e-FILING REPORT COVER SHEET

Send completed Cover Sheet and the Report in an email addressed to:
PUC.FilingCenter@state.or.us

REPORT NAME: Annual Report 2017 - FERC Form 1

COMPANY NAME: Pacific Power

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒No ☐Yes

If yes, please submit only the cover letter electronically. Submit confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

If known, please select designation: ☒RE (Electric) ☐RG (Gas) ☐RW (Water) ☐RO (Other)

Report is required by: ☒OAR OAR 860-027-0045
☐Statute
☐Order
☐Other

Is this report associated with a specific docket/case? ☐No ☒Yes

If yes, enter docket number: RE 68

List applicable Key Words for this report to facilitate electronic search:
Annual Report 2017 FERC Form 1

DO NOT electronically file with the PUC Filing Center:

- Annual Fee Statement form and payment remittance or
- OUS or RSPF Surcharge form or surcharge remittance or
- Any other Telecommunications Reporting or
- Any daily safety or safety incident reports or
- Accident reports required by ORS 654.715

Please file the above reports according to their individual instructions.

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

May 1, 2018

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, Oregon 97301-3398

Attn: Filing Center

RE: RE 68—PacifiCorp's FERC Form 1

PacifiCorp d/b/a Pacific Power submits for filing its FERC Form No. 1 for the year ended December 31, 2017.

It is respectfully requested that any information requests regarding this filing be addressed as follows:

By e-mail (preferred): datarequest@pacificorp.com

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

Informal questions may be directed to me at (503) 813-6583.

Sincerely,

Natasha Siores
Manager, Regulatory Affairs

Enclosure

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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

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** 2017/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/forms/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/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.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 1,168 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 168 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 2017/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 Mark Staehnke	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* (503) 813-5784	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name Nikki L. Kobliha 02 Title Vice President, CFO and Treasurer	03 Signature Nikki L. Kobliha (Signature on file)	04 Date Signed *(Mo, Da, Yr)* 04/13/2018

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 2017/Q4

LIST OF SCHEDULES (Electric Utility)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission 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		

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.

Nikki L. Kobliha, Vice President, Chief Financial Officer and Treasurer
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 electric utility company headquartered in Oregon that serves 1.9 million retail electric customers, including residential, commercial, industrial, irrigation and other customers in portions of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp is principally engaged in the business of generating, transmitting, distributing and selling electricity. In addition to retail sales, PacifiCorp buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants. 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.

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 2017/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., Mr. Walter Scott, Jr., a member of BHE's Board of Directors (along with family members and related or affiliated entities) and Mr. Gregory E. Abel, BHE's Executive Chairman, beneficially own 90.2%, 8.8% and 1.0%, respectively, of BHE's voting 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 2017/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 ceased mining operations in 2015.

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

Glenrock Coal Company ceased mining operations in 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. The Foundation's two 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 2017/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			
2	Chairman of the Board of Directors		
3	and Chief Executive Officer, PacifiCorp	Gregory E. Abel	
4	President and Chief Executive Officer, Pacific Power	Stefan A. Bird	346,000
5	President and Chief Executive Officer,		
6	Rocky Mountain Power	Cindy A. Crane	346,000
7	Vice President, Chief Financial Officer and Treasurer,		
8	PacifiCorp	Nikki L. Kobliha	217,079
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Schedule Page: 104 Line No.: 1 Column: c

PacifiCorp sets forth compensation information for its "named executive officers" for the year ended December 31, 2017, 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 C.F.R. §388.107(d)(f).

Schedule Page: 104 Line No.: 3 Column: b

Gregory E. Abel received no direct compensation from PacifiCorp. PacifiCorp reimbursed 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.

For further executive compensation information, refer to BHE's Annual Report on Form 10-K, for the year ended December 31, 2017.

On January 10, 2018, Gregory E. Abel resigned as PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer and William J. Fehrman was elected as PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer. For further information, refer to Item 13 in Important Changes During the Year, in this Form No. 1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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, 2017:	
2	Gregory E. Abel	
3	(Chairman of the Board of Directors and CEO, PacifiCorp)	666 Grand Avenue, 29th Floor, Des Moines, IA 50309
4	Stefan A. Bird	
5	(President and CEO, Pacific Power)	825 N.E. Multnomah Street, Suite 2000, Portland, OR 97232
6	Cindy A. Crane	
7	(President and CEO, Rocky Mountain Power)	1407 West North Temple, Suite 310, Salt Lake City, UT 84116
8	Nikki L. Kobliha	
9	(VP, CFO and Treasurer, PacifiCorp)	825 N.E. Multnomah Street, Suite 1900, Portland, OR 97232
10	Douglas L. Anderson	1111 South 103rd Street, Omaha, NE 68124
11	Patrick J. Goodman	666 Grand Avenue, 29th Floor, Des Moines, IA 50309
12	Natalie L. Hocken	825 N.E. Multnomah Street, Suite 2000, Portland, OR 97232
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Schedule Page: 105 Line No.: 2 Column: a

On January 10, 2018, Gregory E. Abel resigned as PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer and William J. Fehrman was elected as PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer. For further information, refer to Item 13 in Important Changes During the Year, in this Form No. 1.

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

Nikki L. Kobliha, Vice President and Chief Financial Officer, was elected as a director of PacifiCorp and appointed as PacifiCorp's Treasurer effective February 1, 2017. For further information, refer to Item 13 in Important Changes During the Year, in this Form No. 1.

Schedule Page: 105 Line No.: 10 Column: a

Douglas L. Anderson, Chief Corporate Counsel of Berkshire Hathaway Energy Company, resigned as a director of PacifiCorp effective January 13, 2017. For further information, refer to Item 13 in Important Changes During the Year, in this Form No. 1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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	20170330-5262	03/30/2017	ER17-1347		
2	20170515-5076	05/15/2017	ER11-3643		
3	20180323-5024	03/23/2018	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 (Revised Depreciation Rates 2017) to be effective 6/1/2017 under FERC Docket No. ER17-1347

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 FERC Docket No. ER11-3643

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

PacifiCorp's Volume No. 11 Open Access Transmission Tariff

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

PacifiCorp submits tariff filing per 35.19(a)(b): FERC Audit Refund Report to be effective N/A under FERC Docket No. 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 2017/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
1	200-201	Summary of Utility Plant & Accum. Prov. for Depr.	(c)	21
2	204-207	Electric Plant in Service	(b)	5
3	204-207	Electric Plant in Service	(g)	5
4	204-207	Electric Plant in Service	(b)	46
5	204-207	Electric Plant in Service	(g)	46
6	204-207	Electric Plant in Service	(b)	75
7	204-207	Electric Plant in Service	(g)	75
8	204-207	Electric Plant in Service	(b)	99
9	204-207	Electric Plant in Service	(g)	99
10	204-207	Electric Plant in Service	(b)	104
11	204-207	Electric Plant in Service	(g)	104
12	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	20
13	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	22
14	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	24
15	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	25
16	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	26
17	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	28
18	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	29
19	320-323	Electric Operation and Maintenance Expenses	(b)	185
20	320-323	Electric Operation and Maintenance Expenses	(b)	197
21	336-337	Depreciation and Amortization of Electric Plant	(b)	7
22	336-337	Depreciation and Amortization of Electric Plant	(d)	1
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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 the fee attached to the franchise agreement.

State	Effective Date	Expiration Date	Fee
California (1)			
None			
Idaho (2)			
Arco	05/03/2017	05/03/2037	—
Oregon (3)			
Bend	12/01/2017	03/31/2018	5.0%
Bonanza	04/11/2017	04/11/2027	5.0%
Corvallis	09/05/2017	09/05/2027	5.0%
Enterprise	07/07/2017	07/07/2027	7.0%
Lakeview	07/01/2017	06/30/2027	7.0%
Lostine	04/26/2017	04/26/2037	7.0%
Malin	06/29/2017	06/29/2027	5.0%
Maywood Park	09/05/2017	09/05/2037	7.0%
Metolius	06/28/2017	06/28/2037	5.0%
Millersburg	06/02/2017	06/02/2027	5.0%
Myrtle Creek	06/02/2017	06/02/2027	7.0%
Oakland	07/28/2017	07/28/2027	3.5%
Redmond	07/28/2017	07/28/2022	7.0%
Riddle	10/30/2017	10/30/2027	5.0%
Tangent	04/11/2017	04/11/2027	7.0%
Wallowa	09/15/2017	09/15/2037	3.5%
Utah (4)			
Alta	02/22/2017	02/22/2022	—
Cottonwood Heights	08/07/2017	08/07/2027	—
Farmington	01/01/2017	01/01/2022	—
Garfield County	04/03/2017	04/03/2037	—
Highland	07/28/2017	07/28/2027	—
Millcreek	08/04/2017	08/04/2037	—
Morgan County	03/27/2017	03/27/2027	—
Moroni	04/06/2017	04/06/2047	—
North Ogden	02/27/2017	02/27/2027	—
Paradise	05/01/2017	05/01/2037	—
Piute County	04/03/2017	04/03/2037	—
South Weber	06/27/2017	06/27/2027	—
Springdale	03/21/2017	03/21/2027	—
Uintah	09/07/2017	09/07/2027	—
Willard	02/02/2017	02/02/2027	—
Washington (4)			
Tieton	12/15/2017	12/15/2037	—
Wyoming (5)			
Casper	10/03/2017	12/31/2017	5.0%
Hanna	05/02/2017	05/02/2037	4.0%
Superior	01/20/2017	01/20/2042	3.0%

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

(5) In Wyoming, the first 1.0% of the franchise agreement fee is an expense to PacifiCorp and is embedded in rates. Any amount above the 1.0% is collected from customers and remitted directly to the applicable municipalities.

ITEM 2.

None.

ITEM 3.

In December 2016, PacifiCorp sold certain facilities located in San Juan County, Utah to the Navajo Tribal Utility Authority and recorded the sale in Account 102, Electric plant purchased or sold. In August 2017, the Federal Energy Regulatory Commission ("FERC") approved the journal entries required by the Uniform System of Accounts in Docket No. AC17-85-000 as filed by PacifiCorp in April 2017. Accordingly, PacifiCorp cleared Account 102, Electric plant purchased or sold and recorded the sale to the appropriate accounts. For further discussion, refer to Important Changes During the Year, Item 3, in PacifiCorp's Form No. 1 for the year ended December 31, 2016.

ITEM 4.

None.

ITEM 5.

In April 2017, PacifiCorp filed its 2017 Integrated Resource Plan ("IRP") with state commissions. The IRP includes investments in renewable energy resources, upgrades to PacifiCorp's existing wind fleet and energy efficiency measures to meet future customer needs. The estimated $3 billion plan set to be in place by 2020, also incorporates building an additional transmission line segment to facilitate the expansion of wind generation.

Refer to pages 424-425, Transmission lines added or altered during the year, in this Form No. 1 for additional information regarding transmission lines added or removed during the year ended December 31, 2017.

ITEM 6.

Short-term Debt

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt. As of December 31, 2017, PacifiCorp had $80 million of short-term debt outstanding at a weighted average interest rate of 1.83%.

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

- Idaho Public Utilities Commission ("IPUC") – Case No. PAC-E-16-03, Order No. 33476, dated March 4, 2016, effective through April 30, 2021.
- FERC – Docket No. ES16-3-000, dated December 4, 2015, letter order effective January 1, 2016 through December 31, 2017 and Docket No. ES18-3-000, dated December 20, 2017, letter order effective January 1, 2018 through December 31, 2019.
- Oregon Public Utility Commission ("OPUC") – Docket No. UF-4120, Order No. 98-158, dated April 16, 1998.
- Washington Utilities and Transportation Commission ("WUTC") – Docket No. UE-980404, dated April 8, 1998.

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

Long-term Debt

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $1.325 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:

- IPUC – Case No. PAC-E-14-05, Order No. 33083, dated July 29, 2014, effective through June 30, 2019.

- OPUC – Docket No. UF-4288, Order No. 14-268, dated July 22, 2014.

As of December 31, 2017, PacifiCorp had $216 million of letters of credit providing credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $213 million plus interest. These letters of credit were fully available as of December 31, 2017 and expire periodically through March 2019.

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, 2017, PacifiCorp estimated it would be able to issue up to $10.1 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.

For further discussion, refer to Note 7 of Notes to Financial Statements, in this Form No. 1.

ITEM 7.

None.

ITEM 8.

For the year ended December 31, 2017, PacifiCorp's bargaining unit wage scale changes were as follows:

Unions Represented	% Increase (1)	Effective Date(s)	Estimated Annual Financial Impact (2)
IBEW 57 Combustion Turbine (UT)	1.87%	01/26/2017	$ 59,745
IBEW 57 Laramie (WY)	1.03%	06/26/2017	5,682
IBEW 57 Power Delivery (UT, ID & WY)	1.83%	01/26/2017	1,459,183
IBEW 57 Power Supply (UT, ID & WY)	1.86%	01/26/2017	684,299
IBEW 125 (OR, WA)	1.89%	01/26/2017	514,899
IBEW 659 (OR, CA)	1.36%	04/26/2017	429,251
UWUA 127 (WY)	0.53%	09/26/2017	247,484
UWUA 197 (OR)	0.93%	09/06/2017	14,064
Total			$ 3,414,607

(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.

In March 2018, Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp, declared and paid a dividend of $18.0 million to PacifiCorp.

For the year ended December 31, 2017, Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp, paid a dividend of $27.0 million to PacifiCorp. In addition, Fossil Rock Fuels, LLC, a wholly owned subsidiary of PacifiCorp, distributed $5.2 million of dividends, consisting of $3.4 million unappropriated retained earnings distribution and $1.8 million return of capital to PacifiCorp.

Refer to page 429, Transactions with associated (affiliated) companies, in this Form No. 1 for information regarding related-party transactions.

There have been no officer, director or security holder transactions during the year ended December 31, 2017, other than preferred and common stock dividends declared and paid.

ITEM 11.

(Reserved.)

ITEM 12.

None.

ITEM 13.

On January 10, 2018, Gregory E. Abel resigned as PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer and William J. Fehrman was elected as PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer.

Nikki L. Kobliha, Vice President and Chief Financial Officer, was elected as a director of PacifiCorp and appointed as PacifiCorp's Treasurer effective February 1, 2017.

Douglas L. Anderson, Chief Corporate Counsel of Berkshire Hathaway Energy Company, resigned as a director of PacifiCorp effective January 13, 2017.

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, 2017, 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, 2017, 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 13, 2018

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	27,861,824,875	27,271,434,702
3	Construction Work in Progress (107)	200-201	676,995,960	655,882,614
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		28,538,820,835	27,927,317,316
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	10,301,826,872	9,693,954,266
6	Net Utility Plant (Enter Total of line 4 less 5)		18,236,993,963	18,233,363,050
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)		18,236,993,963	18,233,363,050
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		13,710,649	13,733,068
19	(Less) Accum. Prov. for Depr. and Amort. (122)		3,045,138	2,987,502
20	Investments in Associated Companies (123)		69,928	69,928
21	Investment in Subsidiary Companies (123.1)	224-225	186,007,067	200,451,214
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)		97,005,097	99,989,115
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		5,835,163	6,428,837
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		766,962	2,153,282
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		300,349,728	319,837,942
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		4,805,006	14,877,880
36	Special Deposits (132-134)		9,003,656	8,880,097
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		8,735,365	32,867
39	Notes Receivable (141)		2,730,593	2,458,965
40	Customer Accounts Receivable (142)		419,318,429	388,665,430
41	Other Accounts Receivable (143)		46,887,023	43,345,202
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		9,773,266	7,116,112
43	Notes Receivable from Associated Companies (145)		0	1,673,326
44	Accounts Receivable from Assoc. Companies (146)		73,462,590	24,733,333
45	Fuel Stock (151)	227	197,499,391	214,693,832
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	235,276,870	228,261,286
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		75,998,324	65,837,449
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		1,343,210	1,658,607
61	Accrued Utility Revenues (173)		255,154,000	274,945,000
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		8,996,262	20,541,832
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		766,962	2,153,282
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)		1,328,670,491	1,281,335,712
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		26,785,398	29,888,534
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	1,055,465,461	1,538,109,950
73	Prelim. Survey and Investigation Charges (Electric) (183)		510,567	978,052
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)		-23,327	-21,901
78	Miscellaneous Deferred Debits (186)	233	76,159,711	61,472,266
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)		5,139,793	5,779,388
82	Accumulated Deferred Income Taxes (190)	234	836,588,163	541,859,343
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,000,625,766	2,178,065,632
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		21,866,639,948	22,012,602,336

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

Represents amounts due from Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp, pursuant to an umbrella loan agreement for which the interest rate is determined daily and is equal to the lowest cost of short-term borrowings PacifiCorp could otherwise incur externally. At December 31, 2016, the interest rate on the outstanding loan balance was 0.96%.

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

As of December 31, 2017, Account 146, Accounts receivable from associated companies, included $71,800,895 of income taxes receivable from Berkshire Hathaway Energy Company, PacifiCorp’s indirect parent company.

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

As of December 31, 2016, Account 146, Accounts receivable from associated companies, included $18,474,407 of income taxes receivable from Berkshire Hathaway Energy Company, PacifiCorp’s indirect parent company.

Schedule Page: 110 Line No.: 77 Column: c

The credit balance represents a timing difference between work incurred and advances received from customers.

Schedule Page: 110 Line No.: 77 Column: d

The credit balance represents a timing difference between work incurred and advances received from customers.

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	2,984,484,352	2,803,600,023
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	104,337,295	116,946,442
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)	-15,266,178	-12,594,198
16	Total Proprietary Capital (lines 2 through 15)		7,554,861,860	7,389,258,658
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	7,041,475,000	7,093,197,000
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)		47,048	58,074
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		10,464,531	11,483,368
24	Total Long-Term Debt (lines 18 through 23)		7,031,057,517	7,081,771,706
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		18,233,170	21,090,034
27	Accumulated Provision for Property Insurance (228.1)		6,095,041	0
28	Accumulated Provision for Injuries and Damages (228.2)		13,502,436	-1,507,842
29	Accumulated Provision for Pensions and Benefits (228.3)		167,737,085	364,084,317
30	Accumulated Miscellaneous Operating Provisions (228.4)		34,624,221	36,933,054
31	Accumulated Provision for Rate Refunds (229)		5,099,189	0
32	Long-Term Portion of Derivative Instrument Liabilities		24,804,055	25,100,250
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		214,900,520	214,786,003
35	Total Other Noncurrent Liabilities (lines 26 through 34)		484,995,717	660,485,816
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		80,000,000	270,000,000
38	Accounts Payable (232)		436,508,588	377,797,383
39	Notes Payable to Associated Companies (233)		9,005,123	0
40	Accounts Payable to Associated Companies (234)		146,997,905	148,165,802
41	Customer Deposits (235)		47,576,366	45,984,008
42	Taxes Accrued (236)	262-263	46,331,988	42,398,601
43	Interest Accrued (237)		119,870,086	118,648,155
44	Dividends Declared (238)		40,475	40,475
45	Matured Long-Term Debt (239)		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 2017/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)		19,610,180	20,497,658
48	Miscellaneous Current and Accrued Liabilities (242)		83,984,662	76,469,862
49	Obligations Under Capital Leases-Current (243)		2,004,747	5,938,747
50	Derivative Instrument Liabilities (244)		38,902,575	28,451,943
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		24,804,055	25,100,250
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,006,028,640	1,109,292,384
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		36,720,467	32,324,218
57	Accumulated Deferred Investment Tax Credits (255)	266-267	15,670,323	18,259,559
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	204,360,620	176,253,764
60	Other Regulatory Liabilities (254)	278	2,101,876,268	115,848,090
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	185,416,334	306,993,377
63	Accum. Deferred Income Taxes-Other Property (282)		2,972,737,275	4,518,977,533
64	Accum. Deferred Income Taxes-Other (283)		272,914,927	603,137,231
65	Total Deferred Credits (lines 56 through 64)		5,789,696,214	5,771,793,772
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		21,866,639,948	22,012,602,336

Schedule Page: 112 Line No.: 28 Column: d

As of December 31, 2016, Account 228.2, Accumulated provision for injuries and damages, included expected insurance recoveries.

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

Represents amounts due to Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp, pursuant to an umbrella loan agreement for which the interest rate is determined daily and is equal to the lowest cost of short-term borrowings PacifiCorp could otherwise incur externally. At December 31, 2017, the interest rate on the outstanding loan balance was 1.83%.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	5,242,965,626	5,201,080,711		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,425,109,768	2,446,363,957		
5	Maintenance Expenses (402)	320-323	400,069,497	399,131,517		
6	Depreciation Expense (403)	336-337	727,650,690	709,094,974		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	41,396,782	38,577,000		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	5,083,195	5,083,195		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		150,507	150,507		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	196,653,710	189,632,535		
15	Income Taxes - Federal (409.1)	262-263	237,993,786	199,451,072		
16	- Other (409.1)	262-263	40,955,946	36,762,420		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	1,065,406,630	749,775,939		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	987,845,373	645,592,915		
19	Investment Tax Credit Adj. - Net (411.4)	266	-3,698,228	-4,341,401		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		178	188		
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)		4,148,926,732	4,124,088,612		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,094,038,894	1,076,992,099		

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 2017/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
						1
5,242,965,626	5,201,080,711					2
						3
2,425,109,768	2,446,363,957					4
400,069,497	399,131,517					5
727,650,690	709,094,974					6
						7
41,396,782	38,577,000					8
5,083,195	5,083,195					9
						10
						11
150,507	150,507					12
						13
196,653,710	189,632,535					14
237,993,786	199,451,072					15
40,955,946	36,762,420					16
1,065,406,630	749,775,939					17
987,845,373	645,592,915					18
-3,698,228	-4,341,401					19
						20
						21
178	188					22
						23
						24
4,148,926,732	4,124,088,612					25
1,094,038,894	1,076,992,099					26

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 2017/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		1,094,038,894	1,076,992,099		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		3,280,869	1,554,611		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		3,080,394	1,617,614		
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		110,838	72,626		
35	Nonoperating Rental Income (418)		263,039	198,175		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	17,814,281	17,851,891		
37	Interest and Dividend Income (419)		7,989,045	9,486,317		
38	Allowance for Other Funds Used During Construction (419.1)		19,939,361	27,450,081		
39	Miscellaneous Nonoperating Income (421)		2,280,438	1,157,759		
40	Gain on Disposition of Property (421.1)		299,714	1,777,232		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		48,675,515	57,785,826		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		53,895	29,654		
44	Miscellaneous Amortization (425)		1,328,501	1,344,292		
45	Donations (426.1)		3,297,350	2,317,647		
46	Life Insurance (426.2)		-8,228,460	-6,068,477		
47	Penalties (426.3)		-22,896	25,500		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,427,597	1,710,497		
49	Other Deductions (426.5)		6,007,522	13,228,391		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		3,863,509	12,587,504		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	314,104	280,899		
53	Income Taxes-Federal (409.2)	262-263	997,900	-41,603,403		
54	Income Taxes-Other (409.2)	262-263	135,598	-5,653,211		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	90,136,224	148,815,498		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	88,460,786	103,275,215		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		373,166	311,468		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		2,749,874	-1,746,900		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		42,062,132	46,945,222		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		360,014,410	359,474,830		
63	Amort. of Debt Disc. and Expense (428)		4,121,973	4,142,215		
64	Amortization of Loss on Reaquired Debt (428.1)		639,595	667,665		
65	(Less) Amort. of Premium on Debt-Credit (429)		11,026	11,026		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		24,990	9,137		
68	Other Interest Expense (431)		14,124,383	12,460,408		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		11,250,383	15,316,302		
70	Net Interest Charges (Total of lines 62 thru 69)		367,663,942	361,426,927		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		768,437,084	762,510,394		
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)		768,437,084	762,510,394		

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, 2017 and 2016, depreciation expense associated with transportation equipment was $15,045,329 and $14,483,977, 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, 2017 and 2016, payroll taxes were $39,077,979 and $38,739,981, 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 2017/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		2,778,346,006	2,861,256,994
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		750,622,803	744,658,503
17	Appropriations of Retained Earnings (Acct. 436)			
18	Appropriation of excess earnings at certain hydroelectric generating facilities	215.1	-10,591,983	(8,918,577)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-10,591,983	(8,918,577)
23	Dividends Declared-Preferred Stock (Account 437)			
24	Preferred Stock, various series and rates	238	-161,902	(161,902)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-161,902	(161,902)
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock	238	-600,000,000	(875,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-600,000,000	(875,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings	216.1	30,423,428	56,510,988
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,948,638,352	2,778,346,006
	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 2017/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)		35,846,000	25,254,017
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		35,846,000	25,254,017
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,984,484,352	2,803,600,023
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		116,946,442	155,605,539
50	Equity in Earnings for Year (Credit) (Account 418.1)		17,814,281	17,851,891
51	(Less) Dividends Received (Debit)			
52	Transfers to/from Unappropriated Retained Earnings (Account 216)		-30,423,428	(56,510,988)
53	Balance-End of Year (Total lines 49 thru 52)		104,337,295	116,946,442

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

Outstanding shares of preferred stock as of December 31, 2017 and dividends on preferred stock during the year ended December 31, 2017 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, 2016 and dividends on preferred stock during the year ended December 31, 2016 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.: 37 Column: c

During the year ended December 31, 2017, paid distributions from subsidiaries of PacifiCorp were as follows:

Pacific Minerals, Inc.	$27,000,000
Fossil Rock Fuels, LLC	3,394,000
Trapper Mining Inc.	29,428
	$30,423,428

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

During the year ended December 31, 2016, paid distributions from subsidiaries of PacifiCorp were as follows:

Pacific Minerals, Inc.	$55,000,000
Fossil Rock Fuels, LLC	1,430,267
Trapper Mining Inc.	80,721
	$56,510,988

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 2017/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)	768,437,084	762,510,394
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	748,385,225	725,220,132
5	Amortization:	47,834,694	45,030,703
6			
7			
8	Deferred Income Taxes (Net)	79,236,695	149,723,307
9	Investment Tax Credit Adjustment (Net)	-4,071,394	-4,652,869
10	Net (Increase) Decrease in Receivables	15,260,809	-26,219,152
11	Net (Increase) Decrease in Inventory	10,178,857	-20,966,443
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-34,768,339	-166,766,587
14	Net (Increase) Decrease in Other Regulatory Assets	-8,349,118	105,266,641
15	Net Increase (Decrease) in Other Regulatory Liabilities	26,841,343	16,847,524
16	(Less) Allowance for Other Funds Used During Construction	19,939,361	27,450,081
17	(Less) Undistributed Earnings from Subsidiary Companies	-12,609,147	-38,659,097
18	Amounts Due To/From Affiliates (Net)	-51,495,765	5,365,962
19	Derivative Collateral (Net)	-5,600,000	6,300,000
20	Other Operating Activities:	7,874,142	4,212,127
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,592,434,019	1,613,080,755
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-797,523,778	-930,851,398
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	-28,783,864	-27,450,081
31	Other (provide details in footnote):		-301,580
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-768,739,914	-903,702,897
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	1,680,014	8,657,775
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		-1,672,000
40	Contributions and Advances from Assoc. and Subsidiary Companies	3,507,000	2,033,659
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other Investing Activities:	9,546,359	-438,149
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-754,006,541	-895,121,612
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		249,910,111
67	Other (provide details in footnote):	9,000,000	
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	9,000,000	249,910,111
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-51,722,000	-66,142,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-1,299,802	-15,921,244
77	Repayment of Capital Lease Obligations	-5,689,206	-1,641,181
78	Net Decrease in Short-Term Debt (c)	-189,924,944	
79			
80	Dividends on Preferred Stock	-161,902	-161,902
81	Dividends on Common Stock	-600,000,000	-875,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-839,797,854	-708,956,216
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-1,370,376	9,002,927
87			
88	Cash and Cash Equivalents at Beginning of Period	14,910,747	5,907,820
89			
90	Cash and Cash Equivalents at End of period	13,540,371	14,910,747

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

During the years ended December 31, 2017 and 2016, depreciation expense associated with transportation equipment and capital lease assets were $20,734,535 and $16,125,158, respectively.

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

	Years Ended December 31, 2017	2016
Amortization of software development & other intangibles	$ 42,725,283	$ 39,921,292
Amortization of electric plant acquisition adjustments	5,083,195	5,083,195
Amortization of a regulatory asset	26,216	26,216
	$ 47,834,694	$ 45,030,703

Schedule Page: 120 Line No.: 16 Column: b

Includes an adjustment of $8,844,503 to Account 419.1, Allowance for other funds used during construction, per FERC Docket No. FA16-4-000.

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

	Years Ended December 31, 2017	2016
Depreciation and depletion included in cost of fuel	$ 2,039,189	$ 2,043,175
Net gain on sale of property	(282,093)	(1,822,720)
Write-off of assets under construction	8,006,117	7,170,982
Noncash adjustment to allowance for borrowed funds used during construction, per FERC Docket No. FA16-4-000	4,429,935	-
Change in corporate owned life insurance cash surrender value	(8,195,039)	(6,044,333)
Amortization of debt issuance expenses and bond discount/premium	4,110,947	4,131,189
Changes in derivative contract assets/liabilities, net	(881,283)	-
Other	(1,353,631)	(1,266,166)
	$ 7,874,142	$ 4,212,127

Schedule Page: 120 Line No.: 31 Column: c

During the year ended December 31, 2016, the acquisition of certain transmission facilities and associated electric plant from Flowell Electric Association, Inc., subject to Commission approval, were as follows:

Account 101, Electric plant in service	$ (387,367)
Account 108, Accumulated provision for depreciation of electric utility plant	85,787
	$ (301,580)

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, 2017	2016
Other investments/special funds	$ 714,850	$ 1,818,766
Temporary facilities	-	45,628
Restricted cash	1,138,310	141,908
Investment in long-term incentive plan securities	(2,174,547)	(2,444,451)
Investment in supplemental executive retirement plan	9,867,746	-
	$ 9,546,359	$ (438,149)

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

Net proceeds of affiliate borrowing from subsidiary company, Pacific Minerals, Inc.

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

	Years Ended December 31, 2017	2016
Net repayments of affiliate borrowing from subsidiary company, Pacific Minerals, Inc.	$ -	$ (15,237,000)
Other deferred financing and long-term debt redemption costs	(1,299,802)	(684,244)
	$ (1,299,802)	$ (15,921,244)

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, which includes PacifiCorp and its subsidiaries, is a United States regulated electric utility company serving retail customers, including residential, commercial, industrial, irrigation and other customers in portions 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. AC11-132-000, 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. AC11-132-000, 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 net non-current assets or liabilities 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 other special deposits on the Comparative Balance Sheet. Total cash and cash equivalents were as follows as of December 31 (in millions):

	2017	2016
Cash (131)	$ 5	$ 15
Temporary cash investments (136)	9	—
Total cash and cash equivalents	$ 14	$ 15

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, 2017 and 2016, PacifiCorp had no unrealized gains and losses on available-for-sale securities. Trading securities are carried at fair value with realized and unrealized gains and losses recognized in earnings.

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):

	2017	2016
Beginning balance	$ 7	$ 7
Charged to operating costs and expenses, net	15	12
Write-offs, net	(12)	(12)
Ending balance	$ 10	$ 7

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 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 liabilities or assets. For a derivative contract not probable of inclusion in rates, changes in the fair value are recognized in earnings.

Inventories

Inventories consist mainly of materials and supplies totaling $235 million and $228 million as of December 31, 2017 and 2016, respectively, and fuel stocks, totaling $198 million and $215 million as of December 31, 2017 and 2016, respectively. Inventories are stated at the lower of average cost or net realizable value.

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 regulated 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.

Impairment

PacifiCorp evaluates long-lived assets for impairment, including utility plant, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the carrying value is written down to the estimated fair value and any resulting impairment loss is reflected on the Statement of Income. The impacts of regulation are considered when evaluating the carrying value of regulated assets.

Revenue Recognition

Revenue is recognized as electricity is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2017 and 2016, unbilled revenue was $255 million and $275 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. On December 22, 2017, the Tax Cuts and Jobs Act ("2017 Tax Reform") was signed into law which, among other items, reduces the federal corporate tax rate from 35% to 21%. Changes in deferred income tax assets and liabilities that are associated with income tax benefits and expense for the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences that PacifiCorp deems probable to be passed on to its customers in most state jurisdictions are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. 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 March 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2017-07, which amends FASB Accounting Standards Codification ("ASC") Topic 715, "Compensation - Retirement Benefits." The amendments in this guidance require that an employer disaggregate the service cost component from the other components of net benefit cost and report the service cost component in the same line item as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the statement of operations separately from the service cost component and outside the subtotal of operating income. Additionally, the guidance only allows the service cost component to be eligible for capitalization when applicable. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted. This guidance must be adopted retrospectively for the presentation of the service cost component and the other components of net benefit cost in the statement of operations and prospectively for the capitalization of the service cost component in the balance sheet. PacifiCorp adopted this guidance on January 1, 2018 and the adoption will not have a material impact on its financial statements and disclosures included within Notes to Financial Statements. In accordance with FERC Order No. AI18-1-000, PacifiCorp will disclose any changes in accounting practice in response to this guideline in its respective FERC Forms filed to the Commission quarterly and annually, within the Notes to the Financial Statements. Disclosures should include potential rate impacts resulting from these changes, including the effects on rate base and current period expenses. Jurisdictional entities should also make similar disclosures on future rate filings, as applicable.

In November 2016, the FASB issued ASU No. 2016-18, which amends FASB ASC Subtopic 230-10, "Statement of Cash Flows - Overall." The amendments in this guidance require that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. PacifiCorp adopted this guidance on January 1, 2018 and the adoption will not have a material impact on its financial statements and disclosures included within Notes to Financial Statements.

In August 2016, the FASB issued ASU No. 2016-15, which amends FASB ASC Topic 230, "Statement of Cash Flows." The amendments in this guidance address the classification of eight specific cash flow issues within the statement of cash flows with the objective of reducing the existing diversity in practice. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. PacifiCorp adopted this guidance January 1, 2018 and the adoption of this guidance will not have a material impact on the financial statements.

In February 2016, the FASB issued ASU No. 2016-02, which creates FASB ASC Topic 842, "Leases" and supersedes Topic 840 "Leases." This guidance increases transparency and comparability among entities by recording lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. A lessee should recognize in the balance sheet a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from previous guidance. This guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted, and is required to be adopted using a modified retrospective approach. PacifiCorp plans to adopt this guidance effective January 1, 2019 and is currently evaluating the impact on its financial statements and disclosures included within Notes to Financial Statements.

In January 2016, the FASB issued ASU No. 2016-01, which amends FASB ASC Subtopic 825-10, "Financial Instruments - Overall." The amendments in this guidance address certain aspects of recognition, measurement, presentation and disclosure of financial instruments including a requirement that all investments in equity securities that do not qualify for equity method accounting or result in consolidation of the investee be measured at fair value with changes in fair value recognized in net income. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption not permitted, and is required to be adopted prospectively by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. PacifiCorp adopted this guidance on January 1, 2018 and the adoption will not have a material impact on its financial statements and disclosures included within Notes to Financial Statements.

In May 2014, the FASB issued ASU No. 2014-09, which creates FASB 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. In August 2015, the FASB issued ASU No. 2015-14, which defers the effective date of ASU No. 2014-09 one year to interim and annual reporting periods beginning after December 15, 2017. During 2016 and 2017, the FASB issued several ASUs that clarify the implementation guidance for ASU No. 2014-09 but do not change the core principle of the guidance. 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 adopted this guidance on January 1, 2018 under the modified retrospective method and the adoption will not have an impact on its financial statements but will increase the disclosures included within Notes to Financial Statements. The timing and amount of revenue recognized after adoption of the new guidance will not be different than before as a majority of revenue is recognized when PacifiCorp has the right to invoice as it corresponds directly with the value to the customer of PacifiCorp's performance to date. PacifiCorp plans to quantitatively disaggregate revenue in the required financial statement footnote by customer class.

Subsequent Events

PacifiCorp has evaluated the impact of events occurring after December 31, 2017 up to February 23, 2018, the date that PacifiCorp's GAAP financial statements were filed with the United States Securities and Exchange Commission and has updated such evaluation for disclosure purposes through April 13, 2018. 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 2.9% for the years ended December 31, 2017 and 2016, respectively.

(4) Jointly Owned Utility Facilities

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

The amounts shown in the table below represent PacifiCorp's share in each jointly owned facility as of December 31, 2017 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4	67%	$ 1,442	$ 621	$ 12
Hunter No. 1	94	474	168	7
Hunter No. 2	60	297	103	1
Wyodak	80	469	211	1
Colstrip Nos. 3 and 4	10	247	133	4
Hermiston	50	180	81	1
Craig Nos. 1 and 2	19	365	235	3
Hayden No. 1	25	74	35	—
Hayden No. 2	13	43	22	—
Foote Creek	79	40	26	—
Transmission and distribution facilities	Various	794	286	67
Total		$ 4,425	$ 1,921	$ 96

(5) Regulatory Matters

Regulatory Assets

PacifiCorp had regulatory assets not earning a return on investment of $584 million and $1.013 billion as of December 31, 2017 and 2016, respectively.

Utah Mine Disposition

In December 2014, PacifiCorp filed an advice letter with the California Public Utility Commission ("CPUC") to request approval to sell certain Utah mining assets and to establish memorandum accounts to track the costs associated with the Utah Mine Disposition for future recovery. In July 2015, the CPUC Energy Division issued a letter requiring PacifiCorp to file a formal application for approval of the sale of certain Utah mining assets. Accordingly, in September 2015, PacifiCorp filed an application with the CPUC. On February 6, 2017, a joint motion was filed with the CPUC seeking approval of a settlement agreement reached by PacifiCorp and all other parties. The agreement states, among other things, that the decision to sell certain Utah mining assets is in the public interest. Parties also reserve their rights to additional testimony, briefs, and hearings to the extent the CPUC determines that additional California Environmental Quality Act proceedings are necessary. A CPUC decision on the joint motion and settlement agreement is expected in 2018.

(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):

2017:		
Credit facilities	$	1,000
Less:		
Short-term debt		(80)
Tax-exempt bond support		(130)
Net credit facilities	$	790
2016:		
Credit facilities	$	1,000
Less:		
Short-term debt		(270)
Tax-exempt bond support		(142)
Net credit facilities	$	588

PacifiCorp has a $600 million unsecured credit facility expiring in June 2020 with two one-year extension options subject to lender consent and a $400 million unsecured credit facility expiring in June 2020 with a one-year extension option subject to lender consent. 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 variable interest rates based on the Eurodollar 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, 2017 and 2016, the weighted average interest rate on commercial paper borrowings outstanding was 1.83% and 0.96%, respectively. 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, 2017 and 2016, PacifiCorp had $230 million and $269 million, respectively, of fully available letters of credit issued under committed arrangements. As of December 31, 2017 and 2016, $216 million and $255 million, respectively, of these letters of credit, support PacifiCorp's variable-rate tax-exempt bond obligations and expire through March 2019 and $14 million support certain transactions required by third parties 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.

PacifiCorp currently has regulatory authority from the Oregon Public Utility Commission and the Idaho Public Utilities Commission to issue an additional $1.325 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 to issue up to $1.325 billion additional first mortgage bonds through January 2019.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $27 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2017.

PacifiCorp has entered into long-term agreements that qualify as capital leases and expire at various dates through March 2035 for transportation services, a power purchase agreement 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 $20 million and $27 million as of December 31, 2017 and 2016, respectively, were included in net utility plant in the Comparative Balance Sheet.

As of December 31, 2017, the annual principal maturities of long-term debt and total capital lease obligations for 2018 and thereafter are as follows (in millions):

	Long-term Debt	Capital Lease Obligations	Total
2018	$ 586	$ 4	$ 590
2019	350	4	354
2020	38	3	41
2021	420	6	426
2022	605	2	607
Thereafter	5,042	18	5,060
Total	7,041	37	7,078
Unamortized discount	(10)	—	(10)
Amounts representing interest	—	(17)	(17)
Total	$ 7,031	$ 20	$ 7,051

(8) Income Taxes

Tax Cuts and Jobs Act

The 2017 Tax Reform impacts many areas of income tax law. The most material items include the reduction of the federal corporate tax rate from 35% to 21% effective January 1, 2018 and limitations on bonus depreciation for utility property. GAAP requires the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate change was enacted. As a result of the 2017 Tax Reform, PacifiCorp reduced deferred income tax liabilities $2,357 million. As it is probable the change in deferred taxes will be passed back to customers through regulatory mechanisms, PacifiCorp increased net regulatory liabilities by $2,358 million.

In December 2017, the Securities and Exchange Commission issued Staff Accounting Bulletin ("SAB") 118 to assist in the implementation process of the 2017 Tax Reform by allowing for calculations to be classified as provisional and subject to remeasurement. There are three different classifications for the accounting: (1) completed, (2) not complete but reasonably estimable or (3) not complete and amounts are not reasonably estimable. PacifiCorp has recorded the impacts of the 2017 Tax Reform and believes all the impacts to be complete with the exception of interpretations of the bonus depreciation rules. PacifiCorp has determined the amounts recorded and the interpretations relating to this item to be provisional and subject to remeasurement during the measurement period upon obtaining the necessary additional information to complete the accounting. PacifiCorp believes its interpretations for bonus depreciation to be reasonable, however, as the guidance is clarified estimates may change. The accounting is estimated to be completed by December 2018.

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

	2017	2016
Current:		
Federal	$ 239	$ 158
State	41	31
Total	280	189
Deferred:		
Federal	63	129
State	16	21
Total	79	150
Investment tax credits	(4)	(5)
Total income tax expense	$ 355	$ 334

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:

	2017	2016
Federal statutory income tax rate	35%	35%
State income taxes, net of federal income tax benefit	3	3
Federal income tax credits	(5)	(6)
Other	(1)	(2)
Effective income tax rate	32%	30%

Income tax credits relate primarily to production tax credits earned by PacifiCorp's wind-powered generating facilities. Federal renewable electricity production tax credits are earned as energy from qualifying wind-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Wind-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in-service.

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

	2017	2016
Deferred income tax assets:		
Regulatory liabilities	$ 517	$ 44
Employee benefits	84	202
Derivative contracts and unamortized contract values	48	67
State carryforwards	83	69
Asset retirement obligations	50	78
Other	54	82
	836	542
Deferred income tax liabilities:		
Property, plant and equipment	(3,157)	(4,826)
Regulatory assets	(261)	(586)
Other	(12)	(17)
	(3,430)	(5,429)
Net deferred income tax liability	$ (2,594)	$ (4,887)

The following table provides PacifiCorp's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2017 (in millions):

	State
Net operating loss carryforwards	$ 1,356
Deferred income taxes on net operating loss carryforwards	$ 63
Expiration dates	2018 - 2032
Tax credit carryforwards	$ 20
Expiration dates	2018- indefinite

The United States Internal Revenue Service has closed its examination of PacifiCorp's income tax returns through December 31, 2009. The statute of limitations for PacifiCorp's state income tax returns have expired through December 31, 2009, with the exception of California and Utah, for which the statute of limitations have expired through March 31, 2006. The statute of limitations expiring for state filings may not preclude the state from adjusting the state net operating loss carryforward utilized in a year for which the examination is not closed.

(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 previously contributed to a multiemployer pension plan for benefits offered to certain bargaining units.

Pension and Other Postretirement Benefit Plans

PacifiCorp's pension plans include non-contributory defined benefit pension plans, collectively 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. 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 earned benefits based on a cash balance formula through December 31, 2016. Effective January 1, 2017, non-union employee participants with a cash balance benefit in the Retirement Plan are no longer eligible to receive pay credits in their 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. The SERP was closed to new participants as of March 21, 2006 and froze future accruals for active participants as of December 31, 2014.

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

Net Periodic Benefit Cost

For purposes of calculating the expected return on plan assets, a market-related value is used. The market-related value of plan assets is calculated by spreading the difference between expected and actual investment returns over a five-year period beginning after the first year in which they occur.

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

	Pension		Other Postretirement	
	2017	**2016**	**2017**	**2016**
Service cost	$ —	$ 4	$ 2	$ 2
Interest cost	49	54	14	15
Expected return on plan assets	(72)	(75)	(21)	(21)
Net amortization	14	34	(6)	(5)
Net period benefit cost (credit)	$ (9)	$ 17	$ (11)	$ (9)

Funded Status

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

	Pension		Other Postretirement	
	2017	**2016**	**2017**	**2016**
Plan assets at fair value, beginning of year	$ 999	$ 1,043	$ 302	$ 305
Employer contributions	54	5	1	1
Participant contributions	—	—	7	6
Actual return on plan assets	166	51	49	17
Benefits paid	(108)	(100)	(27)	(27)
Plan assets at fair value, end of year	$ 1,111	$ 999	$ 332	$ 302

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

	Pension		Other Postretirement	
	2017	2016	2017	2016
Benefit obligation, beginning of year	$ 1,276	$ 1,289	$ 358	$ 362
Service cost	—	4	2	2
Interest cost	49	54	14	15
Participant contributions	—	—	7	6
Actuarial (gain) loss	34	29	(23)	—
Benefits paid	(108)	(100)	(27)	(27)
Benefit obligation, end of year	$ 1,251	$ 1,276	$ 331	$ 358
Accumulated benefit obligation, end of year	$ 1,251	$ 1,276		

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	
	2017	2016	2017	2016
Plan assets at fair value, end of year	$ 1,111	$ 999	$ 332	$ 302
Less - Benefit obligation, end of year	1,251	1,276	331	358
Funded status	$ (140)	$ (277)	$ 1	$ (56)
Amounts recognized on the Comparative Balance Sheet:				
Other special funds	$ —	$ —	$ 1	$ —
Miscellaneous current and accrued liabilities	(4)	(5)	—	—
Accumulated provision for pension and benefits(1)	(136)	(272)	—	(56)
Amounts recognized	$ (140)	$ (277)	$ 1	$ (56)

(1) The accumulated provision for pension and benefits for 2017 includes $5 million of pension assets.

