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.12 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 326.12 Line No.: 13 Column: l
Settlement adjustment.

Schedule Page: 326.13 Line No.: 5 Column: b
Settlement adjustment.

Schedule Page: 326.13 Line No.: 5 Column: l
Settlement adjustment.

Schedule Page: 326.13 Line No.: 9 Column: l
Reserve share.

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

Schedule Page: 326.13 Line No.: 10 Column: l
Settlement adjustment.
Schedule Page: 326.13 Line No.: 13 Column: a
This footnote applies to all occurrences of "Tesoro Refining & Marketing Co, LLC" on pages 326-327. Complete name is Tesoro Refining & Marketing Company, LLC.
Schedule Page: 326.13 Line No.: 14 Column: b
Settlement adjustment.
Schedule Page: 326.13 Line No.: 14 Column: l
Settlement adjustment.
Schedule Page: 326.14 Line No.: 2 Column: a
This footnote applies to all occurrences of "The Confederated Tribe of Warm Springs" on pages 326-327. Complete name is The Confederated Tribe of Warm Springs Utilities.
Schedule Page: 326.14 Line No.: 7 Column: b
Settlement adjustment.
Schedule Page: 326.14 Line No.: 7 Column: l
Settlement adjustment.
Schedule Page: 326.14 Line No.: 12 Column: a
This footnote applies to all occurrences of "Tri-State Generation and Transmission" on pages 326-327. Complete name is Tri-State Generation and Transmission Association, Inc.
Schedule Page: 326.14 Line No.: 12 Column: b
Tri-State Generation and Transmission Association, Inc. - contract termination date: December 31, 2020.
Schedule Page: 326.14 Line No.: 13 Column: l
Line loss.
Schedule Page: 326.14 Line No.: 14 Column: b
Settlement adjustment.
Schedule Page: 326.14 Line No.: 14 Column: l
Purchase of renewable energy credit certificates for Washington renewable portfolio standard requirements.
Schedule Page: 326.15 Line No.: 1 Column: b
Secondary, economy and/or non-firm.
Schedule Page: 326.15 Line No.: 1 Column: l
Purchase of renewable energy credit certificates for Washington renewable portfolio standard requirements.
Schedule Page: 326.15 Line No.: 2 Column: l
Line loss.
Schedule Page: 326.15 Line No.: 4 Column: a
This footnote applies to all occurrences of "U.S. Dept of the Interior" on pages 326-327. Complete name is U.S. Department of the Interior - Bureau of Land Management.
Schedule Page: 326.15 Line No.: 6 Column: b
US Magnesium LLC - contract termination date: December 31, 2014.
Schedule Page: 326.15 Line No.: 6 Column: l
Ancillary services.
Schedule Page: 326.15 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: 326.15 Line No.: 11 Column: a
This footnote applies to all occurrences of "Wasatch Integrated Waste Mgmt District" on pages 326-327. Complete name is Wasatch Integrated Waste Management District.
Schedule Page: 326.15 Line No.: 13 Column: b
Western Area Power Administration - contract termination date: May 31, 2022.
Schedule Page: 326.15 Line No.: 13 Column: l
Line loss.
Schedule Page: 326.15 Line No.: 14 Column: l

Reserve share.

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

Line loss.

Schedule Page: 326.16 Line No.: 5 Column: l

Settlement associated with insufficient line loss compensation in past.

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

Reflects transactions that did not physically settle.

Schedule Page: 326.16 Line No.: 7 Column: l

Reflects transactions that did not physically settle.

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

Purchases of greenhouse gas allowances for compliance with the California Air Resources Board greenhouse gas cap-and-trade program.

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

Deferrals and associated amortization under various energy cost adjustment mechanisms.

Schedule Page: 326.16 Line No.: 10 Column: l

Represents the difference between actual purchase expenses for the period as reflected on the individual line items within this schedule and the accruals charged to Account 555, Purchased Power, during this period.

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

Exchange energy expense.

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

PacifiCorp imbalance energy service for others.

Schedule Page: 326.17 Line No.: 2 Column: l

Storage and exchange charges.

Schedule Page: 326.17 Line No.: 3 Column: l

Imbalance energy.

Schedule Page: 326.17 Line No.: 4 Column: l

Storage and exchange charges.

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

Storage and exchange charges.

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

Exchange energy expense.

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

PacifiCorp imbalance energy service for others.

Schedule Page: 326.17 Line No.: 9 Column: l

Imbalance energy.

Schedule Page: 326.17 Line No.: 10 Column: l

EIM entity settlements in Energy Imbalance Market.

Schedule Page: 326.17 Line No.: 11 Column: l

EIM participating resource settlements in Energy Imbalance Market.

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

PacifiCorp imbalance energy service for others.

Schedule Page: 326.17 Line No.: 13 Column: l

Exchange energy expense.

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

PacifiCorp imbalance energy service for others.

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

PacifiCorp imbalance energy service for others.

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

PacifiCorp imbalance energy service for others.

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

Storage and exchange charges.

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

Exchange energy expense.

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

PacifiCorp imbalance energy service for others.

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

PacifiCorp imbalance energy service for others.

Schedule Page: 326.18 Line No.: 8 Column: a

This footnote applies to all occurrences of "J.P. Morgan Ventures Energy Corp" on pages 326-327. Complete name is J.P. Morgan Ventures Energy Corporation.

Schedule Page: 326.18 Line No.: 8 Column: l

PacifiCorp imbalance energy service for others.

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

Station service for third-party wind project.

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

Reimbursement for providing station service to third-party wind project.

Schedule Page: 326.18 Line No.: 12 Column: l

Reimbursement for providing station service to third-party wind project.

Schedule Page: 326.18 Line No.: 13 Column: l

PacifiCorp imbalance energy service for others.

Schedule Page: 326.18 Line No.: 14 Column: l

PacifiCorp imbalance energy service for others.

Schedule Page: 326.19 Line No.: 1 Column: l

PacifiCorp imbalance energy service for others.

Schedule Page: 326.19 Line No.: 2 Column: l

PacifiCorp imbalance energy service for others.

Schedule Page: 326.19 Line No.: 4 Column: l

PacifiCorp imbalance energy service for others.

Schedule Page: 326.19 Line No.: 6 Column: l

PacifiCorp imbalance energy service for others.

Schedule Page: 326.19 Line No.: 7 Column: l

PacifiCorp imbalance energy service for others.

Schedule Page: 326.19 Line No.: 8 Column: l

Exchange energy expense.

Schedule Page: 326.19 Line No.: 10 Column: l

Storage and exchange charges.

Schedule Page: 326.19 Line No.: 11 Column: l

Exchange energy expense.

Schedule Page: 326.19 Line No.: 14 Column: l

Exchange energy expense.

Schedule Page: 326.20 Line No.: 1 Column: l

PacifiCorp imbalance energy service for others.

Schedule Page: 326.20 Line No.: 2 Column: l

PacifiCorp imbalance energy service for others.

Schedule Page: 326.20 Line No.: 3 Column: l

PacifiCorp imbalance energy service for others.

Schedule Page: 326.20 Line No.: 4 Column: a

This footnote applies to all occurrences of "Southern CA Public Power Authority" on pages 326-327. Complete name is Southern California Public Power Authority.

Schedule Page: 326.20 Line No.: 4 Column: l

PacifiCorp imbalance energy service for others.

Schedule Page: 326.20 Line No.: 5 Column: l

PacifiCorp imbalance energy service for others.

Schedule Page: 326.20 Line No.: 6 Column: l

PacifiCorp imbalance energy service for others.

Schedule Page: 326.20 Line No.: 7 Column: l

PacifiCorp imbalance energy service for others.

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: l

PacifiCorp imbalance energy service for others.

Schedule Page: 326.20 Line No.: 11 Column: a

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

Schedule Page: 326.20 Line No.: 11 Column: l

PacifiCorp imbalance energy service for others.

Schedule Page: 326.20 Line No.: 12 Column: l

PacifiCorp imbalance energy service for others.

Schedule Page: 326.20 Line No.: 13 Column: l

PacifiCorp imbalance energy service for others.

Schedule Page: 326.20 Line No.: 14 Column: l

PacifiCorp imbalance energy service for others.

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.: 4 Column: l

Reimbursement for third-party services provided.

Schedule Page: 326.21 Line No.: 5 Column: b

Not applicable-adjustment for inadvertent interchange.

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 2014/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Arizona Public Service Company	Arizona Public Service Company		OS
2	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	FNO
3	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	AD
4	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	NF
5	Black Hills/Colorado Electric Utility Company			NF
6	Black Hills/Colorado Electric Utility Company			SFP
7	Black Hills Corporation	PacifiCorp Energy	Montana-Dakota Utilities	FNO
8	Black Hills Corporation	PacifiCorp Energy	Montana-Dakota Utilities	AD
9	Black Hills Corporation			NF
10	Black Hills Corporation			AD
11	Black Hills Corporation			SFP
12	Black Hills Corporation	PacifiCorp Energy	Black Hills Corporation	LFP
13	Black Hills Corporation	PacifiCorp Energy	Black Hills Corporation	AD
14	Black Hills Wyoming			SFP
15	Black Hills Wyoming			NF
16	Bonneville Power Administration			OS
17	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
18	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
19	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	LFP
20	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
21	Bonneville Power Administration	Bonneville Power Administration	Umpqua Indian Utility Cooperative	FNO
22	Bonneville Power Administration	Bonneville Power Administration	Umpqua Indian Utility Cooperative	AD
23	Bonneville Power Administration	Bonneville Power Administration	Benton REA	FNO
24	Bonneville Power Administration	Bonneville Power Administration	Benton REA	AD
25	Bonneville Power Administration	Bonneville Power Administration	Umatilla Electric & Columbia	FNO
26	Bonneville Power Administration	Bonneville Power Administration	Umatilla Electric & Columbia	AD
27	Bonneville Power Administration	U. S. Bureau of Reclamation	Bonneville Power Administration	LFP
28	Bonneville Power Administration	U. S. Bureau of Reclamation	Bonneville Power Administration	AD
29	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
30	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
31	Bonneville Power Administration	Bonneville Power Administration	Yakama Power	FNO
32	Bonneville Power Administration	Bonneville Power Administration	Yakama Power	AD
33	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
34	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
R.S. 436		Borah/Brady Sub				1
V11-1,2,3	Yellowtail Sub	Sheridan Substation	1	3,464	3,464	2
V11-1,2,3	Yellowtail Sub	Sheridan Substation	1	408	408	3
V11-1,2,8	Various	Various		2,688	2,688	4
V11-1,2,8	Various	Various		1,398	1,398	5
V11-1,2,7	Various	Various		1,829	1,829	6
V11-1,2	Various	Sheridan Substation	45			7
V11-1,2	Various	Sheridan Substation	56			8
V11-1,2,8	Various	Various		13,155	13,155	9
V11-1,2,8	Various	Various		397	397	10
V11-1,2,7	Various	Various		4,035	4,035	11
V11-1,2,7	Various	Wyodak Substation	52	182,880	182,880	12
V11-1,2,7	Various	Wyodak Substation	52	6,481	6,481	13
V11-1,2,7	Various	Various		215	215	14
V11-1,2,8	Various	Various		427	427	15
R.S. 369	Midpoint Substation	Summer Lake Sub				16
R.S. 237	Various	Various	336	1,010,505	1,010,505	17
R.S. 237	Various	Various	349	105,694	105,694	18
V11-2,7	Lost Creek Hydro Plt	Alvey Substation	58	241,995	241,995	19
V11-2,7	Lost Creek Hydro Plt	Alvey Substation	58	13,872	13,872	20
V11-1,2,3	Bonneville Power Adm	Gazley Substation	3	23,435	23,435	21
V11-1,2,3	Bonneville Power Adm	Gazley Substation	3	2,323	2,323	22
V11-1,2,3	Bonneville Power Adm	Tieton Substation	1	5,401	5,401	23
V11-1,2,3	Bonneville Power Adm	Tieton Substation	1	862	862	24
V11-1,2,3	McNary Substation	Hinkle Substation	1	908	908	25
V11-1,2,3	McNary Substation	Hinkle Substation	1	114	114	26
V11-2,7	USBR Green Springs	Bonneville Power Adm	19	68,312	68,312	27
V11-2,7	USBR Green Springs	Bonneville Power Adm	19			28
R.S. 368	Malin Substation	Malin Substation		675,121	675,121	29
R.S. 368	Malin Substation	Malin Substation		62,042	62,042	30
V11-1,2,3,4	Bonneville Power Adm		6	34,941	34,941	31
V11-1,2,3,4	Bonneville Power Adm		6	3,760	3,760	32
R.S. 299	Various	Various	168	989,870	989,870	33
R.S. 299	Various	Various	193	108,136	108,136	34
			4,781	**13,674,599**	**13,563,767**	

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
8,971		12,872	21,843	2
		-1,815	-1,815	3
	16,710	704	17,414	4
	14,325	606	14,931	5
	2,249	182	2,431	6
1,124,973		47,411	1,172,384	7
		84,511	84,511	8
	28,653	1,212	29,865	9
		460	460	10
	26,122	1,077	27,199	11
1,279,338		53,914	1,333,252	12
		77,260	77,260	13
				14
				15
				16
3,892,268		67,947	3,960,215	17
		261,846	261,846	18
1,432,868		15,182	1,448,050	19
		81,433	81,433	20
69,611		130,581	200,192	21
		1,482	1,482	22
15,220		2,435	17,655	23
		2,517	2,517	24
3,462		587	4,049	25
		763	763	26
460,567		4,146	464,713	27
		42,504	42,504	28
		224,496	224,496	29
		22,450	22,450	30
129,455		96,418	225,873	31
		16,830	16,830	32
871,166		1,024,573	1,895,739	33
		175,634	175,634	34
45,500,570	**11,536,305**	**31,682,875**	**88,719,750**	

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 2014/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			NF
2	Bonneville Power Administration	Bonneville Power Administration	Clark Public Utilities	FNO
3	Bonneville Power Administration	Bonneville Power Administration	Clark Public Utilities	AD
4	Cargill Power Markets, LLC			NF
5	Cargill Power Markets, LLC			AD
6	Cargill Power Markets, LLC			SFP
7	Cargill Power Markets, LLC			AD
8	Constellation Energy Commodities Group			NF
9	Constellation Energy Commodities Group			SFP
10	Coral Power, LLC			NF
11	Coral Power, LLC			AD
12	Coral Power, LLC			SFP
13	Coral Power, LLC			AD
14	Cowlitz County PUD	Cowlitz County PUD	Bonneville Power Administration	OS
15	Cowlitz County PUD	Cowlitz County PUD	Bonneville Power Administration	AD
16	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	OS
17	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	AD
18	Deseret Generation & Trans.			NF
19	EDF Trading North America, LLC			AD
20	Enel Cove Fort, LLC	Enel Cove Fort, LLC		LFP
21	Enel Cove Fort, LLC	Enel Cove Fort, LLC		AD
22	Fall River Rural Electric Cooperative	Marysville Hydro Partners	Idaho Power Company	OS
23	Fall River Rural Electric Cooperative	Marysville Hydro Partners	Idaho Power Company	AD
24	Foote Creek III, LLC	Foote Creek III, LLC	PacifiCorp Energy	OS
25	Foote Creek III, LLC	Foote Creek III, LLC	PacifiCorp Energy	AD
26	Iberdrola Renewables, LLC			NF
27	Iberdrola Renewables, LLC			AD
28	Iberdrola Renewables, LLC			SFP
29	Iberdrola Renewables, LLC			AD
30	Iberdrola Renewables, LLC	Iberdrola Renewables, LLC		OS
31	Iberdrola Renewables, LLC	Iberdrola Renewables, LLC		AD
32	Iberdrola Renewables, LLC	Exxon Mobil	Nevada Power Company	LFP
33	Iberdrola Renewables, LLC	Exxon Mobil	Nevada Power Company	AD
34	Iberdrola Renewables, LLC	Bonneville Power Administration	Oregon Direct Access	FNO
	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.
V11-1,2,8	Various	Various		298	298	1
V11-1,2,3,4	Cardwell-Merwin		18	107,488	107,488	2
V11-1,2,3,4	Cardwell-Merwin		33	17,073	17,073	3
V11-1,2,8	Various	Various		39,210	39,210	4
V11-1,2,8	Various	Various		13,699	13,699	5
V11-1,2,7	Various	Various				6
V11-1,2,7	Various	Various		1,263	1,263	7
V11-5,6,11	Various	Various		1,789	1,789	8
V11-1-3,7	Various	Various		1,650	1,650	9
V11-1,2,8	Various	Various		50,003	50,003	10
V11-1,2,8	Various	Various		1,208	1,208	11
V11-1,2,7	Various	Various		115,557	115,557	12
V11-1,2,7	Various	Various		10,375	10,375	13
R.S. 234	Swift Unit No. 2	Woodland Substation				14
R.S. 234	Swift Unit No. 2	Woodland Substation				15
R.S. 280	Various	Various	82	612,946	612,946	16
R.S. 280	Various	Various	109	65,185	65,185	17
V11-1,2	Various	Various		6,386	6,386	18
V11-1,2	Various	Various				19
V11	Enel Cove Fort	Red Butte Substation				20
V11	Enel Cove Fort	Mona Substation	26	13,969	13,969	21
R.S. 322	Targhee Substation	Goshen Substation				22
R.S. 322	Targhee Substation	Goshen Substation				23
S.A 761	Foote Creek Sub	Various				24
S.A 761	Foote Creek Sub	Various				25
V11-1-3,8,9,11	Various	Various		248,249	248,249	26
V11-1-3,8,9	Various	Various		30,155	30,155	27
V11-1,2,3,7	Various	Various		67,933	67,933	28
V11-1,2,3,7	Various	Various		13,621	13,621	29
V11-5,6						30
V11-5,6						31
V11-1,2,7	Trona Substation	Red Butte/Mona Sub	31	81,958	81,958	32
V11-1,2,7	Trona Substation	Red Butte/Mona Sub	31	11,604	11,604	33
V11-1,2,3	Ponderosa Substation	Various	4	28,735	28,735	34
			4,781	**13,674,599**	**13,563,767**	

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.
	1,716	73	1,789	1
380,860		65,435	446,295	2
		65,695	65,695	3
	211,114	8,903	220,017	4
		56,052	56,052	5
		1,512	1,512	6
		17,719	17,719	7
	10,933	115,600	126,533	8
	22,748	971	23,719	9
	257,612	10,870	268,482	10
		8,041	8,041	11
	516,445	23,501	539,946	12
		44,858	44,858	13
		135,586	135,586	14
		11,985	11,985	15
2,017,848		2,032,850	4,050,698	16
		481,342	481,342	17
	32,021	1,351	33,372	18
	69	3	72	19
		86,188	86,188	20
		55,617	55,617	21
		138,699	138,699	22
		12,609	12,609	23
		56,769	56,769	24
		3,015	3,015	25
	1,593,054	256,848	1,849,902	26
		173,672	173,672	27
	532,654	39,299	571,953	28
		93,125	93,125	29
		219,643	219,643	30
		39,679	39,679	31
767,602		32,348	799,950	32
		45,449	45,449	33
51,312		9,655	60,967	34
45,500,570	**11,536,305**	**31,682,875**	**88,719,750**	

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	Iberdrola Renewables, LLC		AD
2	Idaho Power Company	Idaho Power Company	Idaho Power Company	OS
3	Idaho Power Company	Exxon Mobil	Nevada Power Company	LFP
4	Idaho Power Company	Exxon Mobil	Nevada Power Company	AD
5	Idaho Power Company			OS
6	Idaho Power Company			AD
7	Idaho Power Company			OS
8	Idaho Power Company			AD
9	Idaho Power Company			NF
10	Idaho Power Company			AD
11	Idaho Power Company			SFP
12	Idaho Power Company			AD
13	Idaho Power Marketing Operations			NF
14	JP Morgan Ventures Energy Corp.			NF
15	JP Morgan Ventures Energy Corp.			AD
16	Los Angeles Department of Water & Power			NF
17	Macquarie Energy, LLC			NF
18	Macquarie Energy, LLC			AD
19	Macquarie Energy, LLC			SFP
20	Macquarie Energy, LLC			AD
21	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	OS
22	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	AD
23	Morgan Stanley Capital Group, Inc.			NF
24	Morgan Stanley Capital Group, Inc.			AD
25	Morgan Stanley Capital Group, Inc.			SFP
26	Morgan Stanley Capital Group, Inc.			AD
27	Nevada Power Company			NF
28	Nevada Power Company			AD
29	Nevada Power Company			SFP
30	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	Grant County PUD	LFP
31	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	Grant County PUD	AD
32	NextEra Energy Resources, LLC			NF
33	NextEra Energy Resources, LLC			AD
34	Noble Americas Energy Solutions LLC	Bonneville Power Administration	Oregon Direct Access	FNO
	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 2014/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.
V11-1,2,3	Malin 500 Substation	Round Mountain Sub	4	2,417	2,417	1
R.S. 427	Goshen Substation	Goshen Substation				2
V11-1,2,7	Trona Substation	Red Butte/Mona Sub		59,643	59,643	3
V11-1,2,7	Trona Substation	Red Butte/Mona Sub				4
R.S. 257	Antelope Substation	Antelope Substation		183,420	183,420	5
R.S. 257	Antelope Substation	Antelope Substation		23,925	23,925	6
R.S. 203	Jim Bridger Sub	Bridger Pump Sub		44,027	44,027	7
R.S. 203	Jim Bridger Sub	Bridger Pump Sub		2,491	2,491	8
V11-1,2,8	Various	Various		54,046	54,046	9
V11-1,2,8	Various	Various		81	81	10
V11-1,2,7	Various	Various		3,080	3,080	11
V11-1,2	Various	Various				12
V11-1,2,8	Various	Various		811	811	13
V11-1-3,8,9,11	Various	Various		28,479	28,479	14
V11-1,2,3	Various	Various		6,172	6,172	15
V11-1,2,8	Various	Various		4,356	4,356	16
V11-1,2,8	Various	Various		5,642	5,642	17
V11-1,2,8	Various	Various		9,248	9,248	18
V11-1,2,7	Various	Various		6,687	6,687	19
V11-1,2,7	Various	Various		8,050	8,050	20
R.S. 302	Duchesne	Duchesne		22,002	22,002	21
R.S. 302	Duchesne	Duchesne		2,208	2,208	22
V11-1-3,8	Various	Various		149,158	149,158	23
V11-1-3,8	Various	Various		10,975	10,975	24
V11-1,2,7	Various	Various		10,892	10,892	25
V11-1,2,7	Various	Various		1,582	1,582	26
V11-1,2,8	Various	Various		4,001	4,001	27
V11-1,2,8	Various	Various		466	466	28
V11-1,2,7	Various	Various		1,500	1,500	29
	Wallula Substation	Wala-MIDC path	103	211,794	211,794	30
V11-5,6,7,9	Wallula Substation	Wala-MIDC path	103	25,327	25,327	31
V11-1,2,3,8,11	Various	Various		1,048	1,048	32
V11-1,2,8	Various	Various		42	42	33
V11-1,2,3,4	Bonneville Power Adm	Various	21	144,786	144,786	34
			4,781	**13,674,599**	**13,563,767**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		3,517	3,517	1
				2
897,147		37,793	934,940	3
		-41,599	-41,599	4
		67,672	67,672	5
		6,152	6,152	6
		14,927	14,927	7
		1,357	1,357	8
	283,378	11,959	295,337	9
		338	338	10
	24,845	1,047	25,892	11
		-36	-36	12
	2,927	124	3,051	13
	576,824	935,693	1,512,517	14
		100,636	100,636	15
	42,511	1,793	44,304	16
	18,059	759	18,818	17
		4,637	4,637	18
	10,579	449	11,028	19
		58,530	58,530	20
		16,050	16,050	21
		1,605	1,605	22
	872,291	37,090	909,381	23
		52,933	52,933	24
	61,717	2,611	64,328	25
		6,933	6,933	26
	23,659	3,191	26,850	27
		1,501	1,501	28
	15,553	656	16,209	29
2,305,807		807,389	3,113,196	30
		259,608	259,608	31
	27,335	10,290	37,625	32
		248	248	33
285,840		48,180	334,020	34
45,500,570	**11,536,305**	**31,682,875**	**88,719,750**	

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 2014/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	Noble Americas Energy Solutions LLC	Bonneville Power Administration	Oregon Direct Access	AD
2	Pacific Gas & Electric Company			OS
3	Pacific Gas & Electric Company			AD
4	Pacific Gas & Electric Company			OS
5	Pacific Gas & Electric Company			NF
6	Portland General Electric Company			NF
7	Portland General Electric Company			AD
8	Portland General Electric Company			SFP
9	Portland General Electric Company			AD
10	Portland General Electric Company			OS
11	Powder River Energy Corporation	Western Area Power Administration	Sheridan-Johnson Rural Elect.	OS
12	Powder River Energy Corporation	Western Area Power Administration	Sheridan-Johnson Rural Elect.	AD
13	Powerex Corporation	Bonneville Power Administration	CAISO	LFP
14	Powerex Corporation	Bonneville Power Administration	CAISO	AD
15	Powerex Corporation	Powerex Corporation	CAISO	LFP
16	Powerex Corporation	Powerex Corporation	CAISO	AD
17	Powerex Corporation	Powerex Corporation	CAISO	LFP
18	Powerex Corporation	Powerex Corporation	CAISO	AD
19	Powerex Corporation	Powerex Corporation	CAISO	LFP
20	Powerex Corporation	Powerex Corporation	CAISO	AD
21	Powerex Corporation	Powerex Corporation	CAISO	LFP
22	Powerex Corporation	Powerex Corporation	CAISO	LFP
23	Powerex Corporation			NF
24	Powerex Corporation			AD
25	Powerex Corporation			SFP
26	Powerex Corporation			AD
27	PPL Energy Plus, LLC			NF
28	PPL Energy Plus, LLC			AD
29	PPL Energy Plus, LLC			SFP
30	Public Svc. Co. of CO			NF
31	Puget Sound Power & Light Company			SFP
32	Puget Sound Power & Light Company			NF
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.
V11-1,2,3,4	Bonneville Power Adm	Various	26	17,414	17,414	1
R.S. 607						2
V11-1,2	Various	Various				3
R.S. 298	Sigurd-Glen Canyon	Pinto-Four Corners				4
V11-1,2,8	Various	Various		260	260	5
V11-1,2,8	Various	Various		9,388	9,388	6
V11-1,2,8	Various	Various		1,149	1,149	7
V11-1,2,7	Various	Various		1,768	1,768	8
V11-1,2,7	Various	Various		1,210	1,210	9
R.S. 137	Various	Various				10
R.S. 123	Various	Buffalo Substation				11
R.S. 123	Various	Buffalo Substation				12
V11-1,2,7	Bonneville Power Adm	CRAG View Substation	83	620,286	620,286	13
V11-1,2,7	Bonneville Power Adm	CRAG View Substation	83	13,947	13,947	14
V11-1,7	Malin 500 Substation	Round Mountain Sub	67			15
V11-1,7	Malin 500 Substation	Round Mountain Sub	67			16
V11-1,7	Malin 500 Substation	Round Mountain Sub	67			17
V11-1,7	Malin 500 Substation	Round Mountain Sub	67			18
V11-1,7	Malin 500 Substation	Round Mountain Sub	66			19
V11-1,7	Malin 500 Substation	Round Mountain Sub	66			20
V11-1,7	Malin 500 Substation	Round Mountain Sub	50			21
V11-1,7	Malin 500 Substation	Round Mountain Sub	150			22
V11-1,2,3,8	Various	Various		488,152	488,152	23
V11-1,2,8	Various	Various		4,162	4,162	24
V11-1,2,3,7	Various	Various		33,375	33,375	25
V11-1,2,7	Various	Various		611	611	26
V11-1,2,8	Various	Various		4,136	4,136	27
V11-1,2,8	Various	Various		641	641	28
V11-1,2,7	Various	Various		4,626	4,626	29
V11-1,2,8	Various	Various				30
V11-1,2,7	Various	Various				31
V11-1,2,8	Various	Various		1,976	1,976	32
V11-1,2,8	Various	Various		492	492	33
V11-1,2	Various	Various		1,200	1,200	34
			4,781	**13,674,599**	**13,563,767**	

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.
		33,610	33,610	1
		13,291,667	13,291,667	2
		1,208,333	1,208,333	3
		220,508	220,508	4
	1,795	76	1,871	5
	67,068	2,833	69,901	6
		6,906	6,906	7
	9,187	387	9,574	8
		7,433	7,433	9
		3,314	3,314	10
		350	350	11
		34	34	12
2,046,940		86,264	2,133,204	13
		121,197	121,197	14
1,644,267		35,516	1,679,783	15
		94,339	94,339	16
1,644,267		35,516	1,679,783	17
		94,339	94,339	18
1,619,726		34,985	1,654,711	19
		92,967	92,967	20
1,227,065		26,505	1,253,570	21
3,681,194		89,200	3,770,394	22
	2,580,409	143,831	2,724,240	23
		21,456	21,456	24
	180,099	18,370	198,469	25
		3,525	3,525	26
	38,499	1,623	40,122	27
		3,637	3,637	28
	29,137	1,232	30,369	29
	173	7	180	30
	19	1	20	31
	13,547	571	14,118	32
	3,947	166	4,113	33
		5,403	5,403	34
45,500,570	**11,536,305**	**31,682,875**	**88,719,750**	