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 $60 million and $55 million as of December 31, 2017 and 2016, respectively. These assets are not included in the plan assets in the above table, but are reflected in temporary cash investments, totaling $9 million and $- million as of December 31, 2017 and 2016, respectively, and other investments, totaling $51 million and $55 million as of December 31, 2017 and 2016, respectively, 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	
	2017	2016	2017	2016
Net loss (gain)	$ 442	$ 518	$ (12)	$ 39
Prior service credit	—	—	(6)	(13)
Regulatory deferrals	(4)	(7)	7	8
Total	$ 438	$ 511	$ (11)	$ 34

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2017 and 2016 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss	Total
Pension			
Balance, December 31, 2015	$ 473	$ 19	$ 492
Net loss arising during the year	51	2	53
Net amortization	(33)	(1)	(34)
Total	18	1	19
Balance, December 31, 2016	491	20	511
Net (gain) loss arising during the year	(60)	1	(59)
Net amortization	(13)	(1)	(14)
Total	(73)	—	(73)
Balance, December 31, 2017	$ 418	$ 20	$ 438

	Regulatory Asset (Liability)
Other Postretirement	
Balance, December 31, 2015	$ 26
Net loss arising during the year	3
Net amortization	5
Total	8
Balance, December 31, 2016	34
Net gain arising during the year	(51)
Net amortization	6
Total	(45)
Balance, December 31, 2017	$ (11)

The net loss, prior service credit and regulatory deferrals that will be amortized in 2018 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Regulatory Deferrals	Total
Pension	$ 16	$ —	$ (2)	$ 14
Other postretirement	—	(6)	1	(5)
Total	$ 16	$ (6)	$ (1)	$ 9

Plan Assumptions

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

	Pension		Other Postretirement	
	2017	2016	2017	2016
Benefit obligations as of December 31:				
Discount rate	3.60%	4.05%	3.60%	4.05%
Rate of compensation increase	N/A	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:				
Discount rate	4.05%	4.40%	4.05%	4.35%
Expected return on plan assets	7.25	7.50	7.25	7.50
Rate of compensation increase	N/A	2.75	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 historical performance and forward-looking views of the financial markets.

As a result of a plan amendment effective on January 1, 2017, the benefit obligation for the Retirement Plan is no longer affected by future increases in compensation. As a result of a labor settlement reached with United Mine Workers of America ("UMWA") in December 2014, the benefit obligation for the other postretirement plan is no longer affected by healthcare cost trends.

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $4 million and $- million, respectively, during 2018. 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 of its other postretirement benefit plan is subject to tax deductibility and subordination limits and other considerations.

The expected benefit payments to participants in PacifiCorp's pension and other postretirement benefit plans for 2018 through 2022 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2018	$ 108	$ 25
2019	107	25
2020	103	26
2021	99	23
2022	94	23
2023-2027	393	100

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, 2017:

	Pension(1)	Other Postretirement(1)
	%	%
Debt securities(2)	33 - 38	33 - 37
Equity securities(2)	49 - 60	61 - 65
Limited partnership interests	7 - 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, 2017:				
Cash equivalents	$ —	$ 43	$ —	$ 43
Debt securities:				
United States government obligations	45	—	—	45
Corporate obligations	—	60	—	60
Municipal obligations	—	9	—	9
Agency, asset and mortgage-backed obligations	—	37	—	37
Equity securities:				
United States companies	416	—	—	416
International companies	22	—	—	22
Total assets in the fair value hierarchy	$ 483	$ 149	$ —	632
Investment funds[(2)] measured at net asset value				416
Limited partnership interests[(3)] measured at net asset value				63
Investments at fair value				$ 1,111
As of December 31, 2016:				
Cash equivalents	$ —	$ 10	$ —	$ 10
Debt securities:				
United States government obligations	25	—	—	25
Corporate obligations	—	36	—	36
Municipal obligations	—	6	—	6
Agency, asset and mortgage-backed obligations	—	37	—	37
Equity securities:				
United States companies	389	—	—	389
International companies	15	—	—	15
Investment funds[(2)]	83	—	—	83
Total assets in the fair value hierarchy	$ 512	$ 89	$ —	601
Investment funds[(2)] measured at net asset value				337
Limited partnership interests[(3)] measured at net asset value				61
Investments at fair value				$ 999

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

(2) Investment funds are substantially comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 60% and 40% respectively, for 2017 and 54% and 46%, respectively, for 2016, and are invested in United States and international securities of approximately 57% and 43%, respectively, for 2017 and 39% and 61%, respectively, for 2016.

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

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

	Input Levels for Fair Value Measurements			
	Level 1[(1)]	Level 2[(1)]	Level 3[(1)]	Total
As of December 31, 2017:				
Cash and cash equivalents	$ 4	$ 3	$ —	$ 7
Debt securities:				
United States government obligations	11	—	—	11
Corporate obligations	—	16	—	16
Municipal obligations	—	2	—	2
Agency, asset and mortgage-backed obligations	—	16	—	16
Equity securities:				
United States companies	98	—	—	98
International companies	6	—	—	6
Investment funds[(2)]	32	—	—	32
Total assets in the fair value hierarchy	$ 151	$ 37	$ —	188
Investment funds[(2)] measured at net asset value				140
Limited partnership interests[(3)] measured at net asset value				4
Investments at fair value				$ 332
As of December 31, 2016:				
Cash and cash equivalents	$ 4	$ 1	$ —	$ 5
Debt securities:				
United States government obligations	11	—	—	11
Corporate obligations	—	13	—	13
Municipal obligations	—	2	—	2
Agency, asset and mortgage-backed obligations	—	13	—	13
Equity securities:				
United States companies	93	—	—	93
International companies	4	—	—	4
Investment funds[(2)]	32	—	—	32
Total assets in the fair value hierarchy	$ 144	$ 29	$ —	173
Investment funds[(2)] measured at net asset value				125
Limited partnership interests[(3)] measured at net asset value				4
Investments at fair value				$ 302

(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 63% and 37%, respectively, for 2017 and 62% and 38%, respectively, for 2016, and are invested in United States and international securities of approximately 77% and 23%, respectively, for 2017 and 71% and 29%, respectively, for 2016.

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

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 based on observable market inputs. Shares of mutual funds not registered under the Securities Act of 1933, private equity limited partnership interests, common and commingled trust funds and investment entities are reported at fair value based on the net asset value per unit, which is used for expedience purposes. A fund's net asset value is based on the fair value of the underlying assets held by the fund less its liabilities.

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, previously contributed to the UMWA 1974 Pension Plan (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's subsidiary, Energy West Mining Company, triggered involuntary withdrawal from the UMWA 1974 Pension Plan in June 2015 when the UMWA employees ceased performing work for the subsidiary. PacifiCorp recorded its estimate of the withdrawal obligation in December 2014 when withdrawal was considered probable and deferred the portion of the obligation considered probable of recovery to a regulatory asset. PacifiCorp has subsequently revised its estimate due to changes in facts and circumstances for a withdrawal occurring by July 2015. As communicated in a letter received in August 2016, the plan trustees have determined a withdrawal liability of $115 million. Energy West Mining Company began making installment payments in November 2016 and has the option to elect a lump sum payment to settle the withdrawal obligation. The ultimate amount paid by Energy West Mining Company to settle the obligation is dependent on a variety of factors, including the results of ongoing negotiations with the plan trustees.

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 occurred as a result of Energy West Mining Company's withdrawal from the UMWA 1974 Pension Plan. 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 withdrew during the three years prior to a mass withdrawal.

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):

Plan name	Employer Identification Number	PPA zone status or plan funded status percentage for plan years beginning July 1, 2017	2016	Funding improvement plan	Surcharge imposed under PPA(1)	Contributions(1) 2017	2016	Year contributions to plan exceeded more than 5% of total contributions(2)
UMWA 1974 Pension Plan	52-1050282	Critical and Declining	Critical and Declining	Implemented	Yes	$ —	$ —	None
Local 57 Trust Fund	87-0640888	At least 80%	At least 80%	None	None	$ 7	$ 8	2015, 2014

(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 Plan, 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 Plan, information is for plan years beginning July 1, 2015 and 2014. Information for the plan year beginning July 1, 2016 is not yet available. For the Local 57 Trust Fund, information is for plan years beginning July 1, 2015 and 2014. Information for the plan year beginning July 1, 2016 is not yet available.

The current collective bargaining agreements governing the Local 57 Trust Fund expire in 2020.

Defined Contribution Plan

PacifiCorp's 401(k) plan covers substantially all employees. PacifiCorp's matching contributions are based on each participant's level of contribution and, as of January 1, 2017, all participants receive contributions based on eligible pre-tax annual compensation. Contributions cannot exceed the maximum allowable for tax purposes. PacifiCorp's contributions to the 401(k) plan were $39 million and $34 million for the years ended December 31, 2017 and 2016, 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 $955 million and $917 million as of December 31, 2017 and 2016, respectively.

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

	2017	2016
Beginning balance	$ 215	$ 224
Change in estimated costs	(8)	2
Additions	6	—
Retirements	(6)	(19)
Accretion	8	8
Ending balance	$ 215	$ 215

Certain of PacifiCorp's decommissioning and reclamation obligations relate to jointly owned facilities and mine sites. PacifiCorp is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, PacifiCorp may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. PacifiCorp's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities.

(11) Risk Management and Hedging Activities

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

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

There have been no significant changes in PacifiCorp's accounting policies related to derivatives. Refer to Notes 2 and 12 for additional information on derivative contracts.

The following table, which reflects master netting arrangements and excludes contracts that have been designated as normal under the normal purchases or normal sales exception afforded by GAAP, summarizes the fair value of PacifiCorp's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Comparative Balance Sheet (in millions):

	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities	Total
As of December 31, 2017:					
Not designated as hedging contracts(1):					
Commodity assets	$ 11	$ 1	$ 1	$ —	$ 13
Commodity liabilities	(3)	—	(32)	(82)	(117)
Total	8	1	(31)	(82)	(104)
Total derivatives	8	1	(31)	(82)	(104)
Cash collateral receivable	—	—	17	57	74
Total derivatives - net basis	$ 8	$ 1	$ (14)	$ (25)	$ (30)
As of December 31, 2016:					
Not designated as hedging contracts(1):					
Commodity assets	$ 24	$ 2	$ 1	$ —	$ 27
Commodity liabilities	(6)	—	(14)	(84)	(104)
Total	18	2	(13)	(84)	(77)
Total derivatives	18	2	(13)	(84)	(77)
Cash collateral receivable	—	—	10	59	69
Total derivatives - net basis	$ 18	$ 2	$ (3)	$ (25)	$ (8)

(1) PacifiCorp's commodity derivatives are generally included in rates and as of December 31, 2017 and 2016, a regulatory asset of $101 million and $73 million, respectively, was recorded related to the net derivative liability of $104 million and $77 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):

	2017	2016
Beginning balance	$ 73	$ 133
Changes in fair value recognized in regulatory assets	47	(27)
Net gains reclassified to operating revenue	9	10
Net losses reclassified to energy costs	(28)	(43)
Ending balance	$ 101	$ 73

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	2017	2016
Electricity sales	Megawatt hours	(9)	(3)
Natural gas purchases	Decatherms	113	84
Fuel oil purchases	Gallons	—	11

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, 2017, 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 $110 million and $97 million as of December 31, 2017 and 2016, respectively, for which PacifiCorp had posted collateral of $74 million and $69 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, 2017 and 2016, PacifiCorp would have been required to post $34 million and $22 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, 2017 and December 31, 2016, PacifiCorp would have been required to post $233 million and $221 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, 2017:					
Assets:					
Commodity derivatives	$ —	$ 13	$ —	$ (4)	$ 9
Money market mutual funds[2]	21	—	—	—	21
Investment funds	21	—	—	—	21
	$ 42	$ 13	$ —	$ (4)	$ 51
Liabilities - Commodity derivatives	$ —	$ (117)	$ —	$ 78	$ (39)
As of December 31, 2016:					
Assets:					
Commodity derivatives	$ —	$ 27	$ —	$ (7)	$ 20
Money market mutual funds[2]	13	—	—	—	13
Investment funds	17	—	—	—	17
	$ 30	$ 27	$ —	$ (7)	$ 50
Liabilities - Commodity derivatives	$ —	$ (104)	$ —	$ 76	$ (28)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $74 million and $69 million as of December 31, 2017 and 2016, respectively.

(2) Amounts are included in other special funds, other special deposits 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 and investment funds are stated at fair value and are primarily accounted for as available-for-sale securities. When available, PacifiCorp uses a readily observable quoted market price or net asset value of an identical security in an active market to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics.

PacifiCorp's long-term debt is carried at cost on the Comparative Balance Sheet. 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):

	2017		**2016**	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
Long-term debt	$ 7,031	$ 8,370	$ 7,082	$ 8,204

(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 consolidated 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 provided that the United States Department of the Interior would conduct scientific and engineering studies to assess whether removal of the Klamath hydroelectric system's mainstem dams was in the public interest and would advance restoration of the Klamath Basin's salmonid fisheries. If it was determined that dam removal should proceed, dam removal would begin no earlier than 2020.

Congress failed to pass legislation needed to implement the original KHSA. Hence, in February 2016, the principal parties to the KHSA (PacifiCorp, the states of California and Oregon and the United States Departments of the Interior and Commerce) executed an agreement in principle committing to explore potential amendment of the KHSA to facilitate removal of the Klamath dams through a FERC process without the need for federal legislation. On April 6, 2016, PacifiCorp, the states of California and Oregon, and the United States Departments of the Interior and Commerce and other stakeholders executed an amendment to the KHSA. Consistent with the terms of the amended KHSA, on September 23, 2016, PacifiCorp and the Klamath River Renewal Corporation ("KRRC"), a private, independent nonprofit 501(c)(3) organization formed by certain signatories of the amended KSHA, jointly filed an application with the FERC to transfer the license for the four mainstem Klamath River hydroelectric generating facilities from PacifiCorp to the KRRC. Also on September 23, 2016, the KRRC filed an application with the FERC to surrender the license and decommission the same four facilities. The KRRC's license surrender application included a request for the FERC to refrain from acting on the surrender application until after the transfer of the license to the KRRC is effective. On March 15, 2018, the FERC issued an order splitting the existing license for the Klamath Project into two licenses. The Klamath Project (FERC License No. 2082) contains East Side, West Side, Keno and Fall Creek developments and the new Lower Klamath Project (FERC License No. 14803) contains J.C. Boyle, Copco No. 1, Copco No. 2 and Iron Gate developments. In the same order, the FERC deferred consideration of the transfer of the license for the Lower Klamath facilities from PacifiCorp to the KRRC until some point in the future.

Under the amended KHSA, PacifiCorp and its customers continue to be protected from uncapped dam removal costs and liabilities. The KRRC must indemnify PacifiCorp from liabilities associated with dam removal. The amended KHSA also limits PacifiCorp's contribution to facilities 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. California voters approved a water bond measure in November 2014 from which the state of California's contribution towards facilities removal costs will be drawn. In accordance with this bond measure, additional funding of up to $250 million for facilities removal costs was included in the California state budget in 2016, with the funding effective for at least five years. If facilities 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 the KRRC or an entity other than PacifiCorp in order for removal to proceed.

If certain conditions in the amended KHSA are not satisfied and the license does not transfer to the KRRC, PacifiCorp will resume relicensing with the FERC.

As of December 31, 2017, PacifiCorp's assets included $55 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, depending upon the state jurisdiction.

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 $239 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, 2017 are as follows (in millions):

	2018	2019	2020	2021	2022	2023 and Thereafter	Total
Contract type:							
Purchased electricity contracts - commercially operable	$ 276	$ 165	$ 161	$ 150	$ 145	$ 1,574	$ 2,471
Purchased electricity contracts - non-commercially operable	9	18	26	26	27	451	557
Fuel contracts	695	619	591	453	337	1,268	3,963
Construction commitments	85	29	3	—	—	—	117
Transmission	112	96	66	49	39	428	790
Operating leases and easements	7	7	7	7	6	97	131
Maintenance, service and other contracts	36	34	22	25	14	80	211
Total commitments	$ 1,220	$ 968	$ 876	$ 710	$ 568	$ 3,898	$ 8,240

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 $14 million for 2017 and 2016, respectively.

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 operating 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 2017 and 2016, 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 certain generating plant, 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, 2096. 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 certain of its assets, primarily wind-powered generating facilities, are located. Rent expense totaled $15 million for the years ended December 31, 2017 and 2016.

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 consolidated financial results.

(14) Preferred Stock

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 2018, PacifiCorp declared a dividend of $250 million which was paid to PPW Holdings LLC, a wholly owned subsidiary of BHE and PacifiCorp's direct parent company ("PPW Holdings") in March 2018.

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, 2017, 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, 2017, PacifiCorp's actual common equity percentage, as calculated under this measure, was 54%, and PacifiCorp would have been permitted to dividend $2.5 billion under this commitment.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings 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, 2017, 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):

	2017	2016
Interest paid, net of amounts capitalized	$ 350	$ 351
Income taxes paid, net[1]	$ 331	$ 187
Supplemental disclosure of non-cash investing and financing activities:		
Accounts payable related to utility plant additions	$ 147	$ 101

(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 PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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				(12,014,638)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				488,311
3	Preceding Quarter/Year to Date Changes in Fair Value				(1,067,871)
4	Total (lines 2 and 3)				(579,560)
5	Balance of Account 219 at End of Preceding Quarter/Year				(12,594,198)
6	Balance of Account 219 at Beginning of Current Year				(12,594,198)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				548,090
8	Current Quarter/Year to Date Changes in Fair Value				(3,220,070)
9	Total (lines 7 and 8)				(2,671,980)
10	Balance of Account 219 at End of Current Quarter/Year				(15,266,178)

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1 to 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			(12,014,638)		
2			488,311		
3			(1,067,871)		
4			(579,560)	762,510,394	761,930,834
5			(12,594,198)		
6			(12,594,198)		
7			548,090		
8			(3,220,070)		
9			(2,671,980)	768,437,084	765,765,104
10			(15,266,178)		

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)	27,390,139,622	27,390,139,622
4	Property Under Capital Leases	20,237,917	20,237,917
5	Plant Purchased or Sold		
6	Completed Construction not Classified	268,844,467	268,844,467
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	27,679,222,006	27,679,222,006
9	Leased to Others		
10	Held for Future Use	26,134,386	26,134,386
11	Construction Work in Progress	676,995,960	676,995,960
12	Acquisition Adjustments	156,468,483	156,468,483
13	Total Utility Plant (8 thru 12)	28,538,820,835	28,538,820,835
14	Accum Prov for Depr, Amort, & Depl	10,301,826,872	10,301,826,872
15	Net Utility Plant (13 less 14)	18,236,993,963	18,236,993,963
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	9,599,722,773	9,599,722,773
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	580,017,263	580,017,263
22	Total In Service (18 thru 21)	10,179,740,036	10,179,740,036
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	122,086,836	122,086,836
33	Total Accum Prov (equals 14) (22,26,30,31,32)	10,301,826,872	10,301,826,872

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
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Schedule Page: 200 Line No.: 21 Column: c

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Classification (a)	Ref. Line No. (Column)	Electric (c)
Amortization of Other Utility Plant	21(c)	$ 580,017,263
Less: Intangible mining plant(1)		11,949
Revised Amortization of Other Utility Plant		$ 580,005,314

(1) To adjust PacifiCorp's formula rate, per FERC Docket No. FA16-4-000 for amortization of mining assets related to production plant.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	206,797,066	2,712,052
4	(303) Miscellaneous Intangible Plant	677,391,601	56,139,163
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	884,188,667	58,851,215
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	92,712,595	277,307
9	(311) Structures and Improvements	1,018,623,608	18,277,820
10	(312) Boiler Plant Equipment	4,545,102,284	105,905,611
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	974,487,555	17,455,225
13	(315) Accessory Electric Equipment	489,371,864	4,887,950
14	(316) Misc. Power Plant Equipment	31,121,380	1,310,867
15	(317) Asset Retirement Costs for Steam Production	141,879,562	7,198,952
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	7,293,298,848	155,313,732
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	31,842,095	4,470,172
28	(331) Structures and Improvements	266,871,297	10,069,406
29	(332) Reservoirs, Dams, and Waterways	496,112,457	9,577,783
30	(333) Water Wheels, Turbines, and Generators	129,287,827	3,421,273
31	(334) Accessory Electric Equipment	81,315,515	1,973,887
32	(335) Misc. Power PLant Equipment	2,376,872	9,256
33	(336) Roads, Railroads, and Bridges	23,251,414	676,292
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	1,031,057,477	30,198,069
36	D. Other Production Plant		
37	(340) Land and Land Rights	45,478,205	
38	(341) Structures and Improvements	227,671,314	627,020
39	(342) Fuel Holders, Products, and Accessories	16,237,258	-59,066
40	(343) Prime Movers	2,922,254,312	13,954,935
41	(344) Generators	475,162,261	4,222,993
42	(345) Accessory Electric Equipment	327,689,620	2,362,251
43	(346) Misc. Power Plant Equipment	15,911,453	40,428
44	(347) Asset Retirement Costs for Other Production	13,031,355	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	4,043,435,778	21,148,561
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	12,367,792,103	206,660,362

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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
			209,509,118		3
6,542,800		425,700	727,413,664		4
6,542,800		425,700	936,922,782		5
					6
					7
			92,989,902		8
6,960,723			1,029,940,705		9
35,176,820	-4,595,173	4,007,566	4,615,243,468		10
					11
6,720,092	-1,572,087		983,650,601		12
1,898,961		-3,484,562	488,876,291		13
427,798			32,004,449		14
9,000,747	-10,340,449		129,737,318		15
60,185,141	-16,507,709	523,004	7,372,442,734		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
89			36,312,178		27
132,385		94,498	276,902,816		28
1,024,886		-94,498	504,570,856		29
316,482			132,392,618		30
240,792			83,048,610		31
4,317			2,381,811		32
26,208			23,901,498		33
					34
1,745,159			1,059,510,387		35
					36
			45,478,205		37
179,055			228,119,279		38
-9,740			16,187,932		39
5,161,801	-1,065,372	939,604	2,930,921,678		40
1,882,804			477,502,450		41
1,211,192		-939,604	327,901,075		42
45,493			15,906,388		43
			13,031,355		44
8,470,605	-1,065,372		4,055,048,362		45
70,400,905	-17,573,081	523,004	12,487,001,483		46

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	255,798,637	9,351,621
49	(352) Structures and Improvements	242,638,070	15,241,885
50	(353) Station Equipment	2,104,342,313	101,979,030
51	(354) Towers and Fixtures	1,291,140,475	5,515,291
52	(355) Poles and Fixtures	920,968,349	33,229,594
53	(356) Overhead Conductors and Devices	1,213,340,115	27,044,059
54	(357) Underground Conduit	3,519,394	
55	(358) Underground Conductors and Devices	8,035,354	
56	(359) Roads and Trails	11,937,200	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	6,051,719,907	192,361,480
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	62,113,932	1,648,419
61	(361) Structures and Improvements	112,377,028	3,653,721
62	(362) Station Equipment	997,337,161	30,556,231
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	1,151,503,495	37,544,164
65	(365) Overhead Conductors and Devices	739,638,373	17,867,937
66	(366) Underground Conduit	359,267,271	12,417,672
67	(367) Underground Conductors and Devices	841,132,222	24,977,031
68	(368) Line Transformers	1,310,749,847	48,079,642
69	(369) Services	743,490,472	35,282,317
70	(370) Meters	192,964,294	17,289,084
71	(371) Installations on Customer Premises	8,837,157	62,807
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	61,890,748	1,341,620
74	(374) Asset Retirement Costs for Distribution Plant	1,507,080	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	6,582,809,080	230,720,645
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	21,544,358	150,657
87	(390) Structures and Improvements	241,961,606	7,702,060
88	(391) Office Furniture and Equipment	75,133,918	14,842,909
89	(392) Transportation Equipment	110,614,591	11,640,538
90	(393) Stores Equipment	15,398,780	585,812
91	(394) Tools, Shop and Garage Equipment	64,086,679	3,986,834
92	(395) Laboratory Equipment	32,873,041	1,790,406
93	(396) Power Operated Equipment	163,198,650	23,918,128
94	(397) Communication Equipment	443,004,548	18,313,325
95	(398) Miscellaneous Equipment	8,214,144	79,600
96	SUBTOTAL (Enter Total of lines 86 thru 95)	1,176,030,315	83,010,269
97	(399) Other Tangible Property	1,854,828	
98	(399.1) Asset Retirement Costs for General Plant	39,748	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	1,177,924,891	83,010,269
100	TOTAL (Accounts 101 and 106)	27,064,434,648	771,603,971
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)	27,064,434,648	771,603,971

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
-28,826		284,907	265,463,991		48
190,965			257,688,990		49
10,194,980	-503,520	-227,598	2,195,395,245		50
114,672	-1,544,795		1,294,996,299		51
2,721,897	-2,759,685	-490,986	948,225,375		52
1,992,747	-1,233,806	-133,812	1,237,023,809		53
			3,519,394		54
			8,035,354		55
			11,937,200		56
					57
15,186,435	-6,041,806	-567,489	6,222,285,657		58
					59
2,920		-62,950	63,696,481		60
177,457		-1,252	115,852,040		61
4,163,010		-295,406	1,023,434,976		62
					63
5,799,448		42,470	1,183,290,681		64
2,605,936		57,112	754,957,486		65
1,434,479			370,250,464		66
2,045,747			864,063,506		67
9,108,644			1,349,720,845		68
721,337			778,051,452		69
4,462,941			205,790,437		70
88,997			8,810,967		71
					72
593,109			62,639,259		73
	-162,314		1,344,766		74
31,204,025	-162,314	-260,026	6,781,903,360		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
-32,779		-32,779	21,695,015		86
3,933,141			245,730,525		87
7,656,845		106,144	82,426,126		88
3,890,180		970	118,365,919		89
574,165		17,775	15,428,202		90
2,963,584		-214,430	64,895,499		91
1,368,812		97,640	33,392,275		92
7,629,491			179,487,287		93
2,102,643		21,103	459,236,333		94
45,007		70,313	8,319,050		95
30,131,089		66,736	1,228,976,231		96
			1,854,828		97
			39,748		98
30,131,089		66,736	1,230,870,807		99
153,465,254	-23,777,201	187,925	27,658,984,089		100
					101
					102
					103
153,465,254	-23,777,201	187,925	27,658,984,089		104

Schedule Page: 204 Line No.: 4 Column: b

Includes mining assets related to production plant of $23,300.

Schedule Page: 204 Line No.: 4 Column: g

Includes mining assets related to production plant of $14,654.

Schedule Page: 204 Line No.: 5 Column: b

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Account (a)	Ref. Line No. (Column)	Balance Beg. of Year (b)
TOTAL Intangible Plant	5(b)	$ 884,188,667
Less: Intangible mining plant(1)		23,300
Revised TOTAL Intangible Plant		$ 884,165,367

(1) To adjust PacifiCorp's formula rate, per FERC Docket No. FA16-4-000 for mining assets related to production plant.

Schedule Page: 204 Line No.: 5 Column: g

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Account (a)	Ref. Line No. (Column)	Balance End of Year (g)
TOTAL Intangible Plant	5(g)	$ 936,922,782
Less: Intangible mining plant(1)		14,654
Revised TOTAL Intangible Plant		$ 936,908,128

(1) To adjust PacifiCorp's formula rate, per FERC Docket No. FA16-4-000 for mining assets related to production plant.

Schedule Page: 204 Line No.: 46 Column: b

Adjustments to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, are as follows:

Account (a)	Ref. Line No. (Column)	Balance Beg. of Year (b)
TOTAL Production Plant	46(b)	$12,367,792,103
Less: (317) Asset Retirement Costs for Steam Production(1)	15(b)	141,879,562
Less: (326) Asset Retirement Costs for Nuclear Production(1)	24(b)	-
Less: (337) Asset Retirement Costs for Hydraulic Production(1)	34(b)	-
Less: (347) Asset Retirement Costs for Other Production(1)	44(b)	13,031,355
Revised TOTAL Production Plant		$12,212,881,186

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 204 Line No.: 46 Column: g

Adjustments to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, are as follows:

Account (a)	Ref. Line No. (Column)	Balance End of Year (g)
TOTAL Production Plant	46(g)	$12,487,001,483
Less: (317) Asset Retirement Costs for Steam Production(1)	15(g)	129,737,318
Less: (326) Asset Retirement Costs for Nuclear Production(1)	24(g)	-
Less: (337) Asset Retirement Costs for Hydraulic Production(1)	34(g)	-
Less: (347) Asset Retirement Costs for Other Production(1)	44(g)	13,031,355
Revised TOTAL Production Plant		$12,344,232,810

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 204 Line No.: 75 Column: b

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Account (a)	Ref. Line No. (Column)	Balance at Beg. of Year (b)
TOTAL Distribution Plant	75(b)	$ 6,582,809,080
Less: (374) Asset Retirement Costs for Distribution Plant(1)	74(b)	1,507,080
Revised TOTAL Distribution Plant		$ 6,581,302,000

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 204 Line No.: 75 Column: g

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Account (a)	Ref. Line No. (Column)	Balance at End of Year (g)
TOTAL Distribution Plant	75(g)	$ 6,781,903,360
Less: (374) Asset Retirement Costs for Distribution Plant(1)	74(g)	1,344,766
Revised TOTAL Distribution Plant		$ 6,780,558,594

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

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

Account 39921, Land owned in fee

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

Refer to footnote on page 204, line no. 97, column (b)

Schedule Page: 204 Line No.: 99 Column: b

Adjustments to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, are as follows:

Account (a)	Ref. Line No. (Column)	Balance at Beg. of Year (b)
TOTAL General Plant	99(b)	$ 1,177,924,891
Less: (399) Other Tangible Property(1)	97(b)	1,854,828
Less: (399.1) Asset Retirement Costs for General Plant(2)	98(b)	39,748
Revised TOTAL General Plant		$ 1,176,030,315

(1) To adjust PacifiCorp's formula rate, per FERC Docket No. FA16-4-000 for mining assets related to production plant.

(2) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 204 Line No.: 99 Column: g

Adjustments to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, are as follows:

Account (a)	Ref. Line No. (Column)	Balance at End of Year (g)
TOTAL General Plant	99(g)	$ 1,230,870,807
Less: (399) Other Tangible Property(1)	97(g)	1,854,828
Less: (399.1) Asset Retirement Costs for General Plant(2)	98(g)	39,748
Revised TOTAL General Plant		$ 1,228,976,231

(1) To adjust PacifiCorp's formula rate, per FERC Docket No. FA16-4-000 for mining assets related to production plant.

(2) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 204 Line No.: 104 Column: b

Adjustments to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, are as follows:

Account (a)	Ref. Line No. (Column)	Balance at Beg. of Year (b)
Revised TOTAL Intangible Plant(1)		$ 884,165,367
Revised TOTAL Production Plant(2)		12,212,881,186
TOTAL Transmission Plant	58(b)	6,051,719,907
Revised TOTAL Distribution Plant(3)		6,581,302,000
Revised TOTAL General Plant(4)		1,176,030,315
(102) Electric Plant Purchased	101(b)	-
(Less) (102) Electric Plant Sold	102(b)	-
(103) Experimental Plant Unclassified	103(b)	-
Revised TOTAL Electric Plant in Service		$26,906,098,775

(1) Refer to footnote on page 204, line no. 5, column (b)
(2) Refer to footnote on page 204, line no. 46, column (b)
(3) Refer to footnote on page 204, line no. 75, column (b)
(4) Refer to footnote on page 204, line no. 99, column (b)

Schedule Page: 204 Line No.: 104 Column: e

Includes adjustments to PacifiCorp's formula rate, per FERC Docket No. FA16-4-000.

Schedule Page: 204 Line No.: 104 Column: g

Adjustments to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, are as follows:

Account (a)	Ref. Line No. (Column)	Balance at End of Year (g)
Revised TOTAL Intangible Plant(1)		$ 936,908,128
Revised TOTAL Production Plant(2)		12,344,232,810
TOTAL Transmission Plant	58(g)	6,222,285,657
Revised TOTAL Distribution Plant(3)		6,780,558,594
Revised TOTAL General Plant(4)		1,228,976,231
(102) Electric Plant Purchased	101(g)	-
(Less) (102) Electric Plant Sold	102(g)	-
(103) Experimental Plant Unclassified	103(g)	-
Revised TOTAL Electric Plant in Service		$27,512,961,420

(1) Refer to footnote on page 204, line no. 5, column (g)
(2) Refer to footnote on page 204, line no. 46, column (g)
(3) Refer to footnote on page 204, line no. 75, column (g)
(4) Refer to footnote on page 204, line no. 99, column (g)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Barnes Butte Substation	2007	2027	746,268
3	Wild Horse Wind Plant	2007	2039	6,763,094
4	Twelve Mile Wind Plant	2007	2039	2,160,207
5	Jumbers Point Substation	2008	2022	1,173,276
6	Mountain Green Substation	2009	2025	284,996
7	Hoggard Substation	2009	2025	254,397
8	Oquirrh-Terminal 345kV Transmission Line	2009	2022	396,020
9	Bend Service Center	2010	2022	3,507,838
10	Legacy Substation	2010	2025	562,276
11	Aeolus Substation	2011	2020	1,013,577
12	Anticline Substation	2011	2020	964,043
13	Populus Substation	2011	2024	254,753
14	Lassen Substation	2012	2018	683,318
15	Old Mill Substation	2012	2026	1,838,281
16	Chimney Butte-Paradise 230kV Transmission Line	2013	2025	598,457
17	Fiddlers Canyon Substation	2016	2028	1,136,587
18	Gateway Area Substation	2017	2021	2,884,997
19	Miscellaneous, each under $250,000:			912,001
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			26,134,386

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

Land purchased for wind farms with an estimated construction date of 2039, subject to environmental and economic reviews and the timing of completion of the Energy Gateway Transmission Expansion Program.

Schedule Page: 214 Line No.: 4 Column: c

Land purchased for wind farms with an estimated construction date of 2039, subject to environmental and economic reviews and the timing of completion of the Energy Gateway Transmission Expansion Program.

Schedule Page: 214 Line No.: 11 Column: c

Property is expected to be placed in-service in 2020, subject to environmental and economic reviews and timing of completion of the Energy Gateway Transmission Expansion Program.

Schedule Page: 214 Line No.: 12 Column: c

Property is expected to be placed in-service in 2020, subject to environmental and economic reviews and timing of completion of the Energy Gateway Transmission Expansion Program.

Schedule Page: 214 Line No.: 19 Column: c

Various dates and plans.

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 2017/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	Prospect No. 3 Hydro Relicensing	1,519,201
3	Cybersecurity Framework Initiatives	1,152,191
4	Production:	
5	Wind Repowering/New Development/Safe Harbor Equipment Purchases	123,115,482
6	Lewis River System Relicensing Implementation	6,802,773
7	Naughton Ash Transport Wastewater Zero Discharge	5,150,533
8	Toketee Dam Rehabilitation Evaluation	2,587,368
9	Jim Bridger U1 Replace Finishing Superheater	2,262,451
10	Lewis River System Maximum Flood Improvement Study	1,850,004
11	Colstrip U3 and U4: Water Management System	1,635,141
12	Jim Bridger Coal Combustion Residual Bottom Ash Concrete Heating System	1,550,790
13	Merwin Spillway Gate Wood Extension Replacement	1,315,839
14	Hunter U1 Scrubber Overhaul Components	1,200,757
15	Transmission:	
16	Aeolus - Mona 500kV Line	87,859,407
17	Boardman - Hemingway 500kV Line	63,640,580
18	Populus - Hemingway 500kV Line	54,870,989
19	Windstar - Populus 230 - 500kV Line	50,319,376
20	Aeolus - Bridger/Anticline 500kV Line	41,659,965
21	Wallula - McNary 230kV Line	17,323,394
22	Vantage - Pomona Heights 230kV Line	16,088,398
23	Purgatory Flat New 138kV Substation	14,116,978
24	Oquirrh - Terminal 345kV Line	13,127,881
25	Sams Valley New 500 - 230kV Substation	8,241,144
26	Goshen Spare 345 - 161kV 700 MVA Transformer TPL	3,135,582
27	NERC Reliability Standards PRC-002 & MOD-033	3,110,656
28	Syracuse Substation Install 2nd 345 - 138kV Transformer TPL	2,901,077
29	Jordanelle - Midway Construct 138kV Line	2,856,959
30	Riverdale - El Monte Upgrade 46kV to 138kV Line	2,817,589
31	NE Portland Voltage Conversion Project - Transmission Lines and Substations	2,424,546
32	Shirley Basin - Freezeout - Standpipe 230kV Line	1,264,871
33	Cowlitz Public Utility District No. 1, Interconnection Study	1,247,136
34	Kinport Substation Replace 345kV Series Capacitor	1,164,302
35	Distribution:	
36	Gromore New 115 - 12kV Substation	5,905,231
37	Porter Rockwell Substation 2nd 138 - 13.2kV Transformer	3,527,561
38	Lassen Substation - New Substation	3,387,906
39	Jordan Valley Underground Cable Testing and Replacement Project	2,207,539
40		
41	Miscellaneous Projects each under $1,000,000	123,654,363
42		
43	TOTAL	676,995,960

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 2017/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	9,026,397,312	9,026,397,312		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	727,650,690	727,650,690		
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):	22,602,759	22,602,759		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	750,253,449	750,253,449		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	144,477,982	144,477,982		
13	Cost of Removal	43,110,899	43,110,899		
14	Salvage (Credit)	2,787,937	2,787,937		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	184,800,944	184,800,944		
16	Other Debit or Cr. Items (Describe, details in footnote):	7,872,956	7,872,956		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	9,599,722,773	9,599,722,773		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	3,251,016,239	3,251,016,239		
21	Nuclear Production				
22	Hydraulic Production-Conventional	392,220,491	392,220,491		
23	Hydraulic Production-Pumped Storage				
24	Other Production	1,032,628,210	1,032,628,210		
25	Transmission	1,679,410,018	1,679,410,018		
26	Distribution	2,783,524,484	2,783,524,484		
27	Regional Transmission and Market Operation				
28	General	460,923,331	460,923,331		
29	TOTAL (Enter Total of lines 20 thru 28)	9,599,722,773	9,599,722,773		

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

Account 143, Other accounts receivable: depreciation expense billed to joint owners	$ 230,341
Account 182.3, Other regulatory assets or Account 254, Other regulatory liabilities: asset retirement obligations asset depreciation	11,863,642
Account 182.3, Other regulatory assets: deferral of Carbon depreciation	(5,081,468)
Account 182.3, Other regulatory assets: deferral of increased depreciation, due to depreciation study rates, net of amortization	(1,440,734)
Transportation depreciation charged to operations and maintenance expense and construction work in progress based on usage activity	15,045,329
Account 503, Steam from other sources: Blundell depreciation	1,985,649
Total Other Accounts	$ 22,602,759

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	$ 4,606,332
Other items include:	3,266,624
- Recovery from third parties for asset relocations and damaged properties	
- Insurance recoveries	
- Adjustments of reserve related to electric plant sold and/or purchased	
- Reclassifications from electric plant	
Total Other Debit or Cr. Items	$ 7,872,956

Schedule Page: 219 Line No.: 20 Column: c

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Item (a)	Ref. Line No. (Column)	Electric Plant in Service (c)
Steam Production	20(c)	$ 3,251,016,239
Less: Asset retirement obligations related cost components(1)		39,678,616
Revised Steam Production		$ 3,211,337,623

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 219 Line No.: 22 Column: c

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Item (a)	Ref. Line No. (Column)	Electric Plant in Service (c)
Hydraulic Production - Conventional	22(c)	$ 392,220,491
Less: Asset retirement obligations related cost components(1)		2,631,201
Revised Hydraulic Production - Conventional		$ 389,589,290

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 219 Line No.: 24 Column: c

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Item (a)	Ref. Line No. (Column)	Electric Plant in Service (c)
Other Production	24(c)	$ 1,032,628,210
Less: Asset retirement obligations related cost components(1)		(2,879,623)
Revised Other Production		$ 1,035,507,833

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 219 Line No.: 25 Column: c

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Item (a)	Ref. Line No. (Column)	Electric Plant in Service (c)
Transmission	25(c)	$ 1,679,410,018
Less: Asset retirement obligations related cost components(1)		(903,601)
Revised Transmission		$ 1,680,313,619

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 219 Line No.: 26 Column: c

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Item (a)	Ref. Line No. (Column)	Electric Plant in Service (c)
Distribution	26(c)	$ 2,783,524,484
Less: Asset retirement obligations related cost components(1)		755,207
Revised Distribution		$ 2,782,769,277

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 219 Line No.: 28 Column: c

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Item (a)	Ref. Line No. (Column)	Electric Plant in Service (c)
General	28(c)	$ 460,923,331
Less: Asset retirement obligations related cost components(1)		(200,941)
Revised General		$ 461,124,272

(1) In accordance with 18 C.F.R. §35.18(a-c) a public utility that files a transmission rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

Schedule Page: 219 Line No.: 29 Column: c

Adjustments to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, are as follows:

Item (a)	Ref. Line No. (Column)	Electric Plant in Service (c)
Revised Steam Production(1)		$ 3,211,337,623
Nuclear Production	21(c)	-
Revised Hydraulic Production - Conventional(2)		389,589,290
Hydraulic Production - Pumped Storage	23(c)	-
Revised Other Production(3)		1,035,507,833
Revised Transmission(4)		1,680,313,619
Revised Distribution(5)		2,782,769,277
Regional Transmission and Market Operation	27(c)	-
Revised General(6)		461,124,272
Revised TOTAL		$ 9,560,641,914

(1) Refer to footnote on page 219, line no. 20, column (c)
(2) Refer to footnote on page 219, line no. 22, column (c)
(3) Refer to footnote on page 219, line no. 24, column (c)
(4) Refer to footnote on page 219, line no. 25, column (c)
(5) Refer to footnote on page 219, line no. 26, column (c)
(6) Refer to footnote on page 219, line no. 28, column (c)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Pacific Minerals, Inc.	1973		
2	Common Stock			1
3	Paid-in Capital			47,960,000
4	Undistributed Subsidiary Earnings			109,099,488
5	SUBTOTAL			157,059,489
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			7,331,504
22	SUBTOTAL			13,369,504
23				
24	Fossil Rock Fuels, LLC	2011		
25	Paid-in Capital			29,504,770
26	Undistributed Subsidiary Earnings			515,450
27	SUBTOTAL			30,020,220
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 81,669,772		TOTAL	200,451,214

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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
14,506,589		96,606,077		4
14,506,589		144,566,078		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
428,173		7,730,250		21
428,173		13,768,250		22
				23
				24
		27,669,770		25
2,879,519		968		26
2,879,519		27,670,738		27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
17,814,281		186,007,067		42

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

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

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

During the year ended December 31, 2017, Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp, paid a dividend of $27,000,000 million to PacifiCorp.

Schedule Page: 224 Line No.: 21 Column: g

During the year ended December 31, 2017, Trapper Mining Inc., a subsidiary of PacifiCorp, paid a dividend of $29,428 to PacifiCorp.

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

During the year ended December 31, 2017, Fossil Rock Fuels, LLC, a wholly owned subsidiary of PacifiCorp, returned $1,835,000 of capital to PacifiCorp.

Schedule Page: 224 Line No.: 26 Column: g

During the year ended December 31, 2017, Fossil Rock Fuels, LLC, a wholly owned subsidiary of PacifiCorp, paid distributions of $3,394,000 to 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 2017/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)	214,693,832	197,499,391	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)	142,252,190	150,015,776	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	73,437,874	73,975,748	Electric
8	Transmission Plant (Estimated)	715,287	381,386	Electric
9	Distribution Plant (Estimated)	11,798,517	10,875,356	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	57,418	28,604	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	228,261,286	235,276,870	
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)	442,955,118	432,776,261	

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

General plant materials and supplies

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

General plant materials and supplies

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)	2018 No. (d)	2018 Amt. (e)
1	Balance-Beginning of Year	682,969.00		156,646.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	28,130.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	654,839.00		156,646.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	2,259.00		2,259.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	2,259.00			
40	Balance-End of Year			2,259.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2019		2020		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
151,417.00		156,646.00		4,072,760.00		5,220,438.00		1
								2
								3
								4
				156,644.00		156,644.00		5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						28,130.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
151,417.00		156,646.00		4,229,404.00		5,348,952.00		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

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	Q1803	1,160	561.6	1,160	456
3	Q1918-1919	84	561.6	84	456
4	Q1977	11,843	561.6	11,843	456
5	Q2068-2072			4,574	456
6	Q2089			2,780	456
7	Q2111-2115	138	561.6	138	456
8	Q2113-2115	4,207	561.6	4,207	456
9	Q2116	4,259	561.6		
10	Q2132-2138	6,309	561.6	6,309	456
11	Q2141	524	561.6	3,820	456
12	Q2151	138	561.6		
13	Q2169	4,102	561.6		
14	Q2170	3,503	561.6		
15	Q2198-2204	2,687	561.6	2,687	456
16	Q2234	4,957	561.6	4,957	456
17	Q2292	3,036	561.6	3,036	456
18	Q2293	5,409	561.6	5,409	456
19	Q2323	454	561.6	454	456
20	Q2326	550	561.6	550	456
21	**Generation Studies**				
22	GIQ016	2,912	561.7	2,912	456
23	GIQ0640	549	561.7	3,417	456
24	GIQ0650	24,263	561.7	24,263	456
25	GIQ0687	535	561.7	535	456
26	GIQ0706	3,625	561.7	3,625	456
27	GIQ0707	22,190	561.7	25,296	456
28	GIQ0708	14,787	561.7	14,787	456
29	GIQ0710	18	561.7	18	456
30	GIQ0712	20,008	561.7	20,008	456
31	GIQ0713	14,111	561.7	14,111	456
32	GIQ0715	10,951	561.7	10,951	456
33	GIQ0718	4,874	561.7	4,874	456
34	GIQ0719	15,035	561.7	15,035	456
35	GIQ0720	61,400	561.7	61,400	456
36	GIQ0721	3,537	561.7	3,537	456
37	GIQ0726	1,574	561.7	2,182	456
38	GIQ0729	16,399	561.7	16,259	456
39	GIQ0730	292	561.7	292	456
40	GIQ0731	15,466	561.7	15,466	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 2017/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Q2370	722	561.6	722	456
3	AREF 83949217	1,855	561.6		
4	AREF 84348467	447	561.6		
5	AREF 84348468	550	561.6		
6	AREF 84879085	1,992	561.6		
7	AREF 84879111	1,682	561.6		
8	AREF 85227199	4,311	561.6		
9	AREF 85227206	2,456	561.6		
10	AREF 85227209	2,765	561.6		
11	AREF 85227213	2,817	561.6		
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0733	1,541	561.7	1,541	456
23	GIQ0734	17,719	561.7	17,719	456
24	GIQ0736	1,708	561.7	1,708	456
25	GIQ0737	21,354	561.7	30,201	456
26	GIQ0738	12,768	561.7	12,768	456
27	GIQ0739	14,558	561.7	14,558	456
28	GIQ0741	3,463	561.7	3,463	456
29	GIQ0745	18,689	561.7	18,689	456
30	GIQ0752	13,568	561.7	13,568	456
31	GIQ0753	14,858	561.7	14,858	456
32	GIQ0754	13,870	561.7	14,350	456
33	GIQ0755	12,029	561.7	12,029	456
34	GIQ0757	6,048	561.7	6,222	456
35	GIQ0762	337	561.7	3,132	456
36	GIQ0763	33,286	561.7	47,714	456
37	GIQ0764	23,573	561.7	23,573	456
38	GIQ0766	21,647	561.7	21,647	456
39	GIQ0767	13,230	561.7	13,230	456
40	GIQ0769	146	561.7	146	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 2017/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
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9					
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11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0770	2,462	561.7	2,462	456
23	GIQ0771	22,023	561.7	22,023	456
24	GIQ0774	14,438	561.7	14,438	456
25	GIQ0777	23,290	561.7	23,290	456
26	GIQ0778	23,276	561.7	23,276	456
27	GIQ0779	328	561.7	328	456
28	GIQ0780	933	561.7	933	456
29	GIQ0781	29,851	561.7	29,851	456
30	GIQ0782	17,664	561.7	17,664	456
31	GIQ0783	22,993	561.7	22,993	456
32	GIQ0784	32,932	561.7	32,932	456
33	GIQ0785	19,850	561.7	19,850	456
34	GIQ0786	34,489	561.7	34,489	456
35	GIQ0787	11,211	561.7	11,211	456
36	GIQ0788	13,846	561.7	13,846	456
37	GIQ0789	31,062	561.7	31,062	456
38	GIQ0792	12,009	561.7	12,009	456
39	GIQ0793	11,252	561.7	11,252	456
40	GIQ0794	8,452	561.7	8,452	456

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
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9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0795	14,135	561.7	14,135	456
23	GIQ0796	22,318	561.7	22,318	456
24	GIQ0797	9,943	561.7	9,943	456
25	GIQ0798	111	561.7	111	456
26	GIQ0799	21,828	561.7	21,828	456
27	GIQ0800	12,715	561.7	12,715	456
28	GIQ0801	23,049	561.7	23,049	456
29	GIQ0802	11,557	561.7	11,557	456
30	GIQ0803	2,579	561.7	2,579	456
31	GIQ0804	1,297	561.7	1,297	456
32	GIQ0805	1,786	561.7	1,786	456
33	GIQ0806	20,472	561.7	19,912	456
34	GIQ0807	11,161	561.7	11,161	456
35	GIQ0808			1,340	456
36	GIQ0809	18,390	561.7	18,390	456
37	GIQ0810	13,778	561.7	13,778	456
38	GIQ0811	500	561.7	500	456
39	GIQ0815	437	561.7	437	456
40	GIQ0816	289	561.7	289	456

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0817	143	561.7	143	456
23	GIQ0818	507	561.7	507	456
24	GIQ0819	2,222	561.7	2,478	456
25	GIQ0820	203	561.7		
26	GIQ0821	148	561.7		
27	GIQ0822	171	561.7		
28	GIQ0823	111	561.7		
29	GIQ0824	24,288	561.7	24,288	456
30	GIQ0825	38,980	561.7	38,980	456
31	GIQ0826	1,597	561.7	1,597	456
32	GIQ0827	1,370	561.7	1,370	456
33	GIQ0828	1,298	561.7	1,298	456
34	GIQ0829	1,156	561.7	1,156	456
35	GIQ0830	1,334	561.7	1,334	456
36	GIQ0831			230	456
37	GIQ0835	27,936	561.7	27,936	456
38	GIQ0836	13,753	561.7	13,753	456
39	GIQ0837	240	561.7	776	456
40	GIQ0838	4,525	561.7	4,525	456

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0839	1,895	561.7	1,895	456
23	GIQ0840	16,945	561.7	16,945	456
24	GIQ0841	1,770	561.7	1,770	456
25	GIQ0842	1,081	561.7	1,286	456
26	GIQ0843	1,119	561.7	1,119	456
27	GIQ0844	939	561.7	939	456
28	GIQ0845	24,151	561.7	24,151	456
29	GIQ0846	28,130	561.7	28,130	456
30	GIQ0847	942	561.7	942	456
31	GIQ0849	24,262	561.7	24,262	456
32	GIQ0850	22,564	561.7	22,564	456
33	GIQ0851	174	561.7	174	456
34	GIQ0852	6,637	561.7	6,637	456
35	GIQ0853	7,695	561.7	7,695	456
36	GIQ0854	1,869	561.7	1,869	456
37	GIQ0855	7,692	561.7	7,692	456
38	GIQ0856	11,801	561.7	11,801	456
39	GIQ0858	5,570	561.7	5,570	456
40	GIQ0859	3,874	561.7	3,874	456

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0860	1,732	561.7	1,732	456
23	GIQ0861	1,293	561.7	1,293	456
24	GIQ0862	11,174	561.7	11,174	456
25	GIQ0863	14,546	561.7	14,546	456
26	GIQ0864	1,652	561.7	1,652	456
27	GIQ0865	1,419	561.7	1,419	456
28	GIQ0866	5,857	561.7	5,857	456
29	GIQ0867	1,505	561.7	1,505	456
30	GIQ0868	12,211	561.7	12,211	456
31	GIQ0869	14,470	561.7	14,470	456
32	GIQ0870	8,991	561.7	8,991	456
33	GIQ0871	1,395	561.7	1,395	456
34	GIQ0872	1,532	561.7	1,532	456
35	GIQ0873	1,043	561.7	1,043	456
36	GIQ0874	222	561.7	222	456
37	GIQ0875	1,474	561.7	1,474	456
38	GIQ0876	716	561.7	716	456
39	GIQ0877	24,854	561.7	24,854	456
40	GIQ0878	9,879	561.7	9,879	456

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0879	2,260	561.7	2,260	456
23	GIQ0880	11,228	561.7	11,228	456
24	GIQ0881	5,348	561.7	5,348	456
25	GIQ0882	1,036	561.7	1,036	456
26	GIQ0883	826	561.7	826	456
27	GIQ0884	801	561.7	801	456
28	GIQ0885	6,444	561.7	6,444	456
29	GIQ0886	6,833	561.7	6,833	456
30	GIQ0887	7,743	561.7	7,743	456
31	GIQ0888	11,661	561.7	11,661	456
32	GIQ0889	2,759	561.7	2,759	456
33	GIQ0890	6,805	561.7	6,805	456
34	GIQ0891	1,845	561.7	1,845	456
35	GIQ0892	961	561.7	961	456
36	GIQ0893	1,971	561.7	1,971	456
37	GIQ0894	1,401	561.7	1,401	456
38	GIQ0895	9,714	561.7	9,714	456
39	GIQ0896	3,445	561.7	3,445	456
40	GIQ0897	13,587	561.7	13,587	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 2017/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
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6					
7					
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9					
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11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0898	894	561.7	894	456
23	GIQ0899	1,449	561.7	1,449	456
24	GIQ0900	912	561.7	912	456
25	GIQ0901	1,564	561.7	1,564	456
26	GIQ0903	876	561.7	876	456
27	GIQ0904	5,879	561.7	5,879	456
28	GIQ0905	3,079	561.7	3,079	456
29	GIQ0906	7,117	561.7	7,117	456
30	GIQ0907	4,004	561.7	4,004	456
31	GIQ0908	949	561.7	949	456
32	GIQ0909	11,828	561.7	11,828	456
33	GIQ0910	821	561.7	821	456
34	GIQ0911	10,204	561.7	10,204	456
35	GIQ0913	880	561.7	880	456
36	GIQ0914	6,644	561.7	6,232	456
37	GIQ0915	4,947	561.7	4,947	456
38	GIQ0916	4,600	561.7	4,600	456
39	GIQ0917	4,371	561.7	4,371	456
40	GIQ0918	4,470	561.7	4,470	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 2017/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
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13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0919	2,980	561.7	2,980	456
23	GIQ0920	2,689	561.7	2,689	456
24	GIQ0921	924	561.7	924	456
25	GIQ0922	1,228	561.7	1,228	456
26	GIQ0923	9,931	561.7	9,931	456
27	GIQ0924	1,353	561.7	1,353	456
28	GIQ0925	1,474	561.7	1,474	456
29	GIQ0926	1,238	561.7	1,238	456
30	GIQ0927	1,132	561.7	1,132	456
31	GIQ0928	854	561.7	854	456
32	GIQ0929	637	561.7	637	456
33	GIQ0930	415	561.7	415	456
34	GIQ0931	871	561.7	871	456
35	GIQ0932	229	561.7	229	456
36	GIQ0933	566	561.7	566	456
37	GIQ0934	709	561.7	709	456
38	GIQ0935	452	561.7	452	456
39	GIQ0936	629	561.7	629	456
40	GIQ0937	1,256	561.7	1,256	456

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
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20					
21	**Generation Studies**				
22	GIQ0938	1,413	561.7	1,413	456
23	GIQ0939	2,540	561.7	2,540	456
24	GIQ0940	2,100	561.7	2,100	456
25	GIQ0941	5,714	561.7	5,714	456
26	GIQ0942	865	561.7	865	456
27	GIQ0943	417	561.7	417	456
28	GIQ0944	454	561.7	454	456
29	GIQ0945	459	561.7	459	456
30	GIQ0946	2,187	561.7	2,187	456
31	GIQ0947	914	561.7	914	456
32	GIQ0948	755	561.7	755	456
33	GIQ0949	737	561.7	737	456
34	GIQ0950	1,197	561.7	1,197	456
35	GIQ0951	865	561.7	865	456
36	GIQ0952	886	561.7	886	456
37	GIQ0953	3,844	561.7	3,844	456
38	GIQ0954	1,990	561.7	1,990	456
39	GIQ0955	680	561.7	680	456
40	GIQ0956	942	561.7	942	456

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
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17					
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19					
20					
21	**Generation Studies**				
22	GIQ0957	612	561.7	612	456
23	GIQ0958	1,051	561.7	1,051	456
24	GIQ0959	815	561.7	815	456
25	GIQ0960	778	561.7	778	456
26	GIQ0961	815	561.7	815	456
27	GIQ0962	1,014	561.7	1,014	456
28	GIQ0963	1,539	561.7	1,539	456
29	GIQ0964	4,821	561.7	4,821	456
30	GIQ0966	631	561.7	631	456
31	GIQ0967	539	561.7	539	456
32	GIQ0968	693	561.7	693	456
33	GIQ0969	772	561.7	772	456
34	GIQ0970	454	561.7	454	456
35	GIQ0971	874	561.7	874	456
36	GIQ0972	382	561.7	382	456
37	GIQ0973	517	561.7	517	456
38	GIQ0974	1,134	561.7	1,134	456
39	GIQ0975	610	561.7	610	456
40	GIQ0976	1,009	561.7	1,009	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					
3					
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19					
20					
21	**Generation Studies**				
22	GIQ0977	873	561.7	873	456
23	GIQ0978	832	561.7	832	456
24	GIQ0979	474	561.7	474	456
25	GIQ0980	983	561.7	983	456
26	GIQ0981	983	561.7	983	456
27	GIQ0982	818	561.7	818	456
28	GIQ0983	211	561.7	211	456
29	GIQ0984	211	561.7	211	456
30	GIQ0985	498	561.7	498	456
31	GIQ0986	148	561.7	148	456
32	GIQ0987	178	561.7	178	456
33	GIQ0988	178	561.7	178	456
34	GIQ0989	287	561.7	287	456
35	GIQ0990	240	561.7	240	456
36	GIQ0991	408	561.7	408	456
37	GIQ0992	175	561.7	175	456
38	GIQ0993	63	561.7	63	456
39	GIQ0994	74	561.7	74	456
40	GIQ0995	74	561.7	74	456

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
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20					
21	**Generation Studies**				
22	Pre-Application Studies - East	19,384	561.7	19,384	456
23	Pre-Application Studies - West	19,956	561.7	19,956	456
24	Customer Studies Accruals	(700)	561.7		
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	458,210	2,054,473	908	2,512,683	
2	DSM Balancing Account - ID	263,284	3,896,866	908,431	4,160,150	
3	DSM Balancing Account - UT		4,369,016			4,369,016
4	DSM Balancing Account - WA	2,515,256	11,288,887	908	13,660,558	143,585
5	DSM Balancing Account - WY	3,731,359	9,238,930	908	7,460,375	5,509,914
6	Irrigation Load Control - OR	68,998	125,294	908	136,418	57,874
7	Deferred Excess Net Power Costs - CA	4,754,305	2,095,287	555	3,346,036	3,503,556
8	Deferred Excess Net Power Costs - ID	12,380,361	7,462,597	555	10,358,264	9,484,694
9	Deferred Excess Net Power Costs - UT	12,864,998	6,185,641		11,491,439	7,559,200
10	Deferred Excess Net Power Costs - WY	2,885,525		555,431	2,885,525	
11	Deferred Excess RECs in Rates - UT	2,766,087		456,431	2,682,611	83,476
12	Deferred Excess RECs in Rates - WY		447,138			447,138
13	Deferred Excess RECs in Rates - WA	736,202	456,891	456	1,160,107	32,986
14	Deferred Income Tax Electric	420,840,992	24,980,531	282,283	445,821,523	
15	Solar ITC Basis Adjustment Regulatory Asset	75,159	2,838	282,283	39,840	38,157
16	Tax Adj on Postretirement Benefits - OR (5)	894,326		410.1	894,326	
17	Pension	490,943,147			73,347,987	417,595,160
18	Other Postretirement	34,446,629	7,052,012		41,498,641	
19	Postemployment Costs	2,190,893			852,110	1,338,783
20	Powerdale Decommissioning - ID (10)	103,930		407.3	26,216	77,714
21	Carbon Plant Regulatory Asset - ID (6)	1,914,554		403	478,639	1,435,915
22	Carbon Plant Regulatory Asset - UT (6)	13,778,565		403	3,444,641	10,333,924
23	Carbon Plant Regulatory Asset - WY (6)	4,632,751		403	1,158,188	3,474,563
24	Carbon Plant Inventory Regulatory Asset	3,119,560		506	737	3,118,823
25	Depreciation Study Deferral - ID (1)	5,003,777	1,855,943	403	2,726,443	4,133,277
26	Depreciation Study Deferral - UT (17)	1,856,626		403	128,043	1,728,583
27	Depreciation Study Deferral - WY (17)	6,411,768		403	442,191	5,969,577
28	Generating Plant Liquidated Damages - WY	1,298,704		557	54,288	1,244,416
29	Generating Plant Liquidated Damages - UT	595,000		557	35,000	560,000
30	Klamath Hydroelectric Relicensing Costs - UT (10)	22,835,039	890,403	404	4,483,442	19,242,000
31	Cholla Plant Transaction Costs (26)	547,534		557	547,534	
32	Washington Colstrip Unit No. 3 (22)	213,131		456	52,188	160,943
33	Environmental Costs (10)	48,931,374	34,568,068		4,716,917	78,782,525
34	Asset Retirement Obligations Regulatory Difference	81,673,452	18,210,459			99,883,911
35	Unamortized Contract Values	97,918,622		242	9,110,134	88,808,488
36	Unrealized Loss on Derivative Contracts	72,824,222	28,477,485			101,301,707
37	Solar Feed-In Tariff Deferral - OR (1)	5,546,365	5,218,543		5,435,776	5,329,132
38	Solar Incentive Subscriber Program - UT	1,311,983	349,358	908	110,342	1,550,999
39	Renewable Portfolio Standards Compliance - OR		301,244			301,244
40	Renewable Portfolio Standards Compliance	339,537		555,431	339,537	
41	Protocol - MSP Deferral - UT		4,400,000			4,400,000
42	Protocol - MSP Deferral - WY		799,998			799,998
43	Deferred Intervenor Funding Grants - OR (1)	410,913	369,593	928	244,998	535,508

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS: Written off During the Quarter /Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Deferred Intervenor Funding Grants - CA	40,605	414			41,019
2	Deferred Intervenor Funding Grants - ID	26,865				26,865
3	Catastrophic Event Regulatory Asset - CA (1)	197,343			197,343	
4	Alternative Rate for Energy (CARE) - CA	660,564	102,962		239,026	524,500
5	Deferred Overburden Cost - ID	261,175	1,516,546	501	1,423,498	354,223
6	Deferred Overburden Cost - WY	734,674	4,267,173	501	4,005,161	996,686
7	BPA Balancing Account - OR	3,366,686	2,780,009			6,146,695
8	Asset Sales Balancing Account - OR	282,902	68,392	421.1	28,324	322,970
9	Property Insurance Reserve - OR	854,625	12,901,326	924	7,068,568	6,687,383
10	Misc. Regulatory Assets/Liabilities - OR	264,453	1,120			265,573
11	Depreciation Deferral - WA	6,648				6,648
12	Utah Mine Disposition	166,424,633	9,446,743		19,960,163	155,911,213
13	Preferred Stock Redemption Loss - WY (10)	205,017		407.3	28,442	176,575
14	Preferred Stock Redemption Loss - UT (10)	594,908		407.3	82,531	512,377
15	Preferred Stock Redemption Loss - WA (10)	95,444		407.3	13,318	82,126
16	Mobile Home Park Conversion - CA	10,270	63,552			73,822
17						
18						
19						
20						
21						
22						
23						
24						
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40						
41						
42						
43						
44	**TOTAL :**	1,538,109,950	206,245,732		688,890,221	1,055,465,461

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: d

Account 182.3, Other regulatory assets
Account 431, Other interest expense
Account 555, Purchased power

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

Weighted average remaining life is approximately one year for deferred excess net power cost mechanisms being amortized.

Schedule Page: 232 Line No.: 11 Column: a

Weighted average remaining life is approximately one year for deferred excess renewable energy credits in rates being amortized.

Schedule Page: 232 Line No.: 12 Column: a

Weighted average remaining life is approximately one year for deferred excess renewable energy credits in rates being amortized.

Schedule Page: 232 Line No.: 14 Column: a

Represents income tax benefits and expense 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.: 17 Column: a

Weighted average remaining life being amortized is 20 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.: 17 Column: d

Pensions are associated with labor and generally charged to operations and maintenance expense and construction work in progress. Pension curtailments and remeasurement date changes are charged to Account 926, Employee pensions and benefits.

Schedule Page: 232 Line No.: 18 Column: a

Weighted average remaining life of portion being amortized is 20 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.: 18 Column: d

Other postretirement costs are associated with labor and generally charged to operations and maintenance expense and construction work in progress. Other postretirement remeasurement date changes and Wyoming's share of settlement losses are charged to Account 926, Employee pensions and benefits.

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

Weighted average remaining life is five years.

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

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

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

Weighted average remaining life is 25 years.

Schedule Page: 232 Line No.: 29 Column: a

Weighted average remaining life is 16 years.

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

Account 514, Maintenance of miscellaneous steam plant
Account 545, Maintenance of miscellaneous hydraulic plant
Account 554, Maintenance of miscellaneous other power generation plant
Account 598, Maintenance of miscellaneous distribution plant

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 232 Line No.: 35 Column: a

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

Schedule Page: 232 Line No.: 36 Column: a

Weighted average remaining life is four years.

Schedule Page: 232 Line No.: 37 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.: 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.: 4 Column: d

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

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

Weighted average remaining life is approximately one year for the net property, plant and equipment not considered probable of disallowance and for the portion of losses associated with the assets held for sale. Additionally, the weighted average remaining life is approximately five years for closure costs incurred to date considered probable of recovery.

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

Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting
Account 445, Other sales to public authorities
Account 501, Fuel
Account 506, Miscellaneous steam power expenses

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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)	148,828		557	137,381	11,447
2	Lacomb Irrigation (24)	232,410		557	45,720	186,690
3	Bogus Creek (41)	952,880		557	41,280	911,600
4	Mead Phoenix Availability and					
5	Transmission Charge (46)	11,448,619		565	440,132	11,008,487
6	TGS Buyout (23)	47,709		557	15,473	32,236
7	Point-to-Point Transmission	1,494,708		131, 142	523,676	971,032
8	Hermiston Swap (40)	3,362,323		557	171,693	3,190,630
9	Deferred Coal Costs - Wyodak					
10	Settlement (22)	2,011,090		501	335,182	1,675,908
11	LT Lease Commissions Prepaid	229,147		931	80,684	148,463
12	Lake Side Maintenance Prepaid	12,156,745	4,066,551			16,223,296
13	Lake Side 2 Maintenance Prepaid	12,382,314	4,833,708			17,216,022
14	Chehalis Maintenance Prepaid	5,793,373	3,588,210			9,381,583
15	Currant Creek Maint. Prepaid	3,512,380	2,638,983			6,151,363
16	Lease Incentives	136,613		454	128,618	7,995
17	Credit Agreement Costs	1,324,377	1,120,217	427, 431	712,099	1,732,495
18	PCRB LOC/SBBPA Costs (2)	29,165	13,576	427	39,519	3,222
19	PCRB Mode Conversion Costs	191,737	166,010	427	49,621	308,126
20	'94 Series Restruct. Costs (16)	460,359		427	58,769	401,590
21	Deferred S-3 Shelf Regis. Costs	191,902				191,902
22	BPA LT Transmission Prepaid	3,063,345	136,329	565	988,345	2,211,329
23	Emission Reduction Credits	306,510				306,510
24	Unamortized Contract Values	1,785,425	1,858,107			3,643,532
25	Sales of Electric Utility					
26	Facilities & Properties	149,584	27,552		29,203	147,933
27	IT Licenses and Maint. Prepaid	60,723	100,000	921, 923	64,403	96,320
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	61,472,266				76,159,711

Schedule Page: 233 Line No.: 11 Column: a

The weighted average remaining life is four years.

Schedule Page: 233 Line No.: 16 Column: a

The weighted average remaining life is one year.

Schedule Page: 233 Line No.: 17 Column: a

The weighted average remaining life is three years.

Schedule Page: 233 Line No.: 19 Column: a

The weighted average remaining life is six years.

Schedule Page: 233 Line No.: 26 Column: d

Account 421.2, Loss on disposition of property
Account 539, Miscellaneous hydraulic power generation expenses

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	202,357,014	84,332,107
3	Derivative contracts and unamortized contract values	66,912,983	48,351,596
4	State carryforwards	69,101,510	82,972,793
5	Asset retirement obligations	77,524,010	49,995,035
6	Regulatory liabilities	44,474,964	517,326,439
7	Other	81,488,862	53,610,193
8	TOTAL Electric (Enter Total of lines 2 thru 7)	541,859,343	836,588,163
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)	541,859,343	836,588,163

Notes

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				
3	TOTAL COMMON STOCK	750,000,000		
4				
5	Preferred Stock (Account 204):			
6	5% Cumulative Preferred	126,533	100.00	
7	Serial Preferred, Cumulative:	3,500,000		
8	6.00% Series		100.00	
9	7.00% Series		100.00	
10	No Par Serial Preferred	16,000,000		
11	TOTAL PREFERRED STOCK	19,626,533		
12				
13	Authorized and Unissued Capital Stock			
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
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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
357,060,915	3,417,945,896					3
						4
						5
						6
						7
5,930	593,000					8
18,046	1,804,600					9
						10
23,976	2,397,600					11
						12
						13
						14
						15
						16
						17
						18
						19
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						22
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						40
						41
						42

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

Berkshire Hathaway Energy Company indirectly owns all of the shares of PacifiCorp's outstanding common stock. Therefore, there is no public market for PacifiCorp's common stock.

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

This class of stock is not redeemable.

Schedule Page: 250 Line No.: 8 Column: d

This series of preferred stock is not redeemable.

Schedule Page: 250 Line No.: 9 Column: d

This series of preferred stock is not redeemable.

Schedule Page: 250 Line No.: 13 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, 2017, 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.

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		
20		
21		
22		
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25		
26		
27		
28		
29		
30		
31		
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39		
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, 2017.

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	41,101,061
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
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21		
22	TOTAL	41,101,061

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	8.470% Series due October 1, 2017	19,609,000	
4	5.65% Series due July 15, 2018	500,000,000	3,067,221
5			905,000 D
6	5.50% Series due January 15, 2019	350,000,000	2,515,793
7			2,292,500 D
8	3.85% Series due June 15, 2021	400,000,000	3,007,139
9			744,000 D
10	2.95% Series due February 1, 2022	350,000,000	2,424,350
11			308,000 D
12	2.95% Series due February 1, 2022	100,000,000	254,129
13			-81,000 P
14	2.95% Series due June 1, 2023	300,000,000	1,859,352
15			900,000 D
16	3.60% Series due April 1, 2024	425,000,000	3,345,164
17			255,000 D
18	3.35% Series due July 1, 2025	250,000,000	2,121,421
19			320,000 D
20	7.70% Series due November 15, 2031	300,000,000	2,874,150
21			864,000 D
22	5.90% Series due August 15, 2034	200,000,000	1,892,365
23			722,000 D
24	5.25% Series due June 15, 2035	300,000,000	2,912,021
25			1,080,000 D
26	6.10% Series due August 1, 2036	350,000,000	2,907,881
27			1,141,000 D
28	5.75% Series due April 1, 2037	600,000,000	589,216
29			24,000 D
30	6.25% Series due October 15, 2037	600,000,000	5,127,281
31			750,000 D
32			
33	TOTAL	7,061,084,000	75,133,578

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
04/15/1992	10/01/2017	04/15/1992	10/01/2017		109,390	3
07/17/2008	07/15/2018	07/17/2008	07/15/2018	500,000,000	28,250,000	4
						5
01/08/2009	01/15/2019	01/08/2009	01/15/2019	350,000,000	19,250,000	6
						7
05/12/2011	06/15/2021	05/12/2011	06/15/2021	400,000,000	15,400,000	8
						9
01/06/2012	02/01/2022	01/06/2012	02/01/2022	350,000,000	10,325,000	10
						11
03/06/2012	02/01/2022	03/06/2012	02/01/2022	100,000,000	2,950,000	12
						13
06/06/2013	06/01/2023	06/06/2013	06/01/2023	300,000,000	8,850,000	14
						15
03/13/2014	04/01/2024	03/13/2014	04/01/2024	425,000,000	15,300,000	16
						17
06/19/2015	07/01/2025	06/19/2015	07/01/2025	250,000,000	8,375,000	18
						19
11/21/2001	11/15/2031	11/21/2001	11/15/2031	300,000,000	23,100,000	20
						21
08/24/2004	08/15/2034	08/24/2004	08/15/2034	200,000,000	11,800,000	22
						23
06/13/2005	06/15/2035	06/13/2005	06/15/2035	300,000,000	15,750,000	24
						25
08/10/2006	08/01/2036	08/10/2006	08/01/2036	350,000,000	21,350,000	26
						27
03/14/2007	04/01/2037	03/14/2007	04/01/2037	600,000,000	34,500,000	28
						29
10/03/2007	10/15/2037	10/03/2007	10/15/2037	600,000,000	37,500,000	30
						31
						32
				7,041,475,000	360,014,410	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	6.35% Series due July 15, 2038	300,000,000	2,290,333
2			1,671,000 D
3	6.00% Series due January 15, 2039	650,000,000	6,134,687
4			6,175,000 D
5	4.10% Series due February 1, 2042	300,000,000	2,737,911
6			987,000 D
7	8.53% Series C Medium-Term Notes due Dec. 16, 2021	15,000,000	115,202
8	8.375% Series C Medium-Term Notes due Dec. 31, 2021	5,000,000	38,400
9	8.26% Series C Medium-Term Notes due Jan. 7, 2022	5,000,000	33,243
10	8.27% Series C Medium-Term Notes due Jan. 10, 2022	4,000,000	30,594
11	8.05% Series E Medium-Term Notes due Sept. 1, 2022	15,000,000	131,471
12	8.07% Series E Medium-Term Notes due Sept. 9, 2022	8,000,000	70,118
13	8.12% Series E Medium-Term Notes due Sept. 9, 2022	50,000,000	438,238
14	8.11% Series E Medium-Term Notes due Sept. 9, 2022	12,000,000	105,177
15	8.05% Series E Medium-Term Notes due Sept. 14, 2022	10,000,000	87,648
16	8.08% Series E Medium-Term Notes due Oct. 14, 2022	26,000,000	208,198
17	8.08% Series E Medium-Term Notes due Oct. 14, 2022	25,000,000	200,190
18	8.23% Series E Medium-Term Notes due Jan. 20, 2023	5,000,000	37,914
19	8.23% Series E Medium-Term Notes due Jan. 20, 2023	4,000,000	30,331
20			-81,560 P
21	7.26% Series F Medium-Term Notes due July 21, 2023	27,000,000	246,981
22	7.26% Series F Medium-Term Notes due July 21, 2023	11,000,000	100,622
23	7.23% Series F Medium-Term Notes due Aug. 16, 2023	15,000,000	137,211
24	7.24% Series F Medium-Term Notes due Aug. 16, 2023	30,000,000	274,423
25	6.75% Series F Medium-Term Notes due Sept. 14, 2023	5,000,000	38,250
26	6.75% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
27	6.72% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
28	6.75% Series F Medium-Term Notes due Oct. 26, 2023	20,000,000	152,326
29	6.75% Series F Medium-Term Notes due Oct. 26, 2023	16,000,000	121,861
30	6.75% Series F Medium-Term Notes due Oct. 26, 2023	12,000,000	91,396
31	6.71% Series G Medium-Term Notes due Jan. 15, 2026	100,000,000	904,467
32	Subtotal - First Mortgage Bonds	6,718,609,000	68,661,215
33	TOTAL	7,061,084,000	75,133,578

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
07/17/2008	07/15/2038	07/17/2008	07/15/2038	300,000,000	19,050,000	1
						2
01/08/2009	01/15/2039	01/08/2009	01/15/2039	650,000,000	39,000,000	3
						4
01/06/2012	02/01/2042	01/06/2012	02/01/2042	300,000,000	12,300,000	5
						6
12/16/1991	12/16/2021	12/16/1991	12/16/2021	15,000,000	1,279,500	7
12/31/1991	12/31/2021	12/31/1991	12/31/2021	5,000,000	418,750	8
01/08/1992	01/07/2022	01/08/1992	01/07/2022	5,000,000	413,000	9
01/09/1992	01/10/2022	01/09/1992	01/10/2022	4,000,000	330,800	10
09/18/1992	09/01/2022	09/18/1992	09/01/2022	15,000,000	1,207,500	11
09/09/1992	09/09/2022	09/09/1992	09/09/2022	8,000,000	645,600	12
09/11/1992	09/09/2022	09/11/1992	09/09/2022	50,000,000	4,060,000	13
09/11/1992	09/09/2022	09/11/1992	09/09/2022	12,000,000	973,200	14
09/14/1992	09/14/2022	09/14/1992	09/14/2022	10,000,000	805,000	15
10/15/1992	10/14/2022	10/15/1992	10/14/2022	26,000,000	2,100,800	16
10/15/1992	10/14/2022	10/15/1992	10/14/2022	25,000,000	2,020,000	17
01/20/1993	01/20/2023	01/20/1993	01/20/2023	5,000,000	411,500	18
01/29/1993	01/20/2023	01/29/1993	01/20/2023	4,000,000	329,200	19
						20
07/22/1993	07/21/2023	07/22/1993	07/21/2023	27,000,000	1,960,200	21
07/22/1993	07/21/2023	07/22/1993	07/21/2023	11,000,000	798,600	22
08/16/1993	08/16/2023	08/16/1993	08/16/2023	15,000,000	1,084,500	23
08/16/1993	08/16/2023	08/16/1993	08/16/2023	30,000,000	2,172,000	24
09/14/1993	09/14/2023	09/14/1993	09/14/2023	5,000,000	337,500	25
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	135,000	26
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	134,400	27
10/26/1993	10/26/2023	10/26/1993	10/26/2023	20,000,000	1,350,000	28
10/26/1993	10/26/2023	10/26/1993	10/26/2023	16,000,000	1,080,000	29
10/26/1993	10/26/2023	10/26/1993	10/26/2023	12,000,000	810,000	30
01/23/1996	01/15/2026	01/23/1996	01/15/2026	100,000,000	6,710,000	31
				6,699,000,000	354,726,440	32
				7,041,475,000	360,014,410	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 2017/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Pollution Control Obligations - Secured by Pledged First Mortgage Bonds:		
2	Poll Ctrl Rev Refunding Bonds, Sweetwater County, WY, Series 1994	21,260,000	510,479
3	Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1994	8,190,000	209,777
4	Poll Ctrl Rev Refunding Bonds, Emery County, UT, Series 1994	121,940,000	3,274,246
5	Poll Ctrl Rev Refunding Bonds, Lincoln County, WY, Series 1994	15,060,000	422,858
6	Environ. Imprvmnt Rev Bonds, Converse County, WY, Series 1995	5,300,000	132,043
7	Environ. Imprvmnt Rev Bonds, Lincoln County, WY, Series 1995	22,000,000	404,262
8	Subtotal Pollution Control Obligations - Secured by Pledged First Mortgage Bonds	193,750,000	4,953,665
9			
10	Pollution Control Obligations - Unsecured:		
11	Poll Ctrl Rev Refndng Bonds, City of Forsyth, MT, Series 1988	45,000,000	380,198
12	Poll Ctrl Rev Refndng Bonds, City of Gillette, WY, Ser. 1988	41,200,000	351,905
13	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992A	9,335,000	167,524
14	Poll Ctrl Rev Refndng Bonds, Converse County, WY, Series 1992	22,485,000	242,163
15	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992B	6,305,000	151,908
16	Environ. Imprvmnt Rev Bonds, Sweetwater County, WY, Series 1995	24,400,000	225,000
17	Subtotal - Pollution Control Obligations - Unsecured	148,725,000	1,518,698
18			
19	TOTAL ACCOUNT 221	7,061,084,000	75,133,578
20			
21	Reacquired Bonds: (Account 222)		
22			
23	Advances from Associated Companies: (Account 223)		
24			
25	Other Long-Term Debt: (Account 224)		
26			
27	Long-Term Debt Authorized but Unissued		
28			
29			
30			
31			
32			
33	TOTAL	7,061,084,000	75,133,578

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 2017/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
11/17/1994	11/01/2024	11/17/1994	11/01/2024	21,260,000	370,255	2
11/17/1994	11/01/2024	11/17/1994	11/01/2024	8,190,000	105,793	3
11/17/1994	11/01/2024	11/17/1994	11/01/2024	121,940,000	2,008,425	4
11/17/1994	11/01/2024	11/17/1994	11/01/2024	15,060,000	210,278	5
11/17/1995	11/01/2025	11/17/1995	11/01/2025	5,300,000	67,418	6
11/17/1995	11/01/2025	11/17/1995	11/01/2025	22,000,000	303,544	7
				193,750,000	3,065,713	8
						9
						10
01/01/1988	01/01/2018	01/01/1988	01/01/2018	45,000,000	731,560	11
01/01/1988	01/01/2018	01/01/1988	01/01/2018	41,200,000	503,434	12
09/29/1992	12/01/2020	09/29/1992	12/01/2020	9,335,000	144,872	13
09/29/1992	12/01/2020	09/29/1992	12/01/2020	22,485,000	343,610	14
09/29/1992	12/01/2020	09/29/1992	12/01/2020	6,305,000	98,853	15
12/14/1995	11/01/2025	12/14/1995	11/01/2025	24,400,000	399,928	16
				148,725,000	2,222,257	17
						18
				7,041,475,000	360,014,410	19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				7,041,475,000	360,014,410	33

Schedule Page: 256.2 Line No.: 19 Column: h

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

Schedule Page: 256.2 Line No.: 19 Column: i

Account represents interest expense charge 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 during the year.

Schedule Page: 256.2 Line No.: 27 Column: a

PacifiCorp currently has an effective shelf registration statement filed with the United States Securities and Exchange Commission on Form S-3 to issue up to $1.325 billion additional first mortgage bonds through January 2019.

For authorization for the issuance of long-term debt ($1.575 billion authorized; $1.325 billion available as of December 31, 2017), refer to Item 6 in Important Changes During the Year, in this Form No. 1.

Authorization to borrow the proceeds of pollution control revenue refunding bonds issued by the counties of Emery, Utah; Carbon, Utah; Converse, Wyoming; Lincoln, Wyoming; Sweetwater, Wyoming; and Moffat, Colorado (total of $300,345,000 authorized and $166,450,000 available as of December 31, 2017) and authorization to borrow the proceeds of new pollution control revenue bonds issued 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 (total of $150,000,000 authorized and available as of December 31, 2017) is as follows:

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

- Oregon Public Utility Commission - Docket No. UF-4250, Order No. 08-382, dated July 29, 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 2017/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)	768,437,084
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8	Other	101,534,087
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13	Other	1,357,197,174
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18	Other	35,018,088
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25	Other	1,317,017,347
26	State Tax Deductions	-39,390,670
27	Federal Tax Net Income	835,742,240
28	Show Computation of Tax:	
29		
30	Federal Income Tax at 35.00%	292,509,784
31	Provision to Return Adjustment	-87,781
32	Tax Reserve Changes	2,006,395
33	Renewable Energy Production Tax Credits	-55,436,712
34		
35	Federal Income Tax Accrual	238,991,686
36		
37		
38		
39		
40		
41		
42		
43		
44		

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

Particulars (Details)	Amounts
Contribution in Aid of Construction	60,291,631
MCI F.O.G. Wire Lease	186
Regulatory Asset - Alt Rate for Energy Program (CARE) - CA	136,064
Regulatory Asset - REC Sales Deferral - UT	2,682,611
Regulatory Asset - REC Sales Deferral - WA	703,217
Regulatory Asset - WA Colstrip #3	52,188
Regulatory Liability - Deferred Excess NPC - OR	4,748,273
Regulatory Liability - Deferred Excess NPC - WA	9,556,068
Regulatory Liability - Deferred Excess NPC - WY	4,712,924
Regulatory Liability - Depreciation Decrease - OR	1,120,646
Regulatory Liability - GHG Allowance Revenues - CA	1,926,914
Regulatory Liability - OR Direct Access 5 Year Opt Out	1,418,592
Regulatory Liability - WA Accel Depreciation	11,620,930
Reimbursements	1,759,239
Transmission Service Deposits	151,021
Trapper Mining Stock Basis	629,541
Unearned Joint Use Pole Contact Revenue	24,042
Total	$101,534,087

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

Particulars (Details)	Amounts
Fed/State Tax Expense	355,248,531
Fed/State Tax Expense - Interest	880,395
50% Meals and Entertainment	894,029
Accrued Bonus	1,052,870
Accrued Final Reclamation	357,348
Accrued Retention	1,600,000
Accrued Royalties	1,916,590
Accrued Severance	410,144
Avoided Costs	15,423,326
Bear River Settlement Agreement	48,152
Book Depreciation	780,380,951
Book Depreciation Allocated to Medicare and M&E	82,101
Capitalized Labor and Benefit Costs	23,716,914
Coal Pile Inventory Adjustment	308,305
Company Plane - Nonbusiness Use	17,363
CWIP Reserve	2,789,783
Deferred Compensation	1,105,820
Deferred Revenue - Other	56,495
Environmental Liability - Regulated	26,153,634
Fuel Cost Adjustment	2,099,290
Hermiston Swap	171,693
Hydro Relicensing Obligation	1,328,501
Income Tax Interest	1,988
Insurance Reserve	31,055,822
Joseph Settlement	137,381
Lewis River Settlement Agreement	39,595
Lobbying Expenses	1,457,587
LT Incentive Plan	5,145,000
Medicare Subsidy	7,615,171
Penalties	18,975
Prepaid Membership Fees	39,163
Prepaid Taxes - UPSC	15,566
Prepaid Water Rights	53,750
Property Insurance Reserve - ID	107,011
Property Insurance Reserve - UT	1,908,266

Property Insurance Reserve - WY	332,605
Regulatory Asset - Carbon Plant Decomm/Inventory	736
Regulatory Asset - Carbon Unrecovered Plant - ID	478,639
Regulatory Asset - Carbon Unrecovered Plant - UT	3,444,641
Regulatory Asset - Carbon Unrecovered Plant - WY	1,158,188
Regulatory Asset - Catastrophic Event Deferral - CA	197,343
Regulatory Asset - Cholla Plant Transaction Costs	654,747
Regulatory Asset - Deferred Excess NPC - CA	1,250,748
Regulatory Asset - Deferred Excess NPC - ID	2,895,668
Regulatory Asset - Deferred Excess NPC - UT	5,305,798
Regulatory Asset - Deferred Excess NPC - WY '09 & After	2,885,525
Regulatory Asset - Deferred Independent Evaluator Costs - UT	247,437
Regulatory Asset - Depreciation Increase - ID	870,500
Regulatory Asset - Depreciation Increase - UT	128,043
Regulatory Asset - Depreciation Increase - WY	442,191
Regulatory Asset - DSM Balance Reclass	2,101,754
Regulatory Asset - Environmental Costs - WA	320,777
Regulatory Asset - FAS 158 Pension Liability	15,184,913
Regulatory Asset - Goodnoe Hills Settlement - WY	21,250
Regulatory Asset - Klamath Hydroelectric Relicensing Costs - UT	3,593,040
Regulatory Asset - Lake Side Settlement - WY	27,331
Regulatory Asset - Liquidated Damages - UT	35,000
Regulatory Asset - Liquidated Damages - WY	5,708
Regulatory Asset - Pension MMT - UT	283,176
Regulatory Asset - Post Merger Loss - Reacquired Debt	639,595
Regulatory Asset - Postemployment Costs	852,110
Regulatory Asset - Postretirement MMT - CA	17,488
Regulatory Asset - Postretirement MMT - OR	193,035
Regulatory Asset - Postretirement MMT - UT	278,648
Regulatory Asset - Postretirement Settlement Loss	330,832
Regulatory Asset - Postretirement Settlement Loss CC - WY	22,244
Regulatory Asset - Powerdale Decommissioning - ID	26,216
Regulatory Asset - Preferred Stock Redemption - WY	28,442
Regulatory Asset - Preferred Stock Redemption Loss - UT	82,531
Regulatory Asset - Preferred Stock Redemption Loss - WA	13,318
Regulatory Asset - RPS Compliance Purchases	339,537
Regulatory Asset - Solar Feed-In Tariff Deferral - OR	217,233
Regulatory Asset - STEP Pilot Program Balance Account - UT	5,487,979
Regulatory Asset - Utah Mine Disposition	27,638,620
Regulatory Liability - 50% Bonus Tax Depreciation - UT	999,764
Regulatory Liability - ARO/Reg Diff - Trojan - WA Portion	1,349
Regulatory Liability - Blue Sky - CA	48,964
Regulatory Liability - Blue Sky - ID	44,044
Regulatory Liability - Blue Sky - UT	1,780,835
Regulatory Liability - Blue Sky - WA	7,659
Regulatory Liability - Contra-Carbon Decommissioning - WY	535,226
Regulatory Liability - OR Energy Conservation Charge	485,185
Regulatory Liability - Solar Incentive Program - UT	4,036,807
Regulatory Liability - WA Decoupling Mechanism	1,254,992
Reserve for Bad Debts	2,843,233
TGS Buyout	15,474
Trapper Mine Contract Obligation	164,855
Intercompany Adjustment	3,307,691
Total	$1,357,197,174

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

Particulars (Details)	Amounts
Book Fixed Asset Gain/Loss	(271,940)
Deferred Revenue - Lease Incentives	(106,311)
Dividend Received Deduction - Deferred Compensation	(225,137)
Investment Gain/Loss - Tax	(2,692)
Officer's Life Insurance	(7,951,699)
Regulatory Asset - BPA Balancing Account - OR	(2,780,009)
Regulatory Asset - Sale of REC - OR	(301,243)
Regulatory Asset - Sale of REC - WY	(447,138)
Regulatory Liability - BPA Balancing Account - ID	(46,617)
Regulatory Liability - BPA Balancing Account - WA	(532,201)
Regulatory Liability - Deferred Excess NPC - UT	(840,716)
Regulatory Liability - DSM Balance Reclass	(2,101,754)
Regulatory Liability - Sale of REC - OR	(34,025)
Regulatory Liability - Sale of REC - UT	(408,173)
Regulatory Liability - Sale of REC - WY	(523,321)
Regulatory Liability - UT Home Energy Lifeline	(3,316)
Regulatory Liability - WA Low Energy Program	(627,515)
Equity Earnings in Subsidiaries	(17,814,281)
Total	$(35,018,088)

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

Particulars (Details)	Amounts
Accrued Vacation	(53,978)
Amortization NOPAs 99-00 RAR	(50,796)
Basis Intangible Difference	(152,254)
Capitalized Depreciation	(5,236,210)
Charitable Contribution - Property	(263,959)
Cholla SHL NOPA (Lease Amortization)	(269,058)
Contra Receivable from Joint Owners	(2,766,271)
Cost of Removal	(44,483,613)
Debt AFUDC	(11,196,760)
Deferred Compensation Mark to Market Gain/Loss - Income Statement	(876,952)
Deseret Settlement Receivable	(120,560)
Environmental Liability - Non-Regulated	(127,002)
Equity AFUDC - Temp	(19,840,730)
FAS 112 Book Reserve - Postemployment Benefits	(3,359,967)
FAS 158 Pension Liability	(74,939,966)
FAS 158 Postretirement Liability	(5,734,032)
FAS 158 SERP Liability	(1,265,035)
Federal Tax Depreciation	(859,465,672)
Federal Tax Fixed Asset Gain/Loss	(7,285,105)
Injuries & Damages Accrual - Cash Basis	(23,871,221)
Injuries & Damages Reserve - OR	(1,236,765)
Inventory Reserve	(1,082,565)
LT Incentive Plan Mark to Market Gain/Loss - Income Statement	(1,022,889)
Miscellaneous Current and Accrued Liability	(1,503,880)
N Umpqua Settlement Agreement	(456,258)
Non-deductible Postretirement Costs	(7,615,170)
Oregon Regulatory Asset/Regulatory Liability Consolidation	(1,119)
Pension/Retirement Accrual	(76,916)
Pre-1943 Preferred Stock Dividend - Deduction	(64,761)
Prepaid Aircraft Maintenance	(60,994)
Prepaid Taxes - IPUC	(65,879)
Prepaid Taxes - OPUC	(72,831)
Prepaid Taxes - Property Taxes	(265,663)
Qualified Production Activities Deduction	(34,219,097)
Regulatory Asset - Asset Sales Balancing Account - OR	(40,068)