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 2014/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Rainbow Energy Marketing Corporation			SFP
2	Sacramento Municipal Utility District	Sacramento Municipal Utility Dist	Sacramento Municipal Utility Dist	LFP
3	Sacramento Municipal Utility District	Sacramento Municipal Utility Dist	Sacramento Municipal Utility Dist	AD
4	Sacramento Municipal Utility District	Sacramento Municipal Utility Dist	Sacramento Municipal Utility Dist	LFP
5	Salt River Project	Salt River Project	Salt River Project	LFP
6	Salt River Project			NF
7	Salt River Project			AD
8	Seattle City Light	FPL Energy Vansycle, LLC	Grant County PUD	AD
9	Sierra Pacific Power Company			OS
10	Sierra Pacific Power Company			AD
11	Sierra Pacific Power Company			NF
12	Southern California Edison Company			NF
13	Southern California Edison Company			AD
14	Southern California Edison Company			SFP
15	Southern California Edison Company			AD
16	Southern California Edison Company			OS
17	Southern California Public Power Authority	Powerex Corporation	Southern California Public Power	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	State of South Dakota	Western Area Power Administration	Black Hills Corporation	SFP
21	Tenaska Power Services Company			NF
22	Tenaska Power Services Company			AD
23	Tenaska Power Services Company			SFP
24	Tenaska Power Services Company			AD
25	The Energy Authority, Inc.			NF
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	Tri-State Generation & Trans.		Tri-State Generation & Trans.	OS
31	Tri-State Generation & Trans.		Tri-State Generation & Trans	AD
32	Tri-State Generation & Trans.		Tri-State Generation & Trans.	FNO
33	Tri-State Generation & Trans.		Tri-State Generation & Trans	AD
34	Tri-State Generation & Trans.			NF
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
V11-1,2,7	Various	Various		17,328	17,328	1
V11-1,2,7	Malin Substation	Malin Substation	31	105,118	105,118	2
V11-1,2,7	Malin Substation	Malin Substation		1,632	1,632	3
V11	Malin Substation	Malin Substation				4
V11-1,2,7	Enel Cove Fort	Red Butte Substation	26	121,700	121,700	5
V11-1,2,3,8	Various	Various		3,577	3,577	6
V11-1,2,3,7	Various	Various		1,586	1,586	7
V11-1,2	Wallula Substation	Wala-MIDC path				8
R.S. 674	Sigurd Substation	Utah-Nevada Border				9
R.S. 674	Sigurd Substation	Utah-Nevada Border				10
V11-1,2,8	Various	Various		280	280	11
V11-1-3,8,9,11	Various	Various		315,360	315,360	12
V11-1-3,8,9,11	Various	Various		17,895	17,895	13
V11-1-3,7	Various	Various		1,000	1,000	14
V11-1-3,7	Various	Various		270	270	15
R.S. 298	Sigurd-Glen Canyon	Pinto-Four Corners				16
V11-9,11	Tieton Substation	Various		1,144	1,144	17
V11-1,2,7	Yellowtail Sub	Wyodak Substation	4	12,235	12,235	18
V11-1,2,7	Yellowtail Sub	Wyodak Substation	4	1,496	1,496	19
V11-1,2,7	Various	Various		3,481	3,481	20
V11-1,2,8	Various	Various		43,092	43,092	21
V11-1,2,8	Various	Various		8,321	8,321	22
V11-1,2,7	Various	Various		40,590	40,590	23
V11-1,2,7	Various	Various		11,080	11,080	24
V11-1,2,8	Various	Various		2,661	2,661	25
	South Milford Sub	Mona Substation	11	53,417	53,417	26
	South Milford Sub	Mona Substation	11	5,984	5,984	27
V11-1,2,8	Various	Various		54,023	54,023	28
V11-1,2,8	Various	Various		1,813	1,813	29
R.S. 123	Various	Various	37	133,369	133,369	30
R.S. 123	Various	Various	36	19,900	19,900	31
V11-1,2,3,4	Dave Johnston Sub	Thermopolis Sub	6	47,158	47,158	32
V11-1,2,3,4	Dave Johnston Sub	Thermopolis Sub	1	263	263	33
V11-1,2,8	Various	Various		14,522	14,522	34
			4,781	**13,674,599**	**13,563,767**	

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 2014/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.
	77,386	3,257	80,643	1
767,602		32,348	799,950	2
		59,749	59,749	3
		67,394	67,394	4
639,668		26,958	666,626	5
	19,182	809	19,991	6
		13,063	13,063	7
		-3,524	-3,524	8
		62,654	62,654	9
		6,265	6,265	10
	1,852	77	1,929	11
	2,422,847	1,027,319	3,450,166	12
		231,470	231,470	13
	7,980	1,224	9,204	14
		2,695	2,695	15
		220,508	220,508	16
		18,980	18,980	17
73,631		3,104	76,735	18
		6,057	6,057	19
	21,216	894	22,110	20
	217,861	12,171	230,032	21
		13,516	13,516	22
	171,078	7,478	178,556	23
		81,527	81,527	24
	16,848	711	17,559	25
281,464		85,732	367,196	26
		24,410	24,410	27
	324,042	13,710	337,752	28
		8,987	8,987	29
107,496			107,496	30
		11,179	11,179	31
98,186		20,437	118,623	32
		-1,974	-1,974	33
	71,278	3,010	74,288	34
45,500,570	**11,536,305**	**31,682,875**	**88,719,750**	

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 2014/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.			AD
2	Tri-State Generation & Trans.			SFP
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	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	NF
16	Warm Springs Power Enterprises	Warm Springs Power Enterprises	Portland General Electric Co	OS
17	Warm Springs Power Enterprises	Warm Springs Power Enterprises	Portland General Electric Co	AD
18	Western Area Power Administration	Western Area Power Administration		OS
19	Western Area Power Administration	Western Area Power Administration		AD
20	Western Area Power Administration	Western Area Power Administration		OS
21	Western Area Power Administration	Western Area Power Administration		AD
22	Western Area Power Administration	Western Area Power Administration		OS
23	Western Area Power Administration	Western Area Power Administration	Western Area Power Administration	FNO
24	Western Area Power Administration	Western Area Power Administration	Western Area Power Administration	AD
25	Western Area Power Adm. CO River	Western Area Power Adm. CO River		NF
26	Western Area Power Adm. CO River	Western Area Power Adm. CO River		SFP
27	Western Area Power Adm. CO MO	Western Area Power Adm. CO MO		NF
28	Accrual			
29				
30				
31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
V11-1,2,8	Various	Various		246	246	1
V11-1,2,7	Various	Various		244	244	2
V11-1,2,7	Various	Various		9	9	3
V11-1,2,3	Walla Walla Sub	Burbank Pumps	1	2,372	2,372	4
V11-1,2,3	Walla Walla Sub	Burbank Pumps	1	3	3	5
R.S. 286	Various	Various		21,481	21,481	6
R.S. 286	Various	Various		1,568	1,568	7
R.S. 67	Redmond Substation	Crooked River Pumps		13,028	13,028	8
R.S. 297	Various	Various	422	2,476,308	2,476,308	9
R.S. 297	Various	Various	521	229,844	229,844	10
V11-1,2,3,8	Various	Various		4,241	4,241	11
V11-1,2,8	Various	Various		105	105	12
R.S. 637	Various	Various	115	652,710	652,710	13
R.S. 637	Various	Various	106	59,234	59,234	14
V11-1,2,8	Various	Various		40	40	15
R.S. 591	Pelton Reregulating	Round Butte Sub		80,305	80,305	16
R.S. 591	Pelton Reregulating	Round Butte Sub		7,298	7,298	17
R.S. 262	Various	Various	330	1,583,864	1,489,212	18
R.S. 262	Various	Various	330	187,719	176,455	19
R.S. 263	Various	Various		84,635	79,280	20
R.S. 263	Various	Various		8,557	8,075	21
R.S. 664	Dave Johnston Sub	Various				22
V11-1,2	Wyoming Distribution	Wyoming Distribution	1	10,097	10,097	23
V11-1,2	Wyoming Distribution	Wyoming Distribution	1	2	2	24
V11-1,2,8	Various	Various				25
V11-1,2,7	Various	Various		63	63	26
V11-1,2,8	Various	Various		636	636	27
				-128,476	-127,555	28
						29
						30
						31
						32
						33
						34
			4,781	**13,674,599**	**13,563,767**	

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 2014/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 (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.
		1,287	1,287	1
	1,170	50	1,220	2
		57	57	3
8,690		12,785	21,475	4
		-240	-240	5
		21,481	21,481	6
		1,569	1,569	7
12,532			12,532	8
10,464,185		2,565,912	13,030,097	9
		1,691,156	1,691,156	10
	21,327	3,232	24,559	11
		605	605	12
2,850,553		564,642	3,415,195	13
		222,675	222,675	14
	259	11	270	15
		109,725	109,725	16
		9,975	9,975	17
2,305,111		550,000	2,855,111	18
		233,426	233,426	19
		52,071	52,071	20
		5,825	5,825	21
				22
33,678		42,541	76,219	23
		-1,285	-1,285	24
	10,287	434	10,721	25
	435	64	499	26
	1,274	54	1,328	27
		-1,402,686	-1,402,686	28
				29
				30
				31
				32
				33
				34
45,500,570	**11,536,305**	**31,682,875**	**88,719,750**	

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. 2013 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER11-3646. 2013 annual transmission services true-up refund.

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
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328 Line No.: 5 Column: a
This footnote applies to all occurrences of "Black Hills/Colorado Electric Utility Company" on pages 328-300. 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
Transmission resales, purchase of point-to-point transmission. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 7 Column: b

PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

Schedule Page: 328 Line No.: 7 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.: 7 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 8 Column: b

PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

Schedule Page: 328 Line No.: 8 Column: d

Network transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 347) terminating on December 31, 2017.

Schedule Page: 328 Line No.: 8 Column: m

2013 transmission and ancillary services. 2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund.

Schedule Page: 328 Line No.: 9 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 9 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 9 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 9 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 10 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 10 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 10 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 10 Column: m

2013 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER11-3646.

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

Transmission resales, amount paid by seller. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 12 Column: b

PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

Schedule Page: 328 Line No.: 12 Column: d

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.: 12 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 13 Column: b

PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

Schedule Page: 328 Line No.: 13 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (3rd Revised Service Agreement 67) terminating on December 31, 2023.

Schedule Page: 328 Line No.: 13 Column: m

2013 transmission and ancillary services. 2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund.

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.: 15 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 15 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 16 Column: b

Capacity exchanged and operated by each transmission provider with no receipt or delivery of energy.

Schedule Page: 328 Line No.: 16 Column: c

Capacity exchanged and operated by each transmission provider with no receipt or delivery of energy.

Schedule Page: 328 Line No.: 16 Column: d

Legacy contract executed between PacifiCorp and Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities ("Midpoint-Meridian Transmission Agreement", Rate Schedule 369). This agreement runs concurrently with the AC Intertie Agreement (Rate Schedule 368), which terminates when the facilities subject to that agreement are taken out of service. See also page 332, Transmission of Electricity by Others, in this Form No. 1.

Schedule Page: 328 Line No.: 17 Column: d

Legacy contract (3rd Revised Rate Schedule 237) executed between PacifiCorp and Bonneville Power Administration ("BPA") for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Contract subject to termination upon the earlier of the termination of the "Exchange Agreement" between PacifiCorp and BPA or the time of the termination of all deliveries as defined in the agreement.

Schedule Page: 328 Line No.: 17 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328 Line No.: 18 Column: d

Legacy contract (3rd Revised Rate Schedule 237) executed between PacifiCorp and Bonneville Power Administration ("BPA") for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Contract subject to termination upon the earlier of the termination of the "Exchange Agreement" between PacifiCorp and BPA or the time of the termination of all deliveries as defined in the agreement.

Schedule Page: 328 Line No.: 18 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. 2013 transmission and ancillary services.

Schedule Page: 328 Line No.: 19 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.: 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. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 20 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (3rd Revised Service Agreement 656) terminating on August 31, 2030.

Schedule Page: 328 Line No.: 20 Column: m

2013 transmission and ancillary services. 2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund.

Schedule Page: 328 Line No.: 21 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (8th Revised Service Agreement 229) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 21 Column: f

This footnote applies to all occurrences of "Bonneville Power Adm" on pages 328-330. Complete name is Bonneville Power Administration.

Schedule Page: 328 Line No.: 21 Column: m

Distribution voltage service charge. Primary delivery service. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328 Line No.: 22 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (8th Revised Service Agreement 229) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 22 Column: m

2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund.

Schedule Page: 328 Line No.: 23 Column: c

This footnote applies to all occurrences of "Benton REA" on pages 328-330. Complete name is Benton Rural Electric Association.

Schedule Page: 328 Line No.: 23 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (3rd Revised Service Agreement 539) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 23 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328 Line No.: 24 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (3rd Revised Service Agreement 539) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 24 Column: m

2013 transmission and ancillary services. 2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund.

Schedule Page: 328 Line No.: 25 Column: c

This footnote applies to all occurrences of "Umatilla Electric & Columbia" on pages 328-330. Complete name is Umatilla Electric Cooperative Association and Columbia Basin Electric Cooperative, Inc.

Schedule Page: 328 Line No.: 25 Column: d

Network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 538) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 25 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328 Line No.: 26 Column: d

Network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 538) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 26 Column: m

2013 transmission and ancillary services. 2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund.

Schedule Page: 328 Line No.: 27 Column: b

This footnote applies to all occurrences of "U.S. Bureau of Reclamation" on pages 328-330. Complete name is United States Department of Interior Bureau of Reclamation.

Schedule Page: 328 Line No.: 27 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (5th Revised Service Agreement 179) terminating on September 30, 2025.

Schedule Page: 328 Line No.: 27 Column: m

Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 28 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (5th Revised Service Agreement 179) terminating on September 30, 2025.

Schedule Page: 328 Line No.: 28 Column: m

2013 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER11-3646.

Schedule Page: 328 Line No.: 29 Column: d

Legacy contract (5th Revised Rate Schedule 368) executed between PacifiCorp and Bonneville Power Administration ("BPA") for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Subject to termination upon mutual agreement.

Schedule Page: 328 Line No.: 29 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328 Line No.: 30 Column: d

Legacy contract (5th Revised Rate Schedule 368) executed between PacifiCorp and Bonneville Power Administration ("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. 2013 transmission and ancillary services.

Schedule Page: 328 Line No.: 31 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (6th Revised Service Agreement 328) terminating on July 31, 2028.

Schedule Page: 328 Line No.: 31 Column: g

White Swan/Toppenish Substations

Schedule Page: 328 Line No.: 31 Column: m

Distribution voltage service charge. Primary delivery service. Penalty revenues covering imbalance charges per Schedules 4 and 9. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328 Line No.: 32 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (6th 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

2013 transmission and ancillary services. 2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund.

Schedule Page: 328 Line No.: 33 Column: d

Legacy contract (2nd Revised Rate Schedule 299) executed between PacifiCorp and Bonneville

Power Administration ("BPA") for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Contract terminates with three years notice by BPA or five years notice by PacifiCorp. PacifiCorp provided notice of termination in June 2011.

Schedule Page: 328 Line No.: 33 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Charges for scheduling and operating reserves.

Schedule Page: 328 Line No.: 34 Column: d

Legacy contract (2nd Revised Rate Schedule 299) executed between PacifiCorp and Bonneville Power Administration ("BPA") for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Contract terminates with three years notice by BPA or five years notice by PacifiCorp. PacifiCorp provided notice of termination in June 2011.

Schedule Page: 328 Line No.: 34 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Charges for scheduling and operating reserves. 2013 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 1 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 1 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 1 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 1 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 2 Column: d

Network Transmission Service under the Open Access Transmission Tariff (2nd Revised Service Agreement 735) terminating on September 30, 2028.

Schedule Page: 328.1 Line No.: 2 Column: g

Chelatchie/View 115kV

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. Regulation and frequency response service.

Schedule Page: 328.1 Line No.: 3 Column: d

Network Transmission Service under the Open Access Transmission Tariff (2nd Revised Service Agreement 735) terminating on September 30, 2028.

Schedule Page: 328.1 Line No.: 3 Column: g

Chelatchie/View 115kV

Schedule Page: 328.1 Line No.: 3 Column: m

2013 transmission and ancillary services. 2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund.

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.

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

2013 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 6 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 6 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 6 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 6 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 7 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 7 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 7 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 7 Column: m

2013 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 8 Column: a

This footnote applies to all occurrences of "Constellation Energy Commodities Group" on pages 328-330. Complete name is Constellation Energy Commodities Group, Inc.

Schedule Page: 328.1 Line No.: 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

Unauthorized use of transmission service. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve 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

Transmission resales, purchase of point-to-point transmission. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

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

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

2013 transmission and ancillary services.

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

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.: 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

2013 transmission and ancillary services. Transmission resales, purchase of point-to-point transmission.

Schedule Page: 328.1 Line No.: 14 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.: 14 Column: d

Legacy contract (Rate Schedule 234) providing for transmission and operation of Swift Hydroelectric Plant No. 2, and for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Agreement may be terminated subsequent to the termination of the Power Contract as defined in the agreement by the customer providing at least six months written notice and specifying the date on which the customer will assume responsibility of operations and maintenance of Swift Hydroelectric Plant No. 2.

Schedule Page: 328.1 Line No.: 14 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and or proportional use as defined in the contract.

Schedule Page: 328.1 Line No.: 15 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.: 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. 2013 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 16 Column: a

This footnote applies to all occurrences of "Deseret Generation & Trans." on pages 328-330. Complete name is Deseret Generation and Transmission Co-operative.

Schedule Page: 328.1 Line No.: 16 Column: d

Legacy contract executed between PacifiCorp and Deseret Generation and Transmission Co-operative for transmission service over agreed-upon facilities (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.: 16 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. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 17 Column: d

Legacy contract executed between PacifiCorp and Deseret Generation and Transmission Cooperative 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.: 17 Column: m

Distribution voltage service charge. Meter interrogation services. 2013 transmission and ancillary services. 2013 annual transmission services true-up refund.

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: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 19 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 Line No.: 19 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 20 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 20 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff, (2nd Revised Service Agreement 711) terminating November 30, 2018.

Schedule Page: 328.1 Line No.: 20 Column: m

2013 transmission and ancillary services. 2013 annual transmission services true-up refund.

Schedule Page: 328.1 Line No.: 21 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 21 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff, (2nd Revised Service Agreement 711) terminating November 30, 2018.

Schedule Page: 328.1 Line No.: 21 Column: m
2013 transmission and ancillary services. 2013 annual transmission services true-up refund.

Schedule Page: 328.1 Line No.: 22 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.: 22 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.: 23 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.: 23 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. 2013 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 24 Column: c
PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

Schedule Page: 328.1 Line No.: 24 Column: d
Service Agreement 761 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 March 1, 2024.

Schedule Page: 328.1 Line No.: 24 Column: m
Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Distribution voltage service charge.

Schedule Page: 328.1 Line No.: 25 Column: c
PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

Schedule Page: 328.1 Line No.: 25 Column: d
Service Agreement 761 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 March 1, 2024.

Schedule Page: 328.1 Line No.: 25 Column: m
Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. 2013 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 26 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 26 Column: m
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: 328.1 Line No.: 27 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 27 Column: m
2013 transmission and ancillary services.

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
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.1 Line No.: 29 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 29 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 Line No.: 29 Column: m
2013 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 30 Column: c
Iberdrola Renewables, LLC and Utah Associated Municipal Power Systems

Schedule Page: 328.1 Line No.: 30 Column: d
Ancillary services under the Open Access Transmission Tariff (1st Revised Service Agreement 476) in effect until superseded.

Schedule Page: 328.1 Line No.: 30 Column: f
Long Hollow, WY Switching Station

Schedule Page: 328.1 Line No.: 30 Column: g
Long Hollow, WY Switching Station

Schedule Page: 328.1 Line No.: 30 Column: m
Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 31 Column: c
Iberdrola Renewables, LLC and Utah Associated Municipal Power Systems

Schedule Page: 328.1 Line No.: 31 Column: d
Ancillary services under the Open Access Transmission Tariff (1st Revised Service Agreement 476) in effect until superseded.

Schedule Page: 328.1 Line No.: 31 Column: f
Long Hollow, WY Switching Station

Schedule Page: 328.1 Line No.: 31 Column: g
Long Hollow, WY Switching Station

Schedule Page: 328.1 Line No.: 31 Column: m
2013 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 32 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised

Service Agreement 279). Agreement terminating April 30, 2019.

Schedule Page: 328.1 Line No.: 32 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 33 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 279). Agreement terminating April 30, 2019.

Schedule Page: 328.1 Line No.: 33 Column: m

2013 transmission and ancillary services. 2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund.

Schedule Page: 328.1 Line No.: 34 Column: d

Network transmission service under the Open Access Transmission Tariff (Service Agreement 742) terminating on April 30, 2018.

Schedule Page: 328.1 Line No.: 34 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.: 1 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 1 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreements 697, 698, 699). Agreements terminated in 2013.

Schedule Page: 328.2 Line No.: 1 Column: m

2013 transmission and ancillary services. 2013 annual transmission services true-up refund.

Schedule Page: 328.2 Line No.: 2 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 1.

Schedule Page: 328.2 Line No.: 3 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 212) terminating May 31, 2019.

Schedule Page: 328.2 Line No.: 3 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 4 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff(8th Revised Service Agreement 212) terminating May 31, 2019.

Schedule Page: 328.2 Line No.: 4 Column: m

2013 transmission and ancillary services. 2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund.

Schedule Page: 328.2 Line No.: 5 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 5 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 5 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.: 5 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.: 6 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 6 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 6 Column: d

Legacy contract (Rate Schedule 257) executed between PacifiCorp and Idaho Power Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge for the Antelope Substation terminating coterminous with the Idaho/United States Department of Energy Supply Agreement.

Schedule Page: 328.2 Line No.: 6 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. 2013 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 7 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 7 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 7 Column: d

Legacy contract (Rate Schedule 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.: 7 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.: 8 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 8 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 8 Column: d

Legacy contract (Rate Schedule 203) executed between PacifiCorp and Idaho Power Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge (Service Agreement 203) for the Bridger Pump Substation. Agreement terminates upon 12-months written notice.

Schedule Page: 328.2 Line No.: 8 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. 2013 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 9 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 9 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 9 Column: d

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.: 9 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 10 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 10 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 10 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 10 Column: m
2013 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 11 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 11 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 11 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 11 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 12 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 12 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 12 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 12 Column: m
2013 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
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 13 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 14 Column: a
This footnote applies to all occurrences of "JP Morgan Ventures Energy Corp." on pages 328-330. Complete name is JP Morgan Ventures Energy Corporation.

Schedule Page: 328.2 Line No.: 14 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 14 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 14 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 14 Column: m
Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.2 Line No.: 15 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 15 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 15 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 15 Column: m
2013 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 16 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.2 Line No.: 16 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.2 Line No.: 16 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.
Schedule Page: 328.2 Line No.: 16 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.
Schedule Page: 328.2 Line No.: 17 Column: 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
Transmission resales, amount paid by seller. 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
2013 transmission and ancillary services.
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
Scheduling, system control and dispatch service. Reactive supply and voltage control 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
2013 transmission and ancillary services.
Schedule Page: 328.2 Line No.: 21 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 after October 14, 2016, by providing two years written notice.
Schedule Page: 328.2 Line No.: 21 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.2 Line No.: 22 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 after October 14, 2016, by providing two years written notice.

Schedule Page: 328.2 Line No.: 22 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. 2013 transmission and ancillary services.

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. Generation regulation and frequency response 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.: 24 Column: m

2013 transmission and ancillary services.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 26 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 26 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 26 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 26 Column: m

2013 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 27 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 Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

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
Scheduling, system control and dispatch service. Reactive supply and voltage control service.
Schedule Page: 328.2 Line No.: 28 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.2 Line No.: 28 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.2 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: 328.2 Line No.: 28 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.
Schedule Page: 328.2 Line No.: 29 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.2 Line No.: 29 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.2 Line No.: 29 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.
Schedule Page: 328.2 Line No.: 29 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.
Schedule Page: 328.2 Line No.: 30 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.: 30 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.: 30 Column: e
V11-1-3,5-6,7,9
Schedule Page: 328.2 Line No.: 30 Column: m
Penalty revenues covering imbalance charges per Schedules 4 and 9. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.
Schedule Page: 328.2 Line No.: 31 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.: 31 Column: m
2013 transmission and ancillary services. 2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund.
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

Unauthorized use of transmission service. 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

2013 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 34 Column: d

Transmission service under the Open Access Transmission Tariff (6th Revised Service Agreement 299). Service provided pursuant to rules and regulations of Oregon Direct Access. Agreement termination upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 328.2 Line No.: 34 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.: 1 Column: d

Transmission service under the Open Access Transmission Tariff (6th 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.: 1 Column: m

2013 transmission and ancillary services. 2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund.

Schedule Page: 328.3 Line No.: 2 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 2 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 2 Column: d

Legacy contract (Rate Schedule 607) executed between PacifiCorp and Pacific Gas & Electric Company for transmission service over agreed-upon facilities (Malin to Round Mountain) and/or subject to a sole-use or facilities charge. Terminating December 31, 2017. See PacifiCorp, Docket No. ER07-882, et al, Settlement Agreement, Appendix 2 (filed November 20, 2007).

Schedule Page: 328.3 Line No.: 2 Column: f

Malin to Indian Springs line segment

Schedule Page: 328.3 Line No.: 2 Column: g

Malin to Indian Springs line segment

Schedule Page: 328.3 Line No.: 2 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

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

Legacy contract (Rate Schedule 607) executed between PacifiCorp and Pacific Gas & Electric Company for transmission service over agreed-upon facilities (Malin to Round Mountain) and/or subject to a sole-use or facilities charge. Terminating December 31, 2017. See PacifiCorp, Docket No. ER07-882, et al, Settlement Agreement, Appendix 2 (filed November 20, 2007).

Schedule Page: 328.3 Line No.: 3 Column: m

2013 transmission and ancillary services. 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.: 4 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 4 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 4 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 February 12, 2020.

Schedule Page: 328.3 Line No.: 4 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.: 5 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 5 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 5 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 5 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 6 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 6 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 6 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 6 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 7 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 7 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 7 Column: m

2013 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 8 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 8 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 8 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff

between various parties and points.

Schedule Page: 328.3 Line No.: 8 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 9 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 9 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 9 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 9 Column: m

2013 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 10 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 10 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 10 Column: d

Legacy contract (1st Revised Rate Schedule 137) executed between PacifiCorp and Portland General Electric for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge for the Dalreed Substation, which terminated December 2013.

Schedule Page: 328.3 Line No.: 10 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.: 11 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.: 11 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.: 11 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.: 12 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.: 12 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. 2013 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 13 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.: 13 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.: 13 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 14 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.: 14 Column: m

2013 transmission and ancillary services. 2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund.

Schedule Page: 328.3 Line No.: 15 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.: 15 Column: m

Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 16 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.: 16 Column: m

2013 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER11-3646. 2012 annual transmission services true-up charge. Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 17 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.: 17 Column: m

Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 18 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.: 18 Column: m

2013 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER11-3646. 2012 annual transmission services true-up charge. 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 702) terminating on March 31, 2017.

Schedule Page: 328.3 Line No.: 19 Column: m

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 702) terminating on March 31, 2017.

Schedule Page: 328.3 Line No.: 20 Column: m

2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund. 2013 annual transmission services true-up refund.

Schedule Page: 328.3 Line No.: 21 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 748) terminating on December 31, 2018.

Schedule Page: 328.3 Line No.: 21 Column: m

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 (Service Agreement 749) terminating on December 31, 2018.

Schedule Page: 328.3 Line No.: 22 Column: m

Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 23 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 23 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 23 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 23 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response 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
2013 transmission and ancillary services.

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
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.3 Line No.: 26 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 26 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 26 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 26 Column: m
2013 transmission and ancillary services.

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
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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
2013 transmission and ancillary services.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 30 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.: 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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 32 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 32 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 32 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 32 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 33 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 33 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 33 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 33 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

2013 transmission and ancillary services.

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

This footnote applies to all occurrences of "Sacramento Municipal Utility Dist" on pages 328-330. Complete name is Sacramento Municipal Utility District.

Schedule Page: 328.4 Line No.: 2 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 751) terminating September 30, 2018.

Schedule Page: 328.4 Line No.: 2 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 3 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 751) terminating September 30, 2018.

Schedule Page: 328.4 Line No.: 3 Column: m

2013 transmission and ancillary services. 2013 annual transmission services true-up refund.

Schedule Page: 328.4 Line No.: 4 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (Service Agreement 752) terminating March 31, 2019.

Schedule Page: 328.4 Line No.: 4 Column: m

Extension of commencement date fee.

Schedule Page: 328.4 Line No.: 5 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 765) terminating November 30, 2018.

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. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve 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.

Schedule Page: 328.4 Line No.: 7 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 7 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 7 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 7 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.4 Line No.: 8 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (9th Revised Service Agreement 289) which terminated October 11, 2014.

Schedule Page: 328.4 Line No.: 8 Column: m
2012 annual transmission services true-up charge. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.4 Line No.: 9 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 Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

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 d/b/a NV Energy 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.