Regulatory Asset - CA Mobile Home Park Conversion	(63,552)
Regulatory Asset - Cholla Plant Transaction Costs - ID	(19,233)
Regulatory Asset - Cholla Plant Transaction Costs - OR	(31,390)
Regulatory Asset - Cholla Plant Transaction Costs - WA	(56,588)
Regulatory Asset - Contra Pension MMT & CTG - CA	(93,807)
Regulatory Asset - Contra Pension MMT & CTG - OR	(1,021,761)
Regulatory Asset - Contra Pension CTG	(1,640,983)
Regulatory Asset - Deferred Intervenor Funding Grants - CA	(414)
Regulatory Asset - Deferred Intervenor Funding Grants - OR	(124,595)
Regulatory Asset - Deferred Overburden Costs - ID	(93,048)
Regulatory Asset - Deferred Overburden Costs - WY	(262,012)
Regulatory Asset - DSM	(5,145,040)
Regulatory Asset - Environmental Costs	(30,171,929)
Regulatory Asset - FAS 158 Postretirement Liability	(6,680,000)
Regulatory Asset - Postretirement Settlement Loss CC - UT	(372,012)
Regulatory Asset - Protocol - MSP - Deferral - UT	(4,400,000)
Regulatory Asset - Protocol - MSP - Deferral - WY	(799,998)
Regulatory Asset - Solar Incentive Program - UT	(5,487,979)
Regulatory Asset - UT Subscriber Solar Program	(239,016)
Regulatory Asset - Utah Mine Disposition	(17,125,201)
Regulatory Liability - Blue Sky - OR	(408,301)
Regulatory Liability - Blue Sky - WY	(132,077)
Regulatory Liability - Energy Savings Assistance - CA	(177,701)
Regulatory Liability - Property Insurance Reserve - OR	(5,832,759)
Regulatory Liability - Solar Feed-in Tariff Deferral - CA	(129,700)
Regulatory Liability - Trojan Decommissioning	(29,754)
Repairs Deduction	(126,756,921)
Rogue River - Habitat Enhancement Liability	(58,715)
Tax Depletion - SRC	(29,327)
Wasatch Workers Compensation Reserve	(187,538)
Western Coal Carrier Retiree Medical Accrual	(302,000)
Total	$(1,317,017,347)

Schedule Page: 261 Line No.: 35 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 Company ("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:
ABA Holding, LLC
ABA Management, L.L.C.
Alamo 6 Solar Holdings, LLC
Alamo 6, LLC
Alaska Gas Transmission Company, LLC
Allie Beth Allman Real Estate, Ltd
Apex Home Maintenance, LLC
Arizona HomeServices, LLC
Berkshire Hathaway Energy Company
BG Energy Holding Company LLC
BHE AC Holding, LLC
BHE America Transco, LLC
BHE California Utility Holdco, LLC
BHE Canada LLC
BHE Geothermal, LLC
BHE Hydro, LLC
BHE Midcontinent Transmission Holdings LLC
BHE Renewables, LLC
BHE Solar, LLC
BHE Southwest Transmission Holdings 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
BHER Santa Rita Holdings, LLC
BHES CSG Holdings, LLC

BHH Affiliates, LLC
BHH KC Real Estate, LLC
Big Spring Pipeline Company
Bishop Hill Energy II, LLC
Bishop Hill II Holdings, LLC
Bon Air/Long & Foster Title Agency, LLC
BRER Affiliates, LLC
BRER Real Estate Services, LLC
CalEnergy Company, Inc.
CalEnergy Generation Operating Company
CalEnergy International Services, Inc.
CalEnergy Minerals LLC
CalEnergy Operating Corporation
CalEnergy Pacific Holdings Corp
California Energy Development Corporation
California Energy Management Company
California Energy Yuma Corporation
California Title Company
Capitol Title Company
CBSHome Commercial, LLC
CBSHome Real Estate Company
CBSHome Real Estate of Iowa, Inc.
CE Black Rock Holdings LLC
CE Butte Energy Holdings LLC
CE Butte Energy LLC
CE Electric (NY), Inc.
CE Gen Oil Company
CE Gen Pipeline Corporation
CE Gen Power Corporation
CE Generation LLC
CE Geothermal, Inc.
CE International Investments, Inc.
CE Leathers Company
CE Obsidian Energy LLC
CE Obsidian Holding LLC
CE Red Island Energy Holdings LLC
CE Red Island Energy LLC
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
Champion Realty, Inc.
Chancellor Title Services, Inc.
Columbia Title of Florida, Inc.
Commonsite, Inc.
Conejo Energy Company
Connecticut Referral Group, L.L.C.
Cordova Energy Company, LLC
Cordova Funding Corporation
CTHM, L.L.C.
CTRE, L.L.C.
Dakota Dunes Development Company
DCCO, Inc.
Del Ranch Company
Denver Rental, LLC
Desert Valley Company
DG-SB Project Holdings, LLC
Edina Financial Services, Inc.
Edina Realty Insurance, LLC
Edina Realty Referral Network, Inc.
Edina Realty Title, Inc.
Edina Realty, Inc.
Elmore Company
Esslinger-Wooten-Maxwell, Inc.
E-W-M Referral Services, Inc.
F&R/T LLC
Falcon Power Operating Company
FFR, Inc.
First Network Realty, Inc.
First Realty Group, Inc.
First Realty, Ltd
First Reserve Insurance, Inc.
First Weber Illinois, LLC
First Weber, Inc.
Florida Network LLC
Florida Network Property Management, LLC
For Rent, Inc.
FR Kingfisher Holdings II, LLC
FR Mariah Holdings II, LLC
FRTC, LLC
FSRI Holdings, Inc.
Geronimo Community Solar Gardens Holding Company, LLC
Geronimo Community Solar Gardens, LLC
Gilbraltar Title Services, LLC
GPSF-B
Grande Prairie Wind, LLC
Greystone Partners of Virginia, 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
Home Capital Group Inc.
Home Service Connections, LLC
Home Trust Company
HomeServices Insurance Agency, LLC
HomeServices Insurance, Inc.
HomeServices Lending, LLC
HomeServices MidAtlantic, LLC
HomeServices Northeast, LLC
HomeServices of Alabama, Inc.
HomeServices of America, Inc.
HomeServices of California, Inc.
HomeServices of Colorado, LLC
HomeServices of Connecticut, LLC
HomeServices of Florida, Inc.
HomeServices of Georgia, LLC
HomeServices of Illinois Holdings, LLC
HomeServices of Iowa, Inc.
HomeServices of Kentucky, Inc.
HomeServices of MOKAN, LLC
HomeServices of Nebraska, Inc.
HomeServices of New Jersey, LLC
HomeServices of New York, LLC
HomeServices of Oregon, LLC
HomeServices of Texas, LLC
HomeServices of the Carolinas, Inc.
HomeServices of Washington, LLC
HomeServices of Wisconsin, LLC
HomeServices Referral Network, LLC
HomeServices Relocation, LLC
HomeSvc of IL LLC d/b/a Koenig & Strey GMAC RE
Houlihan Lawrence Affiliates, LLC
Houlihan Lawrence Commercial Real Estate Group, LLC
Houlihan/Lawrence Inc.
HS Franchise Holding, LLC
HSGA Real Estate Group, L.L.C.
HSW Affiliates Holding, LLC
Huff Commercial Group, LLC
Huff-Drees Realty, Inc.
IES Holding II LLC
IMO Company, Inc.
Imperial Magma 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
Jumbo Road Holdings, LLC
Kansas City Title, Inc.
Kelly Associates Real Estate, Inc.
Kelly Associates Referral Network LLC
Kentucky Residential Referral, LLC
Kentwood City Properties, LLC
Kentwood Commercial, LLC
Kentwood DTC, LLC
Kentwood Real Estate Services, LLC
Kentwood, LLC
Kern River Funding Corporation
Keystone Partners, LLC
KR Acquisition 1, LLC
KR Acquisition 2, LLC
KR Holding, LLC
L&F/Fonville Morisey Real Estate, LLC
L&F/Fonville Morisey Title, LLC
Lands of Sierra, Inc.
Larabee School of Real Estate & Insurance, Inc.
LFFS, Inc.
Long & Foster Closing Services, LLC
Long & Foster Institute of Real Estate, Inc.
Long & Foster Insurance Agency, Inc.
Long & Foster Licensing Company, Inc.
Long & Foster Mortgage Ventures, Inc.
Long & Foster Real Estate Ventures, Inc.
Long & Foster Real Estate, Inc.
Long & Foster Settlement Services, LLC
M & M Ranch Acquisition Company LLC
M & M Ranch Holding Company LLC
Magma Land Company I
Magma Power Company
Marshall Wind Energy Holdings, LLC
Marshall Wind Energy, LLC
MEC Construction Services Company
MEHC Insurance Services Ltd.
MEHC Investment, Inc.
MEHC Merger Sub Inc.
Merlin Realty Technologies, LLC
MES Holding, LLC
Metro Referral Associates, Inc.
MHC Investment Company
MHC, Inc.
Mid-America Referral Network, Inc.
MidAmerican Central California Transco LLC
MidAmerican Energy Company
MidAmerican Energy Machining Services LLC
MidAmerican Energy Services, LLC
MidAmerican Funding, LLC
MidAmerican Geothermal Development Corp
MidAmerican Wind Tax Equity Holdings, LLC
Midland Escrow Services, Inc.
Mid-States Title Insurance Agency, Inc.
Midwest Capital Group, Inc.
Midwest Power Transmission Arkansas LLC
Midwest Power Transmission Iowa LLC
Midwest Realty Ventures, LLC
MTL Canyon Holdings LLC
Nebraska Land Title & Abstract Company
Nebraska Referral, Inc.
Nevada Electric Investment Company
Nevada Power Company d/b/a NV Energy, Inc.
New Jersey Realty Services, LLC
Niguel Energy Company
NNGC Acquisition LLC
Norcon Holdings, Inc.
North Country Gas Pipeline Corp.
Northern Consolidated Power, Inc.
Northern Natural Gas Company
Novatus Texas Holdings, LLC
NRS Referral Services, LLC
NV Energy, Inc.
NVE Holdings, LLC
NVE Insurance Co, Inc.
NW Referral Services, LLC
O.E. Merger Sub II, LLC
O.E. Merger Sub III, LLC
O.E. Merger Sub Inc.
PCG Agencies, Inc.
PCRE, L.L.C.
Pearl Solar Holding, LLC
Pearl Solar, LLC
Pickford Escrow Company, Inc.
Pickford Real Estate, Inc.
Pickford Services Company, Inc.
Pilot Butte, LLC
Pinon Pine Corporation
Pinon Pine Investment Company
Pinyon Pines I Holding Company, LLC
Pinyon Pines II Holding Company, LLC
Pinyon Pines Projects Holding, LLC
Pinyon Pines Wind I, LLC
Pinyon Pines Wind II, LLC
PNW Referral, LLC
Preferred Carolinas Realty, Inc.
Preferred Carolinas Title Agency, LLC
Premier Service Abstract, LLC
Priority Title Corporation
Professional Referral Organization, Inc.
Prosperity Home Mortgage, LLC
Pru-One, Inc.
Quad Cities Energy Company
Real Estate Knowledge Services, L.L.C.
Real Estate Links, LLC
Real Estate Referral Network, Inc.
Real Living Real Estate, LLC
Reece & Nichols Alliance, Inc.
Reece & Nichols Insurance, LLC
Reece & Nichols Realtors, Inc.
Reece Commercial, Inc.
Referral Associates of Georgia, LLC
Referral Network of Gloria Nilson, LLC
Referral Network of NY/NJ, LLC
Relocation Advantage Partners, LLC
RGS Settlements of Pennsylvania, LLC
RGS Title of Baltimore, LLC
RGS Title, LLC
RHL Referral Company, LLC
Roberts Brothers, Inc.
Roy H. Long Realty Company, Inc.
S.W. Hydro, Inc.
Sage Title Group, LLC
Salton Sea Brine Processing Company
Salton Sea Funding Corporation
Salton Sea Minerals 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.
SCS Realty Investment Group, LLC
SECI Holdings, Inc.
Settlement Professionals, LLC
Sierra Gas Holding Company
Sierra Pacific Power Company d/b/a NV Energy, Inc.
Solar San Antonio LLC
Solar Star 3, LLC
Solar Star California XIX, LLC
Solar Star California XX, LLC

Solar Star Funding, LLC
Solar Star Projects Holdings, LLC
Southwest Relocation, LLC
SSC XIX, LLC
SSC XX, LLC
The Escrow Firm
The Kentwood Company at Cherry Creek, LLC
The Long & Foster Companies, Inc.
The Referral Company
Thoroughbred Title Services, LLC
TIAC LLC
TitleSouth, LLC
TLTC LLC
Topaz Solar Farms, LLC
TPZ Holding, LLC
TRMC LLC
Two Rivers, Inc.
TX Jumbo Road Wind, LLC
VPC Geothermal LLC
Vulcan Power Company
Vulcan/BN Geothermal Power Company
Wailuku Holding Company LLC
Wailuku Investment LLC
Wailuku River Hydroelectric Power Co, Inc.
Walker Jackson Mortgage Corporation
Walnut Ridge Wind, LLC
Weathervane Referral Network, Inc.

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:

121 Acquisition Co., LLC
121 Development, Inc.
21 SPC, Inc.
2150 Cobb Development, Inc.
21st Communities, Inc.
21st Mortgage Corporation
2701 Camelback Development, Inc.
3Wire Group Inc.
6991 Development, Inc.
A.E. Company, Inc.
AAA Aircraft Supply
Accra Manufacturing Inc.
Accurate Installations, Inc.
Acme Brick Company
Acme Brick DFW, Inc.
Acme Brick Sales Company
Acme Brick Tile & Stone, Inc.
Acme Building Brands, Inc.
Acme Investment Company
Acme Management Company
Acme Ochs Brick and Stone, Inc.
Acme Services Company, L.P.
Active Organics, Inc.
Adalet/Scott Fetzer Company
AEG Processing Center No. 35, Inc.
AEG Processing Center No. 58, Inc.
Aerocraft Heat Treating Co., Inc.
Aerospace Dynamics International, Inc.
Affiliated Agency Operations Co.
Affordable Housing Partners, Inc.
Aipcf V Chi Blocker, Inc.
AJF Warehouse Distributors, Inc.
AL/TEX Homes, Inc.
Albacor Shipping (USA) Inc.
Albecca, Inc.
Alexander Road Insurance Agency, Inc.
Alpha Cargo Motor Express, Inc.
Alu-Forge, Inc.
American All Risk Insurance Services, Inc.
American Commercial Claims Administrators, Inc.
American Dairy Queen Corporation
American Employers Group, Inc.
AmGUARD Insurance Company
Andrews Laser Works Corporation
Applied Group Insurance Holdings, Inc.
Applied Investigations Inc.
Applied Logistics, Inc.
Applied Premium Finance, Inc.
Applied Processing Center No. 60, Inc.
Applied Risk Services of New York, Inc.
Applied Risk Services, Inc.
Applied Underwriters Captive Risk Assurance Company, Inc.
Applied Underwriters, Inc.
Arcturus Manufacturing Corporation
Artform International Inc.
Astrex Electronics, Inc.
Astrex Holding Company
Atlanta International Insurance Company
Atlantic Precision, Inc.
AU Captive Risk Assurance Co.
AU Holding Company, Inc.
Avibank Manufacturing, Inc.
Baroness Small Estates, Inc.
Bayport Systems, Inc.
BCC Development, Inc.
Ben Bridge Jeweler, Inc.
Benjamin Moore & Co.
Benson Industries, Inc.
Benson, Ltd.
Berkshire Hathaway Assurance Corporation
Berkshire Hathaway Automotive Inc.
Berkshire Hathaway Credit Corporation
Berkshire Hathaway Direct Insurance Company
Berkshire Hathaway Finance Corporation
Berkshire Hathaway Global Insurance Services, LLC
Berkshire Hathaway Homestate Insurance Company
Berkshire Hathaway Life Insurance Company of Nebraska
Berkshire Hathaway Specialty Concierge, LLC
Berkshire Hathaway Specialty Insurance Company
Berkshire Indemnity Group Inc.
BH Columbia Inc.
BH Credit LLC
BH Finance, Inc.
BH Media Group Holdings, Inc.
BH Media Group, Inc.
BH Shoe Holdings, Inc.
BH, LLC
BHA Real Estate Holdings, LLC
BHG Life Insurance Company
BHG Structured Settlements, Inc.
BHSF, Inc.
Blue Chip Stamps, Inc.
BN Leasing Corporation
BNJ NetJets, Inc.
BNSF Communications, Inc.
BNSF Logistics International, Inc.
BNSF Railway Company
BNSF Railway International Services, Inc.
BNSF Spectrum, Inc.
Boat America Corporation
Boat Owners Association of the United States
Boat/U.S, Inc.
Boot Royalty Company
Borrego Holdings, Inc.

Borsheim Jewelry Company, Inc.
BR Agency, Inc.
Brainy Toys, Inc.
Brilliant National Services, Inc.
Brittain Machine Inc.
Brooks Sports, Inc.
Brookwood Insurance Company
BTM Manufacturing LP
BuilderMT, Inc.
Burlington Northern Railroad Holdings, Inc.
Burlington Northern Santa Fe British Columbia, Ltd.
Burlington Northern Santa Fe Insurance Company, Ltd.
Burlington Northern Santa Fe Manitoba, Inc.
Burlington Northern Santa Fe, LLC
Business Wire, Inc.
BWVT Motors, Inc.
C & R Insurance Services, Inc.
Caledonian Alloys Inc.
California Insurance Company
Camp Manufacturing Company
Campbell Hausfeld Holdings. Inc.
Campbell Hausfeld/Scott Fetzer Company
Cannon Equipment LLC
Cannon Muskegon Corporation
Carefree/Scott Fetzer Company
Carlton Forge Works
Cavalier Homes, Inc.
CCC Lonestar LLC
Central States Indemnity Co. of Omaha
Central States of Omaha Companies, Inc.
Charter Brokerage Holdings Corp.
Chatwell, Inc.
Chemtool Incorporated
Chippewa Shoe Company
CJE II
Claims Services, Inc.
Clayton Commercial Buildings, Inc.
Clayton Education Corp.
Clayton Homes, Inc.
Clayton Properties Group II, Inc.
CMH Capital, Inc.
CMH Hodgenville, Inc.
CMH Homes, Inc.
CMH Manufacturing West, Inc.
CMH Manufacturing, Inc.
CMH of KY, Inc.
CMH Parks, Inc.
CMH Services, Inc.
CMH Set and Finish, Inc.
CMH Transport, Inc.
Columbia Insurance Company
Combined Claims Services, Inc.
Commercial Casualty Insurance Company
Commercial General Indemnity, Inc.
Compass Aerospace Northwest Inc.
Complementary Coatings Corporation
Composites Horizons LLC
Consolidated Health Plans Inc.
Continental Divide Insurance Company
Continental Indemnity Company
Cornelius Inc.
Cornelius Renew, Inc.
Cort Business Services Corporation
Courtesy Dealership Property, Inc.
Coverage Dynamics Group, Inc.
CoverYourBusiness.com Inc.
Criterion Insurance Agency
CSI Life Insurance Company
CTB Credit Corp
CTB Inc.
CTB International Corp
CTB IW Inc.
CTB Midwest Inc.
CTB MN Investments
Cubic Designs, Inc.
Cumberland Asset Management, Inc.
Cypress Insurance Company
D.I. Properties Inc.
DAA Development, Inc.
Dairy Queen Corporate Stores, Inc.
Dairy Queen Of Georgia, Inc.
DCI Marketing Inc.
Delta Wholesale Liquors, Inc.
Denver Brick Company
Designed Metal Connections, Inc.
Dickson Testing Co., Inc.
DL Trading Holdings I, Inc.
DQ Funding Corporation
DQ Joint Venture Stores, Inc.
DQ Managed Stores, Inc.
DQ Wholly-Owned Stores, Inc.
DQF, Inc.
DQGC, Inc.
DragonFly Aeronautics LLC
Duracell Distributing Inc.
Duracell Manufacturing Co.
Duracell U.S. Operations Inc.
Dynamic Development, Inc.
EastGUARD Insurance Company
Eco Color Company
Ecodyne Corporation
ELIM/STAFF
Ellis & Watts Global Industries, Inc.
Elm Street Corporation
Empire Distributors of North Carolina, Inc.
Empire Distributors, Inc.
Environment One Corporation
Exacta Aerospace Inc.
Executive Jet Management, Inc.
Exsif Worldwide, Inc.
ExtruMed, Inc.
Faraday Capital Limited
Farrow Machine & Manufacturing Co., Inc.
Fatigue Technology Inc.
FFBH Development, Inc.
Finial Holdings, Inc.
Finial Reinsurance Company
First American Carriers, Inc.
First Berkshire Hathaway Life Insurance Company
FlightSafety Capital Corp.
FlightSafety Development Corp.
FlightSafety International Inc.
FlightSafety New York, Inc.
FlightSafety Properties, Inc.
FlightSafety Services Corporation
Floors, Inc.
Fontaine Commercial Trailer, Inc.
Fontaine Engineered Products, Inc.
Fontaine Fifth Wheel Company
Fontaine Modification Company
Fontaine Spray Suppression Company
Fontaine Trailer Company LLC
Fontaine Truck Equipment Company LLC
Fontana Wood Products, Inc.
Footwear Investment Company
Forest River Financial Services, Inc.
Forest River Holdings, Inc.
Forest River Manufacturing LLC
Forest River, Inc.
Fortner Aerospace Manufacturing Inc.
Freedom Warehouse Corp.
FreightWise, Inc.
Fruit of the Loom Direct, Inc.
Fruit of the Loom Trading Company

Fruit of the Loom, Inc.
Fruit of the Loom, Inc. (Sub)
FTI Manufacturing Inc.
FTL Regional Sales Co., Inc.
Garan Central America Corp.
Garan Incorporated
Garan Manufacturing Corp.
Garan Services Corp
Gateway Underwriters Agency, Inc.
GEICO Advantage Insurance Company
GEICO Casualty Co.
GEICO Choice Insurance Company
GEICO Corporation
GEICO General Insurance Co.
GEICO Indemnity Co.
GEICO Insurance Agency
GEICO Marine Insurance Company
GEICO Products, Inc.
GEICO Secure Insurance Company
Gen Re Intermediaries Corporation
General Re Corporation
General Re Financial Products Corporation
General Re Life Corporation
General Re New England Asset Management
General Reinsurance Corporation
General Star Indemnity Company
General Star Management Company
General Star National Insurance Company
Genesis Insurance Company
Genesis Management and Insurance Services Corporation
Giles Industries, Inc.
Government Employees Financial Corp.
Government Employees Insurance Co.
GRD Holdings Corporation
Greenville Metals Inc.
GUARDco, Inc.
H. H. Brown Shoe Company, Inc.
H.J. Justin & Sons, Inc.
Hackney Ladish Inc.
Halex/Scott Fetzer Company
Hallmark Sweet, Inc.
Hamilton Aviation Inc.
Hawthorn Life International, Ltd.
HDS Redevelopment Corporation
HeatPipe Technology, Inc.
Helicomb International Inc.
Helzberg's Diamond Shops, Inc.
Henley Holdings, LLC
HFWBH Development, Inc.
HG-Power Plant. Inc.
Hohmann & Barnard, Inc.
Homefirst Agency, Inc.
Homemakers Plaza, Inc.
Horizon Wine & Spirits - Chattanooga, Inc.
Horizon Wine & Spirits - Nashville, Inc.
Howell Penncraft, Inc.
Huntington Alloys Corporation
IdeaLife Insurance Company
Illinois Insurance Company
Ingersoll Cutting Tool Company
Innovative Building Products, Inc.
Innovative Coatings Technology Corporation
International American Group Inc.
International Dairy Queen, Inc.
International Insurance Underwriters, Inc.
International Traders, Inc.
Intrepid JSB, Inc.
Ironwood Plastics Inc.
Iscar Metals Inc.
ITTI Group USA Holdings, Inc.
ITTI Investment Holdings, Inc.
J.L. Mining Company
J.S Justin, Inc.
JDS Properties, Inc.
JL Fiber Services Inc.
Johns Manville China, Ltd.
Johns Manville Corporation
Johns Manville, Inc.
Jordan's Furniture, Inc.
Justin Belt Company, Inc.
Justin Boot Company
Justin Brands, Inc.
Justin Industries, Inc.
Kahn Ventures, Inc.
Karmelkorn Shoppes, Inc.
Ken's Spray Equipment, Inc.
Klune Holdings Inc.
Klune Industries Inc.
Kova Solutions, Inc.
L.A. Terminals, Inc.
Leesburg Yarn Mills, Inc.
Lipotec Group Corp.
LJ Aero Holdings Inc.
LJ Synch Holdings Inc.
LMG Ventures, LLC
Lockwood Street Urban Renewal Corporation
Los Angeles Junction Railway Company
LSP Holding, Inc.
Lubricant Investments, Inc.
Lubrizol Advanced Materials China, Inc.
Lubrizol Advanced Materials Gibraltar, Inc.
Lubrizol Advanced Materials Holding Corporation
Lubrizol Advanced Materials International, Inc.
Lubrizol Advanced Materials, Inc.
Lubrizol Enterprises, Inc.
Lubrizol Inter-Americas Corporation
Lubrizol International Management Corporation
Lubrizol Oilfield Solutions, Inc.
Lubrizol Overseas Trading Corporation
Lubrizol Specialty Products, Inc.
M & C Products, Inc.
M&M Tradition Holdings Corp.
Mapletree Transportation, Inc.
Marathon Suspension Systems, Inc.
Marmon Beverage Technologies, Inc.
Marmon Crane Services, Inc.
Marmon Distribution Services, Inc.
Marmon Energy Services Company
Marmon Engineered Components Company
Marmon Foodservice Technologies LLC
Marmon Holdings, Inc.
Marmon Merchandising Holdings, Inc.
Marmon Retail Products, Inc.
Marmon Retail Store Equipment LLC
Marmon Retail Technologies Company
Marmon Tubing, Fittings & Wire Products, Inc.
Marmon Water, Inc.
Marmon Wire & Cable, Inc.
Marmon-Herrington Company
Marquis Jet Holdings, Inc.
Marquis Jet Partners, Inc.
Martin Mills, Inc.
Maryland Ventures, Inc.
McCarty-Hull Cigar Company, Inc.
McLane Beverage Distribution, Inc.
McLane Beverage Holding, Inc.
McLane Company, Inc.
McLane Eastern, Inc.
McLane Express, Inc.
McLane Foodservice, Inc.
McLane Mid-Atlantic, Inc.
McLane Midwest, Inc.
McLane Minnesota, Inc.
McLane New Jersey, Inc.

McLane Ohio, Inc.
McLane Southern, Inc.
McLane Suneast, Inc.
McLane Western, Inc.
McWilliams Forge Company
Meadowbrook Meat Company, Inc.
Medical Protective Finance Corporation
Medical Protective Insurance Services, Inc.
MedPro Group, Inc.
MedPro Risk Retention Services, Inc.
Metalac Fasteners Inc.
Meyn LLC
Midwest Northwest Properties, Inc.
Miller-Sage, Inc.
Mindware Corporation
MiTek Holdings, Inc.
MiTek Industries, Inc.
MiTek USA, Inc.
Montana Retail Properties, Inc.
Morgantown-National Supply, Inc.
Mount Vernon Fire Insurance Company
Mount Vernon Specialty Insurance Company
Mouser Electronics, Inc.
MPP Administrators, Inc.
MPP Co., Inc.
MPP Pipeline Corporation
MS Property Company
MVVT Development, Inc.
MW Wholesale, Inc.
National Fire & Marine Insurance Company
National Indemnity Company
National Indemnity Company of Mid-America
National Indemnity Company of the South
National Liability & Fire Insurance Company
Nationwide Uniforms
Nebraska Furniture Mart, Inc.
NetJets Aviation, Inc.
NetJets Europe Holdings, LLC
NetJets Inc.
NetJets International, Inc.
NetJets Large Aircraft, Inc.
NetJets Sales, Inc.
NetJets Services, Inc.
NetJets U.S., Inc.
NFM of Kansas, Inc.
NFM Services, LLC
NJE Holdings, LLC
NJI Sales, Inc.
Nocona Boot Company
Noranco Manufacturing (USA) Ltd.
NorGUARD Insurance Company
North American Casualty Co.
Northern States Agency, Inc.
Norvell Electronics, Inc.
Noveon Hilton Davis, Inc.
NSS Technologies Inc.
Oak River Insurance Company
Old United Casualty Company
Omaha World-Herald Company
Orange Julius Of America
Oriental Trading Company, Inc.
OTC Brands, Inc.
OTC Direct, Inc.
OTC Worldwide Holdings, Inc.
P Chem, Inc.
Particle Sciences, Inc.
PCC Flow Technologies Holdings Inc.
PCC Flow Technologies Inc.
PCC Rollmet Inc.
PCC Specialty Products Inc.
PCC Structurals Inc.
Penn Coal Land, Inc.
Pennsylvania Insurance Company
Perfection Hy-Test Company
Permaswage Holdings, Inc.
PFVT Development, Inc.
Pine Canyon Land Company
PJR Management, Inc.
Plasma Coating Corporation
Plaza Financial Services Co.
Plaza Resources Co.
PLICO
PLICO Financial, Inc.
PLICO Sponsored Captive Insurance - Cell 1
PLICO Sponsored Captive Insurance Co.
Precision Brand Products, Inc.
Precision Castparts Corp
Precision Founders Inc.
Precision MO Corp
Precision Steel Warehouse - Charlotte
Precision Steel Warehouse, Inc.
Press Forge Company
Primus International Holding Company
Primus International Inc.
Princeton Advertising & Marketing Group, Inc.
Princeton Insurance Company
Princeton Risk Protection, Inc.
Priority One Financial Services, Inc.
Pro Installations, Inc.
Procrane Holdings, Inc.
Professional Datasolutions, Inc.
Progressive Incorporated
Promesa Health, Inc.
Protective Coating Inc.
QS Partners LLC
R.C. Willey Home Furnishings
Rabun Apparel, Inc.
Radnor Specialty Insurance Company
Railserve, Inc.
Railsplitter Holdings Corporation
Rathgibson Holding Co LLC
RCP Investment, Inc.
Red River Providers Association RPG
Redwood Fire and Casualty Insurance Company
RENTCO Trailer Corporation
Resolute Management Inc.
Richline Group, Inc.
Ridgeline Captive Management, Inc.
Ringwalt & Liesche Co.
Rio Grande, Inc.
Roxell USA, Inc.
Royal Cargo Line, Inc.
Rush Air Inc.
Russell Athletic Corporation
Sager Electrical Supply Co. Inc.
Salado Sales, Inc.
Santa Fe Pacific Insurance Company
Santa Fe Pacific Pipeline Holdings, Inc.
Santa Fe Pacific Pipelines, Inc.
Santa Fe Pacific Railroad Company
Schill Loans, Inc.
Schulz Investment Corporation
Schulz U.S.A. Inc.
Scott Fetzer Financial Group, Inc.
ScottCare Corporation
See's Candies, Inc.
Sees Candy Shops, Incorporated
Seventeenth Street Realty, Inc.
SFEG Corp.
SFVT Development, Inc.
Shaw Contract Flooring Services, Inc.
Shaw Diversified Services, Inc.
Shaw Floors, Inc.
Shaw Funding Company

Shaw Industries Group, Inc.
Shaw Industries, Inc.
Shaw International Services, Inc.
Shaw Retail Properties, Inc.
Shaw Transport, Inc.
Shultz Steel Company
SHX Flooring, Inc.
SidePlate Systems, Inc.
Smilemakers Canada Inc.
Smilemakers, Inc.
SN Management, Inc.
Soco West, Inc.
Somerset Services, Inc.
SOS Metals San Diego, LLC
SOS Metals, Inc.
Southern Energy Homes, Inc.
Southwest United Industries Inc.
Special Metals Corporation
Specialized Pipe Services, Inc.
Spectra Contract Flooring Puerto Rico, Inc.
SPS International Investment Company
SPS Technologies LLC
SSP-SiMatrix Inc.
SSS Acquisition Inc.
SSS Acquisition Sub, Corp
Stahl/Scott Fetzer Company
Star Furniture Company
Star Lake Railroad Company
Stern/Leach Company
Strategic Staff Management, Inc.
Stratoflight
SXP CRA-OCTG Inc.
SXP Schulz Xtruded Products LP
Synchronous Aerospace Group
Syrgis Holdings, Inc.
Taegutec Inc.
TBS USA, Inc.
Texas Honing Inc.
Texas Insurance Company
The Ben Bridge Corporation
The BN and SF Railway de Mexico, S.A. de C.V.
The Buffalo News, Inc.
The BVD Licensing Corporation
The Duracell Company Inc.
The Fechheimer Brothers Co.
The Indecor Group, Inc.
The Lubrizol Corporation
The Medical Protective Company
The Pampered Chef, Ltd.
The Scott Fetzer Company
The Wilkins Corporation
The Zia Company
THI Acquisition Inc.
TIMET Asia Inc.
TIMET Real Estate Corporation
Titanium Metals Corporation
TMCA International Inc.
TMI Climate Solutions, Inc.
TOHVT Development, Inc.
Tony Lama Company
Tool-Flo Manufacturing, Inc.
Top Five Club, Inc.
Total Quality Apparel Resources
TPC European Holdings, LTD.
TPC North America, Ltd.
Transco, Inc.
Transportation Technology Services, Inc.
TRH Holding Corp.
Triangle Suspension Systems, Inc.
TSE Brakes, Inc.
TTI, Inc.
Tucker Safety Products, Inc.
TXFM, Inc.
TXVT Development, Inc.
U.S. Investment Corporation
U.S. Underwriters Insurance Co.
UCFS Europe Company
Unified Supply Chain, Inc.
Uni-Form Components Co.
Union Sales, Inc.
Union Tank Car Company
Union Underwear Co., Inc.
Unione Italiana Reinsurance Company of America, Inc.
United Consumer Financial Services Company
United Direct Finance, Inc.
United States Aviation Underwriters, Incorporated
United States Liability Insurance Company
University Swaging Corporation
UTLX Company
Van Enterprises, Inc.
Vanderbilt ABS Corp.
Vanderbilt Mortgage and Finance, Inc.
Vanderbilt Property&Casualty Insurance Co., Ltd.
Vanderbilt SPC, Inc.
Vanity Fair, Inc.
Veritas Insurance Group, Inc.
Vesta Funding, Inc.
Vesta Intermediate Funding, Inc.
VFI-Mexico, Inc.
Vision Retailing, Inc.
VNDR Development, Inc.
VT Insurance Acquisition Sub Inc.
Warwick Chemicals USA, Inc.
Wayne/Scott Fetzer Company
Weaver Manufacturing Inc.
Webb Wheel Products, Inc.
Western Builders Supply, Inc.
Western Fruit Express Company
Western/Scott Fetzer Company
WestGUARD Insurance Company
Whittaker, Clark & Daniels, Inc.
WMC Corp.
World Book Encyclopedia, Inc.
World Book, Inc.
World Book/Scott Fetzer Company
World Investments, Inc.
Worldwide Containers, Inc.
WPLG, Inc.
Wyman Gordan Investment Castings Inc.
Wyman Gordon Company
Wyman Gordon Forgings Cleveland Inc.
Wyman Gordon Forgings Inc.
Wyman Gordon Pennsylvania LLC
Wyman SC Inc.
X-L-Co., Inc.
XTRA Companies, Inc.
XTRA Corporation
XTRA Finance Corporation
XTRA Intermodal, Inc.

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	79,951		238,991,686	290,464,615	-53,479,324
3	FICA	689,033		36,054,306	36,209,472	
4	Unemployment	-36,484		232,854	230,530	
5	Foreign Withholding Taxes	1,522,888				
6	Subtotal	2,255,388		275,278,846	326,904,617	-53,479,324
7						
8	State:					
9						
10	Arizona:					
11	Property	1,832,048		3,661,029	3,662,562	
12	Income			258,487	-418,547	677,034
13	Subtotal	1,832,048		3,919,516	3,244,015	677,034
14						
15	California:					
16	Property			2,263,167	2,263,167	
17	Unemployment			25,064	24,932	
18	Franchise-Income			1,754,123	1,688,390	65,733
19	Use	8,990		103,212	102,559	
20	Local Franchise	1,316,338		1,231,867	1,236,750	
21	Subtotal	1,325,328		5,377,433	5,315,798	65,733
22						
23	Colorado:					
24	Property	2,200,000		2,353,529	2,223,529	
25	Subtotal	2,200,000		2,353,529	2,223,529	
26						
27	Idaho:					
28	Property	3,372,628		6,223,807	5,944,653	
29	Income			2,778,707	2,730,499	48,208
30	KWh	15,674		78,800	76,138	
31	Unemployment	1,164		43,443	42,160	
32	Use	26,956		272,959	294,096	
33	Subtotal	3,416,422		9,397,716	9,087,546	48,208
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	42,398,601	12,903,355	525,118,142	574,430,299	-52,756,557

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 2017/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
2,086,346		237,993,786			997,900	2
540,378	6,511				36,054,306	3
-34,160					232,854	4
1,522,888						5
4,115,452	6,511	237,993,786			37,285,060	6
						7
						8
						9
						10
1,830,515		3,661,029				11
		257,081			1,406	12
1,830,515		3,918,110			1,406	13
						14
						15
		2,126,416			136,751	16
132					25,064	17
		1,747,986			6,137	18
9,643					103,212	19
1,311,455		1,231,867				20
1,321,230		5,106,269			271,164	21
						22
						23
2,330,000		2,352,595			934	24
2,330,000		2,352,595			934	25
						26
						27
3,651,782		6,222,774			1,033	28
		2,769,263			9,444	29
18,336		78,800				30
2,447					43,443	31
5,819					272,959	32
3,678,384		9,070,837			326,879	33
						34
						35
						36
						37
						38
						39
						40
46,331,988	13,392,342	475,603,442			49,514,700	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 2017/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR: Taxes Accrued (Account 236) (b)	BALANCE AT BEGINNING OF YEAR: Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Montana:					
2	Property	2,728,411		5,667,215	5,563,806	
3	Corporate License-Income			241,669	236,105	5,564
4	Unemployment			264	264	
5	Energy License	60,000		205,239	205,239	
6	Wholesale Energy	42,000		146,233	146,233	
7	Subtotal	2,830,411		6,260,620	6,151,647	5,564
8						
9	Nevada:					
10	Commerce Tax	16,242		19,740	22,161	
11	Subtotal	16,242		19,740	22,161	
12						
13	New Mexico:					
14	Property			21,671	21,671	
15	Income			-25,792	81,312	-107,104
16	Subtotal			-4,121	102,983	-107,104
17						
18	Oregon:					
19	Property		12,155,895	24,640,988	25,003,906	
20	Unemployment	49,055		1,436,393	1,421,818	
21	Excise-Income			16,728,926	17,151,144	-422,218
22	City of Portland-Income			45,939	44,673	1,266
23	Department of Energy		747,460	1,614,478	1,734,036	
24	Tri-Met	344,305		998,562	959,128	
25	Lane County			1,435	1,435	
26	Franchise	4,941,198		30,722,628	30,904,096	
27	Subtotal	5,334,558	12,903,355	76,189,349	77,220,236	-420,952
28						
29	Texas:					
30	Unemployment			44	44	
31	Subtotal			44	44	
32						
33	Utah:					
34	Property	708,454		73,106,722	73,083,205	
35	Income			19,309,485	18,855,201	454,284
36	Unemployment	3,599		132,849	133,364	
37	Navajo Nation			11	11	
38	Use	274,648		3,365,425	3,315,549	
39	Subtotal	986,701		95,914,492	95,387,330	454,284
40						
41	TOTAL	42,398,601	12,903,355	525,118,142	574,430,299	-52,756,557

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
2,831,820		5,667,215				2
		240,849			820	3
					264	4
60,000		205,239				5
42,000		146,233				6
2,933,820		6,259,536			1,084	7
						8
						9
13,821		19,740				10
13,821		19,740				11
						12
						13
		21,671				14
		-26,100			308	15
		-4,429			308	16
						17
						18
	12,518,813	23,553,718			1,087,270	19
63,630					1,436,393	20
		16,675,083			53,843	21
		45,759			180	22
	867,018	1,614,478				23
383,739					998,562	24
					1,435	25
4,759,730		30,722,628				26
5,207,099	13,385,831	72,611,666			3,577,683	27
						28
						29
					44	30
					44	31
						32
						33
731,971		73,074,714			32,008	34
		19,246,025			63,460	35
3,084					132,849	36
		11				37
324,524					3,365,425	38
1,059,579		92,320,750			3,593,742	39
						40
46,331,988	13,392,342	475,603,442			49,514,700	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 2017/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	Washington:					
2	Property	10,000,000		11,755,905	10,055,905	
3	Unemployment	1,402		36,719	36,935	
4	Business & Occupation	3,881		27,557	28,338	
5	Public Utility	1,275,000		13,451,381	13,431,381	
6	Natural Gas Use Tax	238,674		1,925,248	1,937,888	
7	Use	41,538		638,165	637,731	
8	Forest Excise Tax			41,009	41,009	
9	Subtotal	11,560,495		27,875,984	26,169,187	
10						
11	Wyoming:					
12	Property	8,101,910		16,822,221	16,513,021	
13	Wind Generation Tax	2,048,055		1,811,786	2,072,139	
14	Unemployment	1,822		116,046	115,378	
15	Franchise	294,900		1,947,093	1,962,993	
16	Use	171,903		1,255,182	1,342,357	
17	Annual Report			70,926	70,926	
18	Subtotal	10,618,590		22,023,254	22,076,814	
19						
20	State Other:	2,603				
21						
22	Miscellaneous:					
23	Goshute Possessory			25,422	25,422	
24	Sho-Ban Possessory			287,936	287,936	
25	Navajo Possessory	19,815		14,329	26,981	
26	Ute Possessory			43,185	43,185	
27	Crow Possessory			72,306	72,306	
28	Umatilla Possessory			68,562	68,562	
29	Subtotal	22,418		511,740	524,392	
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	42,398,601	12,903,355	525,118,142	574,430,299	-52,756,557

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
11,700,000		11,524,431			231,474	2
1,186					36,719	3
3,100		27,557				4
1,295,000		13,451,381				5
226,034					1,925,248	6
41,972					638,165	7
					41,009	8
13,267,292		25,003,369			2,872,615	9
						10
						11
8,411,110		16,609,668			212,553	12
1,787,702		1,811,786				13
2,490					116,046	14
279,000		1,947,093				15
84,728					1,255,182	16
		70,926				17
10,565,030		20,439,473			1,583,781	18
						19
2,603						20
						21
						22
		25,422				23
		287,936				24
7,163		14,329				25
		43,185				26
		72,306				27
		68,562				28
9,766		511,740				29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
46,331,988	13,392,342	475,603,442			49,514,700	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 taxes, Federal, 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.: 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 taxes, other income and deductions, which represents state income tax applicable to other income and deductions.

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

$135,344	Account 408.2, Taxes other than income taxes, other income and deductions
1,407	Account 589, Rents
$136,751	

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 a portion 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 taxes, 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
Account 408.2, Taxes other than income taxes, other income and deductions

Schedule Page: 262 Line No.: 28 Column: l
Account 408.2, Taxes other than income taxes, other income and deductions

Schedule Page: 262 Line No.: 29 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.: 29 Column: l
Account 409.2, Income taxes, other income and deductions, which represents state income tax applicable to other income and deductions.

Schedule Page: 262 Line No.: 31 Column: l
Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

Schedule Page: 262 Line No.: 32 Column: l
Charged to same account as related goods.

Schedule Page: 262.1 Line No.: 3 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: 262.1 Line No.: 3 Column: l
Account 409.2, Income taxes, other income and deductions, which represents state income tax applicable to other income and deductions.

Schedule Page: 262.1 Line No.: 4 Column: l

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

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

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

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

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

Schedule Page: 262.1 Line No.: 19 Column: l

$ 24,209	Account 408.2, Taxes other than income taxes, other income and deductions
132,346	Account 589, Rents
930,715	Account 107, Construction work in progress
$1,087,270	

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: f

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

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

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

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

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

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

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

Schedule Page: 262.1 Line No.: 25 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

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

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

Account 408.2, Taxes other than income taxes, other income and deductions

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

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

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

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

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

Charged to same account as related goods.

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

$ 41,608	Account 408.2, Taxes other than income taxes, other income and deductions
189,866	Account 107, Construction work in progress
$ 231,474	

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

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

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

Account 151, Fuel stock

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

Charged to same account as related goods.

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

Account 408.2, Taxes other than income taxes, other income and deductions

Schedule Page: 262.2 Line No.: 12 Column: l

$ 4,054	Account 408.2, Taxes other than income taxes, other income and deductions
14,556	Account 589, Rents
193,943	Account 107, Construction work in progress
$ 212,553	

Schedule Page: 262.2 Line No.: 14 Column: l

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

Schedule Page: 262.2 Line No.: 16 Column: l

Charged to same account as related goods.

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 2017/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	15,871,919			411.4, 420	3,803,082	
6	30%	245,767			420	11,696	
7	Idaho	97,601			411.4, 420	9,913	8,773
8	TOTAL	16,215,287				3,824,691	8,773
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	Idaho	2,044,272	190	875,030	420	255,476	607,128
12	Total Nonutility	2,044,272		875,030		255,476	607,128
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
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28							
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47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
12,068,837	38.82 and 30		5
234,071	24		6
96,461	38.82 and 30		7
12,399,369			8
			9
			10
3,270,954	30		11
3,270,954			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
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			39
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			41
			42
			43
			44
			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%	$15,668,179	-	$ -	411.4(1)	$3,700,548	$ -	$11,967,631	38.82
10%	203,740	-	-	420(2)	102,534	-	101,206	30
	$15,871,919		$ -		$3,803,082	$ -	$12,068,837	

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

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

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	$ 47,182	-	$ -	411.4(1)	$ 6,453	$ 8,773	$ 49,502	38.82
Idaho	50,419	-	-	420(2)	3,460	-	46,959	30
	$ 97,601		$ -		$ 9,913	$ 8,773	$ 96,461	

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

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

Represents change in federal tax rate from 35% to 21% debited to Account 411.4, Investment tax credit adjustment-net.

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

Represents an adjustment to the balance at the beginning of year and change in federal tax rate from 35% to 21% 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 2017/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Working Capital Deposits	5,093,355	131	65,743	699,000	5,726,612
2	Reclamation Costs - Trapper Mine	6,072,271			180,212	6,252,483
3	Western Coal Carriers Benefits					
4	Obligation	10,883,000	131	302,000		10,581,000
5	Deferred Compensation Plans	8,306,137	131,920	803,815	1,909,634	9,411,956
6	Long-Term Incentive Plan	10,966,099	131	533,990	5,678,990	16,111,099
7	Regulated Environmental					
8	Liabilities	26,150,079	131,182.3	7,292,977	33,446,611	52,303,713
9	Non-Regulated Environmental					
10	Liabilities	2,093,646	131,426.5	230,735	103,733	1,966,644
11	Unearned Joint Use					
12	Pole Contact Revenue	2,900,121	454	6,222,190	6,246,232	2,924,163
13	Misc. Security Deposits	5,400	172	500	70,775	75,675
14	Lease Incentives	800,614	931	106,311		694,303
15	Cowlitz/Lewis River O&M (1)	122,234	539	296,377	298,531	124,388
16	Employee Housing Security Deposits	18,900	131	3,400	4,400	19,900
17	Cogeneration Bonds-Sunnyside	413,417				413,417
18	Transmission Security Deposits	1,638,000	131	5,000	3,280,000	4,913,000
19	Transmission Service Deposits	358,196	131	636,639	787,660	509,217
20	MCI F.O.G. Wire Lease (1)	557,201	454	3,344,150	3,344,339	557,390
21	Unamortized Contract Values	90,593,913	242	8,198,665		82,395,248
22	Accrued Right-of-Way Obligations	3,813,087	131	916,471	547,205	3,443,821
23	Facility Use Fee (2)	45,833	456	54,378	102,540	93,995
24	Eagle Mountain Contract					
25	Liability (1)	1,504,075	555	1,504,075		
26	Energy Supply Management					
27	Deferral (1)	370,833	456	341,666	350,000	379,167
28	Deer Creek Accrued Royalties	3,547,353			1,916,076	5,463,429
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	176,253,764		30,859,082	58,965,938	204,360,620

Schedule Page: 269 Line No.: 12 Column: a

The weighted average remaining life is one year.

Schedule Page: 269 Line No.: 14 Column: a

The weighted average remaining life is seven years.

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	306,993,377	17,159,552	138,736,595
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	306,993,377	17,159,552	138,736,595
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)	306,993,377	17,159,552	138,736,595
18	Classification of TOTAL			
19	Federal Income Tax	270,268,393	15,797,899	134,887,719
20	State Income Tax	36,724,984	1,361,653	3,848,876
21	Local Income Tax			

NOTES

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
						185,416,334	4
							5
							6
							7
						185,416,334	8
							9
							10
							11
							12
							13
							14
							15
							16
						185,416,334	17
							18
						151,178,573	19
						34,237,761	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 2017/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)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	4,518,977,533	2,419,195,656	2,275,715,441
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	4,518,977,533	2,419,195,656	2,275,715,441
6	Nonutility			
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	4,518,977,533	2,419,195,656	2,275,715,441
10	Classification of TOTAL			
11	Federal Income Tax	4,005,871,103	2,318,057,738	2,187,564,886
12	State Income Tax	513,106,430	101,137,918	88,150,555
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		182.3, 254	1,877,088,644	182.3, 254	187,368,171	2,972,737,275	2
							3
							4
			1,877,088,644		187,368,171	2,972,737,275	5
							6
							7
							8
			1,877,088,644		187,368,171	2,972,737,275	9
							10
			1,842,225,259		153,719,819	2,447,858,515	11
			34,863,385		33,648,352	524,878,760	12
							13

NOTES (Continued)

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

Debits to adjust Account 282, Accumulated deferred income taxes-other property are credited to the following accounts:

$ 276,646,867 Account 182.3, Other regulatory assets
1,600,441,777 Account 254, Other regulatory liabilities(1)
$ 1,877,088,644

(1) Primarily represents a reduction in the accumulated deferred income tax balance as a result of the reduction in the federal tax rate change from 35% to 21%, which was subsequently deferred as a regulatory liability in order to pass the benefit on to customers.

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

Credits to adjust Account 282, Accumulated deferred income taxes-other property are debited to the following accounts:

$ 171,866,796 Account 182.3, Other regulatory assets
15,501,375 Account 254, Other regulatory liabilities(1)
$ 187,368,171

(1) Primarily represents a reduction in the accumulated deferred income tax balance as a result of the reduction in the federal tax rate change from 35% to 21%, which was subsequently deferred as a regulatory liability in order to pass the benefit on to customers.

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	585,921,442	16,073,856	126,539,833
4	Other	17,215,789	14,377,415	18,212,713
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	603,137,231	30,451,271	144,752,546
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)	603,137,231	30,451,271	144,752,546
20	Classification of TOTAL			
21	Federal Income Tax	531,020,244	21,459,032	136,702,024
22	State Income Tax	72,116,987	8,992,239	8,050,522
23	Local Income Tax			

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
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
33,166,385	51,223,369		207,719,614		11,087,905	260,766,772	3
10,117,078	9,853,102	190, 283	13,838,610	190, 283	12,342,298	12,148,155	4
							5
							6
							7
							8
43,283,463	61,076,471		221,558,224		23,430,203	272,914,927	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
43,283,463	61,076,471		221,558,224		23,430,203	272,914,927	19
							20
38,439,269	57,242,352		194,636,407		20,433,312	222,771,074	21
4,844,194	3,834,119		26,921,817		2,996,891	50,143,853	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 3 Column: g
Account 182.3, Other regulatory assets
Account 190, Accumulated deferred income taxes
Account 283, Accumulated deferred income taxes-other

Schedule Page: 276 Line No.: 3 Column: i
Account 182.3, Other regulatory assets
Account 190, Accumulated deferred income taxes
Account 283, Accumulated deferred income taxes-other

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 2017/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	DSM Balancing Account - CA				1,175,496	1,175,496
2	DSM Balancing Account - ID				1,127,251	1,127,251
3	DSM Balancing Account - UT	4,404,503	131,232	54,942,812	50,538,309	
4	Oregon Energy Conservation Charge	3,286,888	131,232	35,948,679	36,433,863	3,772,072
5	Deferred Excess Net Power Costs - UT	4,840,097	555	840,716		3,999,381
6	Deferred Excess Net Power Costs - WA	8,863,736			9,556,067	18,419,803
7	Deferred Excess Net Power Costs - WY	3,186,133			4,712,924	7,899,057
8	Deferred Excess RECs in Rates - UT	408,173	456	408,173		
9	Deferred Excess RECs in Rates - WY	523,321	456	796,705	273,384	
10	Decoupling Mechanism - WA		419	25,466	1,280,458	1,254,992
11	Income Tax Reg. Liability - Flow Through - WA	62,036	411.1	172,746	304,014	193,304
12	Investment Tax Credit Regulatory Liability	8,465,568	190	6,282,774	1,011,753	3,194,547
13	Deferred Income Tax Electric		411.1,190,282	1,771,514,698	3,728,130,925	1,956,616,227
14	Tax on Bonus Depreciation - WY	462,729			999,764	1,462,493
15	Other Postretirement				10,385,290	10,385,290
16	Greenhouse Gas Allowance Compliance - CA	411,834	131,232,456	8,178,197	10,105,110	2,338,747
17	Solar Feed-In Tariff Deferral - CA	1,217,125	440,442,444	129,700		1,087,425
18	Solar Incentive Program - UT	15,850,03		5,327,580	3,876,409	14,398,860
19	STEP Pilot Program - UT		107	1,725,906	7,213,885	5,487,979
20	Independent Evaluator Costs - UT				247,437	247,437
21	Renewable Portfolio Standards Compliance - OR	34,025	555,419	34,025		
22	Utah Home Energy Lifeline	1,581,730	142	73,528	70,212	1,578,414
23	Washington Low Income Program	2,005,596	142	471,723	(155,792)	1,378,081
24	California Energy Savings Assistance Program	724,546	440,442,444	559,692	381,992	546,846
25	FERC Rate True-up - OR (3)	20,048,925	456	4,104,696	8,852,969	24,797,198
26	Asset Retirement Obligations Reg. Difference	5,419,878	230	1,348,900		4,070,978
27	BPA Balancing Account - WA	1,175,277	440,442	537,758	5,557	643,076
28	BPA Balancing Account - ID	3,630,232	440,442	74,777	28,161	3,583,616
29	Blue Sky - OR	2,546,484	440,442	2,077,282	1,668,981	2,138,183
30	Blue Sky - WA	258,249	440,442	197,911	205,570	265,908
31	Blue Sky - CA	231,006	440,442	28,252	77,216	279,970
32	Blue Sky - UT	6,740,649	440,442	1,217,613	2,998,448	8,521,484
33	Blue Sky - ID	152,127	440,442	12,774	56,818	196,171
34	Blue Sky - WY	564,191	440,442	334,759	202,680	432,112
35	Injuries & Damages Reserve - OR	8,782,141	228.2	8,782,141		
36	Property Insurance Reserve - ID	555,611	228.1	555,611		
37	Property Insurance Reserve - UT	3,102,836	228.1	3,102,836		
38	Property Insurance Reserve - WY	88,711	228.1	88,711		
39	Depreciation Deferral - OR	2,893,603			1,120,646	4,014,249
40	Deferred Steam Accel. Depreciation - WA	2,801,877			11,620,930	14,422,807
41	TOTAL	115,848,090		1,911,299,326	3,897,327,504	2,101,876,268

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Merwin Fish Collector Project - WA	3,432				3,432
2	Direct Access 5-Year Opt Out - OR (10)	524,790	442	1,402,185	2,820,777	1,943,382
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	TOTAL	115,848,090		1,911,299,326	3,897,327,504	2,101,876,268

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) X An Original (2) __ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

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

Effective January 1, 2017, annual expenditures on demand side management programs are amortized over 10 years, per the Utah Public Service Commission in Docket No. 16-035-36.

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

Weighted average remaining life is 39 years.

Schedule Page: 278 Line No.: 13 Column: a

Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to certain property-related basis differences and other various differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.

Schedule Page: 278 Line No.: 18 Column: c

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	1,884,431,867	1,851,336,999
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,569,999,446	1,544,450,403
5	Large (or Ind.) (See Instr. 4)	1,373,506,114	1,428,765,000
6	(444) Public Street and Highway Lighting	19,817,707	20,068,906
7	(445) Other Sales to Public Authorities	3,322,249	21,985,292
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	4,851,077,383	4,866,606,600
11	(447) Sales for Resale	217,427,479	177,098,460
12	TOTAL Sales of Electricity	5,068,504,862	5,043,705,060
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	5,068,504,862	5,043,705,060
15	Other Operating Revenues		
16	(450) Forfeited Discounts	10,272,123	9,371,769
17	(451) Miscellaneous Service Revenues	5,342,009	5,643,618
18	(453) Sales of Water and Water Power	54,199	75,033
19	(454) Rent from Electric Property	18,455,411	20,494,188
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	25,295,388	21,137,492
22	(456.1) Revenues from Transmission of Electricity of Others	115,041,634	100,653,551
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	174,460,764	157,375,651
27	TOTAL Electric Operating Revenues	5,242,965,626	5,201,080,711

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
16,625,426	16,057,814	1,622,276	1,598,695	2
				3
17,665,137	16,856,945	208,378	205,329	4
20,756,851	20,924,472	33,200	33,258	5
141,243	141,491	3,470	3,470	6
61,165	337,215		2	7
				8
				9
55,249,822	54,317,937	1,867,324	1,840,754	10
7,218,497	6,640,965			11
62,468,319	60,958,902	1,867,324	1,840,754	12
				13
62,468,319	60,958,902	1,867,324	1,840,754	14

Line 12, column (b) includes $ 255,154,000 of unbilled revenues.

Line 12, column (d) includes 3,105,479 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, in 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, in PacifiCorp's 12/31/2016 FERC 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:

	2017	2016
Account service charges - disconnects/reconnects/returned check charges	$ 4,304,054	$ 4,337,678
Customer contract flat rate billings and facility buyout charges	999,199	1,265,230

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:

	2017	2016
Wind-based ancillary services	$ 9,781,935	$ 10,840,910
Amortization of California greenhouse gas allowance revenue	8,113,014	11,196,617
Flyash/by-product sales	4,491,627	4,323,364
Revenue from generation interconnection and transmission service request studies	1,784,329	1,244,979
Timber sales	1,269,886	727,541
Renewable energy credit sales, including amortization and deferrals	1,088,549	(7,116,003)
Maintenance charges for work on transmission facilities	676,198	524,742
Net profit on sales of materials and supplies inventory	578,093	(a)
Steam sales	483,973	468,274
Energy exchange credits	395,600	4,908,564
Service territory fixed cost recovery fee	303,473	351,447
Deferral of Oregon retail customers' allocated share of the incremental Open Access Transmission Tariff revenues associated with FERC Docket No. ER11-3643-000, net of amortization	(3,978,799)	(7,093,960)
Phase shifting equipment fee from Western Electricity Coordinating Council	(a)	404,456

(a) Amount is less than $250,000.

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SALES OF ELECTRICITY BY RATE SCHEDULES

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL SALES					
2	CALIFORNIA					
3	06CHCK000R-CA RES CHECK M			1		
4	06NETMT135 - RES NET MTR	1,764	229,644	295	5,980	0.1302
5	06OALT015R-OUTD AR LGT SR	281	80,358	302	930	0.2860
6	06RESD000D-RES SRVC	175,528	24,253,503	17,450	10,059	0.1382
7	06RESDDL06-CA LOW INCOME	121,039	16,758,514	11,212	10,795	0.1385
8	06RGNSV025-CA SMALL GEN	1,335	291,673	478	2,793	0.2185
9	06RESD0DM9 - MULTI FAMILY	173	20,416	7	24,714	0.1180
10	06RESD0DS8-MULT FAM SBMET	1,503	162,152	17	88,412	0.1079
11	06RESD00DN - RES SVC - DEL NO	79,119	11,029,983	6,751	11,720	0.1394
12	REVENUE_ACCT ADJ		-1,998,037			
13	DSM REVENUE-RESIDENTIAL		1,395,474			
14	BLUE SKY REV-RESIDENTIAL		25,329			
15	SOLAR FEED-IN REVENUE		50,297			
16	UNBILLED REV - UNCOLLECTIBLE		-3,000			
17	UNBILLED REVENUE	-612	-133,000			0.2173
18						
19	IDAHO					
20	07LNX00010-MNTHLY 80%GUAR		1,073			
21	07LNX00035-ADV 80%MO GUAR		2,742			
22	07NETMT135 - ID RES NET MTR	2,846	280,752	248	11,476	0.0986
23	07OALCO007-CUST OWN LIGHT	10	3,851	1	10,000	0.3851
24	07OALT07AR-SECURITY AR LG	91	37,573	121	752	0.4129
25	07RESD0001-RES SRVC	491,129	57,108,294	50,401	9,744	0.1163
26	07RESD0036-RES SRVC-OPTIO	209,218	20,944,986	12,034	17,386	0.1001
27	07RGNSV06A-LRG GEN SVC-RES	248	19,560	2	124,000	0.0789
28	07RGNSV23A-SM GEN SVC-RES	8,568	980,359	1,016	8,433	0.1144
29	REVENUE_ACCT ADJ		-228,920			
30	DSM REVENUE-RESIDENTIAL		1,687,303			
31	BLUE SKY REV-RESIDENTIAL		11,654			
32	UNBILLED REV - UNCOLLECTIBLE		-9,000			
33	UNBILLED REVENUE	328	-60,000			-0.1829
34						
35	OREGON					
36	01CHCK000R-RES CHECK MTR			1		
37	01COST0004 - 01RESD0004	5,280,752	324,688,946			0.0615
38	01COSTR023 RES GEN SRV CST	100,446	6,125,446			0.0610
39	01COSTR028, OR RES GEN SVC	50,228	3,073,630			0.0612
40	01FXRENEWR - FIXED		-1			
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
43	TOTAL	55,249,822	4,912,720,881	1,867,324	29,588	0.0889

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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	01HABIT004 - 01RESD0004	55,256	3,341,193			0.0605
2	01HABTR023-RES GEN SVC HAB	185	11,665			0.0631
3	01LNX00102-LINE EXT 80% G		9,711			
4	01LNX00109-REF/NREF ADV +		5,118			
5	01LNX00300 - LINE EXT 80% GTY		173			
6	01LNX00311 - LINE EXT 80% GTY		96			
7	01NETMT135-NET METERING		2,118,474	4,453		
8	01NMTOU135-TOU NET METERING		15,065	24		
9	01OALTB15R-OUTD AR LGT RE	2,184	357,512	2,507	871	0.1637
10	01PTOU0004 - 01RESD0004	16,582	1,048,097			0.0632
11	01PTOU0005-01RESEV05T TOU	6	283			0.0472
12	01RENEW004 - 01RESD0004	366,115	21,734,540			0.0594
13	01RENWR023-RENEW USAGE	719	43,446			0.0604
14	01RESD0004-RES SRVC		306,600,338	492,170		
15	01RESD004T - RES TIME OPT		848,488	1,103		
16	01RESEV05T-ELECT VEHICLE		361	1		
17	01RGNSB023-SMALL GENERAL		7,383,972	16,778		
18	01RGNSB028 -GEN SVC > 30 KW		1,423,252	213		
19	01RNETM023-NET METER RES		122,137	82		
20	01RNETM028-NET METER RES		12,962	1		
21	01UPPL000R-BASE SCH FALL			2		
22	01VIR04136-VOLUME INCENTIVE		403,009	471		
23	OR GAIN ON SALE OF ASSET		30,571			
24	REVENUE_ACCT ADJ		-3,272,144			
25	DSM REVENUE-RESIDENTIAL		20,977,060			
26	BLUE SKY REV-RESIDENTIAL		632,007			
27	SOLAR FEED-IN REVENUE		2,069,426			
28	UNBILLED REV - UNCOLLECTIBLE		7,000			
29	UNBILLED REVENUE	-68,125	-8,688,000			0.1275
30						
31	UTAH					
32	08BLSKY01R-BLUESKY ENERGY		-7			
33	08CFR00001-MTH FACILITY S		726			
34	08CHCK000R-UT RES CHECK M			1		
35	08COOLKPRR -COOL KEEPER			100,440		
36	08LNX00001-MTHLY 80% GUAR		2,764			
37	08LNX00005-MTHLY MIN GUAR		396			
38	08LNX00013-80% MNTHLY MIN		24,737			
39	08LNX00108-ANN COST MTHLY		1,656			
40	08MHTP0006-MOBILE HOME &	12,127	952,025	8	1,515,875	0.0785
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
43	TOTAL	55,249,822	4,912,720,881	1,867,324	29,588	0.0889

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1	08MHTP0023-MOBILE HOME &	128	10,587	1	128,000	0.0827
2	08NETMT135 - NET MTR	88,996	11,051,548	22,325	3,986	0.1242
3	08NMT03135-LOW INCOME RES	536	62,056	99	5,414	0.1158
4	08OALT007R-SECURITY AR LG	2,385	690,056	2,413	988	0.2893
5	08PTLD000R-POST TOP LIGHT	1	105	2	500	0.1050
6	08RESD0001-RES SRVC	6,510,875	745,562,707	739,101	8,809	0.1145
7	08RESD0002-RES SRVC-OPTIO	3,273	368,768	397	8,244	0.1127
8	08RESD0003-LIFELINE PRGRM	172,644	19,421,111	22,458	7,687	0.1125
9	08RESD002E-RES ELECT VEHICLE	63	5,638	8	7,875	0.0895
10	08RGNSV006-GEN SRVC-RES	103,176	8,182,286	257	401,463	0.0793
11	08RGNSV023-GEN SRVC-RES	97,681	11,078,614	13,220	7,389	0.1134
12	08RGNSV06A-UT SM GEN SVC	10,022	877,911	25	400,880	0.0876
13	08RGNSV06B-UT SM GEN SVC	36	4,963	1	36,000	0.1379
14	08RNM06135 - UT NET MTR, GEN	2,444	220,470	9	271,556	0.0902
15	08RNM23135 - UT NET MTR, GEN	607	90,353	255	2,380	0.1489
16	08SSLR0001 - RESIDENTIAL	24,342	3,146,567	1,758	13,846	0.1293
17	08SSLR0003-LOW INCOME	266	32,438	27	9,852	0.1219
18	08SSLRRG23-SM GEN SUBSCR	48	7,321	15	3,200	0.1525
19	08UPPL000R-BASE SCH FALL			4		
20	REVENUE ADJ - DEF NPC		2,772,752			
21	REVENUE_ACCT ADJ		-22,557,575			
22	DSM REVENUE-RESIDENTIAL		1,298,126			
23	BLUE SKY REV-RESIDENTIAL		986,726			
24	SOLAR FEED-IN REVENUE		2,229,788			
25	UNBILLED REV - UNCOLLECTIBLE		-16,000			
26	UNBILLED REVENUE	-58,181	-6,307,000			0.1084
27						
28	WASHINGTON					
29	02BLSKY01R-BLUESKY ENERGY		-1			
30	02LNX00109-REF/NREF ADV +		1,866			
31	02NETMT135 - WA RES NET MTR	8,649	885,087	681	12,700	0.1023
32	02OALTB15R-WA OUTD AR LGT	984	153,498	1,075	915	0.1560
33	02RESD0016-WA RES SRVC	1,586,200	154,710,677	101,219	15,671	0.0975
34	02RESD0017-BILL ASSISTANCE	79,777	7,749,985	5,086	15,686	0.0971
35	02RESD0018-WA 3 PHASE RES	2,301	244,181	83	27,723	0.1061
36	02RESD018X-WA 3 PHASE RES	366	38,147	15	24,400	0.1042
37	02RGNSB024-WA SM GEN SVC	22,191	2,645,452	3,440	6,451	0.1192
38	02RGNSB036-RES LRG GEN SVC <	1,347	107,580	2	673,500	0.0799
39	02RNM24135-NET METER SM GEN	7	1,601	5	1,400	0.2287
40	REVENUE ADJ - DEF NPC		457,432			
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
43	TOTAL	55,249,822	4,912,720,881	1,867,324	29,588	0.0889

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1	REVENUE_ACCT ADJ		-12,697,666			
2	DSM REVENUE-RESIDENTIAL		6,093,687			
3	BLUE SKY REV-RESIDENTIAL		170,288			
4	UNBILLED REV - UNCOLLECTIBLE		-11,000			
5	UNBILLED REVENUE	13,901	1,890,000			0.1360
6						
7	WYOMING					
8	05BLSKY01R-BLUESKY ENERGY		-1			
9	05LNX00102-LINE EXT 80% G		787			
10	05LNX00109-REF/NREF ADV +		48			
11	05NETMT135 - EXP PARTIALREQ	1,546	186,130	173	8,936	0.1204
12	05OALT015R-OUTD AR LGT SR	847	118,060	1,000	847	0.1394
13	05RESD0002-WY RES SRVC	875,004	97,603,265	101,704	8,603	0.1115
14	05RGNSV025-WY SM GEN SVC	9,577	1,169,482	1,499	6,389	0.1221
15	09OALT207R-SECURITY AR LG		157	1		
16	REVENUE ADJ - DEF NPC		-128,749			
17	REVENUE_ACCT ADJ		179,729			
18	DSM REVENUE-RESIDENTIAL		816,806			
19	DSM REVENUE-RES GEN SVC		26,811			
20	BLUE SKY REV-RESIDENTIAL		291,132			
21	UNBILLED REV - UNCOLLECTIBLE		-4,000			
22	UNBILLED REVENUE	37,873	4,073,000			0.1075
23	05RESD0002-WY RES SRVC	113,526	12,819,009	12,438	9,127	0.1129
24	05RGNSV025- SM GEN SVC-RES	456	75,322	140	3,257	0.1652
25	09OALT207R-SECURITY AR LG	71	17,396	84	845	0.2450
26	05NETMT135 - EXP PARTIAL REQ	339	40,342	32	10,594	0.1190
27	09RES00002			1		
28	09RESD0002			4		
29	DSM REVENUE-RESIDENTIAL		184,260			
30	DSM REVENUE-RES GEN SVC		1,954			
31	BLUE SKY REV-RESIDENTIAL		19,134			
32	UNBILLED REVENUE	2,079	231,000			0.1111
33						
34	LESS MULTIPLE BILLINGS			-127,372		
35						
36	TOTAL RESIDENTIAL SALES	16,625,426	1,884,431,867	1,622,276	10,248	0.1133
37						
38						
39						
40						
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
43	TOTAL	55,249,822	4,912,720,881	1,867,324	29,588	0.0889

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1	COMMERCIAL SALES					
2	CALIFORNIA					
3	06GNSV0025-CA GEN SRVC	54,412	9,840,883	6,482	8,394	0.1809
4	06GNSV025F-GEN SRVC-< 20	963	190,887	85	11,329	0.1982
5	06GNSV0A32-GEN SRVC-20 KW	87,326	13,552,870	1,067	81,843	0.1552
6	06LGSV048T-LRG GEN SERV	31,357	3,302,785	9	3,484,111	0.1053
7	06NMT48135-CA GEN SVC NET	2,540	264,166	1	2,540,000	0.1040
8	06LGSV0A36-LRG GEN SRVC-O	63,507	8,393,744	153	415,078	0.1322
9	06LNX00102-LINE EXT 80% GTY		2,354			
10	06LNX00105-CNTRCT $ MIN G		2,145			
11	06LNX00109-REF/NREF ADV +		96,078			
12	06LNX00311 - LINE EXT 80% GTY		27,011			
13	06NMT36135-G SVC NT ->100	2,171	299,043	4	542,750	0.1377
14	06OALT015N-OUTD AR LGT SR	657	190,177	477	1,377	0.2895
15	06RCFL0042-AIRWAY & ATHLE	161	36,367	36	4,472	0.2259
16	06NMT25135-CA GEN SVC NET	76	14,165	12	6,333	0.1864
17	06NMT32135-CA GEN SVC NET	1,271	216,291	17	74,765	0.1702
18	06LNX00110-REF/NREF ADV +		2,107			
19	REVENUE_ACCT ADJ		-1,249,294			
20	DSM REVENUE-COMMERCIAL		875,729			
21	BLUE SKY REV-COMMERCIAL		3,059			
22	SOLAR FEED-IN REVENUE		47,523			
23	UNBILLED REVENUE	-6,865	-1,042,000			0.1518
24						
25	IDAHO					
26	07CISH0019-COMM & IND SPA	5,098	450,401	93	54,817	0.0883
27	07GNSV0006-GEN SRVC-LRG P	243,033	20,286,219	1,012	240,151	0.0835
28	07GNSV0009-GEN SRVC-HI VO	49,055	3,151,457	2	24,527,500	0.0642
29	07GNSV0023-GEN SRVC-SML P	147,599	14,889,065	6,734	21,918	0.1009
30	07GNSV0035-GEN SRVCOPTION	905	69,944	2	452,500	0.0773
31	07GNSV006A-GEN SRVC-LRG P	25,997	2,309,007	184	141,288	0.0888
32	07GNSV023A-GEN SRVC-SML P	27,418	2,745,246	1,268	21,623	0.1001
33	07GNSV023F-GEN SRVC SML P	6	1,701	4	1,500	0.2835
34	07LNX00010-MNTHLY 80%GUAR		21,580			
35	07LNX00035-ADV 80%MO GUAR		231,711			
36	07LNX00040-ADV+REFCHG+80%		43,881			
37	07OALT007N-SECURITY AR LG	251	98,103	171	1,468	0.3908
38	07OALT07AN-SECURITY AR LG	10	3,932	10	1,000	0.3932
39	07LNX00312 - ID LINE EXT		26,088			
40	07NMT06135 - NET MTR - LG GEN	1,930	163,153	3	643,333	0.0845
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
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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	07NMT23135 - NET MTR - SM GEN	1,123	92,843	22	51,045	0.0827
2	07LNX00015-ANNUAL 80%GUAR		1,104			
3	07LNX00311 - LINE EXT 80% GTY		26,965			
4	07LNX00300 - 80% MTHLY MIN		2,065			
5	REVENUE_ACCT ADJ		-134,693			
6	DSM REVENUE-COMMERCIAL		934,375			
7	BLUE SKY REV-COMMERCIAL		1,042			
8	UNBILLED REVENUE	-156	-53,000			0.3397
9						
10	OREGON					
11	01COST0023, OR GEN SRV, COST	1,026,722	60,702,784			0.0591
12	01COST0048 - 01LGSV0048	1,011,294	49,801,321			0.0492
13	01COST023F - GEN SRV COST	2,977	187,427			0.0630
14	01COSTB023 - OR GEN SRV	26,041	1,562,706			0.0600
15	01COSTEV45-ELECT VEHICLE	15	910			0.0607
16	01COSTL030 - OR LRG GEN SRV,	1,125,752	59,206,693			0.0526
17	01COSTS028, OR GEN SERV	1,964,662	120,547,595			0.0614
18	01GNSB0023, OR GEN SRV BPA		1,692,056	2,886		
19	01GNSB0028, OR GEN SRV BPA		2,015,487	296		
20	01GNSB023T - OR GEN SRV TOU		31,252	52		
21	01GNSEV45T-ELECT VEHICLE		2,959	3		
22	01GNSV0023, GEN SRV < 30 KW		54,916,805	57,024		
23	01GNSV0028, GEN SRV > 30 KW		58,547,949	9,127		
24	01GNSV023F - GEN SRV - FLAT RA	10,710	1,705,182	772	13,873	0.1592
25	01GNSV023M - GEN SRV, MANUAL	80	8,083	2	40,000	0.1010
26	01GNSV023T, OR GEN SRV, TOU		163,246	197		
27	01HABT0023, OR HABITAT BLEND	3,505	209,222			0.0597
28	01HABTB023 - OR HABITAT BLEND	43	2,566			0.0597
29	01LGSB0030, GEN DEL SRV, > 200		976,424	21		
30	01LGSV0030 - LG GEN SRV > 1000		29,514,614	634		
31	01LGSV0048-1000KW AND OVR		17,960,694	90		
32	01LGSV048M-LRG GEN SRVC 1	60,982	3,845,324	1	60,982,000	0.0631
33	01LNX00100-LINE EXT 60% G		1,815			
34	01LNX00102-LINE EXT 80% G		568,441			
35	01LNX00103-LINE EXT 80% G		4,733			
36	01LNX00105-CNTRCT $ MIN G		12,386			
37	01LNX00109-REF/NREF ADV +		1,037,332			
38	01LNX00110-REF/NREF ADV +		7,416			
39	01LNX00311 - LINE EXT 80% GTY		180,030			
40	01LNX00120 - LINE EXT 60% GTY		53			
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
43	TOTAL	55,249,822	4,912,720,881	1,867,324	29,588	0.0889

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1	01LNX00300 - LINE EXT 80% GTY		223,443			
2	01LPRS047M-PART REQ SRVC	47,949	4,472,624	5	9,589,800	0.0933
3	01NMT23135 - NET MTR GEN < 30		283,765	311		
4	01NMT28135 - NET MTR GEN > 30		1,303,509	174		
5	01NMT30135 -NET MTR GEN > 200		1,434,639	28		
6	01NMT48135-NET MTR GEN SVC		434,606	3		
7	01OALT015N-OUTD AR LGT NR	5,347	795,545	2,801	1,909	0.1488
8	01OALTB15N-OUTD AR LGT NR	1,435	241,899	1,042	1,377	0.1686
9	01PTOU0023, OR GEN SRV, TOU	2,947	175,945			0.0597
10	01PTOUB023, OR GEN SRV, TOU	510	30,885			0.0606
11	01RCFL0054-REC FIELD LGT	1,363	135,577	104	13,106	0.0995
12	01RENW0023, OR RENW USAGE	10,771	651,573			0.0605
13	01RENWB023 - OR RENEWABLE	85	5,293			0.0623
14	01STDAY023 - DAY STD OFR SCH	3,442	199,320			0.0579
15	01STDAY028 - DAY STD OFF SCH	13,059	775,165			0.0594
16	01STDAY030 - STD DAY OFF SCH	4,670	242,380			0.0519
17	01VIR23136-VOL INC <=30KW		169,906	110		
18	01VIR28136-VOL INC >30KW		643,689	99		
19	01VIR30136-VOL INC >200KW		345,056	9		
20	01VIR48136-VOL INC >1000KW		119,137	1		
21	01LGSB0048 - LG GSVC > 1000		89,398	1		
22	01LGSV028M - LGSV, <1000 KW	500	46,007	1	500,000	0.0920
23	01GNSV0728 - GEN SVC DIR ACC		93,709	6		
24	01GNSV0730 -GEN SVC DIR ACC		2,098,805	15		
25	01GNSV0748 LG GEN SVC DIR		7,994,135	3		
26	OR GAIN ON SALE OF ASSET		27,456			
27	REVENUE_ACCT ADJ		-1,359,720			
28	DSM REVENUE-COMMERCIAL		13,208,670			
29	BLUE SKY REV-COMMERCIAL		917,705	101		
30	SOLAR FEED-IN REVENUE		1,743,521			
31	UNBILLED REVENUE	-99,047	-10,311,000			0.1041
32						
33	UTAH					
34	08ABL-NRES - APPLICANT BUILT		7,368			
35	08BLSKY01N-BLUESKY ENERGY		-1			
36	08CFR00051-MTH FAC SRVCHG		38,597			
37	08CFR00052-ANN FAC SVCCHG		2			
38	08COOLKPRN - A/C DIRECT LOAD			2,235		
39	08GNSV0006-GEN SRVC-DISTR	4,987,595	431,303,470	11,078	450,225	0.0865
40	08GNSV0009-GEN SRVC-HI VO	756,484	44,876,613	38	19,907,474	0.0593
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
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1	08GNSV0023-GEN SRVC-DISTR	1,221,802	125,395,944	71,601	17,064	0.1026
2	08GNSV006A-GEN SRVC-ENERG	248,155	30,384,602	1,946	127,521	0.1224
3	08GNSV006B-GEN SRVC-DEM&	3,746	355,455	16	234,125	0.0949
4	08GNSV006M-MNL DIST VOLTG	5,253	353,196	4	1,313,250	0.0672
5	08GNSV009A-GEN SRVC HI VO	22,145	1,548,500	2	11,072,500	0.0699
6	08GNSV009M-MANL HIGH VOLT	181,676	11,031,607	1	181,676,000	0.0607
7	08GNSV023F-GEN SRVC FIXED	1,301	192,520	129	10,085	0.1480
8	08GNSV023M-GNSV DIST VOLT	302	25,827	7	43,143	0.0855
9	08GNSV06AM-MNL ENERGY TOD	187	27,810	1	187,000	0.1487
10	08GNSV06MN-GNSV DIST VOLT	34,179	2,797,535	586	58,326	0.0818
11	08LNX00002-MTHLY 80% GUAR		392,068			
12	08LNX00004-ANNUAL 80%GUAR		44,590			
13	08LNX00006-FIXD MTHLY MIN		3,488			
14	08LNX00014-80% MIN MNTHLY		1,578,463			
15	08LNX00017-ADV/REF&80%ANN		205,676			
16	08LNX00158-ANNUALCOST MTH		32,149			
17	08LNX00300 - LINE EXT 80% PLUS		164,895			
18	08LNX00310 - IRR 80% ANN MIN		71,936			
19	08LNX00312 UT IRG LINE EXT		12,271			
20	08NMT06135-NET MTR GEN SV	112,496	9,967,754	243	462,947	0.0886
21	08NMT08135 -NET MTR GEN SVC	96,298	6,981,677	11	8,754,364	0.0725
22	08NMT23135 -NET MTR GEN SVC	7,424	816,794	606	12,251	0.1100
23	08NMT6A135-NET MTR GEN SVC	6,853	986,405	60	114,217	0.1439
24	08OALT007N-SECURITY AR LG	7,649	1,823,671	4,056	1,886	0.2384
25	08POLE0075-POLES W/LIGHT		212	2		
26	08PRSV031M-BKUP MNT&SUPPL	103,361	7,317,451	4	25,840,250	0.0708
27	08PTLD000N-POST TOP LIGHT	6	452	2	3,000	0.0753
28	08SSLR0006-GEN SVC SUBSCR	3,289	402,059	10	328,900	0.1222
29	08SSLR0023-SM GEN SVC	2,390	348,530	173	13,815	0.1458
30	08SSLR006A-GEN SVC SUBSCR	27,409	3,692,848	278	98,594	0.1347
31	08TOSS015F-TRAFFIC SIG NM	171	16,427	20	8,550	0.0961
32	08TOSS0015-TRAF & OTHER S	3,016	328,392	993	3,037	0.1089
33	08MONL0015-MTR OUTDONIGHT	15,685	1,165,531	505	31,059	0.0743
34	08LNX00311 - LINE EXT 80% GTY		342,236			
35	08GNSV0008 -GEN SVC TOU	897,294	68,580,377	133	6,746,571	0.0764
36	08GNSV008M -GEN SVC TOU	18,913	1,678,373	3	6,304,333	0.0887
37	REVENUE ADJ - DEF NPC		2,879,767			
38	REVENUE_ACCT ADJ		-18,423,530			
39	DSM REVENUE-COMMERCIAL		612,644			
40	BLUE SKY REV-COMMERCIAL		172,070			
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
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1	SOLAR FEED-IN REVENUE		1,645,836			
2	UNBILLED REVENUE	-12,213	-1,396,000			0.1143
3						
4	WASHINGTON					
5	02GNSB0024-WA GEN SRVC DO	27,501	2,739,410	1,476	18,632	0.0996
6	02GNSB024F-GEN SRVC DOM/F	154	20,249	6	25,667	0.1315
7	02GNSB24FP-WA GEN SVC	193	82,158	78	2,474	0.4257
8	02GNSV0024-WA GEN SRVC	488,554	45,998,854	13,978	34,952	0.0942
9	02GNSV024F-WA GEN SRVC-FL	1,071	152,101	107	10,009	0.1420
10	02LGSB0036-LRG GEN SVC IRG	62,243	5,216,458	105	592,790	0.0838
11	02LGSV0036-WA LRG GEN SRV	773,918	63,011,984	875	884,478	0.0814
12	02LGSV048T-LRG GEN SRVC 1	192,653	14,371,792	37	5,206,838	0.0746
13	02LNX00102-LINE EXT 80% G		47,387			
14	02LNX00103-LINE EXT 80% G		16,759			
15	02LNX00105-CNTRCT $ MIN G		1,849			
16	02LNX00109-REF/NREF ADV +		237,340			
17	02LNX00110-REF/NREF ADV +		38,642			
18	02LNX00112-YR INCURRED CH		669			
19	02LNX00300-LINE EXT 80% G		2,428			
20	02LNX00311 - LINE EXT 80% GTY		60,991			
21	02LNX00312 - WA IRG LINE EXT		12,705			
22	02OALT015N-WA OUTD AR LGT	1,485	215,126	776	1,914	0.1449
23	02OALTB15N-WA OUTD AR LGT	518	82,159	466	1,112	0.1586
24	02RCFL0054-WA REC FIELD L	277	26,198	28	9,893	0.0946
25	02RFNDCENT - CENTRALIA RFN		-1			
26	02NMT24135, NET MTR, WA	3,455	323,844	74	46,689	0.0937
27	02NMT36135-NET MTR LG SVC	9,606	832,387	13	738,923	0.0867
28	02NMT48135-LG SVC NET MTR	10,492	772,684	2	5,246,000	0.0736
29	REVENUE ADJ - DEF NPC		429,475			
30	REVENUE_ACCT ADJ		-8,395,497			
31	DSM REVENUE-COMMERCIAL		5,003,428			
32	BLUE SKY REV-COMMERCIAL		27,158	1		
33	UNBILLED REVENUE	-27,547	-2,499,000			0.0907
34						
35	WYOMING					
36	05GNSV0025-WY GEN SRVC	217,815	21,909,889	17,838	12,211	0.1006
37	05GNSV0028-GEN SVC > 15 KW	862,326	74,791,461	3,208	268,805	0.0867
38	05GNSV025F-GEN SRVC-FL RA	980	159,392	174	5,632	0.1626
39	05LGSV0046-WY LRG GEN SRV	171,324	12,593,756	17	10,077,882	0.0735
40	05LGSV048T-LRG GENSRV TIM	12,978	906,933	1	12,978,000	0.0699
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
43	TOTAL	55,249,822	4,912,720,881	1,867,324	29,588	0.0889

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1	05LNX00100-LINE EXT 60% G		11,636			
2	05LNX00102-LINE EXT 80% G		1,172,596			
3	05LNX00105-CNTRCT $ MIN G		5,495			
4	05LNX00109-REF/NREF ADV +		488,913			
5	05LNX00110-REF/NREF ADV +		4,994			
6	05LNX00114-TEMP SVC 12MO>		1,580			
7	05NMT25135 - NET MTR, GEN	256	26,124	26	9,846	0.1020
8	05NMT28135-NET MTR SM GEN	7,423	672,540	21	353,476	0.0906
9	05OALT015N-OUTD AR LGT SR	2,604	364,716	1,600	1,628	0.1401
10	05RCFL0054-WY REC FIELD L	739	52,859	56	13,196	0.0715
11	05LNX00300-LINE EXT 80% GTY		140,985			
12	05LNX00310-LINE EXT CONTRACT		6,116			
13	05LNX00311-LINE EXT 80% GTY		65,681			
14	05LNX00312 - WY IRG LINE EXT		4,348			
15	REVENUE ADJ - DEF NPC		-145,574			
16	REVENUE_ACCT ADJ		192,708			
17	DSM REVENUE-SMALL		2,078,319			
18	DSM REVENUE-LARGE		90,340			
19	BLUE SKY REV-COMMERCIAL		16,660			
20	UNBILLED REVENUE	3,349	210,000			0.0627
21	05GNSV0025-WY GEN SRVC	29,335	2,945,653	2,379	12,331	0.1004
22	05GNSV0028-GEN SVC > 15 KW	92,438	7,980,022	389	237,630	0.0863
23	05GNSV025F-GEN SRVC-FL RA	199	25,400	32	6,219	0.1276
24	05LNX00102-LINE EXT 80% G		105,293			
25	05LNX00109-REF/NREF ADV +		138,539			
26	05LNX00110-REF/NREF ADV +		863			
27	05LNX00114-TEMP SVC 12MO>		488			
28	05NMT25135 - WY NET MTR, GEN	107	8,797	4	26,750	0.0822
29	05NMT28135-NET MTR SM GEN	429	37,923	2	214,500	0.0884
30	09OALT207N-SECURITY AR LG	273	58,555	138	1,978	0.2145
31	09MONL0213-WY MTR OUTDOOR	318	19,015	12	26,500	0.0598
32	05LNX00300 - LINE EXT 80% GTY		6,130			
33	05LNX00311 - LINE EXT 80% GTY		5,818			
34	DSM REVENUE-SMALL		232,245			
35	BLUE SKY REV-COMMERCIAL		518			
36	UNBILLED REVENUE	-854	-77,000			0.0902
37						
38	LESS MULTIPLE BILLINGS			-24,051		
39						
40	TOTAL COMMERCIAL SALES	17,665,137	1,569,999,446	208,378	84,774	0.0889
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
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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	INDUSTRIAL SALES					
2	CALIFORNIA					
3	06GNSV0025-CA GEN SRVC	628	116,968	88	7,136	0.1863
4	06GNSV0A32-GEN SRVC-20 KW	2,773	454,704	21	132,048	0.1640
5	06LGSV048T-LRG GEN SERV	45,335	4,773,668	8	5,666,875	0.1053
6	06LGSV0A36-LRG GEN SRVC-O	7,917	1,069,231	14	565,500	0.1351
7	REVENUE_ACCT ADJ		-208,229			
8	DSM REVENUE-INDUSTRIAL		135,972			
9	BLUE SKY REV-INDUSTRIAL		20			
10	SOLAR FEED-IN REVENUE		9,407			
11	UNBILLED REVENUE	2,646	297,000			0.1122
12						
13	IDAHO					
14	07CFR00001-MTH FACILITY S		2,084			
15	07CISH0019-COMM & IND SPA	41	4,065	2	20,500	0.0991
16	07GNSV0006-GEN SRVC-LRG P	92,486	6,712,725	105	880,819	0.0726
17	07GNSV0009-GEN SRVC-HI VO	75,878	5,072,751	14	5,419,857	0.0669
18	07GNSV0023-GEN SRVC-SML P	14,732	1,428,705	314	46,917	0.0970
19	07GNSV0035-GEN SRVCOPTION	986	89,436	1	986,000	0.0907
20	07GNSV006A-GEN SRVC LG P	3,488	296,155	22	158,545	0.0849
21	07GNSV023A-GEN SRVC-SML P	2,097	220,516	143	14,664	0.1052
22	07GNSV023S-IDAHO TRAFFIC	5	613	1	5,000	0.1226
23	07LNX00108-ANN COST MTHLY		1,996			
24	07OALT007N-SECURITY AR LG	13	5,164	17	765	0.3972
25	07OALT07AN-SECURITY AR LG		239	1		
26	07SPCL0001	1,477,300	93,703,872	1	1,477,300,000	0.0634
27	07SPCL0002	111,728	6,844,407	1	111,728,000	0.0613
28	REVENUE_ACCT ADJ		-47,403			
29	DSM REVENUE-INDUSTRIAL		281,739			
30	UNBILLED REVENUE	19,933	1,503,000			0.0754
31						
32	OREGON					
33	01COST0023, GEN SRV CST BSD	18,809	1,117,480			0.0594
34	01COST0048 - 01LGSV0048	1,306,813	65,047,487			0.0498
35	01COST023F - GEN SRV CST-BSD	1	65			0.0650
36	01COSTB023 - GEN SRV, CST-BSD	118	6,967			0.0590
37	01COSTL030 - LRG GEN SRV, CST	187,443	9,898,651			0.0528
38	01COSTS028, OR GEN SERV	92,985	5,688,216			0.0612
39	01GNSB0023, OR GEN SRV, BPA		7,756	11		
40	01GNSB0028, OR GEN SRV, BPA		9,386	2		
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
43	TOTAL	55,249,822	4,912,720,881	1,867,324	29,588	0.0889