Schedule Page: 328.4 Line No.: 10 Column: b
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 10 Column: c
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 10 Column: d
Legacy contract (Rate Schedule 674) executed between PacifiCorp and Sierra Pacific Power Company d/b/a NV Energy for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating in September 2022.

Schedule Page: 328.4 Line No.: 10 Column: m
Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. 2013 transmission and ancillary services.

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
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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
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.: 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

2013 transmission and ancillary services.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response 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

2013 transmission and ancillary services.

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 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

This footnote applies to all occurrences of "Southern California Public Power" on pages 328-330. Complete name is Southern California Public Power Authority.

Schedule Page: 328.4 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 (Service Agreement 779) terminating on August 31, 2019.

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 (Service Agreement 779) terminating on August 31, 2019.

Schedule Page: 328.4 Line No.: 19 Column: m

2013 transmission and ancillary services. 2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund.

Schedule Page: 328.4 Line No.: 20 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 779) terminating on August 31, 2019.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

2013 transmission and ancillary services.

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

Transmission resales, amount paid by seller. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

2013 transmission and ancillary services.

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
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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 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 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
2013 transmission and ancillary services. 2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund.

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
2013 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 30 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.: 30 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 30 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. Terminated October 1, 2014.

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. Terminated October 1, 2014.

Schedule Page: 328.4 Line No.: 31 Column: m

2013 transmission and ancillary services.

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

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.: 32 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.: 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

2013 transmission and ancillary services. 2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund.

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: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 34 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

2013 transmission and ancillary services.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

2013 transmission and ancillary services.

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. 2013 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER11-3646. 2013 annual transmission services true-up refund.

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 4 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 4 years written notification.

Schedule Page: 328.5 Line No.: 7 Column: m

2013 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 (Third Amended and Restated Transmission Service and Operating Agreement, Third 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. 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: 328.5 Line No.: 10 Column: d

Legacy contract executed between PacifiCorp and Utah Associated Municipal Power Systems for transmission service over agreed-upon facilities (Third Amended and Restated Transmission Service and Operating Agreement, Third 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

2013 transmission and ancillary services. 2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund.

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. Generation regulation and frequency response 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

2013 transmission and ancillary services.

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. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve 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

2013 transmission and ancillary services. 2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund.

Schedule Page: 328.5 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: 328.5 Line No.: 15 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 16 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.: 16 Column: d

Legacy contract (Rate Schedule 591) executed between PacifiCorp and Warm Springs Power Enterprises for transmission service over agreed-upon facilities and/or subject to sole-use or facilities charge. Agreement terminating January 31, 2032.

Schedule Page: 328.5 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.

Schedule Page: 328.5 Line No.: 17 Column: d

Legacy contract (Rate Schedule 591) executed between PacifiCorp and Warm Springs Power Enterprises for transmission service over agreed-upon facilities and/or subject to sole-use or facilities charge. Agreement terminating January 31, 2032.

Schedule Page: 328.5 Line No.: 17 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.5 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 after 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.

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 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.: 19 Column: m

Fixed termination fee associated with a contract cancellation applied for the duration of this agreement. 2013 transmission and ancillary services.

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 138 kV. Agreement termination upon three years after written notice and mutual consent.

Schedule Page: 328.5 Line No.: 20 Column: m

Charges for low-voltage transmission of power and energy.

Schedule Page: 328.5 Line No.: 21 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.5 Line No.: 21 Column: d

Legacy contract (Rate Schedule 263) executed between PacifiCorp and Western Area Power Administration for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge for load service to low voltage customers for deliveries of power and energy from Salt Lake City Area Integrated Projects, including the Colorado River Storage Projects, to certain municipalities at service below 138 kV. Agreement termination upon three years after written notice and mutual consent.

Schedule Page: 328.5 Line No.: 21 Column: m

Charges for low-voltage transmission of power and energy. 2013 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 22 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 22 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.: 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

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.: 24 Column: d

Evergreen network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 175).

Schedule Page: 328.5 Line No.: 24 Column: m

2013 transmission and ancillary services. 2012 annual transmission services true-up charge. 2013 annual transmission services true-up refund.

Schedule Page: 328.5 Line No.: 25 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.: 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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 28 Column: m

Represents the difference between actual wheeling revenues for the period as reflected on the individual line items within this schedule, and the accruals credited to Account 456.1, Revenues from transmission of electricity for others, during the period.

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 2014/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	548,589	548,589	1,690,366			1,690,366
2	Arizona Public Service	NF	57,950	57,950	317,582			317,582
3	Arizona Public Service	OS	1	1		9,488	15,000	24,488
4	Arizona Public Service	OS						
5	Arizona Public Service	SFP	44,735	44,735	295,818			295,818
6	Ashland, City of	FNS	2,227	2,227		21,346		21,346
7	Avista Corporation	FNS	64,411	66,615	231,694			231,694
8	Avista Corporation	NF	21,589	21,589	124,569			124,569
9	Basin Elect. Power Coop	NF	13,759	13,759		20,501		20,501
10	Big Horn Rural Electric	OLF					203,014	203,014
11	Black Hills Power, Inc.	AD			-40			-40
12	Black Hills Power, Inc.	NF	1,187	1,187	1,187			1,187
13	Black Hills Power, Inc.	OS					1,988	1,988
14	Black Hills Power, Inc.	SFP	625	625	3,968			3,968
15	Bonneville Power Admin	AD			199,191		93,509	292,700
16	Bonneville Power Admin	FNS			6,781,444			6,781,444
	TOTAL		17,778,500	18,261,782	123,849,237	10,001,730	17,484,757	151,335,724

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 2014/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Bonneville Power Admin	LFP	5,557,956	5,557,956	58,311,815			58,311,815
2	Bonneville Power Admin	NF	16,597	16,597		82,252		82,252
3	Bonneville Power Admin	OLF	4,528,946	4,755,610	31,523,361		107,740	31,631,101
4	Bonneville Power Admin	OS	22,289	22,289	9,900	346,225	1,043,744	1,399,869
5	Bonneville Power Admin	OS						
6	Bonneville Power Admin	SFP	1,550,757	1,550,757		7,795,071		7,795,071
7	CA Ind. Sys. Operator	AD				-12,812	-179,668	-192,480
8	CA Ind. Sys. Operator	OS					828,758	828,758
9	CA Ind. Sys. Operator	SFP	212,694	212,694		1,738,060		1,738,060
10	Deseret Gen & Trans	AD			300			300
11	Deseret Gen & Trans	LFP	187,792	187,792	4,693,645			4,693,645
12	Deseret Gen & Trans	NF	171,099	171,099	1,134,223			1,134,223
13	El Paso Electric Co.	NF	39,757	39,757	35,184			35,184
14	El Paso Electric Co.	OS					18,027	18,027
15	El Paso Electric Co.	SFP	31,582	31,582	71,722			71,722
16	Flathead Elect Coop Inc	OS					76,849	76,849
	TOTAL		17,778,500	18,261,782	123,849,237	10,001,730	17,484,757	151,335,724

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 2014/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	Hermiston Gen Co L.P.	OS					191,074	191,074
2	Idaho Power Company	AD			-106,709		-58,221	-164,930
3	Idaho Power Company	FNS			9,331			9,331
4	Idaho Power Company	LFP	1,991,048	2,236,072	5,741,100			5,741,100
5	Idaho Power Company	NF	265,309	265,309	1,162,265			1,162,265
6	Idaho Power Company	OS			-10,895		13,428,563	13,417,668
7	Idaho Power Company	OS						
8	Idaho Power Company	SFP	169,872	169,872	436,850			436,850
9	LA Dept of Water & Pwr	NF	3,357	3,357	36,217			36,217
10	LA Dept of Water & Pwr	OS					5,156	5,156
11	Moon Lake Elect. Assoc.	AD					-1,863	-1,863
12	Moon Lake Elect. Assoc.	FNS					292,764	292,764
13	Morgan City Corporation	LFP	13	13		1,599		1,599
14	Nevada Power Company	AD			-190,582		-64,251	-254,833
15	Nevada Power Company	NF	37,199	37,199	267,471			267,471
16	Nevada Power Company	OS					63,292	63,292
	TOTAL		17,778,500	18,261,782	123,849,237	10,001,730	17,484,757	151,335,724

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 2014/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	Nevada Power Company	SFP	40,200	40,200	198,000			198,000
2	NorthWestern Corp.	NF	114,091	117,304	508,074			508,074
3	NorthWestern Corp.	OS					35,326	35,326
4	NorthWestern Corp.	SFP	50,090	50,090	217,255			217,255
5	Platte River Pwr Auth	LFP	162,547	162,547	849,700			849,700
6	Platte River Pwr Auth	OS					9,299	9,299
7	Portland Gen. Electric	OLF					941	941
8	Public Service Co of CO	LFP	84,355	87,441	990,630			990,630
9	Public Service Co of NM	NF	490	490	2,732			2,732
10	Public Service Co of NM	OS					1,704	1,704
11	Public Service Co of NM	SFP	6,770	6,770	48,507			48,507
12	Salt River Project	NF	138,112	138,112	334,073			334,073
13	Salt River Project	OS					54,292	54,292
14	Sierra Pacific Power Co	NF	9,855	9,855	72,525			72,525
15	Sierra Pacific Power Co	OS					14,288	14,288
16	Sierra Pacific Power Co	SFP	4,177	4,177	33,600			33,600
	TOTAL		17,778,500	18,261,782	123,849,237	10,001,730	17,484,757	151,335,724

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 2014/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	Surprise Valley Electr.	OLF					8,886	8,886
2	Tri-State Gen & Transm	LFP	39,315	42,406	990,630			990,630
3	Tri-State Gen & Transm	NF	32,729	32,729	131,348			131,348
4	Tri-State Gen & Transm	OS					35,071	35,071
5	Tucson Electric Power	LFP	187,696	187,696	596,442			596,442
6	Tucson Electric Power	NF	6,631	6,631	27,930			27,930
7	Tucson Electric Power	OS					62,620	62,620
8	Tucson Electric Power	SFP	9,306	9,306	60,175			60,175
9	Westport Field Svc LLC	LFP			-3,705,509			-3,705,509
10	Western Area Power Admn	AD			7,452		3,444	10,896
11	Western Area Power Admn	FNS			6,500,251			6,500,251
12	Western Area Power Admn	LFP	652,572	652,572	1,693,333			1,693,333
13	Western Area Power Admn	NF	327,759	327,759	641,035			641,035
14	Western Area Power Admn	OS					1,360,066	1,360,066
15	Western Area Power Admn	OS						
16	Western Area Power Admn	SFP	370,465	370,465	880,077			880,077
	TOTAL		17,778,500	18,261,782	123,849,237	10,001,730	17,484,757	151,335,724

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 2014/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	Accrual						-166,655	-166,655
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		17,778,500	18,261,782	123,849,237	10,001,730	17,484,757	151,335,724

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, of this Form No. 1.

Schedule Page: 332 Line No.: 10 Column: b
Big Horn Rural Electric Company - contract termination date: March 10, 2015.

Schedule Page: 332 Line No.: 10 Column: g
Use of facilities.

Schedule Page: 332 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 332 Line No.: 11 Column: e
Settlement adjustment.

Schedule Page: 332 Line No.: 13 Column: g
Ancillary services.

Schedule Page: 332 Line No.: 15 Column: b
Settlement adjustment.

Schedule Page: 332 Line No.: 15 Column: g
Ancillary services. Use of facilities.

Schedule Page: 332.1 Line No.: 1 Column: b
Bonneville Power Administration - contract termination dates: January 1, 2016; July 1, 2016; September 1, 2016; November 1, 2016; December 1, 2016; April 1, 2017; July 1, 2017; November 1, 2017; September 1, 2018; October 1, 2018; December 1, 2018; January 1, 2019; July 1, 2019; September 1, 2019; October 1, 2019; November 1, 2019; December 1, 2019; November 1, 2020; October 1, 2027; November 1, 2033; and evergreen.

Schedule Page: 332.1 Line No.: 3 Column: b
Bonneville Power Administration - contract termination dates: December 31, 2018; September 30, 2027; and evergreen.

Schedule Page: 332.1 Line No.: 3 Column: g
Use of facilities.

Schedule Page: 332.1 Line No.: 4 Column: g
Ancillary services. Use of facilities.

Schedule Page: 332.1 Line No.: 5 Column: b
Bonneville Power Administration - Legacy contract executed between PacifiCorp and Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities ("Midpoint-Meridian Transmission Agreement", Rate Schedule 369). This agreement runs concurrently with the AC Intertie Agreement (Rate Schedule 368), which terminates when the facilities subject to that agreement are taken out of service. See also page 328, Transmission of electricity for others, of this Form No. 1.

Schedule Page: 332.1 Line No.: 7 Column: a
This footnote applies to all occurrences of "CA Ind. Sys. Operator" on page 332. Complete name is California Independent System Operator Corporation.

Schedule Page: 332.1 Line No.: 7 Column: b
Settlement adjustment.

Schedule Page: 332.1 Line No.: 7 Column: f
Settlement adjustment.

Schedule Page: 332.1 Line No.: 7 Column: g
Ancillary services.

Schedule Page: 332.1 Line No.: 8 Column: g
Ancillary services.

Schedule Page: 332.1 Line No.: 10 Column: b
Settlement adjustment.

Schedule Page: 332.1 Line No.: 11 Column: b
Deseret Generation & Transmission Cooperative - contract termination dates: January 1, 2018 and September 1, 2018.

Schedule Page: 332.1 Line No.: 14 Column: g
Ancillary services.

Schedule Page: 332.1 Line No.: 16 Column: g
Use of facilities.

Schedule Page: 332.2 Line No.: 1 Column: a
Hermiston Generating Company, L.P. operates the Hermiston Generating Plant, which is jointly owned. PacifiCorp owns 50% of the plant.

Schedule Page: 332.2 Line No.: 1 Column: g
Use of facilities.

Schedule Page: 332.2 Line No.: 2 Column: b
Settlement adjustment.

Schedule Page: 332.2 Line No.: 2 Column: e
Settlement adjustment.

Schedule Page: 332.2 Line No.: 2 Column: g
Use of facilities.

Schedule Page: 332.2 Line No.: 4 Column: b
Idaho Power Company - contract termination dates: April 1, 2025 and July 1, 2025.

Schedule Page: 332.2 Line No.: 6 Column: e
Credit for unreserved use.

Schedule Page: 332.2 Line No.: 6 Column: g
Ancillary services. Use of facilities. PacifiCorp's portion of specified costs of certain facilities.

Schedule Page: 332.2 Line No.: 7 Column: b
Idaho Power Company - Legacy contract (Rate Schedule 427) executed between PacifiCorp and Idaho Power Company concerning the exchange of transmission services over agreed-upon facilities (Draft Transmission Services Agreement between PacifiCorp and Idaho Power Company, Draft 1 – 5/19/95 (“Goshen Agreement”)). Termination of this agreement occurs at the end of the calendar month following the earlier of the effectiveness of a replacement contract, or upon three years written notice of termination as long as PacifiCorp has facilities in place to serve PacifiCorp's Big Grassy load. See also page 328, Transmission of electricity for others, of this Form No. 1.

Schedule Page: 332.2 Line No.: 9 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.: 10 Column: g
Ancillary services.

Schedule Page: 332.2 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 332.2 Line No.: 11 Column: g
Use of facilities.

Schedule Page: 332.2 Line No.: 12 Column: g
Use of facilities.

Schedule Page: 332.2 Line No.: 13 Column: b
Morgan City Corporation - contract termination date: Evergreen.

Schedule Page: 332.2 Line No.: 14 Column: a
This footnote applies to all occurrences of "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 Berkshire Hathaway Energy Company, PacifiCorp's indirect parent

company.

Schedule Page: 332.2 Line No.: 14 Column: b

Settlement adjustment.

Schedule Page: 332.2 Line No.: 14 Column: e

Settlement adjustment.

Schedule Page: 332.2 Line No.: 14 Column: g

Imbalance energy.

Schedule Page: 332.2 Line No.: 16 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 3 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 5 Column: b

Platte River Power Authority - contract termination date: October 31, 2017.

Schedule Page: 332.3 Line No.: 6 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 7 Column: b

Portland General Electric Company - contract termination date: Upon two years written notice.

Schedule Page: 332.3 Line No.: 7 Column: g

Use of facilities.

Schedule Page: 332.3 Line No.: 8 Column: b

Public Service Company of Colorado - contract termination date: The date that all generating plants comprising PacifiCorp resources associated with this agreement have been retired from service or interests transferred.

Schedule Page: 332.3 Line No.: 10 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 13 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 14 Column: a

This footnote applies to all occurrences of "Sierra Pacific Power Co" on page 332. Sierra Pacific Power Company is a principal subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

Schedule Page: 332.3 Line No.: 15 Column: g

Ancillary services.

Schedule Page: 332.4 Line No.: 1 Column: b

Surprise Valley Electrification Corp. - contract termination date: Evergreen.

Schedule Page: 332.4 Line No.: 1 Column: g

Use of facilities.

Schedule Page: 332.4 Line No.: 2 Column: b

Tri-State Generation and Transmission Association, Inc. - contract termination date: The date that all generating plants comprising PacifiCorp resources associated with this agreement have been retired from service or interests transferred.

Schedule Page: 332.4 Line No.: 4 Column: g

Ancillary services.

Schedule Page: 332.4 Line No.: 5 Column: b

Tucson Electric Power Company - contract termination date: December 1, 2015.

Schedule Page: 332.4 Line No.: 7 Column: g

Ancillary services.

Schedule Page: 332.4 Line No.: 9 Column: b

Westport Field Services, LLC - contract termination date: Evergreen.

Schedule Page: 332.4 Line No.: 9 Column: e

Reimbursement for third-party services provided.

Schedule Page: 332.4 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 332.4 Line No.: 10 Column: g

Ancillary services.

Schedule Page: 332.4 Line No.: 12 Column: b

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

Schedule Page: 332.4 Line No.: 14 Column: g

Ancillary services. Use of facilities.

Schedule Page: 332.4 Line No.: 15 Column: b

Western Area Power Administration - Legacy contract (Rate Schedule 664) executed between PacifiCorp and Western Area Power Administration concerning the exchange of transmission services over agreed-upon facilities. The contract terminates 50 years from execution. See also page 328, Transmission of electricity for others, of this Form No. 1.

Schedule Page: 332.5 Line No.: 1 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.

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 2014/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,114,980
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6		
7	Community & Economic Development and	
8	Corporate Memberships & Subscriptions:	
9	Albina Opportunities Corporation	5,000
10	American Leadership Forum of Oregon	5,000
11	American Wind Energy Association	13,782
12	Associated Oregon Industries	28,000
13	Carbon County Economic Development Corporation	7,000
14	Clatsop Economic Development Resources	5,000
15	Eastern Idaho Economic Development Partners	5,000
16	Economic Development Corporation of Utah	19,000
17	Economic Development for Central Oregon	8,000
18	Equal Employment Advisory Council	6,061
19	Four County Economic Development Corporation	10,000
20	Intermountain Electrical Association	9,000
21	Klamath County Economic Development Association	5,000
22	Oregon Business Association	13,900
23	Oregon Business Council	31,378
24	Oregon Economic Development Association	7,500
25	Oregon Sports Authority	5,000
26	Oregon State University Utility Pole Research Coop	15,000
27	Oregon Tourism Commission	5,000
28	Portland Business Alliance	37,300
29	Redmond Economic Development, Inc.	7,000
30	Rocky Mountain Electrical League	18,000
31	Salt Lake Area Chamber of Commerce	27,230
32	Siskiyou County Economic Development Council, Inc.	5,000
33	South Coast Development Council, Inc.	5,000
34	Southern Oregon Regional Economic Development, Inc.	5,000
35	Strategic Economic Development Corporation	6,400
36	Utah Alliance for Economic Development	5,000
37	Utah Manufacturers Association	6,600
38	Utah Taxpayers Association	18,700
39	Webster Global Site Selectors	5,000
40	Western Energy Institute	44,901
41	Western Energy Supply and Transmission Associates	25,660
42	Wyoming Business Alliance	7,000
43	Wyoming Business Council	5,000
44	Wyoming Taxpayers Association	11,199
45	Yakima County Development Association	7,500
46	TOTAL	2,426,050

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 2014/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
6	Other (Individually < $5,000)	196,494
7		
8	Directors' Fees - Regional Advisory Board	15,754
9		
10	Rating Agency and Trustee Fees:	
11	The Bank of New York Mellon	133,054
12	Computershare Shareowner Services, LLC	-17,059
13	Fitch, Inc.	41,347
14	Moody's Investors Service, Inc.	157,296
15	Standard and Poor's Financial Services, LLC	222,903
16	U.S. Bank National Association	10,303
17	United States Securities and Exchange Commission	8,540
18	Financial Industry Regulatory Authority, Inc.	1,200
19		
20	Regulatory Asset Amortization:	
21	Generating Plant Liquidated Damages - UT	35,000
22	Generating Plant Liquidated Damages - WY	54,288
23		
24	General:	
25	Other	839
26		
27		
28		
29		
30		
31		
32		
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45		
46	TOTAL	2,426,050

Schedule Page: 335.1 Line No.: 12 Column: b

Represents the difference between actual expense for the period and the accruals charged to Account 930.2, Miscellaneous general expenses, during the period for Computershare Shareowner Services, 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 2014/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			39,290,397		39,290,397
2	Steam Production Plant	248,248,020				248,248,020
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	32,023,230		274,362		32,297,592
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	117,620,076				117,620,076
7	Transmission Plant	92,085,625				92,085,625
8	Distribution Plant	133,686,007				133,686,007
9	Regional Transmission and Market Operation					
10	General Plant	39,508,869		1,144,615		40,653,484
11	Common Plant-Electric					
12	TOTAL	663,171,827		40,709,374		703,881,201

B. Basis for Amortization Charges

The amortization of limited-term electric plant is based on straight-line amortization over the life of the asset.

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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	STEAM PRODUCTION						
13	Blundell Plant						
14	310.20 UT	35,883	46.97		2.09		24.00
15	311.00 UT	8,248	42.30	-4.00	2.51		23.30
16	312.00 UT	57,994	34.11	-3.00	2.98		22.20
17	314.00 UT	33,932	32.76	-5.00	3.30		21.50
18	315.00 UT	7,526	39.15	-3.00	2.70		23.10
19	316.00 UT	1,261	29.19	-5.00	3.76		19.30
20							
21	Carbon Plant						
22	311.00 UT	15,579	14.49	-17.00	40.37		1.30
23	312.00 UT	68,203	9.82	-17.00	44.69		1.30
24	314.00 UT	28,155	10.45	-17.00	45.16		1.30
25	315.00 UT	6,302	10.50	-17.00	45.76		1.30
26	316.00 UT	809	6.67	-17.00	56.80		1.30
27							
28	Cholla Plant						
29	310.20 AZ	1,368	34.48		2.89		29.00
30	311.00 AZ	64,092	45.93	-6.00	2.34		28.00
31	312.00 AZ	333,544	37.41	-5.00	2.89		26.20
32	314.00 AZ	67,730	38.37	-7.00	2.85		24.80
33	315.00 AZ	67,923	46.05	-5.00	2.32		27.30
34	316.00 AZ	4,094	33.53	-7.00	3.31		21.40
35							
36	Colstrip Plant						
37	311.00 MT	60,705	55.79	-6.00	1.88		31.50
38	312.00 MT	118,087	47.52	-6.00	2.24		28.10
39	314.00 MT	37,925	41.60	-8.00	2.61		27.30
40	315.00 MT	9,051	56.37	-5.00	1.83		30.00
41	316.00 MT	321	36.94	-7.00	2.90		22.90
42							
43	Craig Plant						
44	311.00 CO	37,497	48.45	-6.00	2.11		20.40
45	312.00 CO	95,910	34.51	-5.00	3.00		19.40
46	314.00 CO	28,475	31.03	-7.00	3.50		19.10
47	315.00 CO	16,995	49.53	-5.00	2.04		19.80
48	316.00 CO	1,226	34.18	-7.00	3.11		16.50
49							
50							

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	Dave Johnston Plant						
13	310.20 WY	100	53.86		2.30		14.00
14	311.00 WY	155,554	20.39	-4.00	5.56		13.80
15	312.00 WY	670,321	19.99	-4.00	5.69		13.60
16	314.00 WY	94,804	24.19	-5.00	4.82		13.20
17	315.00 WY	62,233	20.04	-3.00	5.67		13.80
18	316.00 WY	8,418	18.11	-4.00	6.03		12.60
19							
20	Gadsby Plant						
21	311.00 UT	15,103	43.40	-15.00	2.02		18.60
22	312.00 UT	38,758	39.12	-13.00	2.22		17.50
23	314.00 UT	19,657	37.19	-15.00	2.43		16.80
24	315.00 UT	8,341	34.93	-14.00	2.87		18.30
25	316.00 UT	458	29.04	-13.00	3.17		15.80
26							
27	Hayden Plant						
28	311.00 CO	17,684	23.54	-5.00	4.62		16.70
29	312.00 CO	54,659	30.98	-5.00	3.14		16.00
30	314.00 CO	9,301	27.79	-6.00	3.69		15.80
31	315.00 CO	2,546	48.38	-5.00	1.74		16.10
32	316.00 CO	637	30.28	-6.00	3.22		14.20
33							
34	Hunter Plant						
35	310.20 UT	246	60.93		1.61		29.00
36	311.00 UT	206,744	55.00	-7.00	1.93		27.80
37	312.00 UT	750,440	38.55	-6.00	2.79		26.10
38	314.00 UT	191,922	34.57	-8.00	3.17		25.60
39	315.00 UT	106,650	53.28	-6.00	1.97		26.70
40	316.00 UT	3,691	35.58	-8.00	3.08		20.80
41							
42	Huntington Plant						
43	311.00 UT	119,464	45.56	-7.00	2.39		22.30
44	312.00 UT	547,010	29.78	-6.00	3.64		21.60
45	314.00 UT	121,652	31.75	-7.00	3.43		20.80
46	315.00 UT	47,353	39.00	-6.00	2.78		22.00
47	316.00 UT	2,866	27.99	-7.00	3.96		18.70
48							
49							
50							

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	Camas Co-Gen Plant						
13	311.00 WA	5,734	19.19		6.42		2.00
14	312.00 WA	5,798	18.98		6.51		2.00
15	314.00 WA	18,616	18.76		6.64		2.00
16	315.00 WA	4,304	19.01		6.48		2.00
17							
18	Jim Bridger Plant						
19	310.20 WY	281	61.28		1.36		24.00
20	311.00 WY	139,956	51.14	-8.00	1.87		23.20
21	312.00 WY	699,179	35.97	-7.00	2.86		22.00
22	314.00 WY	201,832	31.25	-8.00	3.36		21.70
23	315.00 WY	60,807	49.15	-7.00	1.93		22.40
24	316.00 WY	4,115	33.02	-8.00	3.12		18.50
25							
26	Naughton Plant						
27	310.20 WY	15	66.74		1.45		16.00
28	311.00 WY	118,149	24.81	-5.00	4.34		15.80
29	312.00 WY	496,398	22.44	-4.00	4.81		15.40
30	314.00 WY	77,837	25.92	-6.00	4.17		15.00
31	315.00 WY	62,960	21.19	-4.00	5.13		15.80
32	316.00 WY	2,011	21.86	-6.00	5.15		13.90
33							
34	Wyodak Plant						
35	310.20 WY	165	57.58		1.65		26.00
36	311.00 WY	51,286	51.08	-5.00	2.01		25.10
37	312.00 WY	300,425	34.28	-4.00	3.09		23.90
38	314.00 WY	63,689	34.60	-6.00	3.12		22.90
39	315.00 WY	28,510	42.62	-4.00	2.44		24.60
40	316.00 WY	1,211	26.65	-6.00	4.07		21.10
41							
42	HYDRAULIC						
43	Ashton/St. Anthony						
44	330.20 ID	29	40.48		2.79		14.00
45	331.00 ID	2,009	34.65	-2.00	3.33		13.80
46	332.00 ID	28,077	17.43	-1.00	6.19		13.90
47	333.00 ID	1,958	35.43	-2.00	3.21		13.60
48	334.00 ID	1,241	30.80	-3.00	3.77		13.00
49	335.00 ID	8	41.77	-1.00	2.82		13.20
50	336.00 ID	6	96.08	-5.00	1.64		13.50