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1	01GNSV0023, OR GEN SRV, < 30		1,039,836	974		
2	01GNSV0028, OR GEN SRV > 30		3,483,006	445		
3	01GNSV023F - GEN SRV - FLT	3	728	2	1,500	0.2427
4	01GNSV023M - OR GEN SRV		311	1		
5	01GNSV023T, GEN SRV, TOU OPT		2,811	3		
6	01GNSV0748 LG GEN SVC DIR		2,677,332	4		
7	01LGSV0030 - LG G SRV > 1000		7,349,079	135		
8	01LGSV0048-1000KW AND OVR		24,046,843	81		
9	01LGSV048M-LRG GEN SRVC 1	70,804	5,299,604	3	23,601,333	0.0748
10	01LNX00102-LINE EXT 80% G		57,653			
11	01LNX00109-REF/NREF ADV +		34			
12	01LNX00300 - LINE EXT 80% GTY		14,832			
13	01LPRS047M-PART REQ SRVC	92,448	6,698,030	1	92,448,000	0.0725
14	01NMT23135 - NET MTR GEN < 30		4,793	5		
15	01NMT28135 - NET MTR GEN > 30		48,947	5		
16	01NMT30135 - NET MTR GEN > 200		41,307	1		
17	01OALT015N-OUTD AR LGT NR	280	40,624	125	2,240	0.1451
18	01OALTB15N-OR OUTD AR LGT	4	547	4	1,000	0.1368
19	01PTOU0023, GEN SRV, TOU ENG	42	2,741			0.0653
20	01RENW0023, RENW USAGE SPLY	56	3,302			0.0590
21	01STDAY028 - DAY STD OFF SCH	209	12,568			0.0601
22	01VIR23136-VOL INC <=30KW		1,099	1		
23	01VIR28136-VOL INC >30 KW		23,510	2		
24	01VIR30136-VOL INC >200KW		29,077	1		
25	OR GAIN ON SALE OF ASSET		18,975			
26	REVENUE_ACCT ADJ		-1,729,443			
27	DSM REVENUE-INDUSTRIAL		1,034,592			
28	BLUE SKY REV-INDUSTRIAL		527,049	34		
29	SOLAR FEED-IN REVENUE		1,157,493			
30	UNBILLED REVENUE	49,505	6,160,000			0.1244
31						
32	UTAH					
33	08CFR00051-MTH FAC SRVCHG		18,523			
34	08EFOP0021-ELEC FURNACE O	1,219	148,115	2	609,500	0.1215
35	08EFOP021M-ELEC FURNACE O	822	150,099	2	411,000	0.1826
36	08GNSV0006-GEN SRVC-DISTR	653,114	58,474,541	1,012	645,370	0.0895
37	08GNSV0009-GEN SRVC-HI VO	2,991,153	172,565,697	109	27,441,771	0.0577
38	08GNSV0023-GEN SRVC-DISTR	53,833	5,576,878	3,223	16,703	0.1036
39	08GNSV006A-GEN SRVC-ENERG	55,738	6,835,467	237	235,181	0.1226
40	08GNSV009A-GEN SRVC HI VO	17,565	1,620,406	6	2,927,500	0.0923
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
43	TOTAL	55,249,822	4,912,720,881	1,867,324	29,588	0.0889

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1	08GNSV009M-MANL HIGH VOLT	704,897	39,358,509	10	70,489,700	0.0558
2	08GNSV023F-GEN SRVC FIXED	3	2,370	1	3,000	0.7900
3	08GNSV06MN-GNSV DIST VOLT	1,249	112,868	24	52,042	0.0904
4	08GNSV09AM-MAN TOD HIVOLT	1,291	143,109	1	1,291,000	0.1109
5	08LNX00002-MTHLY 80% GUAR		645,780			
6	08LNX00014-80% MIN MNTHLY		11,151			
7	08LNX00017-ADV/REF&80%ANN		990			
8	08LNX00311 - LINE EXT 80% GTY		1,089			
9	08LNX00300 - LINE EXT 80% PLUS		47,930			
10	08LNX00310 - IRR 80% ANN MIN		466			
11	08OALT007N-SECURITY AR LG	1,043	225,940	426	2,448	0.2166
12	08TOSS0015-TRAF & OTHER S	9	1,376	9	1,000	0.1529
13	08MONL0015-MTR OUTDONIGHT	12	2,146	6	2,000	0.1788
14	08NMT06135-NET MTR GEN SV	2,104	215,844	6	350,667	0.1026
15	08NMT23135-NET MTR GEN <25	139	16,067	14	9,929	0.1156
16	08NMT6A135-NET MTR GEN SVC T	4,037	554,997	11	367,000	0.1375
17	08PRSV031M-BKUP MNT&SUPPL	45,979	3,684,354	3	15,326,333	0.0801
18	08SPCL0001	612,063	32,718,646	1	612,063,000	0.0535
19	08SPCL0002	875,299	40,823,978	1	875,299,000	0.0466
20	08SPCL0003	991,585	40,642,969	1	991,585,000	0.0410
21	08SSLR0006-GEN SVC SUBSCR	45	5,725	1	45,000	0.1272
22	08SSLR0023-SM GEN SVC	72	19,300	18	4,000	0.2681
23	08SSLR006A-GEN SVC TOU	7,370	1,063,684	24	307,083	0.1443
24	08GNSV06AM-MNL ENERGY TOD	233	32,330	2	116,500	0.1388
25	08GNSV0008 - GEN SVC TOU	947,266	73,343,929	95	9,971,221	0.0774
26	08GNSV008M - GEN SVC TOU	35,730	2,987,650	5	7,146,000	0.0836
27	REVENUE ADJ - DEF NPC		1,779,139			
28	REVENUE_ACCT ADJ		-9,193,489			
29	DSM REVENUE-INDUSTRIAL		354,635			
30	BLUE SKY REV-INDUSTRIAL		58,817	8		
31	SOLAR FEED-IN REVENUE		1,739,304			
32	UNBILLED REVENUE	31,131	2,212,000			0.0711
33						
34	WASHINGTON					
35	02GNSB0024-WA GEN SRVC DO	957	103,829	43	22,256	0.1085
36	02GNSB24FP-WA GEN SVC	2	1,830	1	2,000	0.9150
37	02GNSV0024-WA GEN SRVC	16,231	1,542,266	329	49,334	0.0950
38	02GNSV024F-WA GEN SRVC-FL	33	8,752	4	8,250	0.2652
39	02LGSV0036-WA LRG GEN SRV	97,440	8,218,429	97	1,004,536	0.0843
40	02LGSV048T-LRG GEN SRVC 1	643,122	42,234,666	32	20,097,563	0.0657
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
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1	02LNX00103-LINE EXT 80% G		25,950			
2	02OALT015N-WA OUTD AR LGT	97	13,163	38	2,553	0.1357
3	02OALTB15N-WA OUTD AR LGT	27	4,136	14	1,929	0.1532
4	02PRSV47TM-LRG PART REQMT	2,115	331,288	1	2,115,000	0.1566
5	02LGSB0036-LRG GEN SVC IRG	1,582	198,296	10	158,200	0.1253
6	REVENUE ADJ - DEF NPC		228,542			
7	REVENUE_ACCT ADJ		-4,459,131			
8	DSM REVENUE-INDUSTRIAL		1,991,452			
9	BLUE SKY REVENUE-INDUSTRIAL		29	1		
10	UNBILLED REVENUE	34,589	2,573,000			0.0744
11						
12	WYOMING					
13	05GNSV0025-WY GEN SRVC	21,321	1,996,182	1,178	18,099	0.0936
14	05GNSV0028-GEN SVC > 15 KW	244,978	18,691,020	457	536,057	0.0763
15	05GNSV025F-GEN SRVC-FL RA	26	4,323	8	3,250	0.1663
16	05LGSV0046-WY LRG GEN SRV	1,654,104	112,007,529	61	27,116,459	0.0677
17	05LGSV046M-WY LRG GEN SRV	11,887	864,794	1	11,887,000	0.0728
18	05LGSV048M-TOU>1000KW MAN	291,648	16,940,433	1	291,648,000	0.0581
19	05LGSV048T-LRG GENSRV TIM	1,840,038	106,233,000	11	167,276,182	0.0577
20	05LNX00100-LINE EXT 60% G		86,028			
21	05LNX00102-LINE EXT 80% G		1,103,297			
22	05LNX00105-CNTRCT $ MIN G		42,070			
23	05LNX00109-REF/NREF ADV +		268,499			
24	05LNX00110-REF/NREF ADV +		558			
25	05LNX00300 - LINE EXT 80% GTY		88,978			
26	05LNX00311 - LINE EXT 80% GTY		17,806			
27	05OALT015N-OUTD AR LGT SR	67	8,574	38	1,763	0.1280
28	05PRSV033M-PART SERV REQ	1,313,454	87,259,215	9	145,939,333	0.0664
29	REVENUE ADJ - DEF NPC		-577,341			
30	REVENUE_ACCT ADJ		633,380			
31	DSM REVENUE-SMALL		441,221			
32	DSM REVENUE-LARGE		2,173,911			
33	BLUE SKY REV-INDUSTRIAL		7,272			
34	UNBILLED REVENUE	-109,230	-7,829,000			0.0717
35	05GNSV0025-WY GEN SRVC	4,365	419,165	285	15,316	0.0960
36	05GNSV0028-GEN SVC > 15 KW	54,905	4,115,306	75	732,067	0.0750
37	05GNSV028M-GEN SVC > 15 KW	4,582	288,918	2	2,291,000	0.0631
38	05LGSV0046-WY LRG GEN SRV	28,137	1,955,401	2	14,068,500	0.0695
39	05LGSV048M-TOU>1000KW MAN	171,658	10,757,185	2	85,829,000	0.0627
40	05LGSV048T-LRG GENSRV TIM	1,224,732	76,917,112	13	94,210,154	0.0628
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
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1	05LNX00102-LINE EXT 80% G		460,544			
2	05LNX00109-REF/NREF ADV +		1,989,421			
3	05PRSV033M-PART SERV REQ	96,547	6,098,487	2	48,273,500	0.0632
4	09OALT207N-SECURITY AR LG	5	-483	3	1,667	-0.0966
5	DSM REVENUE-SMALL		102,642			
6	DSM REVENUE-LARGE		628,878			
7	BLUE SKY REV-INDUSTRIAL		34			
8	UNBILLED REVENUE	-4,603	-404,000			0.0878
9						
10	LESS MULTIPLE BILLINGS			-914		
11						
12	TOTAL INDUSTRIAL SALES	19,357,323	1,238,402,278	9,655	2,004,901	0.0640
13						
14	IRRIGATION SALES					
15	CALIFORNIA					
16	06APSV0020-AG PMP SRVC	9,448	1,410,329	756	12,497	0.1493
17	06APSV0115-CA AGRI PUMP TOU	9	1,220	1	9,000	0.1356
18	06APSV020L-AG PMP SRVC-NO	48,604	7,045,209	594	81,825	0.1450
19	06APSV115L-CA AGRI PUMP TOU,	905	113,118	11	82,273	0.1250
20	06LGSV048T-LRG GEN SERV	3,088	361,233	1	3,088,000	0.1170
21	06LNX00103-LINE EXT 80% G		3,374			
22	06LNX00109-REF/NREF ADV +		1,104			
23	06LNX00110-REF/NREF ADV +		30,032			
24	06LNX00310-80% ANN MIN + 80%		5,698			
25	06LNX00312 - CA IRG LINE EXT		30,871			
26	06NML20135-AGRI PUMP-NET MTR	1,312	229,135	16	82,000	0.1746
27	06USBR0020-KLAM IRG ONPRJ	3,418	598,345	275	12,429	0.1751
28	06USBR0115-CA AGR PMP TOU	5	1,041	1	5,000	0.2082
29	06USBR020L-KLAM IRG ONPRJ	15,678	2,577,485	351	44,667	0.1644
30	06USBR115L-CA AGR PMP TOU	689	98,459	10	68,900	0.1429
31	REVENUE_ACCT ADJ		-404,052			
32	DSM REVENUE-IRRIGATION		363,697			
33	BLUE SKY REV-IRRIGATION		32			
34	SOLAR FEED-IN REVENUE		21,818			
35	UNBILLED REVENUE	164	20,000			0.1220
36						
37						
38						
39						
40						
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
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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	IDAHO					
2	07APSA010L - IRG & PUMP LG	374,091	35,173,108	2,610	143,330	0.0940
3	07APSA010S - IRG & PUMP SM	5,349	597,313	344	15,549	0.1117
4	07APSAL10X - IRG & PUMP - LG	176,055	16,747,938	1,559	112,928	0.0951
5	07APSAS10X - IRG & PUMP - SM	7,428	811,454	460	16,148	0.1092
6	07APSV006A-LRG POWER OPT	20	7,288	1	20,000	0.3644
7	07APSV023A-SM POWER OPT	139	14,248	4	34,750	0.1025
8	07APSVCNLL-LG LOAD CANAL	16,625	1,389,345	44	377,841	0.0836
9	07APSVCNLS-SM LOAD CANAL	40	5,957	12	3,333	0.1489
10	07GNSV023A-GEN SRVC-SML P	98	9,327	1	98,000	0.0952
11	07LNX00015-ANNUAL 80%GUAR		65,100			
12	07LNX00035-ADV 80%MO GUAR		503			
13	07LNX00040-ADV+REFCHG+80%		160,921			
14	07LNX00310 80% ANNUAL GTY		33			
15	07LNX00311 - LINE EXT 80% GTY		1,611			
16	07LNX00312 - ID LINE EXT		63,121			
17	07APSN010L - ID LG IRR & PUMP	6,335	576,604	33	191,970	0.0910
18	07APSN010S - IRRIGATION SM	36	4,604	5	7,200	0.1279
19	07APSNS10X - IRRIGATION SM	268	31,055	16	16,750	0.1159
20	REVENUE_ACCT ADJ		-164,753			
21	DSM REVENUE-IRRIGATION		1,178,148			
22	BLUE SKY REV-IRRIGATION		78	2		
23	UNBILLED REVENUE	2				
24						
25	OREGON					
26	01APSV0041-AG PMP SRVC		1,518,568	2,806		
27	01APSV0215-OR IRR TOU PILO		23,222	11		
28	01APSV041L-PUMP SERV >30KW		2,390,837	786		
29	01APSV041T - AGR PUMP SRV		30,049	58		
30	01APSV041X-AG PMP SRVC		1,033,558	2,115		
31	01APSV41XL-OR PUMPING SERV		1,570,935	381		
32	01COST0041 -01APSV0041	127,893	7,665,512			0.0599
33	01COST0048 - 01LGSV0048	108,586	5,465,784			0.0503
34	01COST0215-OR TOU PILOT COST	5,041	209,738			0.0416
35	01COSTS028, OR GEN SERV,	256	15,710			0.0614
36	01CSTUSB41-USBR IRR CONTRA	69,917	4,196,318			0.0600
37	01GNSV0028, OR GEN SRV > 30		11,389	1		
38	01HABIT041 - 01APSV0041	9	565			0.0628
39	01LGSB0048 - LG GEN SVC > 1000		1,031,998	3		
40	01LGSV0048-1000KW AND OVR		1,361,223	3		
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
43	TOTAL	55,249,822	4,912,720,881	1,867,324	29,588	0.0889

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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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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	01LNX00103-LINE EXT 80% G		42,414			
2	01LNX00109-REF/NREF ADV +		-303			
3	01LNX00110-REF/NREF ADV +		193,304			
4	01LNX00310-LINE EXT CONTRACT		20,332			
5	01PTOU0041 - 01APSV0041	573	34,322			0.0599
6	01RENEW041 - 01APSV0041	140	8,409			0.0601
7	01STDAY041 - DAILY STD OFFER	145	8,735			0.0602
8	01USBR0215-OR IRG TOU PILOT		193,168	83		
9	01USBRGV41-IRG TOU W/O BPA		85,595	9		
10	01USBROF41-KLAMATH BASIN		1,297,391	478		
11	01USBRON41-KLAMATH BASIN		1,823,778	1,140		
12	01VIR41136-OR VOLUME INC		60,044	25		
13	01VRU41136-OR VOLUME INC		347,542	104		
14	01VRU41215-OR VOLUME INC		34,759	6		
15	01LNX00312 - OR IRG LINE EXT		30,781			
16	01NMT41135 - NETMTR AG PMP		18,494	18		
17	01NMU41135 -NET MTR-PROJECT		25,417	8		
18	OR GAIN ON SALE OF ASSET		1,432			
19	REVENUE_ACCT ADJ		-78,228			
20	DSM REVENUE-IRRIGATION		681,020			
21	BLUE SKY REV-IRRIGATION		432			
22	SOLAR FEED-IN REVENUE		41,178			
23	UNBILLED REVENUE	-1,433	-380,000			0.2652
24						
25	UTAH					
26	08APSV0010-IRR & SOIL DRA	196,646	15,886,239	2,978	66,033	0.0808
27	08APSV10NS- LG SOIL DRAIN	34,586	2,564,575	247	140,024	0.0742
28	08LNX00004-ANNUAL 80%GUAR		5,753			
29	08LNX00014-80% MIN MNTHLY		8,363			
30	08LNX00017-ADV/REF&80%ANN		200,285			
31	08LNX00310 - IRR, 80% ANN MIN		26,824			
32	08LNX00311 - LINE EXT 80% GTY		356			
33	08LNX00312 UT IRG LINE EXT		30,319			
34	08NMT010NS-IRR & SOIL DRAIN	4	307	1	4,000	0.0768
35	08NMT10135-UT IRR_SOIL DRNG	7,446	596,504	41	181,610	0.0801
36	REVENUE_ACCT ADJ		-44,338			
37	DSM REVENUE-IRRIGATION		-36,591			
38	SOLAR FEED-IN REVENUE		36,919			
39	UNBILLED REVENUE	660	49,000			0.0742
40						
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
43	TOTAL	55,249,822	4,912,720,881	1,867,324	29,588	0.0889

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SALES OF ELECTRICITY BY RATE SCHEDULES

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1	WASHINGTON					
2	02APSV0040-WA AG PMP SRVC	104,493	9,506,256	3,083	33,893	0.0910
3	02APSV040X-WA AG PMP SRVC	48,872	4,535,754	2,076	23,541	0.0928
4	02LNX00102-LINE EXT 80% G		1,194			
5	02LNX00103-LINE EXT 80% G		10,874			
6	02LNX00105-CNTRCT $ MIN G		78			
7	02LNX00109-REF/NREF ADV +		5,880			
8	02LNX00110-REF/NREF ADV +		197,326			
9	02LNX00310 - IRG 80% ANN MIN		12,817			
10	02LNX00311 - LINE EXT 80% GTY		146			
11	02LNX00312 - WA IRG LINE EXT		36,499			
12	02NMT40135-WA NET MTR -IRG	281	24,838	9	31,222	0.0884
13	02NMX40135-WA NET MTR -IRG	36	5,068	1	36,000	0.1408
14	REVENUE ADJ - DEF NPC		42,924			
15	REVENUE_ACCT ADJ		-930,539			
16	DSM REVENUE-IRRIGATION		539,362			
17	BLUE SKY REV-IRRIGATION		337			
18	UNBILLED REVENUE	-400	-729,000			1.8225
19						
20	WYOMING					
21	05APS00040-AG PUMPING SVC	18,988	1,619,288	695	27,321	0.0853
22	05APSNS040-AG PUMPING SVC	1,213	97,134	19	63,842	0.0801
23	05LNX00103-LINE EXT 80% G		4,706			
24	05LNX00109-REF/NREF ADV +		983			
25	05LNX00110-REF/NREF ADV +		46,394			
26	05LNX00310-LINE EXT CONTRACT		655			
27	05LNX00312 - WY IRG LINE EXT		7,585			
28	05APS00040-AG PUMPING SVC	175	13,230	2	87,500	0.0756
29	05LNX00110-REF/NREF ADV +		16,242			
30	05LNX00310-LINE EXT CONTRACT		2,427			
31	09APSNS210-IRR & SOIL DRA	418	37,778	2	209,000	0.0904
32	09APSV0210-IRR & SOIL DRA	5,149	415,229	90	57,211	0.0806
33	REVENUE ADJ - DEF NPC		-1,967			
34	REVENUE_ACCT ADJ		-2,742			
35	DSM REVENUE-IRRIGATION		43,951			
36	BLUE SKY REV-IRRIGATION		12,041			
37	UNBILLED REVENUE	28	10,000			0.3571
38	LESS MULTIPLE BILLINGS			-841		
39						
40	TOTAL IRRIGATION SALES	1,399,528	135,103,836	23,545	59,441	0.0965
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
43	TOTAL	55,249,822	4,912,720,881	1,867,324	29,588	0.0889

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SALES OF ELECTRICITY BY RATE SCHEDULES

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1	PUBLIC STREET & HWY LIGHTING					
2	CALIFORNIA					
3	06CUSL053E-SPECIAL CUST O	1,134	200,449	105	10,800	0.1768
4	06CUSL058F-CUST OWND STR	53	10,422	20	2,650	0.1966
5	06SLCO0051-COMPANY OWNED	686	219,382	78	8,795	0.3198
6	06OALT015N-OUTD AR LGT SR	1	243	1	1,000	0.2430
7	REVENUE_ACCT ADJ		-13,249			
8	DSM REVENUE-PUB ST & HWY LT		11,360			
9	SOLAR FEED-IN REVENUE		656			
10	UNBILLED REVENUE	156	34,000			0.2179
11						
12	IDAHO					
13	07GNSV023S-IDAHO TRAFFIC	155	19,225	27	5,741	0.1240
14	07SLCO0011-STR LGT CO-OWN	131	61,491	59	2,220	0.4694
15	07SLCU012E-ENGY STR LGT	360	40,313	33	10,909	0.1120
16	07SLCU012F-FULL MNT STR	1,861	373,808	189	9,847	0.2009
17	07SLCU012P-PART MNT STR LGT	194	28,388	16	12,125	0.1463
18	REVENUE_ACCT ADJ		-2,312			
19	DSM REVENUE-PUB ST & HWY LT		10,143			
20	UNBILLED REVENUE	85	16,000			0.1882
21						
22	OREGON					
23	01COSL0052-STR LGT SRVC C	388	59,334	35	11,086	0.1529
24	01CUSL0053-CUS-OWNED MTRD	599	44,831	73	8,205	0.0748
25	01CUSL053E-STR LGT SVC	8,672	649,041	196	44,245	0.0748
26	01CUSL053F-STR LGT SRVC C	116	11,236	9	12,889	0.0969
27	01HPSV0051-HI PRESSURE SO	19,115	4,064,707	750	25,487	0.2126
28	01LEDSL051-OR LED PILOT	448	157,885	63	7,111	0.3524
29	01MVSL0050-MERC VAPSTR LG	7,421	990,144	231	32,126	0.1334
30	01OALT015N-OUTD AR LGT NR	15	2,869	10	1,500	0.1913
31	01OALTB15N-OR OUTD AR LGT	3	520	2	1,500	0.1733
32	OR GAIN ON SALE OF ASSET		236			
33	REVENUE_ACCT ADJ		-15,975			
34	DSM REVENUE-PUB ST & HWY LT		183,536			
35	SOLAR FEED-IN REVENUE		10,043			
36	UNBILLED REVENUE	2,697	408,000			0.1513
37						
38						
39						
40						
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
43	TOTAL	55,249,822	4,912,720,881	1,867,324	29,588	0.0889

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1	UTAH					
2	08CFR00012-STR LGTS (CONV		54			
3	08CFR00051-MTH FAC SRVCHG		4,529			
4	08CFR00062-STREET LIGHTS		79			
5	08OALT007N-SECURITY AR LG	67	17,288	21	3,190	0.2580
6	08TOSS015F-TRAFFIC SIG NM	1,150	108,731	121	9,504	0.0945
7	08SLCO0011-STR LGT CO-OWN	13,961	4,365,855	730	19,125	0.3127
8	08TOSS0015-TRAF & OTHER S	3,071	366,904	1,509	2,035	0.1195
9	08MONL0015-MTR OUTDONIGHT	932	75,264	82	11,366	0.0808
10	08SLCU012P-STR LGT CUST-O	3,381	433,339	187	18,080	0.1282
11	08SLCU012F-STR LGT CUST-O	1,095	152,086	75	14,600	0.1389
12	08SLCU012E-DECOR CUST-OWN	47,501	3,180,604	874	54,349	0.0670
13	REVENUE_ACCT ADJ		-303,999			
14	DSM REVENUE-PUB ST & HWY LT		1,246			
15	SOLAR FEED-IN REVENUE		41,238			
16	UNBILLED REVENUE	1,840	211,000			0.1147
17						
18	WASHINGTON					
19	02CFR00012-STR LGTS (CONV		91			
20	02COSL0052-WA STR LGT SRV	151	31,498	14	10,786	0.2086
21	02CUSL053F-WA STR LGT SRV	3,328	249,154	116	28,690	0.0749
22	02CUSL053M-WA STR LGT SRV	951	70,499	105	9,057	0.0741
23	02SLCO0051-WA COMPANY	3,834	797,766	193	19,865	0.2081
24	02MVSL0057-WA MERC VAPSTR	1,638	214,273	40	40,950	0.1308
25	REVENUE ADJ - DEF NPC		1,738			
26	REVENUE_ACCT ADJ		-79,113			
27	DSM REVENUE-PUB ST & HWY LT		32,629			
28	UNBILLED REVENUE	1,622	239,000			0.1473
29						
30	WYOMING					
31	05COSL0057-CO-OWND STR LG	244	50,997	15	16,267	0.2090
32	05CUSL0058-CUST OWND STR	76	4,410	11	6,909	0.0580
33	05CUSL0E58-CUST OWNED STR	1,033	60,995	33	31,303	0.0590
34	05CUSL0M58-CUST OWNED STR	45	3,144	3	15,000	0.0699
35	05HPSV0051-HI PRESSURE SO	5,621	1,076,959	186	30,220	0.1916
36	05MVS00053-MERCURY VAPOR	3,580	422,153	234	15,299	0.1179
37	05OALT015N-OUTD AR LGT SR	38	4,316	3	12,667	0.1136
38	REVENUE_ACCT ADJ		-656			
39	REVENUE ADJUSTMENT -		-1,729			
40	DSM REVENUE-PUB ST & HWY LT		34,655			
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
43	TOTAL	55,249,822	4,912,720,881	1,867,324	29,588	0.0889

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1	UNBILLED REVENUE	360	54,000			0.1500
2	09MONL0213-WY MTR OUTDOOR	29	2,749	1	29,000	0.0948
3	09SLCO0211-STR LGT CO-OWN	1,493	339,129	49	30,469	0.2271
4	09SLCUP212-CUST OWNED	34	5,011	5	6,800	0.1474
5	09TOSS0213-TRAFFIC & OTHER	47	2,400	13	3,615	0.0511
6	DSM REVENUE-PUB ST & HWY LT		7,695			
7	UNBILLED REVENUE	-169	-37,000			0.2189
8						
9	LESS MULTIPLE BILLINGS			-3,047		
10						
11	TOTAL PUBLIC STREET & HWY LT	141,243	19,817,707	3,470	40,704	0.1403
12						
13	OTHER SALES TO PUBLIC AUTH					
14	UTAH					
15	08GNSV009M-MANL HIGH VOLT	61,165	3,363,212			0.0550
16	REVENUE_ACCT ADJ		-72,058			
17	DSM REVENUE-OSPA		13,464			
18	SOLAR FEED-IN REVENUE		17,631			
19						
20	TOTAL OTHER SALES TO PUBLIC	61,165	3,322,249			0.0543
21						
22	FORFEITED DISCOUNTS					
23	CALIFORNIA					
24	06LPAY0300-RES-LATEFEE		250,479			
25	06LPAY0300-COM-LATEFEE		56,945			
26	06LPAY0300-IND-LATEFEE		47,375			
27	06LPAY0300-OTHER-LATEFEE		118			
28						
29	IDAHO					
30	07LPAY0300-RES-LATEFEE		237,271			
31	07LPAY0300-COM-LATEFEE		34,973			
32	07LPAY0300-IND-LATEFEE		218,986			
33	07LPAY0300-OTHER-LATEFEE		2,528			
34						
35	OREGON					
36	01LPAY0300-RES-LATEFEE		3,616,581			
37	01LPAY0300-COM-LATEFEE		716,478			
38	01LPAY0300-IND-LATEFEE		208,617			
39	01LPAY0300-OTHER-LATEFEE		7,853			
40						
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
43	TOTAL	55,249,822	4,912,720,881	1,867,324	29,588	0.0889

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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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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Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	UTAH					
2	08LPAY0300-RES-LATEFEE		2,486,973			
3	08LPAY0300-COM-LATEFEE		585,262			
4	08LPAY0300-IND-LATEFEE		228,856			
5	08LPAY0300-OTHER-LATEFEE		50,929			
6	OTHER		1,575			
7						
8	WASHINGTON					
9	02LPAY0300-RES-LATEFEE		699,102			
10	02LPAY0300-COM-LATEFEE		128,801			
11	02LPAY0300-IND-LATEFEE		32,084			
12	02LPAY0300-OTHER-LATEFEE		-1,086			
13						
14	WYOMING					
15	05LPAY0300-RES-LATEFEE		437,201			
16	05LPAY0300-COM-LATEFEE		111,541			
17	05LPAY0300-IND-LATEFEE		47,593			
18	05LPAY0300-OTHER-LATEFEE		1,761			
19	05LPAY0300-RES-LATEFEE		48,861			
20	05LPAY0300-COM-LATEFEE		10,534			
21	05LPAY0300-IND-LATEFEE		5,290			
22	05LPAY0300-OTHER-LATEFEE		-1,358			
23						
24	TOTAL FORFEITED DISCOUNTS		10,272,123			
25						
26	MISCELLANEOUS SERVICE REV					
27	CALIFORNIA					
28	06CFR00003-MTH MAINTENANC		1,454			
29	06CONN0300-CA RECONNECTIO		14,920			
30	06FCBUYOUT		19,211			
31	06RCHK0300-CA RET CHK CHR		11,328			
32	06TAMP0300-CA TAMP & UNAU		675			
33	06TEMP0300-CA TEMP SRVC C		3,430			
34	06TRBL0300-CA TROUBLE CAL		60			
35	06XMTRTAMP-TAMPERING		175			
36	OTHER		-2,120			
37						
38						
39						
40						
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
43	TOTAL	55,249,822	4,912,720,881	1,867,324	29,588	0.0889

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1	IDAHO					
2	07CFR00001-MTH FAC SRVCHG		1,682			
3	07CONN0300-ID RECONNECTIO		16,085			
4	07FCBUYOUT - FAC CHG BUYOUT		3,205			
5	07RCHK0300-ID RET CHK CHR		34,060			
6	07TAMP0300		375			
7	07TEMP0014-TEMP SRVC CONN		31,735			
8	07XMTRTAMP-TAMPERING		369			
9	07XTRN0011-SALE ORDERS		694			
10	OTHER		-1			
11						
12	OREGON					
13	01CFR00001-MTH FACILITY S		98,301			
14	01CFR00003-MTH MAINTENANC		19,076			
15	01CFR00004-EMRGNCY ST&BY		25,638			
16	01CFR00005-INTERMTNT SRVC		37,088			
17	01CFR00013-MTH MISC CHRG		53,234			
18	01CONN0300-RECONNECTION		206,900			
19	01CONTSERV-OR 3RD PARTY		13,010			
20	01ESSC0600 - ESS CHARGES		4,248			
21	01FCBUYOUT-FAC CHG BUYOUT		178,575			
22	01RCHK0300-RETURNED CHECK		280,320			
23	01TAMP0300-TAMP & UNAUTH		12,825			
24	01TEMP0300-TEMP SRVC CHRG		172,065			
25	01XMTRTAMP-TAMPRING		3,089			
26	01XTHEFREV-THEFT OF SVCS		17			
27	OTHER		-24,670			
28						
29	UTAH					
30	08CFR00051-MTH FAC SRVCHG		85,737			
31	08CFR00052-ANN FAC SVCCHG		424			
32	08CFR00053-MTHLY MAINTFEE		12,203			
33	08CFR00054-NRES EMERGENCY		4,976			
34	08CFR00063-MTH MISC CHARG		2,358			
35	08CFR00064-ANN MISC CHARG		6,660			
36	08CGENFEER-RES CSTMR		5,340			
37	08CONN0300-RECONN&DISCONN		252,180			
38	08CONTSERV-3RD PARTY O/S		93,000			
39	08FCBUYOUT-FAC CHG BUYOUT		327,145			
40	08INFO0300-CUST/3RD P REQ		80			
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
43	TOTAL	55,249,822	4,912,720,881	1,867,324	29,588	0.0889

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1	08MTRVR300 - METER		1,110			
2	08NCON0300-UT FEE NRES RE		3,615			
3	08NETMT135 - NET METERING		88			
4	08NSMTR300-NON STANDARD		1,415			
5	08PRINT300-SCREEN PRINT		360			
6	08RCHK0300-UT RET CHK CHR		472,905			
7	08RCON0001-CONNECT FEE		1,795,090			
8	08RESD0001-RES SRVC		4,334			
9	08SOLRXFEE-SUBSCRI SOLAR		14,250			
10	08SSLR0001 - RES SUBSCRB		220			
11	08TAMP0300-TAMPERING		8,175			
12	08TEMP0014-TEMP SRVC CONN		647,300			
13	08XMTRTAMP-TAMPRING		2,504			
14	08XTHEFREV-THEFT OF SVCS		17			
15	08XTRN0011-SALE ORDERS		27,550			
16	ENERGY FINANSWER NEW COM		1,713			
17	08VISIT300 - UT VISIT, SERVICE		24,990			
18	OTHER		-76,190			
19						
20	WASHINGTON					
21	02CFR00003-MTH MAINTENANC		1,320			
22	02CFR00004-EMRGNCY ST&BY		5,892			
23	02CFR00005-INTERMTNT SRVC		4,457			
24	02CONN0300-WA RECONNECTIO		55,095			
25	02FCBUYOUT - FAC CHG BUYOUT		6,809			
26	02NSMTR300-WA STANDARD		240			
27	02RCHK0300-WA RET CHK CHR		54,660			
28	02RESD0016-WA RES SRVC		80			
29	02TAMP0300-WA TAMP & UNAU		2,400			
30	02TEMP0300-WA TEMP SRVC C		24,855			
31	02XMTRTAMP-TAMPRING		391			
32	OTHER		-1,931			
33						
34	WYOMING					
35	05CFR00003-MTH MAINTENANC		1,768			
36	05CFR00004-EMRGNCY ST&BY		18,581			
37	05CFR00005-INTERMTNT SRVC		10,263			
38	05CFR00013-MTH MISC CHRG		3,186			
39	05CONN0300-WY RECONNECTIO		57,640			
40	05FCBUYOUT - FAC CHG BUYOUT		32,704			
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
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1	05RCHK0300-WY RET CHK CHR		78,300			
2	05RESD0002-WY RES SRVC		1,188			
3	05TAMP0300		450			
4	05TEMP0300-WY TEMP SRVC C		38,760			
5	05XTRN0011 - SALES ORDERS INV		2,217			
6	09CFR00005-INTERMTNT SRVC		339			
7	OTHER		-14,449			
8	05CONN0300-WY RECONNECTIO		7,438			
9	05RCHK0300-WY RET CHK CHR		7,320			
10	05TAMP0300		75			
11	09CFR00001-MTH FAC SRVCHG		5,356			
12	09CFR00014-YR MISC CHRG		3			
13						
14	TOTAL MISC SERVICE REV		5,342,009			
15						
16	SALES OF WATER & WATER PWR					
17	UTAH					
18	WATER & WATER PWR SALES		54,199			
19						
20	TOTAL SALES OF WATER & WTR		54,199			
21						
22	RENT FROM ELEC PROPERTIES					
23	CALIFORNIA					
24	06CFR00006-MTH RNTAL CHRG		1,710			
25	RENT REVENUE-HYDRO		1,250			
26	RENT REVENUE-SUBLEASES		19,200			
27	JOINT USE		520,400			
28						
29	IDAHO					
30	07CFR00009-YR LSE CHRG-EQ		778			
31	07INVCHG00-INVEST MNT CHG		150			
32	07POLE0075-STEEL POLES US		270			
33	RENT REVENUE-HYDRO		68,055			
34	RENT REVENUE-TRANSMISSION		21,551			
35	RENT REVENUE-DISTRIBUTION		550			
36	RENT REVENUE-SUBLEASES		2,216			
37	JOINT USE		170,398			
38						
39						
40						
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
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1	OREGON					
2	01CFR00006-MTH RNTAL CHRG		837,914			
3	RENTS - COMMON		733,551			
4	RENTS - NON COMMON		25			
5	MCI FOGWIRE REVENUE		3,344,150			
6	RENT REVENUE-HYDRO		25,406			
7	RENT REVENUE-TRANSMISSION		283,404			
8	RENT REVENUE-DISTRIBUTION		68,258			
9	RENT REVENUE-GENERAL		69,057			
10	RENT REVENUE-SUBLEASES		27,674			
11	JOINT USE		2,832,724			
12	OTHER		2,190			
13						
14	UTAH					
15	08CFR00056-MTH EQUIP RENT		33			
16	08CFR00058-MTH EQUIP LEAS		534,384			
17	08INVCHG0N-INVEST MNT CHG		4,387			
18	08INVCHG0R-INVEST MNT CHG		223			
19	08POLE0075-STEEL POLES US		50,718			
20	RENTS - NON COMMON		3,600			
21	RENT REVENUE-STEAM		133,499			
22	RENT REVENUE-HYDRO		97,242			
23	RENT REVENUE-TRANSMISSION		1,240,179			
24	RENT REVENUE-DISTRIBUTION		690,415			
25	RENT REVENUE-GENERAL		16,479			
26	RENT REVENUE-SUBLEASES		1,109,573			
27	JOINT USE		3,666,841			
28						
29	WASHINGTON					
30	02CFR00001-MTH FACILITY S		2,104			
31	02CFR00006-MTH RNTAL CHRG		9,073			
32	RENT REVENUE-HYDRO		348,908			
33	RENT REVENUE-TRANSMISSION		33,235			
34	RENT REVENUE-DISTRIBUTION		20,228			
35	RENT REVENUE-GENERAL		44,322			
36	JOINT USE		812,903			
37						
38						
39						
40						
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
43	TOTAL	55,249,822	4,912,720,881	1,867,324	29,588	0.0889

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1	WYOMING					
2	05CFR00001-MTH FACILITY S		11,524			
3	05CFR00006-MTH RNTAL CHRG		2,482			
4	RENTS - NON COMMON		22,876			
5	RENT REVENUE-STEAM		57,127			
6	RENT REVENUE-HYDRO		22,435			
7	RENT REVENUE-TRANSMISSION		4,975			
8	RENT REVENUE-DISTRIBUTION		150			
9	RENT REVENUE-GENERAL		40,933			
10	RENT REVENUE-SUBLEASES		50,877			
11	JOINT USE		347,660			
12	09POLE0075-STEEL POLES US		18,313			
13	RENT REVENUE-STEAM		26,832			
14						
15	TOTAL RENT FROM ELEC PROP		18,455,411			
16						
17	OTHER ELECTRIC REVENUE					
18	ENERGY EXCHANGE CREDITS		395,600			
19	M&S INVENTORY REVENUE		3,286,434			
20	MISC OTHER REVENUE		5,635			
21	OTHER ELEC (EXCLUDE WHEELIN		33,050			
22	RENEWABLE ENERGY CREDITS		1,088,549			
23	WIND BASED ANCILLARY SVC		9,781,935			
24						
25	CALIFORNIA					
26	CA GHG ALLOW REV AMORT		8,113,014			
27	3RD PARTY TRANS O&M		25,194			
28	FISH, WILDLIFE, RECR		7,742			
29						
30	IDAHO					
31	3RD PARTY TRANS O&M		-11,099			
32						
33	OREGON					
34	3RD PARTY TRANS O&M		384,636			
35	EIM REVENUE		24,403			
36	FERC TRANSMISSION REFUND		-3,978,799			
37	OTHER ELEC (EXCLUDE WHEELIN		2,006,597			
38						
39						
40						
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
43	TOTAL	55,249,822	4,912,720,881	1,867,324	29,588	0.0889

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1	UTAH					
2	3RD PARTY TRANS O&M		210,472			
3	ELEC INCOME-OTHER		54,106			
4	FISH, WILDLIFE, RECR		2,620			
5	FLYASH SALES		2,015,873			
6	OTHER ELEC (EXCLUDE WHEELIN		-11			
7						
8	WASHINGTON					
9	TIMBER SALES - UTILITY PROP		1,269,886			
10	FISH, WILDLIFE, RECR		9,885			
11	WASH COLSTRIP 3		-52,188			
12						
13	WYOMING					
14	3RD PARTY TRANS O&M		66,995			
15	FLYASH SALES		2,475,754			
16	WY REG RECOVERY FEE		303,473			
17						
18	TOTAL OTHER ELEC REV		27,519,756			
19						
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39						
40						
41	TOTAL Billed	55,436,309	4,932,511,881	1,867,324	29,688	0.0890
42	Total Unbilled Rev.(See Instr. 6)	-186,487	-19,791,000	0	0	0.1061
43	TOTAL	55,249,822	4,912,720,881	1,867,324	29,588	0.0889

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Helper City	RQ	T-6	1	1	1
3	Helper City Annex	RQ	T-6	1	1	1
4	Navajo Tribal Utility Authority	RQ	T-9	22	22	19
5	Navajo Tribal Util. Auth. (Mexican Hat)	RQ	T-6	0	0	0
6	Navajo Tribal Util. Auth. (Red Mesa)	RQ	T-6	1	1	1
7	Portland General Electric Company	RQ	147	NA	NA	NA
8	Accrual	RQ	NA	NA	NA	NA
9						
10	Non-Requirement Sales:					
11	Arizona Electric Power Cooperative	SF	T-12	NA	NA	NA
12	Arizona Public Service Company	IF	T-12	NA	NA	NA
13	Arizona Public Service Company	SF	T-12	NA	NA	NA
14	Avangrid Renewables, LLC	AD	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 2017/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
5,643	105,896	99,740		205,636	2
3,914	72,092	69,199		141,291	3
159,264	3,153,488	5,218,513	-330,103	8,041,898	4
872	15,820	15,195		31,015	5
8,843	137,312	154,049		291,361	6
4,151		434,938		434,938	7
-759			8,804	8,804	8
					9
					10
239,147		6,122,457		6,122,457	11
119,970		4,138,965		4,138,965	12
38,609		1,322,805		1,322,805	13
9			247	247	14
181,928	3,484,608	5,991,634	-321,299	9,154,943	
7,036,569	9,287,590	370,827,276	-171,842,330	208,272,536	
7,218,497	12,772,198	376,818,910	-172,163,629	217,427,479	

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 2017/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Avangrid Renewables, LLC	SF	T-12	NA	NA	NA
2	Avista Corporation	SF	T-12	NA	NA	NA
3	Avista Corporation	SF	T-13	NA	NA	NA
4	BP Energy Company	SF	T-12	NA	NA	NA
5	Basin Electric Power Cooperative, Inc.	SF	T-12	NA	NA	NA
6	Black Hills Power, Inc.	LF	441	50	50	46
7	Black Hills Power, Inc.	SF	T-12	NA	NA	NA
8	Bonneville Power Administration	AD	T-12	NA	NA	NA
9	Bonneville Power Administration	LU	519	NA	NA	NA
10	Bonneville Power Administration	SF	T-12	NA	NA	NA
11	Bonneville Power Administration	SF	T-13	NA	NA	NA
12	Bonneville Power Administration	SF	WSPP - Q	NA	NA	NA
13	British Columbia Hydro and Power	SF	T-13	NA	NA	NA
14	Brookfield Energy Marketing L.P.	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
785,929		20,363,796		20,363,796	1
92,115		1,684,615		1,684,615	2
48			1,748	1,748	3
991,865		27,363,990		27,363,990	4
20,305		530,655		530,655	5
269,732	7,509,715	5,745,378		13,255,093	6
60,455		1,369,124		1,369,124	7
			-210,116	-210,116	8
51,259		2,530,488		2,530,488	9
119,240		3,177,982		3,177,982	10
173			5,111	5,111	11
1,000		26,400		26,400	12
21			372	372	13
84,166		2,299,170		2,299,170	14
181,928	3,484,608	5,991,634	-321,299	9,154,943	
7,036,569	9,287,590	370,827,276	-171,842,330	208,272,536	
7,218,497	12,772,198	376,818,910	-172,163,629	217,427,479	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
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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	California Independent System Operator	AD	T-12	NA	NA	NA
2	California Independent System Operator	SF	T-12	NA	NA	NA
3	Calpine Energy Services, L.P.	SF	T-12	NA	NA	NA
4	Cargill Power Markets, LLC	AD	T-12	NA	NA	NA
5	Cargill Power Markets, LLC	SF	T-12	NA	NA	NA
6	City of Burbank	SF	T-12	NA	NA	NA
7	City of Burbank	SF	WSPP - Q	NA	NA	NA
8	City of Glendale	SF	T-12	NA	NA	NA
9	City of Hurricane	LF	T-12	NA	NA	NA
10	City of Hurricane	SF	T-12	NA	NA	NA
11	City of Redding	SF	T-12	NA	NA	NA
12	City of Roseville	SF	T-12	NA	NA	NA
13	Clatskanie People's Utility District	SF	T-12	NA	NA	NA
14	ConocoPhillips Company	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
-11			4,609	4,609	1
40,329		1,482,013		1,482,013	2
35,613		631,087		631,087	3
108			3,903	3,903	4
708,306		19,706,508		19,706,508	5
37,093		909,339		909,339	6
1,080		26,892		26,892	7
1,200		52,400		52,400	8
169		10,985		10,985	9
88		4,220		4,220	10
65,196		1,750,063		1,750,063	11
29,247		548,131		548,131	12
5,413		138,870		138,870	13
600		1,300		1,300	14
181,928	3,484,608	5,991,634	-321,299	9,154,943	
7,036,569	9,287,590	370,827,276	-171,842,330	208,272,536	
7,218,497	12,772,198	376,818,910	-172,163,629	217,427,479	

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 2017/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	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	EDF Trading North America, LLC	SF	T-12	NA	NA	NA
2	El Paso Electric Company	SF	T-12	NA	NA	NA
3	Eugene Water & Electric Board	SF	T-12	NA	NA	NA
4	Exelon Generation Company, LLC	AD	T-12	NA	NA	NA
5	Exelon Generation Company, LLC	SF	T-12	NA	NA	NA
6	Gridforce Energy Management	SF	T-13	NA	NA	NA
7	Guzman Renewables Energy Partners LLC	SF	T-12	NA	NA	NA
8	Idaho Power Company	SF	T-12	NA	NA	NA
9	Idaho Power Company	SF	T-13	NA	NA	NA
10	Idaho Power Company	SF	WSPP - Q	NA	NA	NA
11	Imperial Irrigation District	SF	T-3	NA	NA	NA
12	Los Angeles Dept. of Water and Power	SF	T-12	NA	NA	NA
13	Macquarie Energy LLC	SF	T-12	NA	NA	NA
14	Modesto Irrigation District	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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.
1,938,825		53,797,275		53,797,275	1
44,837		1,167,420		1,167,420	2
21,199		514,256		514,256	3
249			6,321	6,321	4
1,450,036		38,808,501		38,808,501	5
209			5,920	5,920	6
5		140		140	7
2,800		77,480		77,480	8
140			3,264	3,264	9
74,908		2,071,802		2,071,802	10
4,554		155,194		155,194	11
17,836		610,246		610,246	12
386,682		9,950,360		9,950,360	13
45,166		1,311,719		1,311,719	14
181,928	3,484,608	5,991,634	-321,299	9,154,943	
7,036,569	9,287,590	370,827,276	-171,842,330	208,272,536	
7,218,497	12,772,198	376,818,910	-172,163,629	217,427,479	