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	Bear River						
13	330.20 ID	6	115.28		1.38		19.80
14	331.00 ID	4,807	38.54	-3.00	3.09		19.30
15	332.00 ID	26,197	34.60	-2.00	3.31		19.60
16	333.00 ID	11,045	33.28	-4.00	3.50		19.20
17	334.00 ID	4,422	30.59	-4.00	3.79		18.20
18	335.00 ID	82	42.57	-1.00	2.73		18.50
19	336.00 ID	844	40.28	-3.00	2.94		19.40
20							
21	Bend						
22	331.00 OR	57	32.00		2.09		3.00
23	332.00 OR	767	8.74		17.64		3.00
24	333.00 OR	97	18.04	-1.00	6.79		3.00
25	334.00 OR	628	25.63		3.53		3.00
26	335.00 OR	15	15.79		3.38		3.00
27	336.00 OR		86.23				
28							
29	Big Fork						
30	331.00 MT	606	52.37	-5.00	1.41		38.30
31	332.00 MT	4,686	53.78	-4.00	1.29		38.70
32	333.00 MT	1,496	50.44	-8.00	1.46		37.20
33	334.00 MT	404	46.04	-8.00	1.52		33.00
34	336.00 MT	232	45.15	-4.00	2.13		38.40
35							
36	Cutler						
37	330.20 UT	1			8.34		
38	330.30 UT	5	96.37		3.11		11.00
39	330.40 UT	91	74.44		3.33		11.00
40	331.00 UT	3,970	28.62	-1.00	5.06		10.80
41	332.00 UT	9,130	30.30	-1.00	5.01		10.80
42	333.00 UT	12,001	17.15	-1.00	7.18		10.90
43	334.00 UT	2,598	17.22	-2.00	7.29		10.60
44	335.00 UT	11	36.34	-1.00	4.52		10.60
45	336.00 UT	572	35.14	-1.00	4.54		10.80
46							
47							
48							
49							
50							

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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	Eagle Point						
13	330.20 OR	12	68.49				
14	331.00 OR	138	33.98	-1.00	1.31		11.90
15	332.00 OR	1,235	33.88	-1.00	1.25		11.90
16	333.00 OR	252	42.71	-4.00	0.31		11.80
17	334.00 OR	126	25.76	-2.00	2.68		11.50
18	336.00 OR	136	24.29	-1.00	2.96		11.90
19							
20	Granite						
21	331.00 UT	535	25.43	-2.00	4.42		16.70
22	332.00 UT	3,768	30.19	-1.00	3.60		16.80
23	333.00 UT	721	38.99	-4.00	3.06		16.30
24	334.00 UT	210	31.63	-3.00	3.63		15.60
25	335.00 UT	1	48.73	-2.00	2.45		16.00
26							
27	Klamath River						
28	330.20 CA/OR	639	24.88		7.02		7.00
29	330.40 CA/OR	253	48.84		5.27		7.00
30	331.00 CA/OR	913	21.42	-1.00	7.87		6.90
31	332.00 CA/OR	11,773	40.24	-1.00	5.79		6.90
32	333.00 CA/OR	315	43.09	-3.00	5.84		6.70
33	334.00 CA/OR	874	19.24	-1.00	8.32		6.80
34	335.00 CA/OR	62	29.11	-1.00	6.92		6.80
35	336.00 CA/OR	241	23.60	-1.00	7.41		6.90
36							
37	Klamath River Accel						
38	330.20 CA/OR	41			3.60		5.00
39	330.40 CA/OR	1			3.61		5.00
40	331.00 CA/OR	14,420			7.78		5.00
41	332.00 CA/OR	35,252			7.26		5.00
42	333.00 CA/OR	17,824			7.65		5.00
43	334.00 CA/OR	15,801			8.82		5.00
44	335.00 CA/OR	183			6.38		5.00
45	336.00 CA/OR	2,567			7.35		5.00
46							
47							
48							
49							
50							

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	Last Chance						
13	331.00 ID	448	35.19	-1.00	3.45		11.80
14	332.00 ID	959	29.40	-1.00	4.03		11.90
15	333.00 ID	1,068	36.38	-2.00	3.35		11.70
16	334.00 ID	266	22.78	-2.00	5.03		11.40
17	336.00 ID	65	40.81	-1.00	3.07		11.80
18							
19	Lifton						
20	330.20 ID	21	99.80		1.87		20.00
21	330.30 ID	24	92.81		1.93		20.00
22	331.00 ID	1,224	51.97	-4.00	2.80		19.10
23	332.00 ID	8,270	40.45	-3.00	3.17		19.50
24	333.00 ID	7,875	26.40	-2.00	4.13		19.70
25	334.00 ID	302	36.10	-4.00	3.53		18.00
26	335.00 ID	3	46.32	-2.00	2.97		18.30
27	336.00 ID	187	29.39	-2.00	3.83		19.60
28							
29	Merwin						
30	330.20 WA	301	121.57		0.50		45.00
31	330.50 WA	212	125.02		0.48		45.00
32	331.00 WA	87,942	48.18	-4.00	2.11		42.90
33	332.00 WA	28,047	54.60	-6.00	1.83		43.10
34	333.00 WA	7,963	65.82	-16.00	1.44		37.20
35	334.00 WA	10,481	44.36	-8.00	2.34		36.30
36	335.00 WA	169	48.09	-3.00	2.07		38.40
37	336.00 WA	2,978	59.30	-5.00	1.62		42.40
38							
39	North Umpqua						
40	331.00 OR	30,289	27.53	-2.00	3.82		24.40
41	332.00 OR	197,618	38.59	-2.00	2.90		24.40
42	333.00 OR	24,650	34.44	-4.00	3.27		24.00
43	334.00 OR	16,743	29.42	-4.00	3.75		22.60
44	335.00 OR	722	36.23	-2.00	3.05		22.90
45	336.00 OR	8,666	41.97	-3.00	2.73		24.20
46							
47							
48							
49							
50							

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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	Olmsted						
13	331.00 UT	188	31.23	-1.00	5.97		3.00
14	334.00 UT	29	13.70		9.28		3.00
15	335.00 UT	3	33.94		4.47		3.00
16	336.00 UT	13	11.31		12.71		3.00
17							
18	Paris						
19	331.00 ID	110	10.31		10.16		4.00
20	332.00 ID	96	46.25	-1.00			
21	333.00 ID	73	31.74	-1.00			
22	334.00 ID	151	14.62	-1.00	4.90		4.00
23	335.00 ID		34.25				
24							
25	Pioneer						
26	330.20 UT	9	134.02		1.09		17.00
27	330.30 UT	111	133.34		1.09		17.00
28	331.00 UT	508	32.02	-2.00	3.54		16.60
29	332.00 UT	8,128	37.80	-2.00	2.97		16.70
30	333.00 UT	1,616	25.26	-2.00	4.31		16.70
31	334.00 UT	544	30.51	-3.00	3.67		15.60
32	335.00 UT	10	39.03	-1.00	2.85		16.00
33	336.00 UT	54	21.11	-1.00	5.17		16.70
34							
35	Prospect #1, 2 & 4						
36	330.20 OR	4	56.24		2.02		25.30
37	330.40 OR	3	102.16		1.36		24.90
38	331.00 OR	3,873	40.66	-3.00	2.77		24.20
39	332.00 OR	31,103	32.55	-2.00	3.27		24.60
40	333.00 OR	3,898	35.11	-4.00	3.18		24.00
41	334.00 OR	6,786	33.85	-5.00	3.34		22.20
42	335.00 OR	19	35.19	-2.00	3.05		23.10
43	336.00 OR	339	39.57	-3.00	2.84		24.20
44							
45							
46							
47							
48							
49							
50							

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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	Prospect #3						
13	331.00 OR	636	21.27		5.46		5.00
14	332.00 OR	4,228	25.67		4.15		5.00
15	333.00 OR	1,809	21.89		4.76		5.00
16	334.00 OR	1,887	21.02	-1.00	5.25		4.90
17	335.00 OR	63	25.01		4.22		4.90
18	336.00 OR	117	36.09	-1.00	3.29		5.00
19							
20	Santa Clara						
21	331.00 UT	180	23.79	-1.00	5.05		6.90
22	332.00 UT	1,139	24.52	-1.00	4.92		7.00
23	333.00 UT	464	26.11	-1.00	4.44		6.90
24	334.00 UT	692	20.82	-1.00	5.46		6.80
25	335.00 UT	8	32.24	-1.00	3.62		6.80
26	336.00 UT	22	80.51	-2.00	1.79		6.80
27							
28	Stairs						
29	331.00 UT	181	39.40	-3.00	2.38		16.60
30	332.00 UT	811	28.73	-2.00	3.56		16.80
31	333.00 UT	518	36.73	-3.00	2.52		16.50
32	334.00 UT	176	33.10	-3.00	2.83		15.60
33	336.00 UT	33	19.20	-1.00	5.08		16.80
34							
35	Swift						
36	330.20 WA	6,277	99.73		0.86		45.00
37	330.50 WA	97	98.01		0.88		45.00
38	331.00 WA	69,952	46.22	-4.00	2.26		43.00
39	332.00 WA	46,648	70.57	-7.00	1.40		42.00
40	333.00 WA	16,298	65.49	-16.00	1.63		37.00
41	334.00 WA	7,786	45.90	-8.00	2.29		35.90
42	335.00 WA	411	64.91	-5.00	1.46		34.20
43	336.00 WA	1,133	52.23	-5.00	1.98		42.70
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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 2014/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	Viva Naughton						
13	331.00 WY	403	49.70	-3.00	2.15		26.10
14	332.00 WY	104	51.79	-2.00	2.04		26.30
15	333.00 WY	497	49.03	-7.00	2.26		25.10
16	334.00 WY	170	42.11	-6.00	2.63		23.20
17	335.00 WY	21	46.04	-2.00	2.29		24.30
18							
19	Wallowa Falls						
20	331.00 OR	168	23.24		4.41		3.00
21	332.00 OR	909	23.14		4.39		3.00
22	333.00 OR	743	15.16		9.10		3.00
23	334.00 OR	731	18.38		4.99		3.00
24	336.00 OR	649	20.11		4.76		3.00
25							
26	Weber						
27	331.00 UT	368	34.24	-1.00	3.55		6.90
28	332.00 UT	1,865	32.11	-1.00	3.90		6.90
29	333.00 UT	943	28.58	-1.00	4.14		6.90
30	334.00 UT	258	12.47	-1.00	9.75		6.80
31	335.00 UT	22	28.45		3.97		6.80
32	336.00 UT	40	25.64	-1.00	4.36		6.90
33							
34	Yale						
35	330.20 WA	762	103.77		0.82		45.00
36	331.00 WA	9,215	62.83	-6.00	1.60		42.10
37	332.00 WA	29,588	70.68	-8.00	1.40		41.80
38	333.00 WA	12,493	63.81	-15.00	1.68		37.70
39	334.00 WA	3,398	48.93	-9.00	2.14		35.00
40	335.00 WA	547	66.44	-5.00	1.40		33.00
41	336.00 WA	1,471	57.33	-5.00	1.76		42.50
42							
43	OTHER PRODUCTION						
44	Chehalis						
45	341.00 WA	23,908	39.75	-3.00	2.65		29.50
46	342.00 WA	1,597	36.50	-2.00	2.87		26.90
47	343.00 WA	200,171	35.70	-4.00	3.04		26.80
48	344.00 WA	69,031	36.45	-4.00	2.94		26.90
49	345.00 WA	39,287	39.21	-3.00	2.69		29.20
50	346.00 WA	3,269	38.83	-1.00	2.66		28.80

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	Currant Creek						
13	341.00 UT	44,165	39.83	-3.00	2.59		31.50
14	342.00 UT	3,300	36.50	-2.00	2.80		28.70
15	343.00 UT	212,744	35.19	-4.00	3.01		28.80
16	344.00 UT	62,977	36.06	-4.00	2.91		28.80
17	345.00 UT	42,568	39.03	-3.00	2.64		31.20
18	346.00 UT	2,983	39.06	-1.00	2.59		30.70
19							
20	Hermiston						
21	341.00 OR	12,845	38.73	-3.00	2.90		22.60
22	342.00 OR	25	36.50	-2.00	3.08		20.70
23	343.00 OR	108,844	33.48	-4.00	3.42		20.80
24	344.00 OR	42,463	35.85	-3.00	3.16		20.80
25	345.00 OR	9,293	39.23	-3.00	2.88		22.40
26	346.00 OR	169	39.06	-1.00	2.84		22.00
27							
28	Lake Side/Lake Side 2						
29	341.00 UT	88,355	39.96	-4.00	2.77		33.50
30	342.00 UT	8,501	36.50	-3.00	3.01		30.60
31	343.00 UT	534,347	36.11	-4.00	3.11		30.40
32	344.00 UT	221,933	36.40	-4.00	3.05		30.60
33	345.00 UT	119,178	39.46	-3.00	2.77		33.10
34	346.00 UT	6,150	39.06	-1.00	2.75		32.70
35							
36	Gadsby Gas Peakers						
37	341.00 UT	4,273	29.80	-1.00	3.43		18.90
38	342.00 UT	2,447	28.45	-1.00	3.61		18.00
39	343.00 UT	54,922	26.97	-2.00	3.91		18.10
40	344.00 UT	16,886	28.61	-2.00	3.64		18.00
41	345.00 UT	2,877	28.31	-1.00	3.62		18.80
42							
43	WIND GENERATION						
44	Dunlap Ranch I						
45	341.00 WY	7,742	28.47	-1.00	3.49		25.30
46	343.00 WY	207,519	29.58	-1.00	3.34		26.20
47	344.00 WY	6,565	29.59	-1.00	3.34		26.20
48	345.00 WY	12,293	29.93		3.26		26.50
49	346.00 WY	149	29.94		3.25		26.50
50							

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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	Foote Creek						
13	341.00 WY	110	29.33	-1.00	3.49		15.30
14	343.00 WY	31,950	30.37	-1.00	2.84		15.50
15	344.00 WY	1,612	30.49	-1.00	2.83		15.50
16	345.00 WY	2,926	30.96	-1.00	2.78		15.70
17							
18	Glenrock/Glenrock III						
19	341.00 WY	10,198	27.88	-1.00	3.53		23.50
20	343.00 WY	438,311	29.01	-1.00	3.37		24.30
21	344.00 WY	13,560	29.01	-1.00	3.37		24.30
22	345.00 WY	29,513	29.33		3.30		24.60
23	346.00 WY	1,157	29.44		3.28		24.60
24							
25	Goodnoe Hills						
26	341.00 WA	5,484	28.49	-1.00	3.44		23.50
27	343.00 WA	162,588	29.53	-1.00	3.30		24.30
28	344.00 WA	4,407	29.46	-1.00	3.31		24.30
29	345.00 WA	10,170	29.73		3.24		24.50
30	346.00 WA	172	29.94		3.21		24.50
31							
32	High Plains / McFadden						
33	341.00 WY	7,815	28.46	-1.00	3.47		24.40
34	343.00 WY	245,688	29.57	-1.00	3.32		25.20
35	344.00 WY	6,963	29.59	-1.00	3.32		25.20
36	345.00 WY	14,750	29.92		3.23		25.50
37	346.00 WY	114	29.94		3.23		25.50
38							
39	Leaning Juniper 1						
40	341.00 OR	4,955	28.49	-1.00	3.39		21.70
41	343.00 OR	157,209	29.47	-1.00	3.25		22.30
42	344.00 OR	5,493	29.36	-1.00	3.28		22.30
43	345.00 OR	9,162	29.70	-1.00	3.23		22.60
44	346.00 OR	81	29.94		3.16		22.60
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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	Marengo/Marengo II						
13	341.00 WA	10,220	28.15	-1.00	3.47		22.60
14	343.00 WA	327,182	29.23	-1.00	3.32		23.30
15	344.00 WA	10,398	29.22	-1.00	3.32		23.30
16	345.00 WA	19,742	29.57	-1.00	3.27		23.60
17	346.00 WA	337	29.48		3.25		23.60
18							
19	Seven Mile Hill						
20	341.00 WY	6,392	28.38	-1.00	3.45		23.50
21	343.00 WY	215,374	29.56	-1.00	3.29		24.30
22	344.00 WY	6,600	29.59	-1.00	3.29		24.30
23	345.00 WY	13,260	29.86		3.22		24.50
24	346.00 WY	520	29.78		3.23		24.50
25							
26	SOLAR GENERATING						
27	Wyoming Solar						
28	344.00 WY	6	20.46		4.11		14.00
29	344.00 WY	55	20.42				
30							
31	Utah Solar						
32	344.00 UT	36	20.49				
33							
34	Oregon Solar						
35	344.00 OR	56	19.88				
36							
37	MOBILE GENERATOR						
38	East Side						
39	344.00 UT	840	50.00	-5.00	1.60	R2	42.50
40							
41	West Side						
42	344.00 OR	849	50.00	-5.00	1.80	R2	46.00
43							
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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	TRANSMISSION PLANT						
13	350.20	177,590	75.00		1.27	R4	63.50
14	352.00	210,411	75.00	-10.00	1.42	R2.5	66.40
15	353.00	1,853,585	58.00	-5.00	1.74	S0	48.90
16	354.00	1,217,800	68.00	-10.00	1.53	R4	55.70
17	355.00	733,629	60.00	-40.00	2.18	R2	46.10
18	356.00	1,073,715	63.00	-30.00	1.88	R3	46.00
19	357.00	3,520	60.00		1.60	R2	48.50
20	358.00	8,035	60.00	-5.00	1.66	R2	48.20
21	359.00	11,937	70.00		1.32	R5	49.40
22							
23	DISTRIBUTION PLANT						
24	360.20 OR	4,644	55.00		1.21	S3	36.80
25	361.00 OR	25,770	60.00	-10.00	1.79	R1.5	49.80
26	362.00 OR	230,331	55.00	-15.00	1.94	R1	43.50
27	364.00 OR	353,395	55.00	-100.00	3.29	R1.5	42.00
28	365.00 OR	246,995	60.00	-70.00	2.63	R0.5	47.40
29	366.00 OR	89,813	70.00	-50.00	1.97	R2.5	54.60
30	367.00 OR	168,094	58.00	-35.00	2.11	R2.5	43.70
31	368.00 OR	415,551	42.00	-20.00	2.44	R1.5	29.00
32	369.10 OR	82,671	55.00	-35.00	2.28	R1	42.50
33	369.20 OR	165,785	55.00	-40.00	2.34	R4	41.30
34	370.00 OR	60,387	27.00	-4.00	3.60	R1	17.90
35	371.00 OR	2,573	25.00	-50.00	4.79	L0	14.30
36	373.00 OR	22,931	44.00	-40.00	2.91	R0.5	33.80
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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	DISTRIBUTION PLANT						
13	360.20 WA	409	50.00		1.63	R3	24.50
14	361.00 WA	2,816	60.00	-5.00	1.64	R2	42.10
15	362.00 WA	56,847	53.00	-20.00	2.14	R1	38.90
16	364.00 WA	97,325	52.00	-100.00	3.64	R1.5	39.40
17	365.00 WA	62,120	60.00	-60.00	2.51	R1	45.10
18	366.00 WA	17,190	50.00	-50.00	2.84	R3	35.40
19	367.00 WA	24,164	50.00	-35.00	2.56	R3	36.80
20	368.00 WA	104,828	43.00	-25.00	2.64	R2	28.90
21	369.10 WA	20,611	55.00	-30.00	2.27	R1	41.90
22	369.20 WA	36,049	55.00	-50.00	2.63	R4	41.30
23	370.00 WA	11,708	25.00	-1.00	3.93	S5	21.20
24	371.00 WA	512	30.00	-25.00	3.48	L0	15.50
25	373.00 WA	4,218	45.00	-30.00	2.64	R1	31.70
26							
27	DISTRIBUTION PLANT						
28	360.20 WY	5,200	50.00		1.99	R4	33.50
29	361.00 WY	14,949	60.00	-10.00	1.83	R2.5	49.90
30	362.00 WY	126,365	55.00	-10.00	1.99	R1	42.20
31	364.00 WY	140,570	50.00	-100.00	3.99	R1	39.10
32	365.00 WY	104,291	57.00	-40.00	2.45	R0.5	44.20
33	366.00 WY	23,881	42.00	-40.00	3.32	R3	30.60
34	367.00 WY	56,808	40.00	-35.00	3.35	R4	26.20
35	368.00 WY	110,125	39.00	-25.00	3.19	R1	28.90
36	369.10 WY	17,925	60.00	-25.00	2.08	R1.5	47.20
37	369.20 WY	39,409	55.00	-50.00	2.72	R4	44.10
38	370.00 WY	14,526	25.00	-2.00	4.04	S5	20.60
39	371.00 WY	962	25.00	-60.00	6.10	O1	12.20
40	373.00 WY	10,478	50.00	-45.00	2.89	R0.5	38.90
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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	DISTRIBUTION PLANT						
13	360.20 UT	12,826	60.00		1.66	R4	49.60
14	361.00 UT	53,857	60.00		1.66	S0.5	50.90
15	362.00 UT	448,775	47.00	-10.00	2.34	R0.5	39.70
16	364.00 UT	346,939	50.00	-80.00	3.59	R0.5	39.60
17	365.00 UT	221,142	52.00	-45.00	2.78	R0.5	40.20
18	366.00 UT	182,797	60.00	-50.00	2.49	R2	49.00
19	367.00 UT	498,612	50.00	-25.00	2.49	R2	38.80
20	368.00 UT	471,178	45.00	-5.00	2.33	R0.5	36.30
21	369.00 UT	257,823	55.00	-25.00	2.27	S5	44.60
22	370.00 UT	76,325	25.00	-2.00	3.90	S5	16.90
23	371.00 UT	4,345	25.00	-60.00	6.37	L0	16.80
24	373.00 UT	22,378	25.00	-20.00	4.78	R0.5	16.90
25							
26	DISTRIBUTION PLANT						
27	360.20 ID	1,227	50.00		1.99	R4	34.20
28	361.00 ID	2,296	60.00		1.66	R2	48.90
29	362.00 ID	29,136	55.00	-10.00	1.99	R1.5	41.20
30	364.00 ID	78,677	50.00	-80.00	3.59	R0.5	39.50
31	365.00 ID	35,857	52.00	-30.00	2.49	R0.5	36.30
32	366.00 ID	8,871	60.00	-40.00	2.33	R2	48.90
33	367.00 ID	26,159	50.00	-15.00	2.29	R2	37.80
34	368.00 ID	75,656	45.00	-5.00	2.33	R0.5	34.20
35	369.00 ID	34,980	55.00	-25.00	2.27	S5	44.00
36	370.00 ID	13,904	25.00	-3.00	3.95	S5	13.10
37	371.00 ID	169	25.00	-45.00	5.77	L0	16.80
38	373.00 ID	666	25.00	-20.00	4.78	R0.5	16.90
39							
40	GENERAL PLANT						
41	390.00 OR	79,565	58.00	-10.00	1.86	R1	47.20
42	392.01 OR	10,154	12.00	10.00	7.04	L2.5	6.90
43	392.05 OR	12,797	16.00	10.00	5.48	L3	8.70
44	392.09 OR	3,327	34.00	15.00	2.44	L2	23.70
45	396.03 OR	7,624	9.00	15.00	9.23	L3	5.50
46	396.07 OR	28,535	15.00	20.00	5.14	L1	9.80
47							
48							
49							
50							

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	GENERAL PLANT						
13	390.00 WA	12,923	40.00	-10.00	2.52	R3	24.70
14	392.01 WA	2,077	13.00	10.00	5.60	L2.5	8.10
15	392.05 WA	4,965	16.00	10.00	5.07	L2.5	9.60
16	392.09 WA	761	33.00	15.00	2.38	S0.5	24.10
17	396.03 WA	1,676	10.00	10.00	5.66	R4	7.30
18	396.07 WA	6,193	13.00	15.00	6.03	L1.5	8.00
19							
20	GENERAL PLANT						
21	389.20 WY	74	50.00		1.98	SQ	43.40
22	390.00 WY	10,747	58.00	-15.00	1.95	R1	47.70
23	392.01 WY	4,499	13.00	10.00	5.85	S1.5	6.10
24	392.05 WY	6,189	15.00	10.00	5.66	L1.5	9.20
25	392.09 WY	3,063	34.00	5.00	2.68	L2	23.20
26	396.03 WY	3,893	9.00	15.00	8.47	L3	5.30
27	396.07 WY	35,877	15.00	25.00	4.86	L0	11.60
28							
29	GENERAL PLANT						
30	390.00 CA	3,305	60.00	-20.00	1.71	R3	46.30
31	392.01 CA	838	10.00	20.00	3.48	S3	6.60
32	392.05 CA	1,214	15.00	15.00	4.49	L2	9.10
33	392.09 CA	488	35.00	5.00	2.32	R2	26.20
34	396.03 CA	1,220	8.00	15.00	7.20	R4	4.30
35	396.07 CA	3,038	14.00	15.00	4.98	L1.5	9.20
36							
37	GENERAL PLANT						
38	389.20 UT	85	45.00		2.03	S0	36.20
39	390.00 UT	91,532	58.00	5.00	1.53	R1	44.60
40	392.01 UT	16,111	12.00	10.00	5.04	L3	5.50
41	392.05 UT	22,246	16.00	10.00	4.56	L2	9.20
42	392.09 UT	7,499	34.00	25.00	1.91	L2	22.40
43	392.30 UT	3,076	10.00	64.00	2.51	SQ	5.30
44	396.03 UT	6,891	9.00	10.00	8.10	L3	5.70
45	396.07 UT	55,636	14.00	15.00	5.36	L0.5	9.90
46							
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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 2014/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	GENERAL PLANT						
13	389.20 ID	5	55.00		1.17	R3	25.10
14	390.00 ID	12,568	58.00	-5.00	1.65	R1	43.40
15	392.01 ID	2,475	12.00	10.00	4.28	S2	7.00
16	392.05 ID	3,061	15.00	15.00	4.34	L2	8.80
17	392.09 ID	983	34.00	10.00	2.28	L2	24.40
18	396.03 ID	2,533	9.00	10.00	7.67	L3	5.90
19	396.07 ID	7,458	18.00	25.00	3.73	L0.5	13.10
20							
21	GENERAL PLANT						
22	AZ, CO, MT, Etc.						
23	390.00	385	45.00		1.51	R2	25.10
24	392.01	602	16.00		2.53	R2	10.70
25	392.05	299	19.00	15.00	2.10	R2.5	13.70
26	392.09	9	25.00		2.18	R1.5	12.80
27	396.07	2,413	25.00	5.00	1.86	R2	17.80
28							
29	GENERAL PLANT						
30	ALL STATES						
31	391.00	28,177	20.00		5.00		
32	391.20	53,280	5.00		20.00		
33	391.30	728	8.00		12.50		
34	393.00	14,660	25.00		4.00		
35	394.00	62,494	24.00		4.17		
36	395.00	33,842	20.00		5.00		
37	397.00	392,330	24.00		4.30		
38	397.20	12,080	11.00		9.09		
39	398.00	7,957	20.00		5.00		
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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 2014/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	MINING						
13	399.30 UT	15,747	22.06	-1.00	3.81		5.70
14	399.31 UT	27,996	46.27	-7.00	2.06		25.80
15	399.41 UT	8,694	46.20	-6.00	2.05		25.80
16	399.44 UT	3,425	13.40		6.29		6.00
17	399.45 UT	104,787	8.60	5.00	11.91		4.70
18	399.46 UT	33,603	8.53	7.00	12.85		5.50
19	399.51 UT	1,275	12.23	5.00	6.96		4.40
20	399.52 UT	5,854	12.21	5.00	8.14		5.50
21	399.60 UT	2,364	10.59	1.00	9.23		4.50
22	399.61 UT	468	8.68		11.35		2.90
23	399.70 UT	38,657	19.73		4.23		6.00
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25							
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Schedule Page: 336 Line No.: 12 Column: b

Depreciation expense associated with transportation equipment is generally charged to operations and maintenance expense and contruction work in progress. During the year ended December 31, 2014, depreciation expense associated with transportation equipment was $13,767,456.

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.: 12 Column: a

The Oregon Public Utility Commission required modifications related to the depreciable lives of coal-fired generating facilities. Below are the affected facilities and the lives and rates required by Oregon.

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)
STEAM PRODUCTION PLANT						
CARBON PLANT						
311.00 UT	15,579		-48.00	34.29		1.30
312.00 UT	68,203		-47.00	37.03		1.30
314.00 UT	28,155		-47.00	36.37		1.30
315.00 UT	6,302		-47.00	36.50		1.30
316.00 UT	809		-47.00	43.59		1.30
CHOLLA PLANT						
310.20 AZ	1,368			5.72		15.00
311.00 AZ	64,092		-5.00	4.04		14.70
312.00 AZ	333,544		-4.00	4.94		14.20
314.00 AZ	67,730		-5.00	4.67		13.80
315.00 AZ	67,923		-4.00	3.98		14.60
316.00 AZ	4,094		-5.00	4.92		13.00
COLSTRIP PLANT						
311.00 MT	60,705		-5.00	2.31		18.40
312.00 MT	118,087		-5.00	2.81		16.80
314.00 MT	37,925		-6.00	3.34		17.00
315.00 MT	9,051		-4.00	2.16		18.20
316.00 MT	321		-6.00	3.24		15.70
CRAIG PLANT						
311.00 CO	37,497		-5.00	2.92		12.70
312.00 CO	95,910		-5.00	4.37		12.20
314.00 CO	28,475		-6.00	5.06		12.20
315.00 CO	16,995		-4.00	2.80		12.60
316.00 CO	1,226		-6.00	3.98		11.30
DAVE JOHNSTON PLANT						
310.20 WY	100			3.18		10.00
311.00 WY	155,554		-4.00	7.50		9.90
312.00 WY	670,321		-4.00	7.66		9.80
314.00 WY	94,804		-4.00	6.32		9.60
315.00 WY	62,233		-3.00	7.70		9.90
316.00 WY	8,418		-4.00	7.69		9.30

HAYDEN PLANT				
311.00 CO	17,684	-5.00	7.49	9.90
312.00 CO	54,659	-5.00	4.62	9.60
314.00 CO	9,301	-5.00	5.65	9.60
315.00 CO	2,546	-4.00	2.59	9.70
316.00 CO	637	-5.00	4.36	9.00
HUNTER PLANT				
310.20 UT	246		2.43	16.00
311.00 UT	206,744	-6.00	2.84	15.50
312.00 UT	750,440	-5.00	4.36	15.00
314.00 UT	191,922	-6.00	4.84	15.00
315.00 UT	106,650	-5.00	2.88	15.40
316.00 UT	3,691	-6.00	4.00	13.50
HUNTINGTON PLANT				
311.00 UT	119,464	-7.00	3.06	16.50
312.00 UT	547,010	-6.00	4.70	16.10
314.00 UT	121,652	-7.00	4.37	15.70
315.00 UT	47,353	-5.00	3.51	16.50
316.00 UT	2,866	-6.00	4.77	14.70
JIM BRIDGER PLANT				
310.20 WY	281		2.43	12.00
311.00 WY	139,956	-7.00	3.19	11.70
312.00 WY	699,179	-6.00	4.85	11.40
314.00 WY	201,832	-7.00	5.78	11.50
315.00 WY	60,807	-6.00	3.36	11.70
316.00 WY	4,115	-7.00	4.71	10.60
NAUGHTON PLANT				
310.20 WY	15		1.60	15.00
311.00 WY	118,149	-5.00	4.63	14.80
312.00 WY	496,398	-5.00	5.21	14.40
314.00 WY	77,837	-6.00	4.44	14.00
315.00 WY	62,960	-4.00	5.46	14.80
316.00 WY	2,011	-5.00	5.38	13.10
WYODAK PLANT				
310.20 WY	165		2.84	13.00
311.00 WY	51,286	-4.00	3.41	12.70
312.00 WY	300,425	-3.00	5.43	12.40
314.00 WY	63,689	-4.00	5.27	12.20
315.00 WY	28,510	-3.00	4.34	12.70
316.00 WY	1,211	-4.00	6.52	11.80

Schedule Page: 336.4 Line No.: 37 Column: a

The depreciation rate changes 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.

Schedule Page: 336.10 Line No.: 32 Column: a

High Plains and McFadden Ridge I wind plants

Schedule Page: 336.11 Line No.: 19 Column: a

Seven Mile Hill and Seven Mile Hill II wind plants

Schedule Page: 336.17 Line No.: 25 Column: a

FERC Sub Acct	Description
310.20	Land Rights
330.20	Land Rights
330.30	Water Rights
330.40	Flood Rights
330.50	Fish/Wildlife
350.20	Land Rights
360.20	Land Rights
369.10	Overhead Services
369.20	Underground Services
389.20	Land Rights
391.20	Personal Computers and Printers
391.30	Office Equipment
392.01	Transportation Equipment - Light Trucks and Vans
392.05	Transportation Equipment - Medium Trucks
392.09	Transportation Equipment - Trailers
392.30	Aircraft
396.03	Light Power Operated Equipment
396.07	Heavy Power Operated Equipment
397.20	Mobile Radio Equipment
399.30	Structures and Improvements
399.31	Structures and Improvements - Prep Plant
399.41	Surface Processing Equipment - Prep Plant
399.44	Surface Electric Power Facilities
399.45	Underground Equipment
399.46	Longwall Equipment
399.51	Vehicles
399.52	Heavy Construction Equipment
399.60	Miscellaneous Equipment
399.61	Computer Equipment
399.70	Mine Development

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 2014/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	5,301,974		5,301,974	
3	Rate Cases and Proceedings		1,540,055	1,540,055	
4					
5	Oregon Public Utility Commission:				
6	Annual Fee	3,390,231		3,390,231	
7	Rate Cases and Proceedings		644,161	644,161	
8	Deferred Intervenor Funding Grants				802,926
9					
10	Wyoming Public Service Commission:				
11	Annual Fee	1,552,185		1,552,185	
12	Rate Cases and Proceedings		1,352,270	1,352,270	
13					
14	Washington Utilities and Transportation				
15	Commission:				
16	Annual Fee	643,084		643,084	
17	Rate Cases and Proceedings		1,414,014	1,414,014	
18					
19	Idaho Public Utilities Commission:				
20	Annual Fee	639,630		639,630	
21	Rate Cases and Proceedings		115,423	115,423	
22	Deferred Intervenor Funding Grants (2)		16,431	16,431	55,462
23					
24	California Public Utilities Commission:				
25	Annual Fee	1,145		1,145	
26	Rate Cases and Proceedings		174,600	174,600	
27	Deferred Intervenor Funding Grants				40,307
28					
29	California Environmental Protection Agency:				
30	Industry Compliance Fee	29,081	14,250	43,331	
31					
32	Multi-State:				
33	Rate Cases and Proceedings		876,832	876,832	
34	Other Regulatory		399,685	399,685	
35					
36	Federal Energy Regulatory Commission:				
37	Annual Fee	1,782,520		1,782,520	
38	Anuual Fee - Hydroelectric Plants	1,940,450		1,940,450	
39	Transmission Rate Cases		108,012	108,012	
40	Other Regulatory		2,344,209	2,344,209	
41					
42	Charges for services from Berkshire Hathaway				
43	Energy Company and its affiliates:				
44	FERC - Transmission Rate Case		348	348	
45					
46	TOTAL	15,280,300	9,000,290	24,280,590	898,695

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 2014/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Electric	928	5,301,974					2
Electric	928	1,540,055					3
							4
							5
Electric	928	3,390,231					6
Electric	928	644,161					7
			266,643			1,069,569	8
							9
							10
Electric	928	1,552,185					11
Electric	928	1,352,270					12
							13
							14
							15
Electric	928	643,084					16
Electric	928	1,414,014					17
							18
							19
Electric	928	639,630					20
Electric	928	115,423					21
Electric	928	16,431		928	16,431	39,031	22
							23
							24
Electric	928	1,145					25
Electric	928	174,600					26
			40			40,347	27
							28
							29
Electric	928	43,331					30
							31
							32
Electric	928	876,832					33
Electric	928	399,685					34
							35
							36
Electric	928	1,782,520					37
Electric	928	1,940,450					38
Electric	928	108,012					39
Electric	928	2,344,209					40
							41
							42
							43
Electric	928	348					44
							45
		24,280,590	266,683		16,431	1,148,947	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 2014/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		
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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
	1,250	930.2	1,250		5
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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 2014/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	105,003,774		
4	Transmission	15,492,573		
5	Regional Market			
6	Distribution	35,675,236		
7	Customer Accounts	39,175,124		
8	Customer Service and Informational	6,429,131		
9	Sales			
10	Administrative and General	39,822,468		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	241,598,306		
12	Maintenance			
13	Production	42,910,933		
14	Transmission	10,037,416		
15	Regional Market			
16	Distribution	66,449,152		
17	Administrative and General	1,797,933		
18	TOTAL Maintenance (Total of lines 13 thru 17)	121,195,434		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	147,914,707		
21	Transmission (Enter Total of lines 4 and 14)	25,529,989		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	102,124,388		
24	Customer Accounts (Transcribe from line 7)	39,175,124		
25	Customer Service and Informational (Transcribe from line 8)	6,429,131		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	41,620,401		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	362,793,740		362,793,740
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 2014/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)	362,793,740		362,793,740
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	141,856,645		141,856,645
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	141,856,645		141,856,645
72	Plant Removal (By Utility Departments)			
73	Electric Plant	7,307,095		7,307,095
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	7,307,095		7,307,095
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock	2,562,661		2,562,661
79	Miscellaneous Other Income Deductions	797,876		797,876
80	Charges to Affiliates	604,655		604,655
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	3,965,192		3,965,192
96	TOTAL SALARIES AND WAGES	515,922,672		515,922,672

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	3,242,368	6,030,615	6,341,843	463,706
3	Net Sales (Account 447)	(1,949)	(1,100)	(266,834)	(1,787,553)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
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43					
44					
45					
46	TOTAL	3,240,419	6,029,515	6,075,009	(1,323,847)

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				146,378,455	MWh	10,356,630
2	Reactive Supply and Voltage	129,068,844	MWh	8,600,455	139,807,710	MWh	9,309,361
3	Regulation and Frequency Response	92,384,862	MWh	31,037,826	99,738,252	MWh	34,221,632
4	Energy Imbalance				-38,394	MWh	-137,927
5	Operating Reserve - Spinning	66,591,811	MWh	25,970,806	72,561,623	MWh	28,332,570
6	Operating Reserve - Supplement	66,591,811	MWh	22,641,216	70,710,010	MWh	24,075,231
7	Other						
8	Total (Lines 1 thru 7)	354,637,328		88,250,303	529,157,656		106,157,497

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 2014/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	14,949	6	800	8,694	111	3,715		792	1,637
2	February	14,968	6	800	8,935	148	3,715		512	1,658
3	March	13,730	18	800	7,936	110	3,715		484	1,485
4	Total for Quarter 1	43,647			25,565	369	11,145		1,788	4,780
5	April	13,101	1	800	7,663	93	3,715		241	1,389
6	May	14,427	28	1500	8,452	91	3,715		483	1,686
7	June	16,115	24	1700	9,266	86	3,869		1,069	1,825
8	Total for Quarter 2	43,643			25,381	270	11,299		1,793	4,900
9	July	18,051	14	1600	10,645	100	3,842		1,436	2,028
10	August	16,457	11	1600	9,940	111	3,529		937	1,940
11	September	15,256	17	1600	9,024	88	3,533		788	1,823
12	Total for Quarter 3	49,764			29,609	299	10,904		3,161	5,791
13	October	13,231	6	1600	7,483	91	3,533		605	1,519
14	November	15,412	17	800	8,505	130	3,376		1,759	1,642
15	December	15,400	30	1900	9,061	151	3,376		1,123	1,689
16	Total for Quarter 4	44,043			25,049	372	10,285		3,487	4,850
17	Total Year to Date/Year	181,097			105,604	1,310	43,633		10,229	20,321

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 Daylight Time

Schedule Page: 400 Line No.: 5 Column: d

Pacific Daylight Time

Schedule Page: 400 Line No.: 6 Column: d

Pacific Daylight Time

Schedule Page: 400 Line No.: 7 Column: d

Pacific Daylight Time

Schedule Page: 400 Line No.: 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.: 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.: 17 Column: e

Year-to-date 2014 Net System Load information was compiled using metering and/or scheduling data. Reflects actual peak net system load for self at time of Transmission System Peak. Peak load includes behind-the-meter generation.

Schedule Page: 400 Line No.: 17 Column: f

Year-to-date 2014 Net System Load information was compiled using metering and/or scheduling data. Reflects actual peak of customers' load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 17 Column: g

Year-to-date 2014 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.: 17 Column: i

Year-to-date 2014 Net System Load information was compiled using reservations in OASIS at time of Transmission System Peak.

Schedule Page: 400 Line No.: 17 Column: j

Year-to-date 2014 Net System Load information was compiled using metering, scheduling and/or contractual data. Reflects actual peak and/or contractual demands of customers' load at time of Transmission System Peak.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	54,999,277
3	Steam	46,275,199			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	225,497
5	Hydro-Conventional	3,784,143			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	10,044,750
7	Other	10,147,955			
8	Less Energy for Pumping	1,973	25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	60,205,324	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	134,392
10	Purchases	9,846,352	27	Total Energy Losses	4,637,928
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	70,041,844
12	Received	4,330,806			
13	Delivered	3,968,188			
14	Net Exchanges (Line 12 minus line 13)	362,618			
15	Transmission For Other (Wheeling)				
16	Received	13,674,599			
17	Delivered	13,563,767			
18	Net Transmission for Other (Line 16 minus line 17)	110,832			
19	Transmission By Others Losses	-483,282			
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	70,041,844			

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 2014/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	6,363,644	988,995	8,455	6	0800 PST
30	February	5,646,244	917,443	8,712	6	0800 PST
31	March	5,817,887	1,006,675	7,640	18	0800 PDT
32	April	5,168,847	680,421	7,381	1	0800 PDT
33	May	5,323,912	502,920	8,198	28	1500 PDT
34	June	5,675,200	705,883	8,909	24	1700 PDT
35	July	6,592,264	649,756	10,314	14	1600 PDT
36	August	6,074,127	733,102	9,696	18	1700 PDT
37	September	5,642,499	801,195	8,718	17	1600 PDT
38	October	5,616,344	974,002	7,245	6	1600 PDT
39	November	6,017,740	1,231,483	8,301	17	0800 PST
40	December	6,103,136	852,875	8,870	30	1900 PST
41	TOTAL	70,041,844	10,044,750			

Schedule Page: 401 Line No.: 26 Column: b

For metered locations only.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Carbon* (b)			Plant Name: *Cholla* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Steam			Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Outdoor Boiler			Full Outdoor
3	Year Originally Constructed			1954			1981
4	Year Last Unit was Installed			1957			1981
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			188.64			414.00
6	Net Peak Demand on Plant - MW (60 minutes)			175			381
7	Plant Hours Connected to Load			8760			7989
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			48			0
12	Net Generation, Exclusive of Plant Use - KWh			1283645000			2633874000
13	Cost of Plant: Land and Land Rights			956546			2635317
14	Structures and Improvements			15578830			64091518
15	Equipment Costs			103469556			473257301
16	Asset Retirement Costs			7036834			39000
17	Total Cost			127041766			540023136
18	Cost per KW of Installed Capacity (line 17/5) Including			673.4614			1304.4037
19	Production Expenses: Oper, Supv, & Engr			191851			1464607
20	Fuel			29430662			64716194
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			1454315			7854932
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			2272687			790211
26	Misc Steam (or Nuclear) Power Expenses			2831179			1981390
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			0			2070839
30	Maintenance of Structures			266798			1262532
31	Maintenance of Boiler (or reactor) Plant			2407648			5668458
32	Maintenance of Electric Plant			694610			1152865
33	Maintenance of Misc Steam (or Nuclear) Plant			264010			2871419
34	Total Production Expenses			39813760			89833447
35	Expenses per Net KWh			0.0310			0.0341
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	592394	1566	0	1511810	3726	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12279	138000	0	9248	126976	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	49.118	136.683	0.000	40.465	166.712	0.000
41	Average Cost of Fuel per Unit Burned	49.320	136.683	0.000	42.396	166.712	0.000
42	Average Cost of Fuel Burned per Million BTU	2.008	23.582	2.022	2.292	31.260	2.313
43	Average Cost of Fuel Burned per KWh Net Gen	0.023	0.000	0.023	0.024	0.000	0.024
44	Average BTU per KWh Net Generation	11332.910	7.070	11339.980	10616.114	7.544	10623.658

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 2014/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Colstrip* (d)			Plant Name: *Craig* (e)			Plant Name: *Dave Johnston* (f)			Line No.
Steam			Steam			Steam			1
Conventional			Outdoor Boiler			Semi-Outdoor			2
1984			1979			1959			3
1986			1980			1972			4
155.61			172.13			816.77			5
157			166			725			6
8581			8694			8760			7
0			0			0			8
148			165			760			9
0			0			0			10
0			0			188			11
1021984000			1205340000			5183347000			12
1788644			137086			10449793			13
60703874			37497228			155554274			14
165246003			142606455			835463641			15
39236			35149			12936975			16
227777757			180275918			1014404683			17
1463.7733			1047.3242			1241.9710			18
27586			301885			122284			19
15871182			23394925			62105841			20
0			0			0			21
980771			1280120			449005			22
0			0			0			23
0			0			0			24
69242			600289			0			25
741345			921567			18599956			26
24937			0			116309			27
0			0			0			28
266039			612610			0			29
449798			413469			2012438			30
2947925			3941026			12774167			31
1040373			1952786			7636382			32
411744			914686			1702890			33
22830942			34333363			105519272			34
0.0223			0.0285			0.0204			35
Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
644853	1607	0	602222	23	0	3520539	13748	0	38
8369	140000	0	9990	133693	0	8221	138000	0	39
21.257	134.238	0.000	36.949	126.581	0.000	17.200	134.243	0.000	40
24.278	134.238	0.000	38.679	126.581	0.000	17.117	134.243	0.000	41
1.450	22.831	1.469	1.936	22.462	1.944	1.041	23.161	1.071	42
0.015	0.000	0.015	0.019	0.000	0.019	0.012	0.000	0.012	43
10561.875	9.243	10571.118	9982.397	0.107	9982.504	11167.357	15.373	11182.730	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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)			81.37			457.73
6	Net Peak Demand on Plant - MW (60 minutes)			78			427
7	Plant Hours Connected to Load			8672			6860
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			579722000			2436169000
13	Cost of Plant: Land and Land Rights			683069			9688975
14	Structures and Improvements			17681882			63225230
15	Equipment Costs			67093265			377882494
16	Asset Retirement Costs			532363			1976952
17	Total Cost			85990579			452773651
18	Cost per KW of Installed Capacity (line 17/5) Including			1056.7848			989.1719
19	Production Expenses: Oper, Supv, & Engr			188049			0
20	Fuel			14512093			50951341
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			888884			3245727
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			168580			-16633
26	Misc Steam (or Nuclear) Power Expenses			557759			1350426
27	Rents			0			43
28	Allowances			0			0
29	Maintenance Supervision and Engineering			284003			0
30	Maintenance of Structures			559927			3299598
31	Maintenance of Boiler (or reactor) Plant			1084289			12258193
32	Maintenance of Electric Plant			348027			4325252
33	Maintenance of Misc Steam (or Nuclear) Plant			351466			211565
34	Total Production Expenses			18943077			75625512
35	Expenses per Net KWh			0.0327			0.0310
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	275147	322	0	1146361	3798	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11309	137269	0	11332	138000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	49.815	143.958	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	52.483	143.958	0.000	43.988	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.320	24.969	2.331	1.941	23.876	1.959
43	Average Cost of Fuel Burned per KWh Net Gen	0.025	0.000	0.025	0.021	0.000	0.021
44	Average BTU per KWh Net Generation	10734.804	3.200	10738.004	10664.799	9.036	10673.835

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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: *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
294.47			495.59			1247.79			5
274			473			1369			6
8556			8141			8760			7
0			0			0			8
269			471			1158			9
0			0			0			10
0			0			215			11
1955381000			3233335000			7624885000			12
9688975			10275401			29653351			13
52461173			91031263			206717666			14
243071566			431576814			1052530874			15
1976952			1976952			5930856			16
307198666			534860430			1294832747			17
1043.2257			1079.2398			1037.7009			18
0			0			0			19
39456154			65514307			155921802			20
0			0			0			21
2456393			3557446			9259566			22
0			0			0			23
0			0			0			24
81237			-49120			15484			25
-3287342			2420280			483364			26
28			48			119			27
0			0			0			28
0			0			0			29
1912689			2651716			7864003			30
7348943			9210093			28817229			31
1468956			3415202			9209410			32
244500			288986			745051			33
49681558			87008958			212316028			34
0.0254			0.0269			0.0278			35
Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
894168	998	0	1466646	7324	0	3507174	12120	0	38
11561	138000	0	11326	138000	0	11388	138000	0	39
0.000	0.000	0.000	0.000	0.000	0.000	44.230	136.622	0.000	40
43.975	0.000	0.000	43.991	0.000	0.000	43.986	136.622	0.000	41
1.902	23.412	1.908	1.942	23.436	1.969	1.931	23.572	1.950	42
0.020	0.000	0.020	0.020	0.000	0.020	0.020	0.000	0.020	43
10573.394	2.957	10576.351	10274.919	13.128	10288.047	10476.030	9.212	10485.242	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: *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)			898			1422
7	Plant Hours Connected to Load			8760			8760
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			909			1415
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			161			342
12	Net Generation, Exclusive of Plant Use - KWh			6300558000			9364549000
13	Cost of Plant: Land and Land Rights			2386782			1161925
14	Structures and Improvements			119455994			139947094
15	Equipment Costs			718833576			965565367
16	Asset Retirement Costs			4288219			5280528
17	Total Cost			844964571			1111954914
18	Cost per KW of Installed Capacity (line 17/5) Including			848.3580			717.0896
19	Production Expenses: Oper, Supv, & Engr			7222			15506594
20	Fuel			117536334			232993037
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			9114860			4145796
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			0
26	Misc Steam (or Nuclear) Power Expenses			9431134			-14397914
27	Rents			2183			203508
28	Allowances			0			0
29	Maintenance Supervision and Engineering			1366194			638411
30	Maintenance of Structures			3144883			10634545
31	Maintenance of Boiler (or reactor) Plant			15965023			26545025
32	Maintenance of Electric Plant			4249840			11993860
33	Maintenance of Misc Steam (or Nuclear) Plant			1278324			2331748
34	Total Production Expenses			162095997			290594610
35	Expenses per Net KWh			0.0257			0.0310
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	2680629	5565	0	5194359	7920	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11975	138000	0	9185	138000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	43.433	137.778	0.000	40.792	136.202	0.000
41	Average Cost of Fuel per Unit Burned	43.561	137.778	0.000	44.647	136.202	0.000
42	Average Cost of Fuel Burned per Million BTU	1.819	23.771	1.830	2.431	23.499	2.441
43	Average Cost of Fuel Burned per KWh Net Gen	0.019	0.000	0.019	0.025	0.000	0.025
44	Average BTU per KWh Net Generation	10190.056	5.119	10195.175	10188.966	4.902	10193.868

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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			289.66			251.64			5
701			284			158			6
8757			8511			5831			7
0			0			0			8
687			266			238			9
0			0			0			10
130			64			34			11
4958589000			2064501000			190758000			12
1094739			210526			1252090			13
118115225			51280955			15102344			14
639040252			393772884			67141700			15
17656470			322234			737912			16
775906686			445586599			84234046			17
1097.1531			1538.3090			334.7403			18
388644			136912			131419			19
105259424			25091919			13875780			20
0			0			0			21
6449955			332452			1269			22
0			0			0			23
0			0			0			24
3230			1581			0			25
11305157			4411909			4183007			26
100			25850			0			27
0			0			0			28
1504678			0			0			29
1397146			286015			126390			30
7141993			5872320			1409685			31
1783604			1357736			3097040			32
837379			123854			33936			33
136071310			37640548			22858526			34
0.0274			0.0182			0.1198			35
Coal	Gas	Composite	Coal	Oil	Composite	Gas			36
Tons	MCF		Tons	Barrels		MCF			37
2673244	76127	0	1543509	2409	0	2702332	0	0	38
9835	1046	0	7980	138000	0	1049	0	0	39
38.944	7.776	0.000	15.999	134.675	0.000	5.135	0.000	0.000	40
39.154	7.776	0.000	16.046	134.675	0.000	5.135	0.000	0.000	41
1.990	7.432	1.999	1.005	23.236	1.018	4.895	0.000	0.000	42
0.021	0.000	0.021	0.012	0.000	0.012	0.073	0.000	0.000	43
10604.770	16.062	10620.832	11931.840	6.762	11938.602	14859.550	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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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)	279.59			38.10		
6	Net Peak Demand on Plant - MW (60 minutes)	250			36		
7	Plant Hours Connected to Load	8321			8578		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	231			32		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			21		
12	Net Generation, Exclusive of Plant Use - KWh	1164903000			274996000		
13	Cost of Plant: Land and Land Rights	842245			41195596		
14	Structures and Improvements	12844996			8248069		
15	Equipment Costs	160780575			100699306		
16	Asset Retirement Costs	214373			1744133		
17	Total Cost	174682189			151887104		
18	Cost per KW of Installed Capacity (line 17/5) Including	624.7798			3986.5382		
19	Production Expenses: Oper, Supv, & Engr	0			42589		
20	Fuel	49011065			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			941766		
23	Steam From Other Sources	0			4303809		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	9519723			0		
26	Misc Steam (or Nuclear) Power Expenses	0			511135		
27	Rents	0			6247		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			294054		
31	Maintenance of Boiler (or reactor) Plant	0			367907		
32	Maintenance of Electric Plant	0			194683		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			73154		
34	Total Production Expenses	58530788			6735344		
35	Expenses per Net KWh	0.0502			0.0245		
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	8653384	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1026	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	5.664	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	5.664	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	5.521	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.042	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	7620.062	0.000	0.000	0.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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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
20	482	82	6
6112	8419	5162	7
0	0	0	8
10	477	119	9
0	0	0	10
0	18	0	11
66234000	2543785000	134919000	12
0	1973791	0	13
5733734	23907900	4273000	14
28718343	313342108	77128902	15
0	689117	0	16
34452077	339912916	81401902	17
560.1964	572.9191	449.4859	18
0	131343	0	19
0	103755001	10201354	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	2327072	624672	25
-10235	686775	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	29716	146321	30
0	0	0	31
0	2302129	631216	32
0	0	126863	33
-10235	109232036	11730426	34
-0.0002	0.0429	0.0869	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
			Gas			Gas			36
			MCF			MCF			37
0	0	0	19454730	0	0	1938971	0	0	38
0	0	0	1016	0	0	1049	0	0	39
0.000	0.000	0.000	5.333	0.000	0.000	5.261	0.000	0.000	40
0.000	0.000	0.000	5.333	0.000	0.000	5.261	0.000	0.000	41
0.000	0.000	0.000	5.251	0.000	0.000	5.015	0.000	0.000	42
0.000	0.000	0.000	0.041	0.000	0.000	0.076	0.000	0.000	43
0.000	0.000	0.000	7766.875	0.000	0.000	15077.862	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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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			550		
7	Plant Hours Connected to Load	8558			7710		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	524			546		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	20			34		
12	Net Generation, Exclusive of Plant Use - KWh	2498058000			2630643000		
13	Cost of Plant: Land and Land Rights	3403277			14530682		
14	Structures and Improvements	44164698			35285907		
15	Equipment Costs	324572642			321281043		
16	Asset Retirement Costs	134848			0		
17	Total Cost	372275465			371097632		
18	Cost per KW of Installed Capacity (line 17/5) Including	656.6863			627.5962		
19	Production Expenses: Oper, Supv, & Engr	63335			73800		
20	Fuel	87949444			91897506		
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	1735241			1891259		
26	Misc Steam (or Nuclear) Power Expenses	709776			534208		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	486763			1136151		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	1126843			295204		
33	Maintenance of Misc Steam (or Nuclear) Plant	46108			64416		
34	Total Production Expenses	92117510			95892544		
35	Expenses per Net KWh	0.0369			0.0365		
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	18034666	0	0	18553782	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1032	0	0	1037	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.877	0.000	0.000	4.953	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.877	0.000	0.000	4.953	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.726	0.000	0.000	4.778	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.035	0.000	0.000	0.035	0.000	0.000
44	Average BTU per KWh Net Generation	7450.079	0.000	0.000	7311.722	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Lake Side 2* (d)			Plant Name: (e)			Plant Name: (f)			Line No.
Combined Cycle									1
Outdoor									2
2014									3
2014									4
655.20			0.00			0.00			5
628			0			0			6
4813			0			0			7
0			0			0			8
631			0			0			9
0			0			0			10
0			0			0			11
1720539000			0			0			12
16796219			0			0			13
53065674			0			0			14
568819804			0			0			15
0			0			0			16
638681697			0			0			17
974.7889			0			0			18
85289			0			0			19
53886571			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
1675929			0			0			25
990826			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
480350			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
57118965			0			0			34
0.0332			0.0000			0.0000			35
Gas									36
MCF									37
11522252	0	0	0	0	0	0	0	0	38
1036	0	0	0	0	0	0	0	0	39
4.677	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
4.677	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
4.512	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.031	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
6940.966	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 2014 were $1.9 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 2014 were $7.9 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

2014 were $28.0 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 2014 were $3.6 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 the Camas Co-Generation unit 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: 403.4 Line No.: 11 Column: d

Refer to the Lake Side Plant on page 402.4 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 2014/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)	22	27
7	Plant Hours Connect to Load	6,158	6,204
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	65,390,000	86,439,000
13	Cost of Plant		
14	Land and Land Rights	107,019	20,914
15	Structures and Improvements	1,621,652	2,345,799
16	Reservoirs, Dams, and Waterways	2,936,826	2,954,724
17	Equipment Costs	5,354,740	10,366,514
18	Roads, Railroads, and Bridges	105,442	479,588
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	10,125,679	16,167,539
21	Cost per KW of Installed Capacity (line 20 / 5)	506.2840	598.7977
22	Production Expenses		
23	Operation Supervision and Engineering	9,390	12,677
24	Water for Power	0	0
25	Hydraulic Expenses	544	734
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	1,037,203	1,283,380
28	Rents	29,076	39,252
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	3,035	3,423
31	Maintenance of Reservoirs, Dams, and Waterways	7,621	10,581
32	Maintenance of Electric Plant	59,407	117,852
33	Maintenance of Misc Hydraulic Plant	15,072	20,347
34	Total Production Expenses (total 23 thru 33)	1,161,348	1,488,246
35	Expenses per net KWh	0.0178	0.0172

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 2014/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
10	17	22	6
8,729	7,681	6,102	7
			8
18	31	29	9
18	31	29	10
1	1	3	11
41,246,000	44,892,000	40,610,000	12
			13
0	0	3,511,105	14
1,331,943	2,343,700	3,969,908	15
5,130,510	14,744,099	9,126,003	16
1,327,380	1,974,558	14,610,169	17
50,817	250,151	572,059	18
0	0	0	19
7,840,650	19,312,508	31,789,244	20
522.7100	742.7888	1,059.6415	21
			22
9,442	19,096	96,484	23
1,199	2,078	-6,325	24
37,117	64,335	90,220	25
0	0	0	26
250,659	426,582	736,397	27
41,086	71,216	12,922	28
0	0	0	29
19,318	53,475	-335	30
23,718	19,531	12,976	31
8,946	54,134	25,270	32
55,483	96,170	350,981	33
446,968	806,617	1,318,590	34
0.0108	0.0180	0.0325	35