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 2017/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	Morgan Stanley Capital Group, Inc.	SF	T-12	NA	NA	NA
2	Municipal Energy Agency of Nebraska	SF	T-12	NA	NA	NA
3	NaturEner Power Watch, LLC	SF	T-13	NA	NA	NA
4	Nevada Power Company	SF	WSPP - Q	NA	NA	NA
5	NextEra Energy Power Marketing, LLC	SF	T-12	NA	NA	NA
6	NorthWestern Corporation	AD	T-12	NA	NA	NA
7	NorthWestern Corporation	SF	T-12	NA	NA	NA
8	NorthWestern Corporation	SF	T-13	NA	NA	NA
9	NorthWestern Corporation	SF	WSPP - Q	NA	NA	NA
10	Portland General Electric Company	SF	T-12	NA	NA	NA
11	Portland General Electric Company	SF	T-13	NA	NA	NA
12	Powerex Corporation	SF	T-12	NA	NA	NA
13	Public Service Company of Colorado	AD	T-12	NA	NA	NA
14	Public Service Company of Colorado	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
442,744		11,199,648		11,199,648	1
5,947		147,571		147,571	2
62			1,103	1,103	3
16,495		428,427		428,427	4
800		28,200		28,200	5
			-204	-204	6
65		310		310	7
328			8,896	8,896	8
50,981		1,332,919		1,332,919	9
48,565		1,170,719		1,170,719	10
170			5,464	5,464	11
95,414		458,064	300	458,364	12
108			4,211	4,211	13
1,455,218		38,916,936		38,916,936	14
181,928	3,484,608	5,991,634	-321,299	9,154,943	
7,036,569	9,287,590	370,827,276	-171,842,330	208,272,536	
7,218,497	12,772,198	376,818,910	-172,163,629	217,427,479	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Public Service Company of New Mexico	SF	T-12	NA	NA	NA
2	PUD No. 1 of Chelan County	SF	T-13	NA	NA	NA
3	PUD No. 1 of Clark County	SF	T-12	NA	NA	NA
4	PUD No. 1 of Douglas County	SF	T-12	NA	NA	NA
5	PUD No. 1 of Snohomish County	SF	T-12	NA	NA	NA
6	PUD No. 2 of Grant County	SF	T-13	NA	NA	NA
7	Puget Sound Energy, Inc.	SF	T-12	NA	NA	NA
8	Puget Sound Energy, Inc.	SF	T-13	NA	NA	NA
9	Rainbow Energy Marketing Corporation	SF	T-12	NA	NA	NA
10	Rainbow Energy Marketing Corporation	SF	WSPP - Q	NA	NA	NA
11	Sacramento Municipal Utility District	SF	T-12	NA	NA	NA
12	Sacramento Municipal Utility District	SF	T-13	NA	NA	NA
13	Salt River Project	AD	T-12	NA	NA	NA
14	Salt River Project	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
93,392		2,818,562		2,818,562	1
8			59	59	2
4,995		123,187		123,187	3
450		12,280		12,280	4
7,670		220,427		220,427	5
33			1,082	1,082	6
76,456		1,686,916		1,686,916	7
25			610	610	8
50,751		1,310,880		1,310,880	9
5,800		145,524		145,524	10
57,694		1,313,546		1,313,546	11
31			2,251	2,251	12
5			99	99	13
129,142		4,022,012		4,022,012	14
181,928	3,484,608	5,991,634	-321,299	9,154,943	
7,036,569	9,287,590	370,827,276	-171,842,330	208,272,536	
7,218,497	12,772,198	376,818,910	-172,163,629	217,427,479	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Seattle City Light	SF	T-12	NA	NA	NA
2	Seattle City Light	SF	T-13	NA	NA	NA
3	Sempra Generation, LLC	AD	T-12	NA	NA	NA
4	Sempra Generation, LLC	SF	T-12	NA	NA	NA
5	Shell Energy North America (US), L.P.	SF	T-12	NA	NA	NA
6	Sierra Pacific Power Company	SF	T-13	NA	NA	NA
7	Southern California Edison Company	SF	T-12	NA	NA	NA
8	Tacoma Power	SF	T-12	NA	NA	NA
9	Tacoma Power	SF	T-13	NA	NA	NA
10	Talen Energy Marketing, LLC	SF	T-12	NA	NA	NA
11	Tenaska Power Services Co.	SF	T-12	NA	NA	NA
12	Tenaska Power Services Co.	SF	WSPP - Q	NA	NA	NA
13	The Energy Authority, Inc.	SF	T-12	NA	NA	NA
14	TransAlta Energy Marketing (U.S.) Inc.	AD	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
28,218		619,700		619,700	1
26			291	291	2
5			129	129	3
1,098,345		31,870,209		31,870,209	4
600,033		15,185,886		15,185,886	5
52			1,820	1,820	6
317,403		7,844,272		7,844,272	7
18,860		376,502		376,502	8
46			895	895	9
376		10,555		10,555	10
251,889		6,685,929		6,685,929	11
78,741		2,157,806		2,157,806	12
64,229		1,728,141		1,728,141	13
74			1,856	1,856	14
181,928	3,484,608	5,991,634	-321,299	9,154,943	
7,036,569	9,287,590	370,827,276	-171,842,330	208,272,536	
7,218,497	12,772,198	376,818,910	-172,163,629	217,427,479	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	TransAlta Energy Marketing (U.S.) Inc.	SF	T-12	NA	NA	NA
2	TransCanada Energy Sales Ltd.	SF	T-12	NA	NA	NA
3	Tri-State Generation & Trans.	SF	T-12	NA	NA	NA
4	Tucson Electric Power Company	SF	T-12	NA	NA	NA
5	Tucson Electric Power Company	SF	WSPP - Q	NA	NA	NA
6	Turlock Irrigation District	SF	T-12	NA	NA	NA
7	UNS Electric, Inc.	SF	T-12	NA	NA	NA
8	Utah Associated Municipal Power Systems	SF	WSPP - Q	NA	NA	NA
9	Utah Municipal Power Agency	LF	433	28	28	22
10	Utah Municipal Power Agency	SF	WSPP - Q	NA	NA	NA
11	Vitol Inc.	SF	T-12	NA	NA	NA
12	Western Area Power Administration	SF	T-12	NA	NA	NA
13	Transmission Loss Sales Revenue	AD	T-11	NA	NA	NA
14	Transmission Loss Sales Revenue	OS	T-11	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
256,681		6,558,711		6,558,711	1
2,376		73,520		73,520	2
23,850		569,695		569,695	3
387,866		12,551,314		12,551,314	4
360		13,500		13,500	5
26,301		741,302		741,302	6
59,246		1,746,154		1,746,154	7
41,582		1,110,787		1,110,787	8
74,966	1,777,875	1,705,072		3,482,947	9
44,631		768,629		768,629	10
1,600		36,758		36,758	11
91,209		2,734,680		2,734,680	12
19			-12,123	-12,123	13
216,761			5,334,444	5,334,444	14
181,928	3,484,608	5,991,634	-321,299	9,154,943	
7,036,569	9,287,590	370,827,276	-171,842,330	208,272,536	
7,218,497	12,772,198	376,818,910	-172,163,629	217,427,479	

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Netting - Bookouts		NA	NA	NA	NA
2	Netting - Trading		NA	NA	NA	NA
3	Accrual		NA	NA	NA	NA
4						
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

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.
-6,967,136			-175,654,149	-175,654,149	1
			-908,433	-908,433	2
-11,309			-452,310	-452,310	3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
181,928	3,484,608	5,991,634	-321,299	9,154,943	
7,036,569	9,287,590	370,827,276	-171,842,330	208,272,536	
7,218,497	12,772,198	376,818,910	-172,163,629	217,427,479	

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

$(400,485) Load retention payment
27,344 Settlement adjustment
43,038 Customer service charges related to:
- Schedule 94, Energy balancing account
- Schedule 98, Renewable energy adjustment
- Schedule 196, Utah Sustainable Transportation and Energy Plan (STEP)

$(330,103)

Schedule Page: 310 Line No.: 5 Column: a

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

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

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

Schedule Page: 310 Line No.: 8 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 Line No.: 14 Column: b

Settlement adjustment.

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

Settlement adjustment.

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

Reserve share.

Schedule Page: 310.1 Line No.: 6 Column: b

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

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

Settlement adjustment.

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

Settlement adjustment.

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

Reserve share.

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

Complete name is British Columbia Hydro and Power Authority.

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

Reserve share.

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

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 310.2 Line No.: 9 Column: b

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

Schedule Page: 310.3 Line No.: 4 Column: b

Settlement adjustment.

Schedule Page: 310.3 Line No.: 4 Column: j

Settlement adjustment.

Schedule Page: 310.3 Line No.: 6 Column: j

Reserve share.

Schedule Page: 310.3 Line No.: 9 Column: j
Reserve share.

Schedule Page: 310.3 Line No.: 12 Column: a
Complete name is Los Angeles Department of Water and Power.

Schedule Page: 310.4 Line No.: 3 Column: j
Reserve share.

Schedule Page: 310.4 Line No.: 4 Column: a
Nevada Power Company is a wholly owned subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

Schedule Page: 310.4 Line No.: 6 Column: b
Settlement adjustment.

Schedule Page: 310.4 Line No.: 6 Column: j
Settlement adjustment.

Schedule Page: 310.4 Line No.: 8 Column: j
Reserve share.

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

Schedule Page: 310.4 Line No.: 12 Column: j
Pond sales.

Schedule Page: 310.4 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 310.4 Line No.: 13 Column: j
Settlement adjustment.

Schedule Page: 310.5 Line No.: 2 Column: a
Complete name is Public Utility District No. 1 of Chelan County.

Schedule Page: 310.5 Line No.: 2 Column: j
Reserve share.

Schedule Page: 310.5 Line No.: 3 Column: a
Complete name is Public Utility District No. 1 of Clark County.

Schedule Page: 310.5 Line No.: 4 Column: a
Complete name is Public Utility District No. 1 of Douglas County.

Schedule Page: 310.5 Line No.: 5 Column: a
Complete name is Public Utility District No. 1 of Snohomish County.

Schedule Page: 310.5 Line No.: 6 Column: a
Complete name is Public Utility District No. 2 of Grant County.

Schedule Page: 310.5 Line No.: 6 Column: j
Reserve share.

Schedule Page: 310.5 Line No.: 8 Column: j
Reserve share.

Schedule Page: 310.5 Line No.: 12 Column: j
Reserve share.

Schedule Page: 310.5 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 310.5 Line No.: 13 Column: j
Settlement adjustment.

Schedule Page: 310.6 Line No.: 2 Column: j
Reserve share.

Schedule Page: 310.6 Line No.: 3 Column: b
Settlement adjustment.

Schedule Page: 310.6 Line No.: 3 Column: j
Settlement adjustment.

Schedule Page: 310.6 Line No.: 6 Column: a
Sierra Pacific Power Company is a wholly owned subsidiary of NV Energy, Inc., which is an

indirect wholly owned subsidiary of Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

Schedule Page: 310.6 Line No.: 6 Column: j

Reserve share.

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

Reserve share.

Schedule Page: 310.6 Line No.: 14 Column: b

Settlement adjustment.

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

Settlement adjustment.

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

Complete name is Tri-State Generation and Transmission Association, Inc.

Schedule Page: 310.7 Line No.: 9 Column: b

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

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

Settlement adjustment.

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

Settlement adjustment.

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

Transmission loss sales revenues collected from PacifiCorp's third party transmission service customers.

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

Transmission loss sales revenues collected from PacifiCorp's third party transmission service customers.

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

Reflects transactions that did not physically settle.

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

Reflects transactions that did not physically settle.

Schedule Page: 310.8 Line No.: 3 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 2017/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	18,564,129	19,302,289
5	(501) Fuel	836,254,849	820,850,664
6	(502) Steam Expenses	75,578,998	77,494,812
7	(503) Steam from Other Sources	4,677,095	4,387,771
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,215,091	1,357,681
10	(506) Miscellaneous Steam Power Expenses	12,187,163	18,783,155
11	(507) Rents	549,315	497,552
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	949,026,640	942,673,924
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	7,999,631	8,590,720
16	(511) Maintenance of Structures	30,784,444	29,659,884
17	(512) Maintenance of Boiler Plant	87,947,278	94,238,044
18	(513) Maintenance of Electric Plant	30,041,778	31,617,221
19	(514) Maintenance of Miscellaneous Steam Plant	12,751,402	9,939,070
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	169,524,533	174,044,939
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	1,118,551,173	1,116,718,863
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	8,658,615	8,994,999
45	(536) Water for Power	120,631	48,260
46	(537) Hydraulic Expenses	3,938,899	4,438,179
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	15,714,600	16,390,065
49	(540) Rents	1,898,750	1,339,115
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	30,331,495	31,210,618
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	389	400
54	(542) Maintenance of Structures	732,787	1,157,602
55	(543) Maintenance of Reservoirs, Dams, and Waterways	2,042,717	4,031,155
56	(544) Maintenance of Electric Plant	2,518,525	2,527,278
57	(545) Maintenance of Miscellaneous Hydraulic Plant	3,269,988	3,013,546
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	8,564,406	10,729,981
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	38,895,901	41,940,599

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	343,362	315,661
63	(547) Fuel	214,054,042	252,938,388
64	(548) Generation Expenses	16,194,351	16,727,699
65	(549) Miscellaneous Other Power Generation Expenses	5,434,018	5,300,600
66	(550) Rents	3,717,449	4,007,994
67	TOTAL Operation (Enter Total of lines 62 thru 66)	239,743,222	279,290,342
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	2,717,666	2,825,560
71	(553) Maintenance of Generating and Electric Plant	15,757,596	17,358,571
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	3,063,915	2,135,375
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	21,539,177	22,319,506
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	261,282,399	301,609,848
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	639,445,881	580,289,645
77	(556) System Control and Load Dispatching	1,310,515	1,686,094
78	(557) Other Expenses	43,501,285	43,257,013
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	684,257,681	625,232,752
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,102,987,154	2,085,502,062
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	6,347,854	7,696,616
84			
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	6,954,702	7,180,746
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	2,007,912	1,818,514
89	(561.5) Reliability, Planning and Standards Development	1,674,277	1,747,640
90	(561.6) Transmission Service Studies	72,957	107,188
91	(561.7) Generation Interconnection Studies	1,696,771	1,290,346
92	(561.8) Reliability, Planning and Standards Development Services	7,484,166	7,528,820
93	(562) Station Expenses	3,413,321	3,574,521
94	(563) Overhead Lines Expenses	505,147	523,824
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	134,473,119	130,788,907
97	(566) Miscellaneous Transmission Expenses	2,349,109	3,701,508
98	(567) Rents	2,161,509	2,406,374
99	TOTAL Operation (Enter Total of lines 83 thru 98)	169,140,844	168,365,004
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,062,627	967,541
102	(569) Maintenance of Structures	51,218	71,460
103	(569.1) Maintenance of Computer Hardware	155,815	163,187
104	(569.2) Maintenance of Computer Software	701,841	290,354
105	(569.3) Maintenance of Communication Equipment	4,911,057	4,163,332
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	11,826,106	11,581,205
108	(571) Maintenance of Overhead Lines	16,851,778	17,444,207
109	(572) Maintenance of Underground Lines	19,786	98,313
110	(573) Maintenance of Miscellaneous Transmission Plant	84,769	116,402
111	TOTAL Maintenance (Total of lines 101 thru 110)	35,664,997	34,896,001
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	204,805,841	203,261,005

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	8,961,333	10,211,712
135	(581) Load Dispatching	10,667,212	11,608,861
136	(582) Station Expenses	3,986,742	4,455,539
137	(583) Overhead Line Expenses	7,809,454	7,582,880
138	(584) Underground Line Expenses	787	1,120
139	(585) Street Lighting and Signal System Expenses	152,074	248,347
140	(586) Meter Expenses	4,220,933	6,053,312
141	(587) Customer Installations Expenses	13,556,316	13,509,277
142	(588) Miscellaneous Expenses	1,975,285	4,583,209
143	(589) Rents	3,178,795	3,318,918
144	TOTAL Operation (Enter Total of lines 134 thru 143)	54,508,931	61,573,175
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	5,400,066	5,375,453
147	(591) Maintenance of Structures	2,463,160	1,997,387
148	(592) Maintenance of Station Equipment	9,002,066	10,617,895
149	(593) Maintenance of Overhead Lines	86,667,266	80,772,052
150	(594) Maintenance of Underground Lines	25,465,187	25,704,585
151	(595) Maintenance of Line Transformers	969,563	1,075,858
152	(596) Maintenance of Street Lighting and Signal Systems	2,930,590	3,239,309
153	(597) Maintenance of Meters	138,623	5,970
154	(598) Maintenance of Miscellaneous Distribution Plant	10,103,297	6,136,247
155	TOTAL Maintenance (Total of lines 146 thru 154)	143,139,818	134,924,756
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	197,648,749	196,497,931
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	2,362,629	2,334,844
160	(902) Meter Reading Expenses	19,666,217	18,089,729
161	(903) Customer Records and Collection Expenses	47,770,750	48,583,852
162	(904) Uncollectible Accounts	15,424,209	12,228,903
163	(905) Miscellaneous Customer Accounts Expenses	881,737	1,949,683
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	86,105,542	83,187,011

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	288,761	278,714
168	(908) Customer Assistance Expenses	87,894,734	143,987,121
169	(909) Informational and Instructional Expenses	3,335,567	3,093,817
170	(910) Miscellaneous Customer Service and Informational Expenses	3,182	54,913
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	91,522,244	147,414,565
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	70,991,765	72,807,417
182	(921) Office Supplies and Expenses	9,355,736	8,563,731
183	(Less) (922) Administrative Expenses Transferred-Credit	31,140,474	33,233,808
184	(923) Outside Services Employed	23,869,244	14,997,016
185	(924) Property Insurance	14,821,125	14,265,351
186	(925) Injuries and Damages	9,434,369	1,256,342
187	(926) Employee Pensions and Benefits	98,462,764	
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	22,853,804	25,261,821
190	(929) (Less) Duplicate Charges-Cr.	103,489,435	3,584,897
191	(930.1) General Advertising Expenses	1,435	1,818
192	(930.2) Miscellaneous General Expenses	2,272,508	2,346,536
193	(931) Rents	3,040,328	4,735,239
194	TOTAL Operation (Enter Total of lines 181 thru 193)	120,473,169	107,416,566
195	Maintenance		
196	(935) Maintenance of General Plant	21,636,566	22,216,334
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	142,109,735	129,632,900
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,825,179,265	2,845,495,474

Schedule Page: 320 Line No.: 185 Column: b

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Account (a)	Ref. Line No. (Column)	Amount for Current Year (b)
(924) Property Insurance	185(b)	$ 14,821,125
Less: Situs property loss reserves, net of reimbursements(1)		9,241,532
Revised (924) Property Insurance		$ 5,579,593

(1) To adjust PacifiCorp's formula rate, per FERC Docket No. FA16-4-000 for situs property loss reserves, net of reimbursements.

Schedule Page: 320 Line No.: 187 Column: b

As required by Commission regulations, pursuant to FERC Docket No. FA16-4-000, the cost of pensions, postretirement other than pensions and other employee benefits are reported in Account 926, Employee pensions and benefits with an offsetting credit to Account 929, Duplicate charges-credit, as pensions and benefits expense is associated with labor and generally charged to operations and maintenance expense and construction work in progress.

In accordance with PacifiCorp's formula rate settlement agreement in FERC Docket No. ER11-3643-000, Section 3.4.2.9 states, in part, all regulatory asset amortizations should be excluded from the calculation of the wholesale transmission revenue requirement and charges under the wholesale formula rates, unless approved by the Commission. During the year ended December 31, 2017, pension and postretirement regulatory asset amortization was $(1,631,128).

Schedule Page: 320 Line No.: 187 Column: c

Pensions and benefits expense is associated with labor and generally charged to operations and maintenance expense and construction work in progress. During the year ended December 31, 2016, pensions and benefits expense was $113,808,905.

Schedule Page: 320 Line No.: 190 Column: b

Includes the offset of debits reflected in Account 926, Employee pensions and benefits.

Schedule Page: 320 Line No.: 197 Column: b

Adjustments to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, are as follows:

Account (a)	Ref. Line No. (Column)	Amount for Current Year (b)
TOTAL Administrative & General Expenses	197(b)	$ 142,109,735
Less: Situs property loss reserves, net of reimbursements(1)		9,241,532
Less: Pension and postretirement regulatory asset amort. (2)		(1,631,128)
Revised TOTAL Administrative & General Expenses		$ 134,499,331

(1) To adjust Account 924, Property insurance. Refer to footnote on page 320, line no. 185, column (b)

(2) To adjust Account 926, Employee pensions and benefits. Refer to footnote on page 320, line no. 187, 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 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Power Purchases:					
2	3Degrees Group, Inc.	OS		NA	NA	NA
3	Apple, Inc.	LU		NA	NA	NA
4	Arizona Electric Power Cooperative	SF		NA	NA	NA
5	Arizona Public Service Company	AD		NA	NA	NA
6	Arizona Public Service Company	LF		NA	NA	NA
7	Arizona Public Service Company	SF		NA	NA	NA
8	Avangrid Renewables, LLC	AD		NA	NA	NA
9	Avangrid Renewables, LLC	SF		NA	NA	NA
10	Avista Corporation	SF		NA	NA	NA
11	BC Solar, LLC	AD		NA	NA	NA
12	BC Solar, LLC	LU		NA	NA	NA
13	BP Energy Company	SF		NA	NA	NA
14	Ballard Hog Farms Inc.	LU		0	0	0
	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
					310,102	310,102	2
6,576				509,402		509,402	3
21,419				932,010		932,010	4
-261					-9,309	-9,309	5
113,733				2,527,428		2,527,428	6
96,214				2,191,140	137,031	2,328,171	7
10					129	129	8
1,919,816				46,463,608		46,463,608	9
207,598				6,621,325	6,209	6,627,534	10
					9	9	11
17,907				1,061,821		1,061,821	12
782,645				17,547,426		17,547,426	13
306			6,541	14,613		21,154	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Basin Electric Power Cooperative	SF		NA	NA	NA
2	Beaver City Corporation	LF		NA	NA	NA
3	Bell Mountain Hydro, LLC	AD		NA	NA	NA
4	Bell Mountain Hydro, LLC	LU		NA	NA	NA
5	Beryl Solar, LLC	LU		3	3	1
6	Big Top, LLC	LU		NA	NA	NA
7	Biomass One, L.P.	AD		NA	NA	NA
8	Biomass One, L.P.	LU		NA	NA	NA
9	Birch Power Company, Inc.	LU		NA	NA	NA
10	Black Cap Solar, LLC	LU		NA	NA	NA
11	Black Hills Power, Inc.	SF		NA	NA	NA
12	Bonneville Power Administration	AD		NA	NA	NA
13	Bonneville Power Administration	LF		NA	NA	NA
14	Bonneville Power Administration	OS		NA	NA	NA
	Total					

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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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)	
248,366				8,682,838		8,682,838	1
30				2,888		2,888	2
-5					447	447	3
823				71,015		71,015	4
5,346			413,009	256,619		669,628	5
3,047				229,526		229,526	6
					3,546	3,546	7
119,240				8,713,895	2,679,744	11,393,639	8
9,310				593,023		593,023	9
591				16,532		16,532	10
3,100				243,440		243,440	11
					19,855	19,855	12
					6,512	6,512	13
					123,599	123,599	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Bonneville Power Administration	SF		NA	NA	NA
2	Bourdet, Peter M.	LU		NA	NA	NA
3	Box Canyon Limited Partnership	LU		5	4	3
4	Brigham Young University - Idaho	IU		NA	NA	NA
5	British Columbia Hydro and Power	SF		NA	NA	NA
6	Brookfield Energy Marketing L.P.	SF		NA	NA	NA
7	Buckhorn Solar, LLC	LU		3	3	1
8	Butter Creek Power, LLC	LU		NA	NA	NA
9	C Drop Hydro, LLC	LU		NA	NA	NA
10	CDM Hydroelectric Company	LU		NA	NA	NA
11	California Independent System Operator	AD		NA	NA	NA
12	California Independent System Operator	SF		NA	NA	NA
13	Calpine Energy Services, L.P.	SF		NA	NA	NA
14	Cargill Power Markets, 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.
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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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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)	
696,332				15,430,328	36,963	15,467,291	1
178				4,793		4,793	2
25,294			427,005	3,533,521		3,960,526	3
39,420				2,171,851		2,171,851	4
14					408	408	5
6,278				363,058		363,058	6
5,358			412,566	257,176		669,742	7
10,267				769,185		769,185	8
2,331				180,467		180,467	9
36,109				2,300,941		2,300,941	10
36					2,556	2,556	11
2,974				576,842		576,842	12
132,028				3,943,414		3,943,414	13
108					4,210	4,210	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

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 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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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	Cargill Power Markets, LLC	SF		NA	NA	NA
2	Cedar Valley Solar, LLC	LU		3	3	0
3	Central Oregon Irrigation District	LU		3	4	3
4	Chevron U.S.A. Inc.	LU		NA	NA	NA
5	Chopin Wind LLC	LU		NA	NA	NA
6	City of Albany	LU		NA	NA	NA
7	City of Anaheim	SF		NA	NA	NA
8	City of Astoria	LU		NA	NA	NA
9	City of Buffalo	LU		0	0	0
10	City of Burbank	SF		NA	NA	NA
11	City of Hurricane	LF		NA	NA	NA
12	City of Hurricane	LF		NA	NA	NA
13	City of Lehi	AD		NA	NA	NA
14	City of Lehi	IF		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)	
145,270				4,518,764		4,518,764	1
5,676			408,858	272,471		681,329	2
39,324			363,191	4,155,353		4,518,544	3
41,131				543,867		543,867	4
26,093				1,342,188		1,342,188	5
958				73,297		73,297	6
11				55		55	7
29				1,040		1,040	8
1,379				38,158		38,158	9
24,576				1,017,161		1,017,161	10
1,369				88,978		88,978	11
798				53,842		53,842	12
					4	4	13
2				259		259	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	City of Portland, Water Bureau	AD		NA	NA	NA
2	City of Portland, Water Bureau	LU		NA	NA	NA
3	City of Preston Idaho	LU		NA	NA	NA
4	City of Redding	SF		NA	NA	NA
5	Clatskanie People's Utility District	SF		NA	NA	NA
6	Commercial Energy Management Inc.	AD		NA	NA	NA
7	Commercial Energy Management Inc.	LU		NA	NA	NA
8	ConocoPhillips Company	SF		NA	NA	NA
9	Consolidated Irrigation Company	LU		NA	NA	NA
10	Cottonwood Hydro, LLC	AD		NA	NA	NA
11	Cottonwood Hydro, LLC	IU		NA	NA	NA
12	Crook County Solar 1, LLC	LU		NA	NA	NA
13	Deschutes Valley Water District	LU		5	6	4
14	Deseret Generation & Transmission Coop	LF		100	100	77
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
-3					-254	-254	1
148				11,496		11,496	2
2,098				122,949		122,949	3
85				600		600	4
847				13,065		13,065	5
					-100	-100	6
2,523				143,802		143,802	7
6,800				223,500		223,500	8
2,270				117,540		117,540	9
41					2,066	2,066	10
3,472				162,277		162,277	11
1,168				31,624		31,624	12
32,086			567,631	4,212,941		4,780,572	13
426,612			17,215,632	9,363,631	4,454,272	31,033,535	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Dorena Hydro, LLC	LU		NA	NA	NA
2	Douglas County	LU		1	1	1
3	Douglas County, Inc.	LU		NA	NA	NA
4	Draper Irrigation Company	IU		NA	NA	NA
5	Dry Creek LLC	LU		NA	NA	NA
6	Duane Wiggins Hydro, Inc.	AD		NA	NA	NA
7	Duane Wiggins Hydro, Inc.	IU		NA	NA	NA
8	eBay Inc.	LU		NA	NA	NA
9	EDF Trading North America, LLC	AD		NA	NA	NA
10	EDF Trading North America, LLC	SF		NA	NA	NA
11	El Paso Electric Company	SF		NA	NA	NA
12	Element Markets, LLC	OS		NA	NA	NA
13	Enterprise Solar, LLC	AD		NA	NA	NA
14	Enterprise Solar, 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)	
14,917				1,156,073		1,156,073	1
7,626			97,747	1,124,084		1,221,831	2
4,876				130,033		130,033	3
548				35,954		35,954	4
15,357				796,269		796,269	5
-18					981	981	6
-9				-491		-491	7
279				20,939		20,939	8
569					13,595	13,595	9
2,056,635				51,282,320		51,282,320	10
18,514				386,898		386,898	11
					31,930	31,930	12
					160,704	160,704	13
224,267				12,407,916		12,407,916	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Eugene Water & Electric Board	SF		NA	NA	NA
2	Eurus Combine Hills I, LLC	LU		NA	NA	NA
3	Evergreen BioPower, LLC	LU		NA	NA	NA
4	Exelon Generation Company, LLC	SF		NA	NA	NA
5	ExxonMobil Production Company	LU		NA	NA	NA
6	Falls Creek H.P. Limited Partnership	LU		4	3	2
7	Farm Power Misty Meadow, LLC	AD		NA	NA	NA
8	Farm Power Misty Meadow, LLC	LU		NA	NA	NA
9	Farmers Irrigation District	LU		NA	NA	NA
10	Fillmore City Corporation	LF		NA	NA	NA
11	Finley BioEnergy, LLC	LU		NA	NA	NA
12	Flathead Electric Cooperative, Inc.	LF		NA	NA	NA
13	Foote Creek II, LLC	LU		NA	NA	NA
14	Foote Creek III, 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)	
11,372				344,691		344,691	1
93,507				4,421,951		4,421,951	2
53,755				3,796,778		3,796,778	3
633,537				15,772,174		15,772,174	4
3,036				73,970		73,970	5
18,028			222,954	2,410,313		2,633,267	6
-23					-7,717	-7,717	7
3,158				244,669		244,669	8
25,037				1,743,895		1,743,895	9
182				19,944		19,944	10
28,194				2,159,587		2,159,587	11
296					4,566	4,566	12
5,430				101,489		101,489	13
66,249				1,339,665		1,339,665	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Four Brothers Solar, LLC	LU		NA	NA	NA
2	Four Corners Windfarm, LLC	LU		NA	NA	NA
3	Four Mile Canyon Windfarm, LLC	LU		NA	NA	NA
4	Georgetown Irrigation Company	LU		NA	NA	NA
5	Grand Valley Power	LF		NA	NA	NA
6	Granite Mountain Holdings LLC	LU		NA	NA	NA
7	Granite Peak Solar, LLC	LU		3	3	1
8	Greenville Solar, LLC	LU		2	2	2
9	Gridforce Energy Management	SF		NA	NA	NA
10	Hammerich 1 & 2	LU		NA	NA	NA
11	Harold Foster & Robert Walker	AD		NA	NA	NA
12	Harold Foster & Robert Walker	LU		NA	NA	NA
13	Idaho Falls, City of	AD		NA	NA	NA
14	Idaho Falls, City of	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 2017/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)	
624,023				31,746,778		31,746,778	1
23,802				1,782,295		1,782,295	2
21,717				1,633,884		1,633,884	3
2,253				141,685		141,685	4
39				8,980		8,980	5
336,659				17,682,308		17,682,308	6
6,182			206,860	208,530		415,390	7
3,388			279,245	162,628		441,873	8
38					1,330	1,330	9
347				8,995		8,995	10
-42					-1,673	-1,673	11
241				9,919		9,919	12
					5,815	5,815	13
44,956					1,650,380	1,650,380	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Idaho Power Company	SF		NA	NA	NA
2	Iron Springs Solar, LLC	LU		NA	NA	NA
3	J Bar 9 Ranch, Inc.	AD		NA	NA	NA
4	J Bar 9 Ranch, Inc.	LU		NA	NA	NA
5	Jake Amy	LU		NA	NA	NA
6	Joseph Community Solar LLC	LU		NA	NA	NA
7	Keeton 1 & 2	LU		NA	NA	NA
8	Kennecott Utah Copper LLC	LU		NA	NA	NA
9	Kennecott Utah Copper LLC	OS		NA	NA	NA
10	Kettle Butte Digester LLC	LU		NA	NA	NA
11	Klamath Falls 2	LU		NA	NA	NA
12	Klamath Falls Solar 1 LLC	LU		NA	NA	NA
13	Lacomb Irrigation District	LU		NA	NA	NA
14	Laho Solar, LLC	LU		3	3	1
	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)	
82,497				1,121,592	920	1,122,512	1
212,005				11,307,401		11,307,401	2
					2	2	3
56				1,336		1,336	4
1,762				108,202		108,202	5
667				17,167		17,167	6
340				8,913		8,913	7
9,437				184,514		184,514	8
1,558							9
4,658				314,976		314,976	10
93				3,512		3,512	11
1,206				71,564		71,564	12
5,044				113,772	41,315	155,087	13
5,627			201,698	189,799		391,497	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

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 2017/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	Latigo Wind Park, LLC	LU		NA	NA	NA
2	Los Angeles Dept. of Water and Power	SF		NA	NA	NA
3	Lower Valley Energy, Inc.	IU		NA	NA	NA
4	Lower Valley Energy, Inc.	LU		NA	NA	NA
5	Loyd Fery	LU		NA	NA	NA
6	Macquarie Energy LLC	SF		NA	NA	NA
7	Marsh Valley Hydro Electric Company	LU		NA	NA	NA
8	Meadow Creek Project Company LLC	LU		NA	NA	NA
9	Middle Fork Irrigation District	LU		NA	NA	NA
10	Milford Flat Solar, LLC	LU		0	3	1
11	Mink Creek Hydro LLC	LU		NA	NA	NA
12	Monsanto Company	IU		NA	NA	NA
13	Morgan City Corporation	LF		NA	NA	NA
14	Morgan Stanley Capital Group, Inc.	SF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
154,655				9,297,439		9,297,439	1
32,632				2,020,610	10,734	2,031,344	2
5,397				167,469		167,469	3
1,016				34,176		34,176	4
255				6,461		6,461	5
149,893				4,239,787		4,239,787	6
7,589				485,739		485,739	7
349,574				25,272,412		25,272,412	8
25,436				1,790,592		1,790,592	9
5,783			34,629	153,845		188,474	10
13,728				859,650		859,650	11
					20,000,000	20,000,000	12
10				910		910	13
921,889				28,873,851		28,873,851	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

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 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	Mountain Wind Power II, LLC	LU		NA	NA	NA
2	Mountain Wind Power, LLC	LU		NA	NA	NA
3	Municipal Energy Agency of Nebraska	SF		NA	NA	NA
4	NaturEner Power Watch, LLC	SF		NA	NA	NA
5	Nevada Power Company	AD		NA	NA	NA
6	Nevada Power Company	SF		NA	NA	NA
7	NextEra Energy Power Marketing, LLC	SF		NA	NA	NA
8	Nichols Gap Limited Partnership	LU		1	1	0
9	Nicholson's Sunny Bar Ranch	LU		NA	NA	NA
10	NorWest Energy 2	LU		NA	NA	NA
11	NorthWestern Corporation	SF		NA	NA	NA
12	Norwest 7, LLC	LU		NA	NA	NA
13	Nucor Corporation	IF		NA	NA	NA
14	O.J. Power Company	LU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
216,909				13,790,567		13,790,567	1
164,766				9,098,223		9,098,223	2
12,094				547,483		547,483	3
1					9	9	4
					-3	-3	5
29,357				913,111	163,193	1,076,304	6
2,600				67,884		67,884	7
3,718			46,881	516,844		563,725	8
1,763				111,412		111,412	9
17,458				1,040,586		1,040,586	10
24,585				266,490	5,449	271,939	11
23				1,146		1,146	12
					7,201,200	7,201,200	13
751				44,232		44,232	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	OSLH, LLC	AD		NA	NA	NA
2	OSLH, LLC	LU		NA	NA	NA
3	Obsidian Renewables, LLC	LU		NA	NA	NA
4	Old Mill Solar, LLC	LU		NA	NA	NA
5	Oregon Environmental Industries, LLC	LU		NA	NA	NA
6	Oregon Institute of Technology	LU		NA	NA	NA
7	Oregon Solar 3 and 6	LU		NA	NA	NA
8	Oregon Solar Incentive	LU		NA	NA	NA
9	Oregon State University	LU		NA	NA	NA
10	Oregon Trail Windfarm, LLC	LU		NA	NA	NA
11	Pacific Canyon Windfarm, LLC	LU		NA	NA	NA
12	Paul Luckey	LU		NA	NA	NA
13	Pavant Solar II, LLC	AD		NA	NA	NA
14	Pavant Solar II, 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)	
					-15	-15	1
19,926				775,332		775,332	2
861				23,216		23,216	3
11,153				836,481		836,481	4
20,213				1,421,801		1,421,801	5
120				2,651		2,651	6
162				6,088		6,088	7
10,465				274,828		274,828	8
89				1,872		1,872	9
20,878				1,566,768		1,566,768	10
16,048				1,210,157		1,210,157	11
233				12,347		12,347	12
-81					-1,977	-1,977	13
119,175				3,053,412		3,053,412	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Pavant Solar III, LLC	AD		NA	NA	NA
2	Pavant Solar III, LLC	LU		NA	NA	NA
3	Pavant Solar, LLC	AD		NA	NA	NA
4	Pavant Solar, LLC	LU		NA	NA	NA
5	Pioneer Wind Park	AD		NA	NA	NA
6	Pioneer Wind Park	LU		NA	NA	NA
7	Platte River Power Authority	SF		NA	NA	NA
8	Portland General Electric Company	AD		NA	NA	NA
9	Portland General Electric Company	LF		NA	NA	NA
10	Portland General Electric Company	SF		NA	NA	NA
11	Power County Wind Park North, LLC	LU		NA	NA	NA
12	Power County Wind Park South, LLC	LU		NA	NA	NA
13	Powerex Corporation	SF		NA	NA	NA
14	Provo City Corporation	LF		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 2017/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)	
767					20,619	20,619	1
48,147				2,542,161		2,542,161	2
					138,289	138,289	3
118,002				4,020,528		4,020,528	4
					1	1	5
269,656				10,786,227		10,786,227	6
3,584					88,474	88,474	7
					-9,332	-9,332	8
10,979					157,528	157,528	9
130,646				3,665,217	9,935	3,675,152	10
64,849				4,643,988		4,643,988	11
58,372				4,198,290		4,198,290	12
517,424				18,281,623		18,281,623	13
47				4,164		4,164	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

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 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Public Service Company of Colorado	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	LF		NA	NA	NA
8	PUD No. 1 of Douglas County	LU		NA	NA	NA
9	PUD No. 1 of Douglas County	SF		NA	NA	NA
10	PUD No. 1 of Snohomish County	SF		NA	NA	NA
11	PUD No. 2 of Grant County	AD		NA	NA	NA
12	PUD No. 2 of Grant County	LU		NA	NA	NA
13	PUD No. 2 of Grant County	SF		NA	NA	NA
14	Puget Sound Energy, Inc.	SF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: 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.
1,157,741				28,308,341		28,308,341	1
182,103				5,360,052		5,360,052	2
162,439				5,532,402	1,685	5,534,087	3
3,244				42,170		42,170	4
					88,210	88,210	5
					-321,350	-321,350	6
55,708				1,930,879		1,930,879	7
237,855					3,367,507	3,367,507	8
22,566				488,990	688	489,678	9
67,775				1,184,589		1,184,589	10
					-872,180	-872,180	11
90,543					-132,532	-132,532	12
109					2,955	2,955	13
283,098				8,300,271	10,277	8,310,548	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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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	Quichapa	AD		NA	NA	NA
2	Quichapa	LU		NA	NA	NA
3	RES Ag - Oak Lea LLC	AD		NA	NA	NA
4	Rainbow Energy Marketing Corporation	SF		NA	NA	NA
5	Rock River 1, LLC	LU		NA	NA	NA
6	Roseburg Forest Products Company	LU		NA	NA	NA
7	Roseburg LFG Energy, LLC	LU		NA	NA	NA
8	Roush Hydro Inc.	LU		NA	NA	NA
9	Sacramento Municipal Utility District	SF		NA	NA	NA
10	Salt River Project	AD		NA	NA	NA
11	Salt River Project	SF		NA	NA	NA
12	Sand Ranch Windfarm, LLC	LU		NA	NA	NA
13	Santiam Water Control District	LU		0	0	0
14	Seattle City Light	SF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
70					-6,836	-6,836	1
24,299				1,453,925		1,453,925	2
-55					-4,467	-4,467	3
88,907				1,368,195		1,368,195	4
147,623				5,237,668		5,237,668	5
59,307				3,588,206		3,588,206	6
9,120				704,921		704,921	7
190				5,090		5,090	8
4					117	117	9
					125	125	10
464,450				12,695,250	3,111	12,698,361	11
20,004				1,508,450		1,508,450	12
1,345			13,334	179,867		193,201	13
98,011				2,683,488	3,872	2,687,360	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Sempra Generation, LLC	AD		NA	NA	NA
2	Sempra Generation, LLC	SF		NA	NA	NA
3	Shell Energy North America (US), L.P.	AD		NA	NA	NA
4	Shell Energy North America (US), L.P.	SF		NA	NA	NA
5	Shiloh Warm Springs Ranch, LLC	AD		NA	NA	NA
6	Shiloh Warm Springs Ranch, LLC	LU		NA	NA	NA
7	Sierra Pacific Power Company	SF		NA	NA	NA
8	Slate Creek Hydro Company, Inc.	LU		1	1	2
9	Solwatt LLC	LU		NA	NA	NA
10	Southern California Edison Company	SF		NA	NA	NA
11	Spanish Fork Wind Park 2, LLC	LU		NA	NA	NA
12	Sprague Hydro LLC	LU		0	1	0
13	St. Anthony Hydro, LLC	AD		NA	NA	NA
14	St. Anthony Hydro, LLC	LU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: 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.
5					100	100	1
394,116				11,462,717		11,462,717	2
-271					-9,369	-9,369	3
280,156				11,169,473		11,169,473	4
36					1,332	1,332	5
906				57,952		57,952	6
63					1,387	1,387	7
8,823			153,753	1,122,624		1,276,377	8
789				20,122		20,122	9
203				4,011		4,011	10
46,460				2,621,025		2,621,025	11
4,285			70,593	587,052		657,645	12
					-8	-8	13
5,512				336,818		336,818	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Stahlbush Island Farms, Inc.	IU		NA	NA	NA
2	SunE DB 24, LLC	LU		3	3	1
3	SunE DB18, LLC	LU		3	3	1
4	SunE Solar XVII Project1, LLC	LU		3	8	3
5	SunE Solar XVII Project2, LLC	LU		3	8	3
6	SunE Solar XVII Project3, LLC	LU		3	8	3
7	Sunnyside Cogeneration Associates	LU		34	51	48
8	Surprise Valley Electrification Corp.	AD		NA	NA	NA
9	Surprise Valley Electrification Corp.	LU		NA	NA	NA
10	Swalley Irrigation District	LU		NA	NA	NA
11	TMF Biofuels, LLC	AD		NA	NA	NA
12	TMF Biofuels, LLC	LU		NA	NA	NA
13	Tacoma Power	SF		NA	NA	NA
14	Talen Energy Marketing, LLC	SF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
746				17,577		17,577	1
6,518			188,062	219,847		407,909	2
6,348			369,179	304,684		673,863	3
7,409			402,615	355,645		758,260	4
7,290			400,716	349,898		750,614	5
7,149			198,783	241,133		439,916	6
414,549			10,926,657	17,868,606		28,795,263	7
10					-1,139	-1,139	8
1,537				70,222		70,222	9
2,205				169,232		169,232	10
519					37,017	37,017	11
24,424				1,786,735		1,786,735	12
70,646				1,986,448	1,796	1,988,244	13
16,601				434,742		434,742	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Tata Chemicals (Soda Ash) Partners	LU		NA	NA	NA
2	Tenaska Power Services Co.	SF		NA	NA	NA
3	Tesoro Refining & Marketing Co, LLC	LU		NA	NA	NA
4	Thayn Hydro LLC	LU		NA	NA	NA
5	The Confederated Tribe of Warm Springs	LU		NA	NA	NA
6	The Energy Authority, Inc.	SF		NA	NA	NA
7	Three Buttes Windpower, LLC	LU		NA	NA	NA
8	Three Peaks Power, LLC	LU		NA	NA	NA
9	Three Sisters Irrigation District	AD		NA	NA	NA
10	Three Sisters Irrigation District	LU		NA	NA	NA
11	Threemile Canyon Wind I, LLC	LU		NA	NA	NA
12	Tooele Army Depot	AD		NA	NA	NA
13	Tooele Army Depot	LU		NA	NA	NA
14	Top of The World Wind Energy LLC	LU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2,805				90,137		90,137	1
22,679				1,079,714		1,079,714	2
7,936				166,954		166,954	3
3,738				145,434		145,434	4
294				7,433		7,433	5
64,714				1,532,875		1,532,875	6
311,597				19,879,429		19,879,429	7
220,926				9,342,072		9,342,072	8
					-75	-75	9
3,539				187,173		187,173	10
18,807				1,439,602		1,439,602	11
-149					-26	-26	12
745				22,018		22,018	13
611,543				40,574,156		40,574,156	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	TransAlta Energy Marketing (U.S.) Inc.	AD		NA	NA	NA
2	TransAlta Energy Marketing (U.S.) Inc.	SF		NA	NA	NA
3	TransCanada Energy Sales Ltd.	SF		NA	NA	NA
4	Tri-State Generation and Transmission	LF		NA	NA	NA
5	Tri-State Generation and Transmission	SF		NA	NA	NA
6	Tucson Electric Power Company	SF		NA	NA	NA
7	Tumbleweed Solar, LLC	LU		NA	NA	NA
8	Turlock Irrigation District	SF		NA	NA	NA
9	U.S. Dept of the Interior	LU		NA	NA	NA
10	UNS Electric, Inc.	SF		NA	NA	NA
11	US Magnesium LLC	LF		NA	NA	NA
12	United States Air Force at Hill Base	LU		NA	NA	NA
13	Utah Associated Municipal Power System	LF		NA	NA	NA
14	Utah Associated Municipal Power System	SF		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)	
175					5,188	5,188	1
717,488				21,187,455		21,187,455	2
5				135		135	3
100,889			6,375,000	3,205,966		9,580,966	4
2,838				92,925	28,208	121,133	5
122,748				3,380,917	854	3,381,771	6
146				5,471		5,471	7
754				52,955	29	52,984	8
25				1,672		1,672	9
12,426				555,955		555,955	10
					5,976,132	5,976,132	11
9,955				537,986		537,986	12
49,516				2,549,093		2,549,093	13
32				832		832	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Utah Municipal Power Agency	IU		NA	NA	NA
2	Utah Municipal Power Agency	SF		185	186	82
3	Utah Red Hills Renewable Park, LLC	LU		NA	NA	NA
4	Vitol Inc.	SF		NA	NA	NA
5	Wagon Trail, LLC	LU		NA	NA	NA
6	Ward Butte Windfarm, LLC	LU		NA	NA	NA
7	Wasatch Integrated Waste Mgmt District	LU		0	0	0
8	Weber County	LU		NA	NA	NA
9	Western Area Power Administration	AD		NA	NA	NA
10	Western Area Power Administration	LF		NA	NA	NA
11	Western Area Power Administration	SF		NA	NA	NA
12	Wolverine Creek Energy, LLC	LU		NA	NA	NA
13	Woodline Solar, LLC	LU		NA	NA	NA
14	Yakima-Tieton Irrigation District	LU		2	1	1
	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 2017/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)	
43,404				2,599,466		2,599,466	1
62,711			2,010,000	1,974,239	480,209	4,464,448	2
209,574				12,174,980		12,174,980	3
101,200				2,926,900		2,926,900	4
6,127				462,482		462,482	5
14,567				1,093,143		1,093,143	6
272			15,484	12,220		27,704	7
950				50,719		50,719	8
					5,966	5,966	9
19,464					628,772	628,772	10
20,157				312,486	172,081	484,567	11
172,117				10,197,944		10,197,944	12
58				2,209		2,209	13
5,941			20,275	211,482		231,757	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	CA Greenhouse Gas Allowance Purchases			NA	NA	NA
2	Netting - Bookouts			NA	NA	NA
3	Netting - Trading			NA	NA	NA
4	Fair Value Adjustment Amortization			NA	NA	NA
5	Net Power Cost Deferrals			NA	NA	NA
6	System Deviation			NA	NA	NA
7	Accrual			NA	NA	NA
8						
9	Power Exchanges:					
10	Arizona Public Service Company	EX	307	NA	NA	NA
11	Avista Corporation	EX	382	NA	NA	NA
12	Bonneville Power Administration	AD	237	NA	NA	NA
13	Bonneville Power Administration	EX	237	NA	NA	NA
14	Bonneville Power Administration	EX	519	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 2017/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)	
					4,258,556	4,258,556	1
-6,967,134					-175,654,149	-175,654,149	2
					-908,433	-908,433	3
					-1,268,595	-1,268,595	4
					26,420,507	26,420,507	5
8,910							6
					-5,160,325	-5,160,325	7
							8
							9
	571,618	571,397			-880,103	-880,103	10
	1,977						11
					-54,358	-54,358	12
	718	7,352			-34,700	-34,700	13
	88,689	86,856			-271,166	-271,166	14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Bonneville Power Administration	EX	T-BPA	NA	NA	NA
2	California Independent System Operator	AD	T-11	NA	NA	NA
3	California Independent System Operator	AD	T-12	NA	NA	NA
4	California Independent System Operator	EX	T-11	NA	NA	NA
5	California Independent System Operator	EX	T-12	NA	NA	NA
6	Emerald People's Utility District	EX	351	NA	NA	NA
7	Eugene Water & Electric Board	EX	T-12	NA	NA	NA
8	Idaho Power Company	EX	708	NA	NA	NA
9	Idaho Power Company	EX	T-6	NA	NA	NA
10	Los Angeles Dept. of Water and Power	EX	OV-1	NA	NA	NA
11	Milford Wind Corridor Phase I, LLC	EX	OV-1	NA	NA	NA
12	Milford Wind Corridor Phase II, LLC	EX	OV-1	NA	NA	NA
13	NorthWestern Corporation	EX	160	NA	NA	NA
14	Portland General Electric Company	EX	T-8	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.
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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)	
	236,915	9,602			203,285	203,285	1
					324,062	324,062	2
					-1,413,935	-1,413,935	3
					32,004,024	32,004,024	4
	2,389,576	3,002,133			-87,320,037	-87,320,037	5
		845			-21,124	-21,124	6
	18,197	17,864			-34,445	-34,445	7
	125,271	120,294					8
	62,990	2,091					9
	3,400				250,288	250,288	10
		2,270			-164,202	-164,202	11
		1,130			-86,086	-86,086	12
	1,206						13
	4,442						14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

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.