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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)	11	29
7	Plant Hours Connect to Load	3,209	8,276
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	24,132,000	56,069,000
13	Cost of Plant		
14	Land and Land Rights	0	62,169
15	Structures and Improvements	986,633	2,037,704
16	Reservoirs, Dams, and Waterways	12,375,292	11,146,387
17	Equipment Costs	1,865,557	4,395,351
18	Roads, Railroads, and Bridges	533,015	341,093
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	15,760,497	17,982,704
21	Cost per KW of Installed Capacity (line 20 / 5)	1,432.7725	544.9304
22	Production Expenses		
23	Operation Supervision and Engineering	13,725	108,716
24	Water for Power	879	-6,958
25	Hydraulic Expenses	27,219	30,619
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	254,640	1,339,772
28	Rents	30,130	12,051
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	28,412	17,014
31	Maintenance of Reservoirs, Dams, and Waterways	41,238	155,869
32	Maintenance of Electric Plant	65,146	92,815
33	Maintenance of Misc Hydraulic Plant	40,686	104,967
34	Total Production Expenses (total 23 thru 33)	502,075	1,854,865
35	Expenses per net KWh	0.0208	0.0331

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 2014/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	81	32	6
8,426	5,266	8,214	7
			8
19	83	32	9
19	83	32	10
1	2	1	11
85,550,000	172,588,000	140,861,000	12
			13
341,706	25,845	0	14
6,991,560	3,458,985	2,474,360	15
13,695,754	15,664,267	15,759,709	16
2,722,639	15,363,498	6,717,588	17
1,095,742	886,710	488,877	18
0	0	0	19
24,847,401	35,399,305	25,440,534	20
1,380.4112	361.2911	795.2652	21
			22
1,490,363	130,104	37,240	23
0	0	2,556	24
6,319	5,296	79,157	25
0	0	0	26
979,956	883,402	711,432	27
26,168	-111,960	87,623	28
0	0	0	29
3,273	7,872	51,699	30
18,678	8,513	136,626	31
95,487	23,058	103,366	32
16,040	45,343	163,807	33
2,636,284	991,628	1,373,506	34
0.0308	0.0057	0.0098	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: 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)	36	146
7	Plant Hours Connect to Load	8,731	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	1
12	Net Generation, Exclusive of Plant Use - Kwh	173,729,000	579,582,000
13	Cost of Plant		
14	Land and Land Rights	0	1,086,564
15	Structures and Improvements	4,783,250	101,021,680
16	Reservoirs, Dams, and Waterways	31,442,142	28,046,815
17	Equipment Costs	11,739,603	18,612,476
18	Roads, Railroads, and Bridges	1,952,391	2,978,489
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	49,917,386	151,746,024
21	Cost per KW of Installed Capacity (line 20 / 5)	1,296.5555	1,115.7796
22	Production Expenses		
23	Operation Supervision and Engineering	20,903	1,190,463
24	Water for Power	3,077	45,183
25	Hydraulic Expenses	95,266	762,185
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	603,752	611,936
28	Rents	105,454	89,565
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	47,752	52,769
31	Maintenance of Reservoirs, Dams, and Waterways	38,304	36,154
32	Maintenance of Electric Plant	25,171	147,545
33	Maintenance of Misc Hydraulic Plant	142,406	479,056
34	Total Production Expenses (total 23 thru 33)	1,082,085	3,414,856
35	Expenses per net KWh	0.0062	0.0059

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	15	36	6
8,717	8,755	8,491	7
			8
45	28	36	9
45	28	36	10
2	2	1	11
226,366,000	21,691,000	206,474,000	12
			13
0	36,698	105,168	14
4,062,128	1,888,351	3,515,947	15
12,755,268	6,321,486	30,120,174	16
3,809,818	5,765,653	7,056,047	17
264,441	503,332	324,221	18
0	0	0	19
20,891,655	14,515,520	41,121,557	20
491.5684	483.8507	1,285.0487	21
			22
78,241	98,833	157,461	23
3,397	-6,325	28,566	24
105,163	27,835	3,278	25
0	0	0	26
654,504	552,799	835,511	27
116,410	10,703	9,621	28
0	0	265	29
95,552	32,766	31,715	30
2,189	2,471	179,357	31
172,566	91,160	74,767	32
157,202	75,406	188,722	33
1,385,224	885,648	1,509,263	34
0.0061	0.0408	0.0073	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 2014/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 1927 Plant Name: Slide Creek (b)	FERC Licensed Project No. 20 Plant Name: Soda (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1951	1924
4	Year Last Unit was Installed	1951	1924
5	Total installed cap (Gen name plate Rating in MW)	18.00	14.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	18	9
7	Plant Hours Connect to Load	8,719	6,147
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	70,420,000	14,510,000
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	14,880,391	8,729,478
17	Equipment Costs	8,966,147	5,386,467
18	Roads, Railroads, and Bridges	463,083	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	26,495,808	15,359,424
21	Cost per KW of Installed Capacity (line 20 / 5)	1,471.9893	1,097.1017
22	Production Expenses		
23	Operation Supervision and Engineering	9,773	46,122
24	Water for Power	1,438	-2,952
25	Hydraulic Expenses	44,540	12,990
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	287,277	372,328
28	Rents	49,303	4,995
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	30,671	34,099
31	Maintenance of Reservoirs, Dams, and Waterways	24,075	0
32	Maintenance of Electric Plant	11,049	38,820
33	Maintenance of Misc Hydraulic Plant	66,580	35,190
34	Total Production Expenses (total 23 thru 33)	524,706	541,592
35	Expenses per net KWh	0.0075	0.0373

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 2014/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 1927 Plant Name: Soda Springs (d)	FERC Licensed Project No. 2111 Plant Name: Swift No. 1 (e)	FERC Licensed Project No. 2071 Plant Name: Yale (f)	Line No.
Storage (Re-Reg)	Storage	Storage	1
Outdoor	Conventional	Conventional	2
1952	1958	1953	3
1952	1958	1953	4
11.00	240.00	134.00	5
12	260	170	6
8,676	6,159	7,491	7
			8
12	264	164	9
12	264	164	10
2	1	1	11
54,071,000	811,753,000	671,963,000	12
			13
0	14,163,614	8,363,013	14
3,960,783	69,951,939	9,214,483	15
89,238,752	46,645,795	29,588,460	16
2,350,076	24,495,462	16,437,193	17
2,068,792	1,133,091	1,471,230	18
0	0	0	19
97,618,403	156,389,901	65,074,379	20
8,874.4003	651.6246	485.6297	21
			22
5,972	1,988,188	1,124,815	23
879	79,735	44,519	24
110,738	1,543,605	750,977	25
0	0	0	26
308,772	509,081	434,419	27
30,130	158,055	88,248	28
0	0	0	29
15,270	45,425	27,877	30
242,318	363,289	53,676	31
22,079	187,130	91,021	32
40,688	771,959	444,652	33
776,846	5,646,467	3,060,204	34
0.0144	0.0070	0.0046	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 2014/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)	8	0
7	Plant Hours Connect to Load	6,655	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	7,064,000	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	33,126	0
24	Water for Power	-2,172	0
25	Hydraulic Expenses	30,976	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	178,113	0
28	Rents	3,698	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	-9,761	0
31	Maintenance of Reservoirs, Dams, and Waterways	-18,880	0
32	Maintenance of Electric Plant	1,189	0
33	Maintenance of Misc Hydraulic Plant	114,605	0
34	Total Production Expenses (total 23 thru 33)	330,894	0
35	Expenses per net KWh	0.0468	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 2014/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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	32,826,000	33,392,168
3	Bend		1913	1.11	1.0	2,498,000	1,568,799
4	Big Fork	2652	1910	4.15	4.6	31,240,000	7,430,076
5	Eagle Point		1957	2.81	3.0	16,187,000	1,898,290
6	East Side	2082	1924	3.20			1,991,695
7	Fall Creek	2082	1903	2.20	2.0	7,396,000	1,433,491
8	Fountain Green		1922	0.16			594,282
9	Granite		1896	2.00	1.3	6,050,000	5,234,569
10	Gunlock		1917	0.75	0.2	532,000	683,045
11	Last Chance		1983	1.73	1.0	3,094,000	2,806,576
12	Paris		1910	0.72	0.1	1,879,000	432,494
13	Pioneer	2722	1897	5.00	2.6	9,008,000	10,982,444
14	Prospect No. 1	2630	1912	3.76	4.6	23,728,000	2,590,026
15	Prospect No. 3	2337	1932	7.20	8.0	35,937,000	8,779,914
16	Prospect No. 4	2630	1944	1.00	0.9	4,567,000	2,409,792
17	Sand Cove		1926	0.80	0.3	415,000	933,722
18	Stairs	597	1895	1.00	1.2	4,648,000	1,721,128
19	Veyo		1920	0.50	0.2	286,000	893,411
20	Viva Naughton		1986	0.74	0.5	1,012,000	1,194,486
21	Wallowa Falls	308	1921	1.10	1.0	2,354,000	3,203,019
22	Weber	1744	1911	3.85	2.0	5,031,000	3,504,940
23	West Side	2082	1908	0.60	0.6	55,000	468,574
24	Keno Regulating Dam	2082					7,527,975
25	Upper Klamath Lake	2082					3,845,151
26	North Umpqua	1927					15,403,557
27							
28	Pumping Plant:						
29	Lifton		1917	-2.80	-3.0	-1,973,000	19,406,748
30							
31	Wind:						
32	Dunlap Ranch 1		2010	111.00	112.0	382,995,000	240,704,548
33	Foote Creek		1999	32.15	30.6	101,592,000	36,597,949
34	Glenrock		2008	99.00	100.0	299,004,000	201,773,148
35	Glenrock III		2009	39.00	40.0	112,823,000	87,723,542
36	Rolling Hills		2009	99.00	100.0	271,147,000	203,222,974
37	Goodnoe Hills		2008	94.00	94.0	216,762,000	183,711,787
38	Leaning Juniper 1		2006	100.00	100.0	215,245,000	178,214,660
39	Marengo		2007	140.40	136.0	367,390,000	240,396,461
40	Marengo II		2008	70.20	70.0	174,766,000	129,587,010
41	Seven Mile Hill		2008	99.00	99.0	335,038,000	201,107,642
42	Seven Mile Hill II		2008	19.50	21.0	73,601,000	42,240,587
43	High Plains		2009	99.00	100.0	324,244,000	220,037,411
44	McFadden Ridge I		2009	28.50	29.0	98,411,000	56,983,526
45							
46	Solar:						

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
4,983,906	587,439		173,100	Water		2
1,413,332	72,273		20,225	Water		3
1,790,380	311,465		153,315	Water		4
675,548	268,850		150,514	Water		5
622,405	11,346		43,148	Water		6
651,587	167,083		55,639	Water		7
3,714,263	5,032		432	Water		8
2,617,285	157,554		39,279	Water		9
910,727	61,963		8,503	Water		10
1,622,298	109,858		15,474	Water		11
600,686	74,370		44,304	Water		12
2,196,489	444,306		118,271	Water		13
688,837	166,494		38,095	Water		14
1,219,433	413,412		269,678	Water		15
2,409,792	60,298		11,261	Water		16
1,167,153	69,677		57,384	Water		17
1,721,128	158,456		18,595	Water		18
1,786,822	59,390		108,944	Water		19
1,614,170	92,467		28,950	Water		20
2,911,835	73,989		53,780	Water		21
910,374	245,686		62,242	Water		22
780,957	30,979		7,656	Water		23
	12,836		1,713			24
	758,188		13,047			25
						26
						27
						28
-6,930,981	308,429		43,097	Water		29
						30
						31
2,168,509	357,133		1,499,213	Wind		32
1,138,350	823,987		1,098,311	Wind		33
2,038,113	611,457		1,681,532	Wind		34
2,249,322	247,113		629,658	Wind		35
2,052,757	574,141		1,598,361	Wind		36
1,954,381	472,331		1,511,541	Wind		37
1,782,147	1,830,660		1,178,211	Wind		38
1,712,226	1,685,427		1,421,542	Wind		39
1,845,969	746,617		1,010,454	Wind		40
2,031,390	858,582		1,773,314	Wind		41
2,166,184	222,299		357,810	Wind		42
2,222,600	1,098,093		1,565,175	Wind		43
1,999,422	308,247		490,003	Wind		44
						45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	Black Cap	2012	2.00	2.0	4,307,000	74,986
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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.
37,493	524,453			Solar		1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
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						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.: 24 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.: 25 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.: 26 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.: 29 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.: 31 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.: 33 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.: 1 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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 #3, 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	16,211.00	694.00	272

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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)	
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	266,364,133	279,703,832	3,089	665,808	242,202	911,099	13
								14
	13,339,699	266,364,133	279,703,832	3,089	665,808	242,202	911,099	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
	211,652,349	3,045,766,779	3,257,419,128	488,475	15,845,636	1,917,195	18,251,306	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 2014/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	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 #1, WY	230.00	230.00	Wood - H	88.00		1
27	BEN LOMOND, UT	NAUGHTON #2, 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	16,211.00	694.00	272

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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
	137,862,059	1,334,182,160	1,472,044,219	87,195	1,697,983	525,051	2,310,229	18
								19
	137,862,059	1,334,182,160	1,472,044,219	87,195	1,697,983	525,051	2,310,229	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
	211,652,349	3,045,766,779	3,257,419,128	488,475	15,845,636	1,917,195	18,251,306	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 2014/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	BUFFALO, WY	SHERIDAN (MDU), WY	230.00	230.00	Wood - H	40.00		1
14	DIXONVILLE, OR	GRANTS PASS, 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	177.00		1
17	JIM BRIDGER, WY	SPENCE, WY	230.00	230.00	Wood - H	149.00		1
18	KLAMATH FALLS, OR	MALIN, OR	230.00	230.00	Wood - H	35.00		1
19	LIMA, WY	ROBERSON, WY	230.00	230.00	Wood - H	2.00		1
20	LONE PINE, OR	KLAMATH FALLS, OR	230.00	230.00	Wood - H	76.00		1
21	LONE PINE, OR	MERIDIAN #1, OR	230.00	230.00	Steel SP	5.00		1
22	LONE PINE, OR	MERIDIAN #2, OR	230.00	230.00	Steel SP	5.00		1
23	MCNARY (BPA), WA	WALLA WALLA, WA	230.00	230.00	Wood - H	56.00		1
24	MERIDIAN, OR	GRANTS PASS, OR	230.00	230.00	Wood - H	35.00		1
25	HIGH PLAINS, WY	PLATTE, WY	230.00	230.00	Wood - H	70.00		1
26	MONUMENT, WY	EXXON, WY	230.00	230.00	Wood - H	13.00		1
27	MONUMENT, WY	CRAVEN CREEK, WY	230.00	230.00	Wood - H	20.00		1
28	NAUGHTON, WY	TREASURETON, ID	230.00	230.00	Wood - H	80.00		1
29	NAUGHTON, WY	MONUMENT, WY	230.00	230.00	Wood - H	30.00		1
30	NAUGHTON, WY	CRAVEN CREEK, WY	230.00	230.00	Wood - H	16.00		1
31	PALISADES SS, WY	BLUE RIM, WY	230.00	230.00	Wood - H	4.00		1
32	PAROWAN VALLEY, UT	SIGURD, UT	230.00	230.00	Wood - H	94.00		1
33	PAROWAN VALLEY, UT	WEST CEDAR, UT	230.00	230.00	Wood - H	26.00		1
34	PAVANT, UT	SIGURD, UT	230.00	230.00	Wood - H	43.00		1
35	JIM BRIDGER, WY	ROCK SPRINGS, WY	230.00	230.00	Wood - H	35.00		1
36					TOTAL	16,211.00	694.00	272

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
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 36/1								18
1272 ACSR 45/7								19
795 ACSR 26/7								20
1272 ACSR 54/19								21
1272 ACSR 36/1								22
1272 ACSR 36/1								23
1272 ACSR 36/1								24
1272 ACSR 45/7								25
1272 ACSR 36/1								26
1272 ACSR 45/7								27
1272 ACSR 45/7								28
1272 ACSR 36/1								29
954 ACSR 54/7								30
1272 ACSR 36/1								31
795 ACSR 45/7								32
795 ACSR 45/7								33
795 ACSR 45/7								34
1272 ACSR 45/7								35
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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION 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	POMONA, WA	UNION GAP, WA	230.00	230.00	Wood - H	8.00		1
2	RIVERTON, WY	ROCK SPRINGS, WY	230.00	230.00	Wood - H	118.00		1
3	RIVERTON, WY	THERMOPOLIS, WY	230.00	230.00	Wood - H	51.00		1
4	ROCK SPRINGS, WY	FLAMING GORGE, UT	230.00	230.00	Wood - H	55.00		1
5	ROCK SPRINGS, WY	JIM BRIDGER, WY	230.00	230.00	Wood - H	35.00		1
6	ROCK SPRINGS, WY	MONUMENT, WY	230.00	230.00	Wood - H	41.00		1
7	SHIRLEY BASIN, WY	DUNLAP RANCH, WY	230.00	230.00	Wood - H	12.00		1
8	SWIFT No. 1, WA	SWIFT No. 2, WA	230.00	230.00	Wood - H	2.00		1
9	SWIFT No. 2, WA	WOODLAND (BPA) SS, WA	230.00	230.00	Wood - H	23.00		1
10	TALBOT, WA	MARENGO II, WA	230.00	230.00	Wood - H	7.00		1
11	TAP TO HANNA, OR	NICKEL MOUNTAIN, OR	230.00	230.00	Wood - H	9.00		1
12	THERMOPOLIS, WY	YELLOWTAIL, MT	230.00	230.00	Wood - H	176.00		1
13	TREASURETON, ID	BRADY, ID	230.00	230.00	Wood - H	66.00		1
14	TROUTDALE (BPA), OR	GRESHAM (PGE), OR	230.00	230.00	Steel Tower	6.00		1
15	TROUTDALE (BPA), OR	LINNEMAN (PGE), OR	230.00	230.00			7.00	1
16	UNION GAP, WA	MIDWAY (BPA), WA	230.00	230.00	Wood - H	39.00		1
17	WALLA WALLA, WA	LEWISTON (AVISTA), ID	230.00	230.00	Wood - H	45.00		1
18	WALLA WALLA, WA	WANAPUM (GPUD), WA	230.00	230.00	Wood - H	33.00		1
19	WANAPUM (GPUD), WA	POMONA, WA	230.00	230.00	Wood - H	37.00		1
20	WINDSTAR, WY	GLENROCK, WY	230.00	230.00	Wood - H	13.00		1
21	WYODAK, WY	BUFFALO, WY	230.00	230.00	Wood - H	69.00		1
22	YAMSAY (BPA), OR	KLAMATH FALLS, OR	230.00	230.00	Wood - H	63.00		1
23	SHERIDAN (MDU), WY	YELLOWTAIL, MT	230.00	230.00	Wood - H	62.00		1
24	230 kV costs and expenses							
25								
26	Subtotal 230 kV					3,329.00	13.00	72
27								
28	ANACONDA, ID	JEFFERSON, ID	161.00	161.00	Wood - H		61.00	1
29	ANTELOPE, ID	GOSHEN, ID	161.00	161.00	Wood - H	45.00		1
30	BONNEVILLE, ID	EAGLEROCK, ID	161.00	161.00	Wood SP	9.00		1
31	EAGLEROCK, ID	SUGARMILL, ID	161.00	161.00	Wood SP	3.00		1
32	GOSHEN, ID	GRACE, ID	161.00	161.00	Wood - H	57.00		1
33	GOSHEN, ID	RIGBY, ID	161.00	161.00	Wood - H	31.00		1
34	RIGBY, ID	SUGARMILL, ID	161.00	161.00	Wood SP	17.00		1
35	SUGARMILL, ID	RIGBY, ID	161.00	161.00	Wood SP	17.00		1
36					TOTAL	16,211.00	694.00	272

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1272 ACSR 36/1								1
1272 ACSR 36/1								2
1272 ACSR 36/1								3
1272 ACSR 36/1								4
1272 ACSR 36/1								5
1272 ACSR 36/1								6
795 ACSR 26/7								7
954 ACSR 45/7								8
954 ACSR 45/7								9
795 ACSR 26/7								10
795 ACSR 26/7								11
1272 ACSR 36/1								12
795 ACSR 26/7								13
954 ACSR 45/7								14
900 ACSR 54/7								15
954 ACSR 45/7								16
1272 ACSR 36/1								17
1272 ACSR 36/1								18
1272 ACSR 36/1								19
1272 ACSR 45/7								20
1272 ACSR 36/1								21
795 ACSR 26/7								22
795 ACSR 26/7								23
	18,427,317	378,604,964	397,032,281	68,117	3,636,619	570,918	4,275,654	24
								25
	18,427,317	378,604,964	397,032,281	68,117	3,636,619	570,918	4,275,654	26
								27
250HH CU /7								28
397.5 ACSR 26/7								29
954 ACSR 45/7								30
954 ACSR 45/7								31
250HH CU /7								32
397.5 ACSR 26/7								33
795 AAC /37								34
397.5 ACSR 26/7								35
	211,652,349	3,045,766,779	3,257,419,128	488,475	15,845,636	1,917,195	18,251,306	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 2014/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	EAGLEROCK, ID	GOSHEN, ID	161.00	161.00	Wood - H	12.00		1
2	YELLOWTAIL, MT	RIMROCK, MT	161.00	161.00	Wood - H	46.00		1
3	RIGBY, ID	JEFFERSON, ID	161.00	161.00	Wood SP	18.00		1
4	GOSHEN, ID	JEFFERSON, ID	161.00	161.00	Wood - H		30.00	1
5	161 kV costs and expenses							
6								
7	Subtotal 161 kV					255.00	91.00	12
8								
9	90TH SOUTH, UT	SANDY, UT	138.00	138.00	Steel - SP	1.00		1
10	90TH SOUTH, UT	DUMAS #1, UT	138.00	138.00	Wood - H	12.00		1
11	90TH SOUTH, UT	DUMAS #2, UT	138.00	138.00	Wood - H	6.00		1
12	90TH SOUTH, UT	OQUIRRH, UT	138.00	138.00	Wood SP	10.00		1
13	ABAJO, UT	PINTO, UT	138.00	138.00	Wood - H	44.00		1
14	AGRIUM, UT	THREEMILE KNOLL, ID	138.00	138.00	Wood - H	4.00		1
15	ANSCHTZ CO-GEN, WY	EVANSTON, WY	138.00	138.00	Wood - H	22.00		1
16	ANTELOPE, ID	SCOVILLE #1, WY	138.00	138.00	Wood - H	1.00		1
17	ANTELOPE, ID	SCOVILLE #2, WY	138.00	138.00	Wood - H	1.00		1
18	ASHGROVE, UT	CLOVER, UT	138.00	138.00	Wood - H	26.00		1
19	ASHLEY, UT	CARBON, UT	138.00	138.00	Wood - H	102.00		1
20	ASHLEY, UT	VERNAL, UT	138.00	138.00	Wood - H	12.00		1
21	BANGERTER, UT	OQUIRRH, UT	138.00	138.00	Wood - H		6.00	1
22	BDO, UT	BDO TAP, UT	138.00	138.00	Wood - SP	1.00		1
23	BEN LOMOND, UT	BRIGHAM CITY, UT	138.00	138.00	Wood - H	14.00		1
24	BEN LOMOND #1, UT	EL MONTE, UT	138.00	138.00	Steel - SP	14.00		1
25	BEN LOMOND #2, UT	EL MONTE, UT	138.00	138.00			13.00	1
26	BEN LOMOND, UT	HONEYVILLE, UT	138.00	138.00	Steel Tower	22.00		1
27	BEN LOMOND, UT	SYRACUSE #1, UT	138.00	230.00	Steel Tower	7.00	13.00	1
28	BEN LOMOND, UT	ANGEL, UT	138.00	138.00	Steel - SP	28.00		1
29	BEN LOMOND, UT	W ZIRCONIUM, UT	138.00	138.00	Wood -SP	14.00		1
30	BEN LOMOND, UT	WHEELON, UT	138.00	138.00	Steel Tower	42.00		1
31	BEN LOMOND, UT	SYRACUSE, UT	138.00	138.00	Steel Tower	25.00		1
32	BONANZA, UT	CHAPITA, UT	138.00	138.00	Wood - H	9.00		1
33	BRIDGERLAND, UT	GREEN CANYON, UT	138.00	138.00	Wood -SP	16.00		1
34	BRIGHAM CITY, UT	WHEELON, UT	138.00	138.00	Wood - H	24.00		1
35	BUTLERVILLE, UT	90TH SOUTH, UT	138.00	138.00	Steel - SP	9.00		1
36					TOTAL	16,211.00	694.00	272

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272 ACSR 45/7								1
556.5 ACSR 26/7								2
397.5 ACSR 26/7								3
250HH CU /7								4
	623,490	22,862,553	23,486,043	288	322,044	1,712	324,044	5
								6
	623,490	22,862,553	23,486,043	288	322,044	1,712	324,044	7
								8
795 AAC /37								9
795 AAC /37								10
795 AAC /37								11
795 ACSR 26/7								12
397.5 ACSR 26/7								13
397.5 ACSR 26/7								14
795 ACSR 26/7								15
397.5 ACSR 26/7								16
397.5 ACSR 26/7								17
397.5 ACSR 26/7								18
397.5 ACSR 26/7								19
397.5 ACSR 26/7								20
								21
397.5 ACSR 26/7								22
1272 ACSR 45/7								23
795 ACSR 45/7								24
795 ACSR 45/7								25
250 CUHD /12								26
795 AAC /37								27
397.5 ACSR 26/7								28
795 AAC /37								29
250 CUHD /12								30
1272 ACSR 45/7								31
795 ACSR 26/7								32
1272 ACSR 45/7								33
795 ACSR 26/7								34
795 AAC /37								35
	211,652,349	3,045,766,779	3,257,419,128	488,475	15,845,636	1,917,195	18,251,306	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 2014/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	CAMERON, UT	PAROWAN, UT	138.00	138.00	Wood - H	35.00		1
2	CAMERON, UT	SIGURD, UT	138.00	138.00	Wood - H	64.00		1
3	CANYON COMP, WY	STR 204, WY	138.00	138.00	Wood - H	12.00		1
4	CARBON, UT	HELPER #2, UT	138.00	138.00	Wood - H	2.00		1
5	CARBON, UT	SPANISH FORK #1, UT	138.00	138.00	Steel Tower	54.00		1
6	CARBON, UT	SPANISH FORK #2, UT	138.00	138.00	Steel Tower	52.00		1
7	CARBON, UT	MOAB, UT	138.00	138.00	Wood - H	120.00		1
8	CLEAR CREEK, WY	PAINTER, UT	138.00	138.00	Wood -SP	5.00		1
9	CLOVER, UT	NEBO, UT	138.00	138.00	Wood -SP	8.00		1
10	COLUMBIA, UT	SUNNYSIDE, UT	138.00	138.00	Wood - H	2.00		1
11	COTTONWOOD, UT	MCCLELLAND, UT	138.00	138.00	Steel - SP	6.00		1
12	COTTONWOOD, UT	HAMMER, UT	138.00	138.00	Wood -SP	5.00		1
13	COTTONWOOD, UT	SILVER CREEK, UT	138.00	138.00	Wood -SP	29.00		1
14	CUTLER, UT	WHEELON, UT	138.00	138.00	Wood -SP	1.00		1
15	DRY CREEK, UT	SPANISH FORK, UT	138.00	138.00	Steel - SP	5.00		1
16	DUMAS, UT	WESTFIELD, UT	138.00	138.00	Wood -SP	18.00		1
17	DYNAMO, UT	TRI-CITY #1, UT	138.00	138.00	Steel - SP	2.00		1
18	DYNAMO, UT	TRI-CITY #2, UT	138.00	138.00			3.00	1
19	EAST LAYTON, UT	105 TAP, UT	138.00	138.00	Steel - SP	15.00		1
20	EBAY TAP, UT	OQUIRRH, UT	138.00	138.00	Wood -SP	1.00		1
21	EL MONTE, UT	STR 30B, UT	138.00	138.00	Steel - SP	4.00		1
22	EL MONTE, UT	PIONEER, UT	138.00	138.00	Steel - SP	1.00		1
23	EVANSTON, WY	RAILROAD, UT	138.00	138.00	Wood -SP	3.00		1
24	FRANKLIN, ID	TREASURETON, ID	138.00	138.00	Wood -SP	10.00		1
25	FRANKLIN, ID	GREEN CANYON, UT	138.00	138.00	Wood -SP	25.00		1
26	GADSBY, UT	THIRD WEST, UT	138.00	138.00	Wood -SP	1.00		1
27	GADSBY, UT	TERMINAL, UT	138.00	138.00	Wood -SP	6.00		1
28	GADSBY, UT	JORDAN, UT	138.00	138.00	Wood -SP	1.00		1
29	GREEN CANYON, UT	NIBLEY, UT	138.00	138.00	Wood -SP	7.00		1
30	GREEN CANYON, UT	WHEELON, UT	138.00	138.00	Wood -SP	19.00		1
31	HALE, UT	MIDWAY, UT	138.00	138.00	Wood - H	19.00		1
32	HALE, UT	TANNER, UT	138.00	138.00	Wood - H	7.00		1
33	HALE, UT	SPANISH FORK, UT	138.00	138.00	Wood - H	18.00		1
34	HAMMER, UT	BUTLERVILLE, UT	138.00	138.00			2.00	1
35	HONEYVILLE, UT	LAMPO, UT	138.00	138.00	Wood - H	25.00		1
36					TOTAL	16,211.00	694.00	272

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
397.5 ACSR 26/7								1
397.5 ACSR 26/7								2
795 ACSR 26/7								3
556.5 ACSR 26/7								4
795 ACSR 26/7								5
1272 ACSR 45/7								6
954 ACSR 54/7								7
795 ACSR 26/7								8
1272 ACSR 45/7								9
397.5 ACSR 26/7								10
795 AAC /37								11
795 AAC /37								12
397.5 ACSR 26/7								13
250 CUHD /12								14
1272 ACSR 45/7								15
795 ACSR 26/7								16
795 ACSR 26/7								17
795 ACSR 26/7								18
795 ACSR 26/7								19
795 ACSR 26/7								20
1272 ACSR 45/7								21
1272 ACSR 45/7								22
795 ACSR 26/7								23
795 ACSR 26/7								24
397.5 ACSR 26/7								25
1272 AAC /61								26
1272 ACSR 45/7								27
1272 ACSR 45/7								28
1272 ACSR 45/7								29
397.5 ACSR 26/7								30
397.5 ACSR 26/7								31
1272 ACSR 45/7								32
1272 ACSR 45/7								33
795 ACSR 26/7								34
397.5 ACSR 26/7								35
	211,652,349	3,045,766,779	3,257,419,128	488,475	15,845,636	1,917,195	18,251,306	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 2014/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	HONEYVILLE, UT	WHEELON, UT	138.00	138.00			14.00	1
2	HUNTINGTON, UT	MCFADDEN, UT	138.00	138.00	Wood - H	7.00		1
3	JERUSALEM, UT	NEBO, UT	138.00	138.00	Wood - H	26.00		1
4	JORDAN, UT	THIRDWEST, UT	138.00	138.00	Wood -SP	1.00		1
5	JORDAN, UT	MCCLELLAND, UT	138.00	138.00	Wood -SP	5.00		1
6	JORDAN, UT	TERMINAL, UT	138.00	138.00	Wood -SP	6.00		1
7	BARNEYS, UT	GRINDING, UT	138.00	138.00	Wood -SP	1.00		1
8	KEARNS, UT	TAYLORSVILLE, UT	138.00	138.00	Wood -SP	3.00		1
9	KEARNS, UT	WEST VALLEY, UT	138.00	138.00	Wood -SP	2.00		1
10	LONE PEAK, UT	CAMP WILLIAMS, UT	138.00	138.00			8.00	1
11	MCCLELLAND, UT	MID VALLEY, UT	138.00	138.00	Wood -SP	6.00		1
12	MCFADDEN, UT	BLACKHAWK, UT	138.00	138.00	Wood - H	11.00		1
13	MID VALLEY, UT	TAYLORSVILLE, UT	138.00	138.00	Wood -SP	4.00	2.00	1
14	MID VALLEY #2, UT	COTTONWOOD, UT	138.00	138.00	Wood -SP	5.00		1
15	MID VALLEY #1, UT	COTTONWOOD, UT	138.00	138.00	Wood -SP	3.00		1
16	MID VALLEY, UT	90TH SOUTH, UT	138.00	138.00	Wood - H	9.00		1
17	MIDDLETON, UT	SAINT GEORGE, UT	138.00	138.00	Wood - H	1.00		1
18	MOAB, UT	PINTO, UT	138.00	138.00	Wood - H	68.00		1
19	NAUGHTON, WY	CANYON COMP, WY	138.00	138.00	Wood - H	36.00		1
20	NAUGHTON, WY	PAINTER, WY	138.00	138.00	Wood - H	48.00		1
21	NEBO, UT	DRY CREEK, UT	138.00	138.00	Wood - H	33.00		1
22	NUCOR STEEL, UT	WHEELON, UT	138.00	138.00	Wood - H	10.00		1
23	ONEIDA, ID	OVID, UT	138.00	138.00	Wood - H	23.00		1
24	ONEIDA, ID	GRACE, ID	138.00	138.00	Wood - H	19.00		1
25	GRINDING, UT	OQUIRRH, UT	138.00	138.00	Wood -SP	14.00		1
26	GRINDING, UT	TOOELE, UT	138.00	138.00	Wood-SP	7.00		1
27	OQUIRRH, UT	TOOELE, UT	138.00	138.00	Steel - SP	23.00		1
28	OQUIRRH, UT	BARNEY, UT	138.00	138.00	Wood - H	5.00		1
29	OQUIRRH, UT	BINGHAM CANYON, UT	138.00	138.00	Wood - H	8.00		1
30	PAINTER, UT	RAILROAD, UT	138.00	138.00	Wood - H	7.00		1
31	PAROWAN, UT	WEST CEDAR, UT	138.00	138.00	Wood - H	21.00		1
32	PARRISH, UT	TERMINAL #1, UT	138.00	138.00	Steel - SP	16.00		1
33	PARRISH, UT	TERMINAL #2, UT	138.00	138.00			14.00	1
34	PARRISH #105, UT	TERMINAL, UT	138.00	138.00	Steel - SP	14.00		1
35	PARRISH, UT	TAP TO N SALT LAKE, UT	138.00	138.00	Steel - SP		8.00	1
36					TOTAL	16,211.00	694.00	272

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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)	
250 CUHD /12								1
397.5 ACSR 26/7								2
397.5 ACSR 26/7								3
1272 AAC /61								4
795 AAC /37								5
1272 AAC /91								6
1272 AAC /61								7
500 AAC /19								8
								9
1272 ACSR 45/7								10
795 AAC 26/7								11
795 AAC 26/7								12
1272 ACSR /61								13
								14
								15
1272 ACSR 45/7								16
397.5 ACSR 26/7								17
397.5 ACSR 26/7								18
795 AAC 26/7								19
795 AAC 26/7								20
795 AAC 26/7								21
397.5 ACSR 26/7								22
336.4 ACSR 26/7								23
250 CUHD /12								24
795 AAC 45/7								25
796 AAC 45/7								26
1272 ACSR 45/7								27
795 AAC 26/7								28
1557.4 ACSR/TW								29
1272 ACSR 45/7								30
397.5 ACSR 26/7								31
795 AAC 45/7								32
795 AAC 26/7								33
795 AAC 45/7								34
795 AAC 26/7								35
	211,652,349	3,045,766,779	3,257,419,128	488,475	15,845,636	1,917,195	18,251,306	36

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	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)	On Structures of Another Line (g)	Number Of Circuits (h)
1	RAILROAD, UT	CANYON COMP, WY	138.00	138.00	Wood - H	17.00		1
2	CENTRAL (UAMPS) #2, UT	SAINT GEORGE, UT	138.00	138.00	Steel - SP	20.00		1
3	CENTRAL (UAMPS) #3, UT	SAINT GEORGE, UT	138.00	138.00	Steel - SP		20.00	1
4	RED BUTTE, UT	SAINT GEORGE, UT	138.00	138.00	Steel - SP	1.00		1
5	RED BUTTE, UT	WEST CEDAR, UT	138.00	138.00	Wood - H	49.00		1
6	RIVERDALE, UT	EAST LAYTON, UT	138.00	138.00	Steel - SP		7.00	1
7	SHICK, UT	PARRISH, UT	138.00	138.00	Wood - H		10.00	1
8	SILVER CREEK, UT	JORDANELLE, UT	138.00	138.00	Wood - SP	10.00		1
9	SPANISH FORK, UT	TANNER, UT	138.00	138.00	Wood - H	10.00		1
10	SUNRISE, UT	OQUIRRH, UT	138.00	138.00	Wood - SP		2.00	1
11	SYRACUSE, UT	CLEARFIELD SOUTH, UT	138.00	138.00	Steel - SP	1.00		1
12	SYRACUSE, UT	PARRISH, UT	138.00	138.00	Steel Tower	15.00		1
13	SYRACUSE, UT	ANGEL #1, UT	138.00	138.00			9.00	1
14	TAP TO ANGEL NORTH, UT	TAP TO PARRISH, UT	138.00	138.00	Wood - H	13.00		1
15	TAYLORSVILLE, UT	90TH SOUTH, UT	138.00	138.00	Wood - SP	6.00	2.00	1
16	TERMINAL, UT	KENNECOTT, UT	138.00	138.00	Steel - SP	9.00		1
17	TERMINAL, UT	ROWLEY, UT	138.00	138.00	Wood - H	53.00		1
18	TERMINAL, UT	MID VALLEY #1, UT	138.00	138.00	Wood - H	7.00		1
19	TERMINAL, UT	MID VALLEY #2, UT	138.00	138.00	Wood - H	7.00		1
20	TERMINAL, UT	TOOELE, UT	138.00	138.00	Wood - H	24.00	6.00	1
21	TERMINAL, UT	WEST VALLEY, UT	138.00	138.00	Wood - SP	7.00		1
22	THREEMILE KNOLL, ID	GRACE #1, ID	138.00	138.00	Wood - H	17.00		1
23	THREEMILE KNOLL, ID	GRACE #2, ID	138.00	138.00	Wood - H	17.00		1
24	THREEMILE KNOLL, ID	MONSANTO #1, ID	138.00	138.00	Wood - H	2.00		1
25	THREEMILE KNOLL, ID	MONSANTO #2, ID	138.00	138.00	Steel - SP	2.00		1
26	TIMP #1, UT	DYNAMO, UT	138.00	138.00	Steel - SP	2.00		1
27	TIMP #2, UT	DYNAMO, UT	138.00	138.00			2.00	1
28	TIMP, UT	HALE, UT	138.00	138.00	Steel - SP	4.00		1
29	TIMP, UT	SPANISH FORK, UT	138.00	138.00	Wood - H	23.00		1
30	TREASURETON, ID	GRACE, ID	138.00	138.00	Steel Tower	25.00		1
31	TREASURETON, ID	GRACE #2, ID	138.00	138.00			25.00	1
32	TREASURETON, ID	ONEIDA, ID	138.00	138.00	Wood - H	6.00		1
33	TRI-CITY, UT	SUNRISE, ID	138.00	138.00	Wood - SP	22.00		1
34	TRI-CITY, UT	BANGERTER, UT	138.00	138.00	Wood - SP	6.00	12.00	1
35	TRI-CITY, UT	WESTFIELD, UT	138.00	138.00	Wood - H	15.00		1
36					TOTAL	16,211.00	694.00	272

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795 ACSR 26/7								1
1272 ACSR 45/7								2
1272 ACSR 45/7								3
1272 ACSR 45/7								4
397.5 ACSR 26/7								5
795 AAC 26/7								6
250 CUHD /12								7
795 AAC 26/7								8
1272 ACSR 45/7								9
								10
1272 ACSR 45/7								11
1272 ACSR 45/7								12
250 CUHD /12								13
795 AAC /37								14
795 AAC /37								15
795 AAC 26/7								16
795 AAC /37								17
1272 ACSR 45/7								18
1272 AAC /61								19
397.5 ACSR 26/7								20
								21
250 CUHD /12								22
1272 ACSR 45/7								23
1272 AAC /61								24
1272 ACSR 45/7								25
								26
								27
								28
								29
250 CUHD /12								30
250 CUHD /12								31
250 CUHD /12								32
								33
								34
1272 ACSR 45/7								35
	211,652,349	3,045,766,779	3,257,419,128	488,475	15,845,636	1,917,195	18,251,306	36

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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.
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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	WEST CEDAR, UT	THREE PEAKS, UT	138.00	138.00	Wood - SP	20.00		1
2	WEST VALLEY, UT	OQUIRRH, UT	138.00	138.00	Wood - H	9.00		1
3	WESTFIELD, UT	HALE, UT	138.00	138.00	Wood - H	14.00		1
4	WHEELON, UT	AMERICAN FALLS, ID	138.00	138.00	Wood - H	86.00		1
5	WHEELON #1, UT	TREASURETON, ID	138.00	138.00	Steel Tower	29.00		1
6	WHEELON #2, UT	TREASURETON, ID	138.00	138.00			29.00	1
7	WHEELON #3, UT	TREASURETON, ID	138.00	138.00	Wood - H	29.00		1
8	FORT DOUGLAS, UT	MCCLELLAND, UT	138.00	138.00	Wood - SP	3.00		1
9	138 kV costs and expenses							
10								
11	Subtotal 138 kV					2,070.00	207.00	140
12								
13	All 115 kV Lines					1,636.00		
14								
15	All 69 kV Lines					2,966.00		
16								
17	All 57 kV Lines					113.00		
18								
19	All 46 kV Lines					2,544.00		
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	16,211.00	694.00	272

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
795 AAC 26/7								1
								2
795 AAC 26/7								3
250 CUHD /12								4
250 CUHD /12								5
250 CUHD /12								6
250 CUHD /12								7
								8
	19,158,601	346,043,380	365,201,981	123,357	1,965,663	109,823	2,198,843	9
								10
	19,158,601	346,043,380	365,201,981	123,357	1,965,663	109,823	2,198,843	11
								12
	5,077,360	179,774,507	184,851,867	4,040	2,057,338	229,146	2,290,524	13
								14
	7,160,941	264,967,484	272,128,425	65,511	3,059,220	207,831	3,332,562	15
								16
	46,327	10,394,900	10,441,227	1,397	41,472	3,791	46,660	17
								18
	9,956,555	242,572,698	252,529,253	135,481	2,399,489	26,721	2,561,691	19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	211,652,349	3,045,766,779	3,257,419,128	488,475	15,845,636	1,917,195	18,251,306	36

Schedule Page: 422 Line No.: 1 Column: a

Certain transmission lines reported on pages 422-423 are part of exchange agreements with various third parties. Refer to the footnotes on pages 328-330 of this FERC Form No. 1 for further discussion.

Schedule Page: 422 Line No.: 2 Column: a

The Dixonville - Meridian 500-kV line is jointly owned by PacifiCorp and the Bonneville Power Administration ("the BPA"). Ownership of the line is as follows: PacifiCorp 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, Avista Corporation 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, Avista Corporation 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, Avista Corporation 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

Broadview - Townsend A 500-kV line is jointly owned by PacifiCorp, NorthWestern Corporation, Puget Sound Energy, Avista Corporation 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

Broadview - Townsend B 500-kV line is jointly owned by PacifiCorp, NorthWestern Corporation, Puget Sound Energy, Avista Corporation 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: 422.2 Line No.: 12 Column: a

Complete name is GONDER (NV ENERGY), UT - NV STATE.

Schedule Page: 422.4 Line No.: 21 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 9 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 14 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 15 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 29 Column: b

Complete name is BINGHAM CANYON (KCC), UT.

Schedule Page: 422.7 Line No.: 2 Column: a

The Central - Saint 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.: 3 Column: a

See Footnote on page 422.7 for line 2 column (a).

Schedule Page: 422.7 Line No.: 10 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 21 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 26 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.: 33 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: 422.8 Line No.: 2 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 8 Column: i

1557.4 ACSR/TW 36/7

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	None						
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						

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.
									1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
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									38
									39
									40
									41
									42
									43
									44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	115.00	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	

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 2014/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
25	1					2
6	1					3
1	3					4
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

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 2014/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	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		3082.00	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	

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 2014/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.
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

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 SUB	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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
6	1					1
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

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 2014/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	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	2.40
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	138.00	46.00	6.60
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		2921.00	1254.47	217.94
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	

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.
7	1					1
7	1					2
14	1					3
20	1					4
4	1					5
20	1					6
721	67					7
						8
						9
30	1					10
71	4	1				11
14	1					12
189	4					13
40	2					14
344	12	1				15
						16
						17
75	1	1				18
445	3					19
15	1					20
67	1					21
67	1					22
67	1					23
25	3					24
75	1					25
908	4					26
217	2					27
233	3					28
30	1					29
76	2					30
168	3					31
700	1					32
533	2					33
3701	30	1				34
						35
						36
						37
32	2					38
68	2					39
100	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	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	CANYONVILLE SUB	DISTRIBUTION-UNATTEN	116.00	12.47	
30	CARNES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	CASEBEER SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
32	CAVEMAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
33	CHERRY LANE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	CHILOQUIN MARKET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	CHINA HAT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	CIRCLE BLVD SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
37	CLEVELAND AVE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	CLOAKE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
39	COBURG SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
40	COLISEUM SUB	DISTRIBUTION-UNATTEN	20.80	4.16	

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 2014/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)	
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
25	1					29
9	3					30
20	1					31
45	2					32
25	1					33
6	3					34
25	1					35
80	2					36
45	2					37
20	1					38
10	3					39
9	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	COLUMBIA SUB	DISTRIBUTION-UNATTEN	115.00	12.47	57.00
2	COOS RIVER SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
3	COQUILLE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
4	CREEK SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
5	CROOKED RIVER RANCH SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
6	CROWFOOT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
7	CULLY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
8	CULVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	DAIRY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	DALLAS SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
11	DALREED SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
12	DESCHUTES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	DEVILS LAKE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
14	DIXON SUB	DISTRIBUTION-UNATTEN	115.00	4.16	
15	DODGE BRIDGE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
16	DOWELL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
17	EASY VALLEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	EMPIRE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
19	ENTERPRISE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	FERN HILL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
21	FIELDER CREEK SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
22	FOOTHILLS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	FRALEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	GARDEN VALLEY SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
25	GAZLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	GLENDALE SUB	DISTRIBUTION-UNATTEN	230.00	12.47	
27	GLENEDEN SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
28	GLIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
29	GOLD HILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	GORDON HOLLOW SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	GOSHEN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
32	GRANT STREET SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
33	GRASS VALLEY SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
34	GREEN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	GRIFFIN CREEK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
36	HAMAKER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	HARRISBURG SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
38	HENLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	HERMISTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	HILLVIEW SUB	DISTRIBUTION-UNATTEN	115.00	20.80	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
55	2	1				1
20	1					2
40	2					3
5	1					4
25	2					5
20	1					6
25	1					7
13	1					8
25	1					9
50	2					10
75	3					11
25	1					12
50	2					13
7	1					14
13	1					15
20	1					16
45	2					17
20	1					18
19	2					19
12	1					20
25	1					21
21	4					22
5	3					23
20	1					24
8	4					25
25	2					26
5	1					27
12	1					28
11	3					29
6	1					30
20	1					31
45	2					32
1	4					33
25	1					34
20	1					35
8	3					36
13	1					37
6	3					38
40	1					39
45	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 2014/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	HINKLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	HOLLADAY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
3	HOLLYWOOD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	HOOD RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	HORNET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	HUMBUG CREEK SUB	DISTRIBUTION-UNATTEN	67.00	12.50	
7	HUNTERS CIRCLE TEMP SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	ILLAHEE FLATS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
9	INDEPENDENCE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
10	JACKSONVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
11	JEFFERSON SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
12	JEROME PRAIRIE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
13	JORDAN POINT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	JOSEPH SUB	DISTRIBUTION-UNATTEN	20.80	12.47	
15	JUNCTION CITY SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
16	KENWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	KILLINGWORTH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	KNAPPA SVENSEN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
19	LAKEPORT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	LANCASTER SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
21	LEBANON SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
22	LINCOLN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
23	LOCKHART SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
24	LYONS SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
25	MADRAS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	MALLORY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
27	MARYS RIVER SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
28	MEDCO SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
29	MEDFORD	DISTRIBUTION-UNATTEN	115.00	12.47	
30	MERLIN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
31	MERRILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	MINAM SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	MODOC SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	MORO SUB	DISTRIBUTION-UNATTEN	20.80	2.40	
35	MURDER CREEK SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
36	MYRTLE CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	MYRTLE POINT SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
38	NELSCOTT SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
39	NEW O'BRIEN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
40	OAK KNOLL SUB	DISTRIBUTION-UNATTEN	115.00	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 2014/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.
20	1					1
75	3					2
50	2					3
40	2					4
20	1					5
9	1					6
12	1					7
2	1					8
20	1					9
75	2					10
12	1					11
20	1					12
20	1					13
6	1	1				14
25	2					15
3	3					16
40	2					17
6	1					18
50	2					19
12	3					20
40	2					21
105	3					22
40	2					23
9	2					24
25	2					25
25	1					26
20	1					27
20	1					28
67	8					29
45	2					30
17	6					31
	1					32
6	3					33
2	3					34
100	4					35
14	1					36
9	1					37
4	1					38
9	1					39
45	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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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	OAKLAND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	OREMET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
3	OVERPASS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	PALLETTE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
5	PARK STREET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
6	PARKROSE SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
7	PENDLETON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	PILOT ROCK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	POWELL BUTTE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	PRINEVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
11	PROVOLT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	QUEEN AVE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
13	RED BLANKET SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
14	REDMOND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
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	20.80	
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	115.00	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 2014/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)	
8	1					1
75	2					2
45	2					3
1	1	1				4
40	2					5
39	2					6
46	7	1				7
22	2					8
6	1					9
50	2					10
11	3					11
50	2					12
2	3					13
50	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

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 2014/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	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		15569.27	2511.60	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	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	RIDDLE SUB	T/D-UNATTENDED	115.00	69.00	
38	SAGE ROAD SUB	T/D-UNATTENDED	115.00	12.47	
39	WINCHESTER SUB	T/D-UNATTENDED	115.00	12.47	69.00
40	TOTAL		1449.00	489.44	338.82

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 2014/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
2	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
4569	345	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
75	2					37
40	2					38
75	5					39
1337	44					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 2014/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	Number of Substations-12				
2					
3	LEMOLO #1 HYDRO	TRANSMISSION-ATTENDE	11.50	12.50	
4	CALAPOOYA SUB	TRANSMISSION-UNATTEN	230.00	69.00	
5	CHILOQUIN SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
6	COLD SPRINGS SUB	TRANSMISSION-UNATTEN	230.00	69.00	2.40
7	COVE SUB	TRANSMISSION-UNATTEN	230.00	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		5950.50	2691.50	431.27
31	Number of Substations-27				
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	

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
						2
2	3	1				3
75	1					4
119	4					5
66	2					6
67	3					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
500	2					25
30	3					26
50	1					27
500	3					28
100	2					29
7261	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

SUBSTATIONS

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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	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	67.00	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	

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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 2014/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	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	DEWEYVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	DIMPLE DELL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
12	DRAPER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	EAST BENCH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
14	EAST HYRUM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	EAST LAYTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
16	EAST MILLCREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	EDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	ELBERTA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	ELK MEADOWS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	ELSINORE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	EMERY CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	EMIGRATION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	ENOCH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
24	ENTERPRISE VALLEY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
25	EUREKA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	FARMINGTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
27	FAYETTE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	FERRON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	FIELDING SUB	DISTRIBUTION-UNATTEN	46.00	12.00	
30	FIFTH WEST SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
31	FLUX SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	FOOL CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	FORT DOUGLAS	DISTRIBUTION-UNATTEN	138.00	13.20	
34	FOUNTAIN GREEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	FREEDOM SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
36	FRUIT HEIGHTS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	GARDEN CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	GATEWAY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	GOLD RUSH SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
40	GORDON AVENUE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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)	
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
4	1					10
60	2					11
23	2					12
30	1					13
6	1					14
60	2					15
20	1					16
19	2					17
5	1					18
3	1					19
2	1					20
3	3					21
25	1					22
14	1					23
10	1					24
3	1					25
30	1					26
1	2					27
5	1					28
6	1					29
50	2					30
4	1					31
2	1					32
40	1					33
7	1					34
	1					35
22	1					36
12	1					37
28	1	1				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 2014/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	GOSHEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	GRANGER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	GRANTSVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	GUNNISON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	HAMMER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
6	HAVASU SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	HELPER CITY SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
8	HENEFER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	HERRIMAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
10	HIGHLAND DIST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	HOGGARD SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
12	HOLDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	HOLLADAY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	HUNTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	HUNTINGTON CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	IRON MOUNTAIN SUB	DISTRIBUTION-UNATTEN	34.50	7.20	
17	IRONTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	IVINS SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
19	JORDAN NARROWS SUB	DISTRIBUTION-UNATTEN	46.00	2.40	
20	JORDAN PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
21	JORDANELLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
22	JUAB SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	JUNCTION SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	KAIBAB SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	KAMAS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	KEARNS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
27	KENSINGTON SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
28	KYUNE SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
29	LAKE PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
30	LARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	LAYTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	LEGRANDE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	LEWISTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	LINCOLN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	LINDON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	LISBON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	LOAFER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	LOGAN CANYON SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
39	LONE TREE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
40	LOWER BEAVER SUB	DISTRIBUTION-UNATTEN	46.00	6.60	

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 2014/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
2	1					1
50	2					2
23	1					3
11	2					4
60	2					5
3	1					6
3	3					7
4	1					8
30	1					9
25	1					10
50	2					11
4	1					12
32	2					13
22	1					14
12	2					15
1	1					16
2	1					17
22	1					18
13	2					19
30	1					20
30	1					21
2	3					22
3	1					23
5	1					24
7	1					25
60	2					26
7	1					27
	1					28
53	2					29
6	1					30
40	2					31
2	1					32
14	1					33
20	1					34
20	1					35
4	1					36
	1					37
1	1					38
20	1					39
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 2014/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	LYNNDYL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	MAESER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	MAGNA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
4	MANILA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
5	MANTUA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	MAPLETON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	MARRIOTT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	MARYSVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	MATHIS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	MCCORNICK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	MCKAY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	MEADOWBROOK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	46.00
13	MEDICAL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	MIDLAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
15	MIDVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	MILFORD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	MILFORD TV SUB	DISTRIBUTION-UNATTEN	46.00	13.20	
18	MINERSVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	MOAB CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	MONTEZUMA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	MOORE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	MORGAN SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
23	MORONI SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	MOSS JUNCTION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	MOUNTAIN DELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	MOUNTAIN GREEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	MYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	NEW HARMONY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	NEWGATE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	NEWTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	NIBLEY SUB	DISTRIBUTION-UNATTEN	138.00	24.90	
32	NORTH BENCH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	NORTH FIELDS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	NORTH LOGAN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	NORTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	NORTH SALT LAKE SUB	DISTRIBUTION-UNATTEN	46.00	13.20	
37	NORTHEAST SUB	DISTRIBUTION-UNATTEN	46.00	12.50	
38	NORTHRIDGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	OAKLAND AVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	OAKLEY 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 2014/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.
4	1					1
12	1					2
30	1					3
22	1					4
2	1					5
14	1					6
20	1					7
3	1					8
9	1					9
6	1					10
20	1					11
42	2					12
57	4					13
30	1					14
25	1					15
14	1					16
	1					17
2	1					18
19	2					19
12	1					20
3	1					21
7	2					22
6	1					23
6	3					24
5	1					25
6	1					26
6	1					27
7	1					28
20	1					29
5	1					30
14	1					31
25	1					32
2	1					33
25	1					34
22	1					35
25	1					36
45	2					37
14	1					38
24	2					39
6	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 2014/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	OLYMPUS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	OPHIR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	ORANGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	ORANGEVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	OREM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	PACK CREEK RESERVOIR	DISTRIBUTION-UNATTEN	46.00	12.47	
7	PANGUITCH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	PARIETTE SUB	DISTRIBUTION-UNATTEN	67.00	24.94	
9	PARK CITY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	PARKWAY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
11	PARLEYS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	PELICAN POINT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	PINE CANYON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
14	PINE CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	PINNACLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	PLAIN CITY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
17	PLEASANT GROVE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
18	PLEASANT VIEW SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	PORTER ROCKWELL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
20	PROMONTORY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	QUAIL CREEK SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
22	QUARRY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
23	QUICHAPA SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
24	RAINS SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
25	RANDOLPH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	RASMUSON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	RATTLESNAKE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
28	RED MOUNTAIN SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
29	RED ROCK SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
30	REDWOOD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	RESEARCH PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	RICH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	RICHFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	RICHMOND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	RIDGELAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
36	RITER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	ROCK CANYON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	ROCKVILLE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
39	ROCKY POINT	DISTRIBUTION-UNATTEN	138.00	13.20	
40	ROSE PARK 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 2014/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
22	1					1
3	1					2
20	1					3
14	1					4
48	2					5
4	1					6
5	1					7
14	1					8
35	2					9
50	2					10
16	2					11
6	1					12
55	2					13
2	1					14
14	1					15
22	1					16
25	1					17
14	1					18
30	1					19
2	1					20
4	1					21
60	2					22
4	1					23
15	1					24
2	1					25
1	3					26
14	1					27
12	1					28
3	1					29
45	2					30
45	2					31
5	1					32
22	2					33
11	1					34
40	2					35
20	1					36
5	1					37
4	1					38
30	1					39
24	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	ROYAL SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
2	SALINA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	SANDY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
4	SARATOGA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
5	SCIPIO SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	SCOFIELD RESERVOIR SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
7	SCOFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	SECOND STREET SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	SEGO CANYON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	SEVEN MILE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	SHARON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	SHIVWITS SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
13	SHORELINE SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
14	SIXTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	SKULL VALLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	SKYPARK SUB	DISTRIBUTION-UNATTEN	138.00	12.50	12.50
17	SNARR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	SNOWVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	SNYDERVILLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
20	SOLDIER SUMMIT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	SOUTH JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
22	SOUTH MILFORD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	SOUTH MOUNTAIN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
24	SOUTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	SOUTH PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
26	SOUTH WEBER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
27	SOUTHWEST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	SPANISH VALLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	SPRINGDALE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
30	ST. JOHNS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	STANSBURY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	SUMMIT CREEK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
33	SUMMIT PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	SUNRISE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
35	SUPERIOR SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	SUTHERLAND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	TAMARISK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
38	TAYLOR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	THIEF CREEK SUB	DISTRIBUTION-UNATTEN	138.00	24.90	
40	THIRD WEST SUB	DISTRIBUTION-UNATTEN	138.00	13.20	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/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)	
	3					1
11	1					2
60	2					3
60	2					4
1	3					5
1	1					6
1	3					7
13	2					8
14	1					9
	1					10
20	1					11
6	1					12
60	2					13
20	1					14
2	1					15
40	1					16
40	2					17
5	1					18
60	2					19
12	1					20
60	2					21
20	2					22
60	2					23
25	1					24
30	1					25
22	1					26
22	2					27
6	1					28
4	1					29
4	1					30
20	1					31
14	1					32
7	1					33
60	2					34
8	1					35
6	1					36
20	1					37
14	1					38
14	1					39
100	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	THIRTEENTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	TOOELE DEPOT SUB	DISTRIBUTION-UNATTEN	46.00	12.50	
3	TOQUERVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	34.50
4	UINTAH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	UNION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	VALLEY CENTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	VERMILLION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	VERNAL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	VICKERS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	VINEYARD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	WALLSBURG SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
12	WALNUT GROVE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
13	WARREN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
14	WASATCH STATE PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	WASHAKIE SUB	DISTRIBUTION-UNATTEN	138.00	4.16	
16	WELBY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	WELFARE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	WEST COMMERCIAL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	WEST JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
20	WEST OGDEN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
21	WEST ROY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	WEST TEMPLE SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
23	WESTWATER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	WHITE MESA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	WHITE ROCK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
26	WILLOWCREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	WILLOWRIDGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	WINCHESTER HILLS SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
29	WINKLEMAN SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
30	WOLF CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	WOOD CROSS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	WOODRUFF SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	TOTAL		19877.30	3535.85	105.47
34	Number of Substations-279				
35					
36	90TH SOUTH SUB	T/D-UNATTENDED	345.00	138.00	12.47
37	ANGEL SUB	T/D-UNATTENDED	138.00	12.47	46.00
38	BDO SUBSTATION	T/D-UNATTENDED	138.00	12.47	
39	BUTLERVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47
40	CENTENNIAL SUB	T/D-UNATTENDED	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 2014/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.
22	1					1
25	1					2
34	2					3
39	2					4
50	2					5
22	1					6
3	1					7
33	2					8
2	1					9
25	1					10
13	1					11
30	1					12
30	1					13
2	3					14
14	1					15
42	2					16
10	1					17
22	1					18
28	1					19
60	2					20
25	1					21
60	3					22
5	1					23
14	1					24
30	1					25
1	1					26
14	1					27
4	1					28
	1					29
6	1					30
20	1					31
2	1					32
5470	380	1				33
						34
						35
1572	5	1				36
135	3					37
30	1					38
205	4					39
40	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	COTTONWOOD SUB	T/D-UNATTENDED	138.00	12.47	46.00
2	DECADE SUB	T/D-UNATTENDED	138.00	12.50	
3	DUMAS SUB	T/D-UNATTENDED	138.00	12.47	
4	EMMA PARK SUBSTATION	T/D-UNATTENDED	138.00	12.47	
5	GROW SUB	T/D-UNATTENDED	138.00	12.47	46.00
6	HALE SUB	T/D-UNATTENDED	138.00	46.00	12.47
7	HIGHLAND SUB	T/D-UNATTENDED	138.00	12.47	46.00
8	JORDAN SUB	T/D-UNATTENDED	138.00	46.00	12.47
9	JUDGE SUB	T/D-UNATTENDED	46.00	12.47	
10	MCCLELLAND SUB	T/D-UNATTENDED	138.00	46.00	12.47
11	MORTON COURT SUB	T/D-UNATTENDED	138.00	12.47	
12	OQUIRRH SUB	T/D-UNATTENDED	345.00	46.00	138.00
13	PARRISH SUB	T/D-UNATTENDED	138.00	12.47	46.00
14	PIONEER PLANT	T/D-UNATTENDED	138.00	12.47	
15	RIVERDALE SUB	T/D-UNATTENDED	138.00	46.00	12.47
16	SEVIER SUB	T/D-UNATTENDED	138.00	46.00	12.47
17	SILVER CREEK SUB	T/D-UNATTENDED	138.00	12.47	46.00
18	SOUTHEAST SUB	T/D-UNATTENDED	138.00	12.47	46.00
19	SYRACUSE SUB	T/D-UNATTENDED	345.00	46.00	138.00
20	TAYLORSVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47
21	TERMINAL SUB	T/D-UNATTENDED	345.00	46.00	138.00
22	TIMP SUB	T/D-UNATTENDED	138.00	46.00	12.47
23	TOOELE SUB	T/D-UNATTENDED	138.00	46.00	12.47
24	TRI CITY SUB	T/D-UNATTENDED	138.00	12.47	
25	WEST VALLEY SUB	T/D-UNATTENDED	138.00	12.47	
26	WESTFIELD SUB	T/D-UNATTENDED	138.00	12.47	
27	TOTAL		5014.00	914.49	860.70
28	Number of Substations-31				
29					
30	EMERY SUB	TRANSMISSION-ATTENDE	345.00	138.00	69.00
31	GADSBY SUB	TRANSMISSION-ATTENDE	138.00	46.00	
32	ABAJO SUB	TRANSMISSION-UNATTEN	138.00	69.00	
33	ASHLEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
34	BARNEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
35	BEN LOMOND SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
36	BLACK ROCK SUB	TRANSMISSION-UNATTEN	230.00	69.00	
37	BLACKHAWK SUB	TRANSMISSION-UNATTEN	138.00	69.00	46.00
38	CAMERON SUB	TRANSMISSION-UNATTEN	138.00	46.00	
39	CAMP WILLIAMS SUB	TRANSMISSION-UNATTEN	345.00	138.00	12.47
40	CLOVER SUB	TRANSMISSION-UNATTEN	345.00	138.00	14.40

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.
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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.
289	7					1
60	2					2
60	2					3
8	1					4
72	3					5
114	2					6
97	2					7
164	2					8
22	1					9
340	3					10
65	2					11
835	4	1				12
97	2					13
30	1					14
180	3					15
34	4					16
100	2					17
50	2					18
600	5					19
358	4					20
1108	6	2				21
130	2					22
249	3					23
30	1					24
30	1					25
20	1					26
7124	83	4				27
						28
						29
783	13	1				30
318	2					31
67	1					32
133	2					33
100	1					34
1813	5					35
75	1					36
100	2					37
25	4					38
169	2					39
448	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 2014/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	COLUMBIA SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
2	CRANER FLAT SUB	TRANSMISSION-UNATTEN	138.00	12.47	
3	CUTLER SUB	TRANSMISSION-UNATTEN	138.00	46.00	
4	EL MONTE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
5	GARKANE SUB	TRANSMISSION-UNATTEN	69.00	46.00	
6	GREEN CANYON SUB	TRANSMISSION-UNATTEN	138.00	46.00	
7	GRINDING SUB	TRANSMISSION-UNATTEN	138.00	13.80	
8	HELPER SUB	TRANSMISSION-UNATTEN	138.00	46.00	
9	HONEYVILLE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
10	HORSESHOE SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
11	HUNTINGTON SUB	TRANSMISSION-UNATTEN	345.00	138.00	24.90
12	JERUSALEM SUB	TRANSMISSION-UNATTEN	138.00	46.00	
13	LAMPO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
14	MATHINGTON SUB	TRANSMISSION-UNATTEN	138.00	46.00	13.20
15	MCFADDEN SUB	TRANSMISSION-UNATTEN	138.00	46.00	
16	MIDDLETON SUB	TRANSMISSION-UNATTEN	138.00	69.00	34.50
17	MIDVALLEY SUB	TRANSMISSION-UNATTEN	345.00	138.00	
18	MIDWAY CITY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
19	MINERAL PRODUCTS SUB	TRANSMISSION-UNATTEN	69.00	46.00	
20	MOAB SUB	TRANSMISSION-UNATTEN	138.00	69.00	
21	NEBO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
22	PAROWAN VALLEY SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
23	PAVANT SUB	TRANSMISSION-UNATTEN	230.00	46.00	
24	PINTO SUB	TRANSMISSION-UNATTEN	345.00	138.00	69.00
25	RED BUTTE SUB	TRANSMISSION-UNATTEN	230.00	138.00	
26	SIGURD SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
27	SMITHFIELD SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
28	SPANISH FORK SUB	TRANSMISSION-UNATTEN	345.00	138.00	46.00
29	ST GEORGE SUB	TRANSMISSION-UNATTEN	138.00	16.50	
30	THREE PEAKS SUB	TRANSMISSION-UNATTEN	345.00	138.00	
31	WEST CEDAR SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
32	TOTAL		8188.00	3331.77	711.88
33	Number of Substations-42				
34					
35	WASHINGTON				
36	ATTALIA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	BOWMAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	CASCADE KRAFT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	4.16
39	CLINTON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
40	DAYTON SUB	DISTRIBUTION-UNATTEN	69.00	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.
71	2					1
40	2					2
50	1					3
312	3					4
33	1					5
67	2					6
225	3					7
142	2					8
35	1					9
80	2					10
270	4					11
67	1					12
75	1					13
75	1					14
45	1					15
141	4					16
900	2					17
67	1					18
12	1					19
67	1					20
67	1					21
138	2					22
133	2					23
258	3					24
414	2					25
1124	6					26
63	2					27
1017	5					28
100	3	1				29
450	1					30
262	3					31
10831	100	2				32
						33
						34
						35
25	1					36
45	2					37
118	6					38
25	1					39
23	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	DODD ROAD SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
2	GRANDVIEW SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
3	HOPLAND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	NACHES	DISTRIBUTION-UNATTEN	116.00	12.00	
5	NOB HILL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
6	NORTH PARK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
7	ORCHARD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
8	PACIFIC SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
9	POMEROY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	PROSPECT POINT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	PUNKIN CENTER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
12	RIVER ROAD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
13	SELAH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	SULPHUR CREEK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
15	SUNNYSIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
16	TIETON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	34.50
17	TOPPENISH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	TOUCHET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	VOELKER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
20	WAITSBURG SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	WAPATO SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
22	WENAS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
23	WHITE SWAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
24	WILEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
25	TOTAL		2922.00	369.49	107.66
26	Number of Substations-29				
27					
28	CENTRAL SUB	T/D-UNATTENDED	69.00	12.47	
29	MILL CREEK SUB	T/D-UNATTENDED	69.00	12.47	
30	UNION GAP SUB	T/D-UNATTENDED	230.00	115.00	12.47
31	TOTAL		368.00	139.94	12.47
32	Number of Substations-3				
33					
34	OUTLOOK SUB	TRANSMISSION-UNATTEN	230.00	115.00	
35	PASCO SUB	TRANSMISSION-UNATTEN	115.00	69.00	7.20
36	POMONA HEIGHTS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
37	WALLA WALLA 230KV SUB	TRANSMISSION-UNATTEN	230.00	69.00	
38	WALLULA SUB	TRANSMISSION-UNATTEN	230.00	69.00	
39	WINE COUNTRY SUB	TRANSMISSION-UNATTEN	230.00	115.00	
40	TOTAL		1265.00	552.00	7.20

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/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)	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	4					1
42	2					2
50	2					3
25	1					4
42	2					5
45	2					6
50	2					7
28	3					8
9	1					9
40	2					10
20	2					11
51	4					12
45	2					13
25	1					14
45	2					15
29	2					16
50	2					17
6	1					18
25	1					19
9	1					20
45	2					21
25	2					22
22	2					23
45	2					24
1034	59					25
						26
						27
14	1					28
45	2					29
333	4					30
392	7					31
						32
						33
125	1					34
39	9					35
300	2					36
300	2					37
120	2					38
250	1					39
1134	17					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 2014/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	Number of Substations-6				
2					
3	WYOMING				
4	ANTELOPE MINE SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
5	ASTLE STREET	DISTRIBUTION-UNATTEN	34.50	13.20	
6	BAILEY DOME SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
7	BAR X SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
8	BIG MUDDY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	BIG PINEY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
10	BLACKS FORK SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
11	BRIDGER PUMP SUB	DISTRIBUTION-UNATTEN	230.00	34.50	13.20
12	BRYAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
13	BUFFALO TOWN SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
14	BYRON SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
15	CASSA SUB	DISTRIBUTION-UNATTEN	57.00	20.80	12.47
16	CENTER STREET SUB	DISTRIBUTION-UNATTEN	115.00	4.16	
17	CHAPMAN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	CHUKAR SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
19	CHURCH AND DWIGHT SUB	DISTRIBUTION-UNATTEN	34.50	0.48	
20	COKEVILLE SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
21	COLUMBIA-GENEVA SUB	DISTRIBUTION-UNATTEN	230.00	13.80	
22	COMMUNITY PARK SUB	DISTRIBUTION-UNATTEN	116.00	13.20	
23	CROOKS GAP SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
24	DEER CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	DJ COAL MINE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
26	DOUGLAS SUB	DISTRIBUTION-UNATTEN	57.00	2.30	
27	DRY FORK SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
28	ELK BASIN SUB	DISTRIBUTION-UNATTEN	34.50	7.20	
29	EMIGRANT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
30	EVANS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
31	EVANSTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
32	FORT CASPER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	FORT SANDERS SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
34	FRANNIE SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
35	FRONTIER SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
36	GARLAND SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
37	GLENDO SUB	DISTRIBUTION-UNATTEN	57.00	4.16	
38	GRASS CREEK SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
39	GREAT DIVIDE SUB	DISTRIBUTION-UNATTEN	115.00	34.50	
40	GREYBULL SUB	DISTRIBUTION-UNATTEN	34.50	4.16	

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (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
25	1					4
12	1					5
2	1					6
25	1					7
7	1					8
14	1					9
150	2					10
73	4					11
25	1					12
2	3					13
2	3					14
2	6	1				15
12	1					16
4	1					17
1	3					18
3	2					19
4	1					20
45	2					21
45	2					22
5	3					23
9	1					24
12	1					25
6	3					26
9	1					27
5	1					28
12	1					29
9	1					30
40	2					31
28	1					32
20	1					33
50	2					34
6	1					35
45	2					36
3	4					37
25	1					38
20	1					39
3	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	HANNA SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
2	JACKALOPE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
3	KEMMERER SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
4	KIRBY CREEK PUMPING STATION	DISTRIBUTION-UNATTEN	34.50	2.40	
5	KIRBY CREEK SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
6	LANDER SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
7	LARAMIE SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
8	LATHAM SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
9	LINCH SUB	DISTRIBUTION-UNATTEN	69.00	13.80	
10	LITTLE MOUNTAIN SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
11	LOVELL SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
12	MILL IRON SUB	DISTRIBUTION-UNATTEN	34.50	13.80	
13	MILLS SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
14	MURPHY DOME SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
15	NUGGETT SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
16	OPAL SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
17	ORIN SUB	DISTRIBUTION-UNATTEN	32.90	7.20	
18	ORPHA SUB	DISTRIBUTION-UNATTEN	57.00	7.20	
19	PARADISE SUB	DISTRIBUTION-UNATTEN	69.00	25.00	
20	PARCO SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
21	PINEDALE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
22	PITCHFORK SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
23	POISON SPIDER SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
24	POLECAT SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
25	RAINBOW SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
26	RAVEN SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
27	RED BUTTE SUB	DISTRIBUTION-UNATTEN	116.00	13.20	
28	REFINERY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
29	SAGE HILL SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
30	SHOSHONI SUB	DISTRIBUTION-UNATTEN	34.50	2.40	
31	SLATE CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	SOUTH CODY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
33	SOUTH ELK BASIN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
34	SOUTH TRONA SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
35	SPRING CREEK SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
36	SVILAR SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
37	TEN MILE STEP DOWN SUB	DISTRIBUTION-UNATTEN	34.50	12.50	
38	TEN MILE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
39	THERMOPOLIS TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
40	THUNDER CREEK SUB	DISTRIBUTION-UNATTEN	57.00	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 2014/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.
6	1					1
25	1					2
10	1					3
3	3					4
2	3					5
25	2					6
50	2					7
25	1					8
12	1					9
20	1					10
4	1					11
12	1	1				12
1	3					13
5	1					14
	1					15
8	1					16
1	1					17
3	3					18
30	1					19
5	1					20
20	1					21
17	9	2				22
3	1					23
1	3					24
12	1					25
200	2					26
50	2					27
45	2					28
6	1					29
2	3					30
1	1					31
14	3	1				32
2	6					33
150	2					34
25	1					35
2	3					36
5	1					37
12	1					38
5	1					39
9	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 2014/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	VETERANS SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
2	WELCH SUB	DISTRIBUTION-UNATTEN	57.00	2.40	
3	WERTZ-SINCLAIR SUB	DISTRIBUTION-UNATTEN	57.00	4.16	12.50
4	WEST ADAMS SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
5	WESTVACO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
6	WORLAND TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
7	WYOPO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
8	WYUTA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	TOTAL		7517.14	1306.83	38.17
10	Number of Substations-85				
11					
12	BUFFALO SUB	T/D-UNATTENDED	230.00	20.80	
13	ELK HORN SUB	T/D-UNATTENDED	115.00	12.50	
14	FIREHOLE SUB	T/D-UNATTENDED	230.00	34.50	
15	HILLTOP SUB	T/D-UNATTENDED	115.00	34.50	20.80
16	LABARGE SUB	T/D-UNATTENDED	69.00	24.90	
17	POINT OF ROCKS SUB	T/D-UNATTENDED	230.00	34.50	
18	RIVERTON 230 SUB	T/D-UNATTENDED	230.00	12.47	34.50
19	YELLOWCAKE SUB	T/D-UNATTENDED	230.00	34.50	
20	TOTAL		1449.00	208.67	55.30
21	Number of Substations-8				
22					
23	DAVE JOHNSTON PLANT/SUB	TRANSMISSION-ATTENDE	230.00	115.00	69.00
24	JIM BRIDGER 345KV SUB	TRANSMISSION-ATTENDE	345.00	230.00	34.50
25	NAUGHTON SUB	TRANSMISSION-ATTENDE	230.00	138.00	69.00
26	BAIROIL SUB	TRANSMISSION-UNATTEN	115.00	34.50	57.00
27	CASPER SUB	TRANSMISSION-UNATTEN	230.00	115.00	13.20
28	CHAPPELL CREEK SUB	TRANSMISSION-UNATTEN	230.00	69.00	
29	CHIMNEY BUTTE SUB	TRANSMISSION-UNATTEN	230.00	69.00	
30	FOOTE CREEK WIND FARM	TRANSMISSION-UNATTEN	230.00	34.50	
31	GLENDO AUTO SUB	TRANSMISSION-UNATTEN	69.00	57.00	
32	MANSFACE SUB	TRANSMISSION-UNATTEN	230.00	34.50	
33	MIDWEST SUB	TRANSMISSION-UNATTEN	230.00	69.00	34.50
34	MINERS SUB	TRANSMISSION-UNATTEN	230.00	34.50	9.70
35	MUSTANG SUB	TRANSMISSION-UNATTEN	230.00	115.00	
36	OREGON BASIN SUB	TRANSMISSION-UNATTEN	230.00	34.50	69.00
37	PLATTE SUB	TRANSMISSION-UNATTEN	230.00	115.00	34.50
38	RAILROAD SUB	TRANSMISSION-UNATTEN	230.00	138.00	
39	ROCK SPRINGS 230 SUB	TRANSMISSION-UNATTEN	230.00	34.50	
40	SAGE SUB	TRANSMISSION-UNATTEN	69.00	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 2014/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)	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	2					1
3	3					2
2	6					3
3	1					4
25	1					5
5	1					6
20	1	1				7
	1					8
1671	156	6				9
						10
						11
20	1					12
25	1					13
50	2					14
45	2	1				15
8	6					16
25	1					17
74	4					18
25	1					19
272	18	1				20
						21
						22
336	4					23
703	7					24
633	4					25
53	3					26
517	5					27
67	1					28
75	1					29
196	2					30
15	2					31
20	1					32
157	3					33
20	1					34
100	1					35
65	2					36
140	3					37
400	1					38
50	2					39
22	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 2014/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	THERMOPOLIS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
2	TOTAL		4048.00	1598.00	390.40
3	Number of Substations-19				
4					
5	CALIFORNIA				
6	Distribution - 42				
7	T/D - 2				
8	Transmission - 6				
9					
10	IDAHO				
11	Distribution - 65				
12	T/D - 5				
13	Transmission - 16				
14					
15	MONTANA				
16	Transmission - 3				
17					
18	OREGON				
19	Distribution - 180				
20	T/D - 12				
21	Transmission - 27				
22					
23	UTAH				
24	Distribution - 279				
25	T/D - 31				
26	Transmission - 42				
27					
28	WASHINGTON				
29	Distribution - 29				
30	T/D - 3				
31	Transmission - 6				
32					
33	WYOMING				
34	Distribution - 85				
35	T/D - 8				
36	Transmission - 19				
37					
38	ALL STATES				
39	Distribution - 680				
40	T/D - 61				

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 2014/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.
175	2					1
3744	46					2
						3
						4
						5
323						6
126						7
762						8
						9
						10
721						11
344						12
3701						13
						14
						15
200						16
						17
						18
4569						19
1337						20
7261						21
						22
						23
5470						24
7124						25
10831						26
						27
						28
1034						29
392						30
1134						31
						32
						33
1671						34
272						35
3744						36
						37
						38
13788						39
9596						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	Transmission - 119				
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					

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 2014/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)	
27633						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

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.: 23 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.: 24 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 2014/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Coal purchases and support services	Bridger Coal Company		158,300,630
3				
4	Coal mining services and information technology			
5	support services	Energy West Mining Company	151, 920	47,664,734
6				
7	Coal purchases	Trapper Mining Inc.	151	9,889,757
8				
9	Administrative and financial support services	Interwest Mining Company		777,745
10				
11	Administrative services under the IASA	BHE		3,738,954
12	Administrative services under the IASA	MEC		5,659,614
13	Administrative services under the IASA	Kern River Gas Transmission Company	107, 923	148,029
14				
15	Gas transportation services and equipment			
16	installation	Kern River Gas Transmission Company	501, 547, 571	3,187,452
17				
18	Relocation services	HomeServices of America, Inc.		1,300,079
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Information technology and administrative			
22	support services	Bridger Coal Company		857,074
23				
24	Financial support services and employee benefits	Interwest Mining Company	557,580,588,921	729,835
25				
26	Administrative services under the IASA	BHE		257,866
27	Administrative services under the IASA	MEC		2,318,734
28	Administrative services under the IASA	HomeServices of America, Inc.	557,560,920,921	322,965
29	Administrative services under the IASA	Kern River Gas Transmission Company		563,688
30	Administrative services under the IASA	Northern Natural Gas Company		426,990
31	Administrative services under the IASA	NV Energy, Inc.		1,225,925
32	Administrative services under the IASA	MEHC Canada Transmission		3,047,749
33	Administrative services under the IASA	BHE U.S. Transmission, LLC		933,555
34	Administrative services under the IASA	Central California Transco, LLC	560, 920, 921	331,413
35	Administrative services under the IASA	CE Casecnan	557	146,951
36				
37	Equipment transfer	CE Casecnan	101, 557	161,914
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Equipment transfer	MEC	513	335,467

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 2014/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3				
4	Rail services / right-of-way fees	BNSF Railway Company	151,507,567,589	39,212,561
5				
6	Banking services and financial transactions			
7	related to energy hedging activity	Wells Fargo & Company		1,912,391
8				
9	Banking services	U.S. Bancorp		815,272
10				
11	Computer hardware and software and computer			
12	systems consulting and maintenance services	International Business Machines Corp	107,165,921,935	2,112,921
13				
14	Rating agency fees	Moody's Investors Service	181, 186, 930.2	418,171
15				
16	Surety bond premium	National Indemnity Company	165	427,920
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
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31				
32				
33				
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40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				

Schedule Page: 429 Line No.: 2 Column: c

Accounts charged for Bridger Coal Company: 151, 501, 513 and 935.

Schedule Page: 429 Line No.: 2 Column: d

Non-power goods or services provided by Bridger Coal Company are as follows:

Coal purchases	$158,295,850
Support services	4,780
	$158,300,630

Schedule Page: 429 Line No.: 5 Column: d

Non-power goods or services provided by Energy West Mining Company are as follows:

Coal mining services	$47,447,164
Information technology support services	217,570
	$47,664,734

Under the terms of the coal mining agreement between PacifiCorp and Energy West Mining Company, Energy West Mining Company provides coal mining services to PacifiCorp that are absorbed directly by PacifiCorp.

Schedule Page: 429 Line No.: 9 Column: c

Accounts charged for Interwest Mining Company: 421, 426.1, 426.5, 557, 923 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 and financial 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 Berkshire Hathaway Energy Company ("BHE") 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 BHE organization.

Legislative and Regulatory: The Legislative and Regulatory allocation is used to allocate costs incurred by BHE'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 BHE 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 BHE: 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 BHE group. Such affiliate charges reflect the ability to obtain price discounts as a result of larger purchasing power.

Excluded from this page are reimbursements by BHE for payments made by PacifiCorp to its employees under the long-term incentive plan ("LTIP") that was maintained by BHE 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 BHE 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.: 16 Column: d

Non-power goods or services provided by Kern River Gas Transmission Company are as follows:

Gas transportation services	$3,173,351
Equipment installation	14,101
	$3,187,452

Schedule Page: 429 Line No.: 18 Column: c

Accounts charged for HomeServices of America, Inc.: 184, 501, 502, 506, 539, 548, 549, 557, 560, 561.2, 580, 581, 590, 592, 593, 597, 901, 902, 903, 908 and 921.

Schedule Page: 429 Line No.: 22 Column: c

Accounts charged for Bridger Coal Company: 232, 426.5, 501, 909 and 929.

Schedule Page: 429 Line No.: 24 Column: d

PacifiCorp provides Interwest Mining Company with financial support 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.: 26 Column: c

Accounts charged for BHE: 426.5, 557, 560, 580, 588, 908, 909, 920 and 921.

Schedule Page: 429 Line No.: 26 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 BHE 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.: 27 Column: c

Accounts charged for MEC: 426.5, 500, 506, 535, 557, 580, 588, 909, 920 and 921.

Schedule Page: 429 Line No.: 27 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 BHE 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.: 29 Column: c

Accounts charged for Kern River Gas Transmission Company: 426.5, 535, 557, 560, 580, 590, 920, 921 and 930.2.

Schedule Page: 429 Line No.: 30 Column: c

Accounts charged for Northern Natural Gas Company: 426.5, 557, 580, 920 and 921.

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 BHE 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: c

Accounts charged for NV Energy, Inc.: 557, 560, 561.5, 580, 588, 593, 597, 903, 908, 909, 920 and 921.

Schedule Page: 429 Line No.: 32 Column: b

This footnote applies to all occurrences of "MEHC Canada Transmission" on page 429. Complete name is MEHC Canada Transmission GP Corporation.

Schedule Page: 429 Line No.: 32 Column: c

Accounts charged for MEHC Canada Transmission: 426.5, 557, 560, 580, 920 and 921.

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 BHE 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: b

BHE U.S. Transmission, LLC was formerly known as MidAmerican Transmission, LLC.

Schedule Page: 429 Line No.: 33 Column: c

Accounts charged for BHE U.S. Transmission, LLC: 426.5, 557, 560, 580, 588, 920 and 921.

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 BHE 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.: 34 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 BHE 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.: 35 Column: b

This footnote applies to all occurrences of “CE Casecnan” on page 429. Complete name is CE Casecnan Water and Energy Company, Inc.

Schedule Page: 429 Line No.: 35 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 BHE 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.: 4 Column: d

Non-power goods or services provided by BNSF Railway Company are as follows:

Rail services	$39,180,671
Right-of-way fees	31,890
	$39,212,561

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.: 7 Column: c

Accounts charged for Wells Fargo & Company: 181, 228.3, 419, 427, 431, 501, 547, 560, 588, 903, 921 and 928.

Schedule Page: 429.1 Line No.: 7 Column: d

Non-power goods or services provided by Wells Fargo & Company are as follows:

Banking services	$1,782,491
Financial transactions related to energy hedging activity	129,900
	$1,912,391

Schedule Page: 429.1 Line No.: 9 Column: c

Accounts charged for U.S. Bancorp: 181, 419, 427, 431, 537, 557, 903, 920, 928 and 930.2.

Schedule Page: 429.1 Line No.: 12 Column: b

Complete name is International Business Machines Corporation.

Schedule	Page No.

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