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Public Service Company of Colorado	EX	319	NA	NA	NA
2	Public Service Company of Colorado	EX	334	NA	NA	NA
3	PUD No. 1 of Cowlitz County	EX	442	NA	NA	NA
4	Seattle City Light	EX	554	NA	NA	NA
5	Tri-State Generation and Transmission	EX	319	NA	NA	NA
6	Warm Springs Power Enterprises	EX	T-11	NA	NA	NA
7	Western Area Power Administration	AD	LAS-4	NA	NA	NA
8	Western Area Power Administration	EX	LAS-4	NA	NA	NA
9	Imbalance Energy Accrual	EX	T-11	NA	NA	NA
10						
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	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.
	242						1
	1,311,576	1,308,395			5,400,000	5,400,000	2
	254,537	291,006					3
	299,087	330,161			-765,673	-765,673	4
	241						5
	8,237	1,108			142,935	142,935	6
	664	2,359			-24,976	-24,976	7
	1,935	23,144			-343,388	-343,388	8
	1,716,181	1,102,408			9,804,264	9,804,264	9
							10
							11
							12
							13
							14
14,002,749	7,097,699	6,880,415	42,048,898	746,060,870	-148,663,887	639,445,881	

Schedule Page: 326 Line No.: 2 Column: b
Secondary, economy, renewable attributes and/or non-firm.

Schedule Page: 326 Line No.: 2 Column: l
Purchase of renewable energy credit certificates for renewable portfolio standard requirements.

Schedule Page: 326 Line No.: 5 Column: b
Settlement adjustment.

Schedule Page: 326 Line No.: 5 Column: l
Settlement adjustment.

Schedule Page: 326 Line No.: 6 Column: b
Arizona Public Service Company - contract termination date: October 31, 2020.

Schedule Page: 326 Line No.: 7 Column: l
Line loss.

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

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

Schedule Page: 326 Line No.: 10 Column: l
Reserve share.

Schedule Page: 326 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 326 Line No.: 11 Column: l
Settlement adjustment.

Schedule Page: 326.1 Line No.: 2 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

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

Schedule Page: 326.1 Line No.: 3 Column: l
Settlement adjustment.

Schedule Page: 326.1 Line No.: 7 Column: b
Settlement adjustment.

Schedule Page: 326.1 Line No.: 7 Column: l
Settlement adjustment.

Schedule Page: 326.1 Line No.: 8 Column: l
Non-generation agreement.

Schedule Page: 326.1 Line No.: 10 Column: a
PacifiCorp has an agreement with Citizens 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.: 12 Column: b
Settlement adjustment.

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

Schedule Page: 326.1 Line No.: 13 Column: b
Bonneville Power Administration - contract termination date: Upon 30 days written notice.

Schedule Page: 326.1 Line No.: 13 Column: l
Ancillary services.

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

Schedule Page: 326.1 Line No.: 14 Column: l
Ancillary services.

Schedule Page: 326.2 Line No.: 1 Column: l
Reserve share.

Schedule Page: 326.2 Line No.: 5 Column: a
Complete name is British Columbia Hydro and Power Authority.

Schedule Page: 326.2 Line No.: 5 Column: l
Reserve share.

Schedule Page: 326.2 Line No.: 11 Column: a
This footnote applies to all occurrences of "California Independent System Operator" on pages 326-327. Complete name is California Independent System Operator Corporation.

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

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

Schedule Page: 326.2 Line No.: 14 Column: b
Settlement adjustment.

Schedule Page: 326.2 Line No.: 14 Column: l
Settlement adjustment.

Schedule Page: 326.3 Line No.: 11 Column: b
City of Hurricane - contract termination date: August 31, 2017.

Schedule Page: 326.3 Line No.: 12 Column: b
City of Hurricane - contract termination date: August 31, 2022.

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

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

Schedule Page: 326.3 Line No.: 14 Column: b
City of Lehi - contract termination date: December 17, 2017.

Schedule Page: 326.4 Line No.: 1 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: 326.4 Line No.: 1 Column: b
Settlement adjustment.

Schedule Page: 326.4 Line No.: 1 Column: l
Settlement adjustment.

Schedule Page: 326.4 Line No.: 6 Column: b
Settlement adjustment.

Schedule Page: 326.4 Line No.: 6 Column: l
Settlement adjustment.

Schedule Page: 326.4 Line No.: 10 Column: b
Settlement adjustment.

Schedule Page: 326.4 Line No.: 10 Column: l
Settlement adjustment.

Schedule Page: 326.4 Line No.: 14 Column: a
Complete name is Deseret Generation and Transmission Co-operative.

Schedule Page: 326.4 Line No.: 14 Column: b
Deseret Generation and Transmission Co-operative - contract termination date: September 30, 2024.

Schedule Page: 326.4 Line No.: 14 Column: l
Reimbursement to counterparty for operation and maintenance costs at coal fired generating facility located in Vernal, Utah.

Schedule Page: 326.5 Line No.: 6 Column: b
Settlement adjustment.

Schedule Page: 326.5 Line No.: 6 Column: l
Settlement adjustment.

Schedule Page: 326.5 Line No.: 9 Column: b
Settlement adjustment.

Schedule Page: 326.5 Line No.: 9 Column: l
Settlement adjustment.

Schedule Page: 326.5 Line No.: 12 Column: b
Secondary, economy, renewable attributes and/or non-firm.

Schedule Page: 326.5 Line No.: 12 Column: l
Purchase of renewable energy credit certificates for renewable portfolio standard requirements.

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

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

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

Schedule Page: 326.6 Line No.: 7 Column: l
Settlement adjustment.

Schedule Page: 326.6 Line No.: 10 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.6 Line No.: 12 Column: b
Flathead Electric Cooperative, Inc. - contract termination date: September 30, 2016.

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

Schedule Page: 326.7 Line No.: 5 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

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

Schedule Page: 326.7 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 326.7 Line No.: 11 Column: l
Settlement adjustment.

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

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

Schedule Page: 326.7 Line No.: 14 Column: l
Labor, equipment and administration fees associated with hydro project in Idaho Falls, Idaho.

Schedule Page: 326.8 Line No.: 1 Column: l
Reserve share.

Schedule Page: 326.8 Line No.: 3 Column: b
Settlement adjustment.

Schedule Page: 326.8 Line No.: 3 Column: l
Settlement adjustment.

Schedule Page: 326.8 Line No.: 9 Column: b
Secondary, economy, renewable attributes and/or non-firm.

Schedule Page: 326.8 Line No.: 13 Column: l
Fixed annual payment.

Schedule Page: 326.9 Line No.: 2 Column: a
This footnote applies to all occurrences of "Los Angeles Dept. of Water and Power" on pages 326-327. Complete name is Los Angeles Department of Water and Power.

Schedule Page: 326.9 Line No.: 2 Column: l
Line loss.

Schedule Page: 326.9 Line No.: 12 Column: l
Compensation for interruptible service and operating reserves.

Schedule Page: 326.9 Line No.: 13 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

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

Reserve share.

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

This footnote applies to all occurrences of "Nevada Power Company" on pages 326-327. Nevada Power Company is a wholly owned subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

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

Settlement adjustment.

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

Settlement adjustment.

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

Line loss.

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

Reserve share.

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

Nucor Corporation - Termination Date: December 31, 2017.

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

Ancillary services.

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

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 326.12 Line No.: 1 Column: b

Settlement adjustment.

Schedule Page: 326.12 Line No.: 1 Column: l

Settlement adjustment.

Schedule Page: 326.12 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 326.12 Line No.: 3 Column: l

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 326.12 Line No.: 5 Column: l

Settlement adjustment.

Schedule Page: 326.12 Line No.: 7 Column: l

Line loss.

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

Settlement adjustment.

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

Operation expense plus amortization of unrecovered costs of Cove Project.

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

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

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

Operation expense plus amortization of unrecovered costs of Cove Project.

Schedule Page: 326.12 Line No.: 10 Column: l

Reserve share.

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

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.13 Line No.: 3 Column: a
Complete name is Public Utility District No. 1 of Chelan County.

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

Schedule Page: 326.13 Line No.: 4 Column: a
Complete name is Public Utility District No. 1 of Clark County.

Schedule Page: 326.13 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: 326.13 Line No.: 5 Column: b
Secondary, economy, renewable attributes and/or non-firm.

Schedule Page: 326.13 Line No.: 5 Column: l
Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.13 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: 326.13 Line No.: 6 Column: b
Settlement adjustment.

Schedule Page: 326.13 Line No.: 6 Column: l
Settlement adjustment.

Schedule Page: 326.13 Line No.: 7 Column: b
Public Utility District No. 1 of Douglas County - contract termination date: August 31, 2018.

Schedule Page: 326.13 Line No.: 8 Column: l
Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.13 Line No.: 9 Column: l
Reserve share.

Schedule Page: 326.13 Line No.: 10 Column: a
Complete name is Public Utility District No. 1 of Snohomish County.

Schedule Page: 326.13 Line No.: 11 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: 326.13 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 326.13 Line No.: 11 Column: l
Settlement adjustment.

Schedule Page: 326.13 Line No.: 12 Column: l
Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.13 Line No.: 13 Column: l
Reserve share.

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

Schedule Page: 326.14 Line No.: 1 Column: b
Settlement adjustment.

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

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

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

Schedule Page: 326.14 Line No.: 9 Column: l
Reserve share.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 326.14 Line No.: 11 Column: l

Line loss.

Schedule Page: 326.14 Line No.: 14 Column: l

Reserve share.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 326.15 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 326.15 Line No.: 3 Column: l

Settlement adjustment.

Schedule Page: 326.15 Line No.: 5 Column: b

Settlement adjustment.

Schedule Page: 326.15 Line No.: 5 Column: l

Settlement adjustment.

Schedule Page: 326.15 Line No.: 7 Column: a

Sierra Pacific Power Company is a wholly owned subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

Schedule Page: 326.15 Line No.: 7 Column: l

Reserve share.

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

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 326.16 Line No.: 11 Column: l

Settlement adjustment.

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

Reserve share.

Schedule Page: 326.17 Line No.: 3 Column: a

Complete name is Tesoro Refining & Marketing Company, LLC.

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

Complete name is The Confederated Tribe of Warm Springs Utilities.

Schedule Page: 326.17 Line No.: 9 Column: b

Settlement adjustment.

Schedule Page: 326.17 Line No.: 9 Column: l

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

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

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

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

Line loss.

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

Line loss.

Schedule Page: 326.18 Line No.: 8 Column: l

Reserve share.

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

Complete name is U.S. Department of the Interior - Bureau of Land Management.

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

US Magnesium LLC - contract termination date: December 31, 2017.

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

Ancillary services.

Schedule Page: 326.18 Line No.: 12 Column: a

Complete name is United States Air Force at Hill Air Force Base.

Schedule Page: 326.18 Line No.: 13 Column: b

Utah Associated Municipal Power System - contract termination date: March 31, 2022.

Schedule Page: 326.19 Line No.: 1 Column: b

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

Schedule Page: 326.19 Line No.: 2 Column: l

West Valley Tolling Agreement for station service and CT run rate charge.

Schedule Page: 326.19 Line No.: 7 Column: a

Complete name is Wasatch Integrated Waste Management District.

Schedule Page: 326.19 Line No.: 9 Column: b

Settlement adjustment.

Schedule Page: 326.19 Line No.: 9 Column: l

Settlement adjustment.

Schedule Page: 326.19 Line No.: 10 Column: b

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

Schedule Page: 326.19 Line No.: 10 Column: l

Line loss.

Schedule Page: 326.19 Line No.: 11 Column: l

Line loss.

Schedule Page: 326.20 Line No.: 1 Column: l

Purchases of greenhouse gas allowances for compliance with the California Air Resources Board greenhouse gas cap-and-trade program.

Schedule Page: 326.20 Line No.: 2 Column: l

Reflects transactions that did not physically settle.

Schedule Page: 326.20 Line No.: 3 Column: l

Reflects transactions that did not physically settle.

Schedule Page: 326.20 Line No.: 4 Column: a

Purchase power agreement fair value adjustment amortization related to the acquisition of Eagle Mountain City, a Utah municipal corporation.

Schedule Page: 326.20 Line No.: 4 Column: l

Amortization of a purchase power agreement adjusted to fair value as part of a service territory acquisition.

Schedule Page: 326.20 Line No.: 5 Column: l

Deferrals and associated amortization under various energy cost adjustment mechanisms.

Schedule Page: 326.20 Line No.: 7 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: 326.20 Line No.: 10 Column: l

Exchange energy expense.

Schedule Page: 326.20 Line No.: 12 Column: b

Settlement adjustment.

Schedule Page: 326.20 Line No.: 12 Column: l

Settlement adjustment.

Schedule Page: 326.20 Line No.: 13 Column: l

Storage and exchange charges.

Schedule Page: 326.20 Line No.: 14 Column: l

Storage and exchange charges.

Schedule Page: 326.21 Line No.: 1 Column: l

Storage and exchange charges.

Schedule Page: 326.21 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 326.21 Line No.: 2 Column: l

Energy Imbalance Market ("EIM") entity settlements in EIM.

Schedule Page: 326.21 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 326.21 Line No.: 3 Column: l

EIM participating resource settlements in EIM.

Schedule Page: 326.21 Line No.: 4 Column: l

EIM entity settlements in EIM.

Schedule Page: 326.21 Line No.: 5 Column: l

EIM participating resource settlements in EIM.

Schedule Page: 326.21 Line No.: 6 Column: l

Exchange energy expense.

Schedule Page: 326.21 Line No.: 7 Column: l

Exchange energy expense.

Schedule Page: 326.21 Line No.: 10 Column: l

Station service for third party wind project.

Schedule Page: 326.21 Line No.: 11 Column: l

Reimbursement for providing station service to third party wind project.

Schedule Page: 326.21 Line No.: 12 Column: l

Reimbursement for providing station service to third party wind project.

Schedule Page: 326.22 Line No.: 2 Column: l

Exchange energy expense.

Schedule Page: 326.22 Line No.: 4 Column: l

Exchange energy expense.

Schedule Page: 326.22 Line No.: 6 Column: l

Imbalance energy settlements between PacifiCorp merchant function and third party transmission providers.

Schedule Page: 326.22 Line No.: 7 Column: b

Settlement adjustment.

Schedule Page: 326.22 Line No.: 7 Column: l

Settlement adjustment.

Schedule Page: 326.22 Line No.: 8 Column: l

Imbalance energy settlements between PacifiCorp merchant function and third party transmission providers.

Schedule Page: 326.22 Line No.: 9 Column: l

Allocations of EIM charge codes to transmission customers.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Arizona Public Service Company	Arizona Public Service Company		NF
3	Avangrid Renewables, LLC			NF
4	Avangrid Renewables, LLC			AD
5	Avangrid Renewables, LLC			SFP
6	Avangrid Renewables, LLC			AD
7	Avangrid Renewables, LLC	Avangrid Renewables, LLC		OS
8	Avangrid Renewables, LLC	Avangrid Renewables, LLC		AD
9	Avangrid Renewables, LLC	Exxon Mobil	Nevada Power Company	LFP
10	Avangrid Renewables, LLC	Exxon Mobil	Nevada Power Company	AD
11	Avangrid Renewables, LLC	Bonneville Power Administration	Oregon Direct Access	FNO
12	Avangrid Renewables, LLC	Avangrid Renewables, LLC		AD
13	Basin Electric Power Cooperative, Inc.	Western Area Power Administration	Powder River Energy Corporation	FNO
14	Basin Electric Power Cooperative, Inc.	Western Area Power Administration	Powder River Energy Corporation	AD
15	Basin Electric Power Cooperative, Inc.	Western Area Power Administration	Powder River Energy Corporation	AD
16	Basin Electric Power Cooperative, Inc.	Western Area Power Administration	Powder River Energy Corporation	NF
17	Basin Electric Power Cooperative, Inc.	Western Area Power Administration	Powder River Energy Corporation	AD
18	Basin Electric Power Cooperative, Inc.	Western Area Power Administration	Powder River Energy Corporation	SFP
19	Black Hills/Colorado Electric Utility Company			NF
20	Black Hills/Colorado Electric Utility Company			AD
21	Black Hills/Colorado Electric Utility Company			SFP
22	Black Hills Corporation	PacifiCorp	Montana-Dakota Utilities	FNO
23	Black Hills Corporation	PacifiCorp	Montana-Dakota Utilities	AD
24	Black Hills Corporation	PacifiCorp	Black Hills Corporation	LFP
25	Black Hills Corporation	PacifiCorp	Black Hills Corporation	AD
26	Black Hills Corporation			NF
27	Black Hills Corporation			AD
28	Black Hills Corporation			SFP
29	Black Hills Power Marketing			NF
30	Black Hills Power Marketing			SFP
31	Black Hills Power Marketing			AD
32	Black Hills Power Marketing			AD
33	Bonneville Power Administration			OS
34	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
R.S. 436		Borah/Brady Sub				1
V11-1-2,8	Various	Various		735	735	2
V11-1-3,8	Various	Various		190,429	190,429	3
V11-1-3,8	Various	Various		24,997	24,997	4
V11-1-3,7	Various	Various		45,045	45,045	5
V11-1-3,7	Various	Various		4,852	4,852	6
V11-3,5,6						7
V11-5,6						8
V11-1,2,7	Trona Substation	Red Butte/Mona Sub	31	65,050	65,050	9
V11-1,2,7	Trona Substation	Red Butte/Mona Sub	31	9,932	9,932	10
V11-1-3,5,6	Ponderosa Substation	Various	26	229,184	229,184	11
V11-1-3,5,6	Ponderosa Substation	Various	20	14,937	14,937	12
V11-1,2,3	Yellowtail Sub	Sheridan Substation	9	66,429	66,429	13
V11-1,2,3	Yellowtail Sub	Sheridan Substation	11	7,628	7,628	14
V11-1,2,3	Dave Johnston Sub	Yellowtail Sub		11,813	11,813	15
V11-1,2,8	Various	Various		76,676	76,676	16
V11-1,2,8	Various	Various		8,166	8,166	17
V11-1,2,7	Various	Various		2,510	2,510	18
V11-1,2,8	Various	Various		14,196	14,196	19
V11-1,2,8	Various	Various		20	20	20
V11-1,2,7	Various	Various		343	343	21
V11-1,2	Various	Sheridan Substation	44	203,838	203,838	22
V11-1,2	Various	Sheridan Substation	51	13,422	13,422	23
V11-1,2,7	Various	Wyodak Substation	52	176,237	176,237	24
V11-1,2,7	Various	Wyodak Substation	52	2,735	2,735	25
V11-1,2,8	Various	Various		35,898	35,898	26
V11-1,2,8	Various	Various		136	136	27
V11-1,2,7	Various	Various		5,487	5,487	28
V11-1,2,8	Various	Various		3,770	3,770	29
V11-1,2,7	Various	Various		105	105	30
V11-1,2,8	Various	Various		4	4	31
V11-1,2,7	Various	Various		5	5	32
R.S. 369	Midpoint Substation	Summer Lake Sub				33
R.S. 237	Various	Various	357	1,008,163	1,008,163	34
			5,808	15,299,651	15,189,461	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
				1
	9,370	391	9,761	2
	1,775,688	300,908	2,076,596	3
		156,461	156,461	4
	687,855	53,515	741,370	5
		44,281	44,281	6
		713,484	713,484	7
		35,870	35,870	8
889,625		38,308	927,933	9
		180,656	180,656	10
409,368		161,171	570,539	11
		104,611	104,611	12
260,875		47,386	308,261	13
		61,200	61,200	14
		150,802	150,802	15
	469,840	20,521	490,361	16
		46,334	46,334	17
	18,580	798	19,378	18
	75,162	3,299	78,461	19
		195	195	20
	1,533	68	1,601	21
1,270,974		53,902	1,324,876	22
		241,535	241,535	23
1,482,708		63,847	1,546,555	24
		301,093	301,093	25
	191,019	8,337	199,356	26
		78	78	27
	40,353	1,675	42,028	28
	24,385	1,064	25,449	29
	749	32	781	30
		23	23	31
		42	42	32
				33
4,087,314		67,947	4,155,261	34
64,991,204	15,586,413	34,464,017	115,041,634	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
2	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	LFP
3	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
4	Bonneville Power Administration	Bonneville Power Administration	Umpqua Indian Utility Cooperative	FNO
5	Bonneville Power Administration	Bonneville Power Administration	Umpqua Indian Utility Cooperative	AD
6	Bonneville Power Administration	Bonneville Power Administration	Benton REA	FNO
7	Bonneville Power Administration	Bonneville Power Administration	Benton REA	AD
8	Bonneville Power Administration	Bonneville Power Administration	Umatilla Electric and Columbia	FNO
9	Bonneville Power Administration	Bonneville Power Administration	Umatilla Electric and Columbia	AD
10	Bonneville Power Administration	U. S. Bureau of Reclamation	Bonneville Power Administration	LFP
11	Bonneville Power Administration	U. S. Bureau of Reclamation	Bonneville Power Administration	AD
12	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
13	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
14	Bonneville Power Administration	Bonneville Power Administration	Yakama Power	FNO
15	Bonneville Power Administration	Bonneville Power Administration	Yakama Power	AD
16	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	FNO
17	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	FNO
18	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
19	Bonneville Power Administration			NF
20	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
21	Bonneville Power Administration			SFP
22	Bonneville Power Administration			FNO
23	Bonneville Power Administration			AD
24	Bonneville Power Administration	Bonneville Power Administration	PUD No. 1 of Clark County	FNO
25	Bonneville Power Administration	Bonneville Power Administration	PUD No. 1 of Clark County	AD
26	Brookfield Energy Marketing L.P.			NF
27	Brookfield Energy Marketing L.P.			AD
28	Calpine Energy Solutions, LLC	Bonneville Power Administration	Oregon Direct Access	FNO
29	Calpine Energy Solutions, LLC	Bonneville Power Administration	Oregon Direct Access	AD
30	Cargill Power Markets, LLC			NF
31	Cargill Power Markets, LLC			AD
32	Cargill Power Markets, LLC			SFP
33	City of Anaheim			NF
34	City of Anaheim			SFP
	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. 237	Various	Various	354	108,166	108,166	1
V11-2,7	Lost Creek Hydro Plt	Alvey Substation	58	89,656	89,656	2
V11-2,7	Lost Creek Hydro Plt	Alvey Substation	58			3
V11-1-3,5,6	Bonneville Power Adm	Gazley Substation	3	23,098	23,098	4
V11-1-3,5,6	Bonneville Power Adm	Gazley Substation	3	2,249	2,249	5
V11-1-3,5,6	Bonneville Power Adm	Tieton Substation	1	5,699	5,699	6
V11-1-3,5,6	Bonneville Power Adm	Tieton Substation	1	996	996	7
V11-1-3,5,6	McNary Substation	Hinkle Substation	1	971	971	8
V11-1-3,5,6	McNary Substation	Hinkle Substation	1	109	109	9
V11-2,7	USBR Green Springs	Bonneville Power Adm	19	63,551	63,551	10
V11-2,7	USBR Green Springs	Bonneville Power Adm	19	4,558	4,558	11
R.S. 368	Malin Substation	Malin Substation		628,185	628,185	12
R.S. 368	Malin Substation	Malin Substation		56,791	56,791	13
V11-1-3,5,6	Bonneville Power Adm		9	51,894	51,894	14
V11-1-3,5,6	Bonneville Power Adm		6	4,160	4,160	15
V11-1-3,5,6	Bonneville Power Adm	Neff Substation	33	20	20	16
V11-1-3,5,6	Goshen Substation	Various	198	1,229,962	1,229,962	17
V11-1-3,5,6	Goshen Substation	Various	354	151,870	151,870	18
V11-1,2,8	Various	Various		161,813	161,813	19
V11-1,2,8	Various	Various				20
V11-1,2,7	Various	Various		3,490	3,490	21
V11-1-3,5,6	Goshen Substation	Various	76	458,534	458,534	22
V11-1-3,5,6	Goshen Substation	Various	95	62,104	62,104	23
V11-1-3,5,6	Cardwell-Merwin		21	118,284	118,284	24
V11-1-3,5,6	Cardwell-Merwin		30	17,861	17,861	25
V11-1,2,8	Various	Various		6,195	6,195	26
V11-1,2,8	Various	Various		104	104	27
V11-1-3,5,6	Bonneville Power Adm	Various	20	144,919	144,919	28
V11-1-3,5,6	Bonneville Power Adm	Various	19	13,077	13,077	29
V11-1,2,8	Various	Various		69,368	69,368	30
V11-1,2,8	Various	Various		760	760	31
V11-1,2,8	Various	Various		1,857	1,857	32
V11-1,2,8	Various	Various		62,419	62,419	33
V11-1,2,7	Various	Various		30,186	30,186	34
			5,808	15,299,651	15,189,461	

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.
		376,671	376,671	1
1,660,634		24,861	1,685,495	2
		333,506	333,506	3
92,995		158,084	251,079	4
		20,217	20,217	5
19,709		5,210	24,919	6
		6,445	6,445	7
2,106		745	2,851	8
		3,144	3,144	9
533,775		5,773	539,548	10
		106,972	106,972	11
		232,452	232,452	12
		21,132	21,132	13
246,195		153,857	400,052	14
		49,500	49,500	15
37		16	53	16
5,554,911		1,656,874	7,211,785	17
		1,142,510	1,142,510	18
	980,140	42,111	1,022,251	19
		6,988	6,988	20
	18,933	798	19,731	21
2,144,011		411,184	2,555,195	22
		398,713	398,713	23
585,412		127,915	713,327	24
		174,494	174,494	25
	38,910	1,689	40,599	26
		386	386	27
332,043		109,245	441,288	28
		101,999	101,999	29
	549,630	23,510	573,140	30
		3,322	3,322	31
	8,636	384	9,020	32
	333,297	14,059	347,356	33
	128,051	5,446	133,497	34
64,991,204	15,586,413	34,464,017	115,041,634	

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	Clatskanie People's Utility District	Clatskanie People's Utility Dist	Clatskanie People's Utility Dist	LFP
2	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	OS
3	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	AD
4	Deseret Generation & Trans.			NF
5	Deseret Generation & Trans.			AD
6	Eagle Energy Partners I, LP			SFP
7	Eagle Energy Partners I, LP			NF
8	Eugene Water & Electric Board	NextEra Energy Resources, LLC		LFP
9	Eugene Water & Electric Board	NextEra Energy Resources, LLC	PUD No. 2 of Grant County	AD
10	Eugene Water & Electric Board	NextEra Energy Resources, LLC		SFP
11	Eugene Water & Electric Board			AD
12	Enel Cove Fort, LLC	Enel Cove Fort, LLC		AD
13	Exelon Generation Company, LLC	Bonneville Power Administration	Oregon Direct Access	FNO
14	Exelon Generation Company, LLC	Bonneville Power Administration	Oregon Direct Access	AD
15	Exelon Generation Company, LLC			NF
16	Exelon Generation Company, LLC			AD
17	Exelon Generation Company, LLC			SFP
18	Fall River Rural Electric Cooperative	Marysville Hydro Partners	Idaho Power Company	OS
19	Fall River Rural Electric Cooperative	Marysville Hydro Partners	Idaho Power Company	AD
20	Foote Creek III, LLC	Foote Creek III, LLC	PacifiCorp	OS
21	Foote Creek III, LLC	Foote Creek III, LLC	PacifiCorp	AD
22	Idaho Power Company	Exxon Mobil	Nevada Power Company	LFP
23	Idaho Power Company	Exxon Mobil	Nevada Power Company	AD
24	Idaho Power Company			OS
25	Idaho Power Company			NF
26	Los Angeles Department of Water & Power			NF
27	Los Angeles Department of Water & Power			SFP
28	Los Angeles Department of Water & Power			AD
29	Macquarie Energy LLC			NF
30	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	OS
31	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	AD
32	Morgan Stanley Capital Group, Inc.			NF
33	Morgan Stanley Capital Group, Inc.			AD
34	Morgan Stanley Capital Group, Inc.			SFP
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
V11-1,2,7	Troutdale Substation	Troutdale Substation	57	181,385	181,385	1
R.S. 280	Various	Various	93	692,508	692,508	2
R.S. 280	Various	Various	49	50,411	50,411	3
V11-1,2,8	Various	Various		9,961	9,961	4
V11-1,2,8	Various	Various		556	556	5
V11-1,2,7	Various	Various		540	540	6
V11-1,2,8	Various	Various				7
V11-1-3,7	Various	Various				8
V11-1-3,7	Various	Various				9
V11-1,2,7	Various	Various	26			10
V11-1,2,7	Various	Various				11
V11-1-3,7	Enel Cove Fort	Red Butte Substation				12
V11-1-3,5,6	Bonneville Power Adm	Various	1	2,805	2,805	13
V11-1-3,5,6	Bonneville Power Adm	Various	1	595	595	14
	Various	Various		9,183	9,183	15
	Various	Various		2,105	2,105	16
V11-1-3,7	Various	Various		4,531	4,531	17
R.S. 322	Targhee Substation	Goshen Substation				18
R.S. 322	Targhee Substation	Goshen Substation				19
S.A. 761	Foote Creek Sub	Various				20
S.A. 761	Foote Creek Sub	Various				21
V11-1,2,7	Trona Substation	Red Butte/Mona Sub	78	13,485	13,485	22
V11-1,2,7	Trona Substation	Red Butte/Mona Sub				23
R.S. 257	Antelope Substation	Antelope Substation				24
V11-1,2,8	Various	Various		5,433	5,433	25
V11-1,2,8	Various	Various		587	587	26
V11-1,2,7	Various	Various		19,336	19,336	27
V11-1,2,7	Various	Various				28
V11-1,2,8	Various	Various		237	237	29
R.S. 302	Duchesne	Duchesne		17,422	17,422	30
R.S. 302	Duchesne	Duchesne		1,564	1,564	31
V11-1,2,8	Various	Various		592,518	592,518	32
V11-1,2,8	Various	Various		2,661	2,661	33
V11-1-3,7	Various	Various		42,314	42,314	34
			5,808	15,299,651	15,189,461	

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.
1,204,397		51,379	1,255,776	1
2,619,282		2,170,248	4,789,530	2
		706,748	706,748	3
	63,660	2,746	66,406	4
		4,021	4,021	5
	4,343	182	4,525	6
	479	20	499	7
		21,374	21,374	8
		89,368	89,368	9
		792,110	792,110	10
		67,493	67,493	11
		-46	-46	12
1,437		616	2,053	13
		6,176	6,176	14
	117,731	882,270	1,000,001	15
		27,638	27,638	16
	25,883	1,098	26,981	17
		138,699	138,699	18
		12,609	12,609	19
		52,003	52,003	20
		9,290	9,290	21
1,045,452		44,102	1,089,554	22
		87,081	87,081	23
		12,408	12,408	24
	48,458	2,072	50,530	25
	4,378	191	4,569	26
	108,062	4,782	112,844	27
		973	973	28
	11,104	467	11,571	29
		17,655	17,655	30
		1,605	1,605	31
	3,627,450	156,044	3,783,494	32
		23,573	23,573	33
	263,918	11,429	275,347	34
64,991,204	15,586,413	34,464,017	115,041,634	

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 2017/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	Morgan Stanley Capital Group, Inc.			AD
2	Municipal Energy Agency of Nebraska			NF
3	Nevada Power Company			NF
4	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	PUD No. 2 of Grant County	LFP
5	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	PUD No. 2 of Grant County	AD
6	NextEra Energy Resources, LLC			NF
7	NextEra Energy Resources, LLC			AD
8	NextEra Energy Resources, LLC			SFP
9	Pacific Gas & Electric Company			OS
10	Pacific Gas & Electric Company			OS
11	Pacific Gas & Electric Company			NF
12	Portland General Electric Company			OS
13	Powder River Energy Corporation	Western Area Power Administration	Sheridan-Johnson Rural Elect.	OS
14	Powder River Energy Corporation	Western Area Power Administration	Sheridan-Johnson Rural Elect.	AD
15	Powerex Corporation	Bonneville Power Administration	CAISO	LFP
16	Powerex Corporation	Bonneville Power Administration	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	AD
23	Powerex Corporation	Powerex Corporation	CAISO	LFP
24	Powerex Corporation	Powerex Corporation	CAISO	AD
25	Powerex Corporation	Powerex Corporation	CAISO	LFP
26	Powerex Corporation	Powerex Corporation	CAISO	AD
27	Powerex Corporation	Powerex Corporation	CAISO	LFP
28	Powerex Corporation	Powerex Corporation	CAISO	LFP
29	Powerex Corporation	Powerex Corporation	CAISO	LFP
30	Powerex Corporation			NF
31	Powerex Corporation			AD
32	Powerex Corporation			SFP
33	PUD No. 1 of Cowlitz County	PUD No. 1 of Cowlitz County	Bonneville Power Administration	OS
34	PUD No. 1 of Cowlitz County	PUD No. 1 of Cowlitz County	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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
V11-1,2,7	Various	Various		200	200	1
V11-1,2,8	Various	Various		566	566	2
V11-1,2,8	Various	Various		39,173	39,173	3
V11-1-3,5-7	Wallula Substation	Wala-MIDC path	103	55,802	55,802	4
V11-1-3,5-7	Wallula Substation	Wala-MIDC path	103	14,252	14,252	5
V11-1-3,8	Various	Various		502	502	6
V11-1-3,8	Various	Various		782	782	7
V11-1-3,7	Various	Various		28	28	8
R.S. 607						9
R.S. 298	Sigurd-Glen Canyon	Pinto-Four Corners				10
V11-1,2,8	Various	Various		498	498	11
R.S. 137	Various	Various				12
R.S. 704	Various	Buffalo Substation				13
R.S. 704	Various	Buffalo Substation				14
V11-1,2,7	Bonneville Power Adm	CRAG View Substation	83	569,922	569,922	15
V11-1,2,7	Bonneville Power Adm	CRAG View Substation	83	36,148	36,148	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	67			19
V11-1,7	Malin 500 Substation	Round Mountain Sub	67			20
V11-1,7	Malin 500 Substation	Round Mountain Sub	66			21
V11-1,7	Malin 500 Substation	Round Mountain Sub	66			22
V11-1,7	Malin 500 Substation	Round Mountain Sub	50			23
V11-1,7	Malin 500 Substation	Round Mountain Sub	50			24
V11-1,7	Malin 500 Substation	Round Mountain Sub	150			25
V11-1,7	Malin 500 Substation	Round Mountain Sub	50			26
V11-1,7	Malin 500 Substation	Round Mountain Sub	150			27
V11-1,7	Malin 500 Substation	Round Mountain Sub	150			28
V11-1,7	Malin 500 Substation	Round Mountain Sub	150			29
V11-3,8	Various	Various		24,371	24,371	30
V11-1,2,8	Various	Various		239	239	31
V11-1-3,7	Various	Various		16,933	16,933	32
R.S. 234	Swift Unit No. 2	Woodland Substation				33
R.S. 234	Swift Unit No. 2	Woodland Substation				34
			5,808	15,299,651	15,189,461	

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.
		1,557	1,557	1
	4,327	186	4,513	2
	177,438	7,847	185,285	3
1,929,556		667,026	2,596,582	4
		452,379	452,379	5
	193,287	13,934	207,221	6
		29,167	29,167	7
	201	28	229	8
		12,500,000	12,500,000	9
		185,048	185,048	10
	2,811	259	3,070	11
		3,314	3,314	12
		324	324	13
		34	34	14
2,372,334		105,632	2,477,966	15
		481,749	481,749	16
2,232,639		56,264	2,288,903	17
		383,791	383,791	18
2,232,639		56,264	2,288,903	19
		383,791	383,791	20
2,195,511		55,311	2,250,822	21
		378,062	378,062	22
1,419,539		35,918	1,455,457	23
		285,973	285,973	24
4,258,617		107,754	4,366,371	25
		857,919	857,919	26
495,052		12,125	507,177	27
495,052		12,125	507,177	28
495,052		12,134	507,186	29
	210,167	8,849	219,016	30
		1,884	1,884	31
	94,331	2,129	96,460	32
		154,715	154,715	33
		13,970	13,970	34
64,991,204	15,586,413	34,464,017	115,041,634	

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 2017/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Rainbow Energy Marketing Corporation			NF
2	Rainbow Energy Marketing Corporation			SFP
3	Sacramento Municipal Utility District	Sacramento Municipal Utility Dist	Sacramento Municipal Utility Dist	LFP
4	Sacramento Municipal Utility District	Sacramento Municipal Utility Dist	Sacramento Municipal Utility Dist	AD
5	Salt River Project	Salt River Project	Salt River Project	LFP
6	Salt River Project	Salt River Project	Salt River Project	AD
7	Salt River Project			NF
8	Shell Energy Corporation, Inc.	NextEra Energy Resources, LLC	PUD No. 2 of Grant County	LFP
9	Shell Energy Corporation, Inc.	NextEra Energy Resources, LLC	PUD No. 2 of Grant County	AD
10	Shell Energy Corporation, Inc.			NF
11	Shell Energy Corporation, Inc.			AD
12	Shell Energy Corporation, Inc.			SFP
13	Shell Energy Corporation, Inc.			AD
14	Sierra Pacific Power Company			OS
15	Sierra Pacific Power Company			AD
16	Simplot Phosphates, LLC	Simplot Phosphates, LLC	Simplot Phosphates, LLC	OS
17	Southern California Edison Company			OS
18	Southern California Edison Company			NF
19	Southern California Edison Company			AD
20	Southern California Public Power Authority	Powerex Corporation	Southern California Public Power	NF
21	State of South Dakota	Western Area Power Administration	Black Hills Corporation	LFP
22	State of South Dakota	Western Area Power Administration	Black Hills Corporation	AD
23	Talen Energy Marketing, LLC			NF
24	Tenaska Power Services Co.			NF
25	Tenaska Power Services Co.			AD
26	Tenaska Power Services Co.			SFP
27	The Energy Authority, Inc.			NF
28	The Energy Authority, Inc.			AD
29	Thermo No. 1 BE-01, LLC	Thermo Geothermal Project		LFP
30	Thermo No. 1 BE-01, LLC	Thermo Geothermal Project		AD
31	TransAlta Energy Marketing (U.S.) Inc.			NF
32	TransAlta Energy Marketing (U.S.) Inc.			AD
33	Tri-State Generation & Trans.		Tri-State Generation & Trans.	FNO
34	Tri-State Generation & Trans.		Tri-State Generation & Trans.	AD
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
V11-1,2,8	Various	Various		125,298	125,298	1
V11-1,2,7	Various	Various				2
V11-1,2,7	Malin Substation	Malin Substation	31	99,252	99,252	3
V11-1,2,7	Malin Substation	Malin Substation	31	13,432	13,432	4
V11-1,2,7	Enel Cove Fort	Red Butte Substation	26	149,883	149,883	5
V11-1,2,7	Enel Cove Fort	Red Butte Substation	26	17,599	17,599	6
V11-1-3,8	Various	Various		3	3	7
V11-1,2,7	Wallula Substation	Wala-MIDC path		117,442	117,442	8
V11-1,2,7	Wallula Substation	Wala-MIDC path		8,305	8,305	9
V11-1-3,8	Various	Various		268,741	268,741	10
V11-1,2,8	Various	Various		7,129	7,129	11
V11-1-3,7	Various	Various		16,233	16,233	12
V11-1,2,7	Various	Various		123	123	13
R.S. 674	Sigurd Substation	Utah-Nevada Border				14
R.S. 674	Sigurd Substation	Utah-Nevada Border				15
V11-3						16
R.S. 298	Sigurd-Glen Canyon	Pinto-Four Corners				17
	Various	Various		91,112	91,112	18
	Various	Various		33,442	33,442	19
V11-1-3,11	Tieton Substation	Various		61	61	20
V11-1,2,7	Yellowtail Sub	Wyodak Substation	4	16,127	16,127	21
V11-1,2,7	Yellowtail Sub	Wyodak Substation	4	1,598	1,598	22
V11-1,2,8	Various	Various		22,283	22,283	23
V11-1,2,8	Various	Various				24
V11-1,2,8	Various	Various		65	65	25
V11-1,2,8	Various	Various		7,013	7,013	26
V11-1,2,8	Various	Various		5,135	5,135	27
V11-1,2,8	Various	Various		307	307	28
V11-1-3,5-7	South Milford Sub	Mona Substation	11	57,326	57,326	29
V11-1-3,5-7	South Milford Sub	Mona Substation	11	6,056	6,056	30
V11-1,2,8	Various	Various		39,250	39,250	31
V11-1,2,8	Various	Various		238	238	32
V11-1-3,5,6	Dave Johnston Sub	Thermopolis Sub	18	126,900	126,900	33
V11-1-3,5,6	Dave Johnston Sub	Thermopolis Sub	20	11,446	11,446	34
			5,808	15,299,651	15,189,461	

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.
	495,827	21,893	517,720	1
	22,657	1,008	23,665	2
736,300		31,840	768,140	3
		180,656	180,656	4
741,368		31,923	773,291	5
		150,594	150,594	6
	12		12	7
				8
				9
	1,657,622	78,055	1,735,677	10
		31,902	31,902	11
	91,683	5,059	96,742	12
		566	566	13
		29,177	29,177	14
		3,133	3,133	15
		7,770	7,770	16
		185,048	185,048	17
	2,499,320	913,273	3,412,593	18
		304,670	304,670	19
		54,739	54,739	20
118,617		5,107	123,724	21
		24,087	24,087	22
				23
	97,950	4,323	102,273	24
		445	445	25
	55,011	2,330	57,341	26
	32,445	1,382	33,827	27
		1,139	1,139	28
326,210		70,353	396,563	29
		73,844	73,844	30
	237,264	10,224	247,488	31
		3,236	3,236	32
499,898		126,322	626,220	33
		101,989	101,989	34
64,991,204	15,586,413	34,464,017	115,041,634	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Tri-State Generation & Trans.			NF
2	Tucson Electric Power Company			NF
3	U.S. Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	FNO
4	U.S. Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	AD
5	U.S. Bureau of Reclamation	Western Area Power Administration	Weber Basin Water Conserv.	OS
6	U.S. Bureau of Reclamation	Western Area Power Administration	Weber Basin Water Conserv.	AD
7	U.S. Bureau of Reclamation	Bonneville Power Administration	Crooked River Irrigation District	OS
8	Utah Associated Municipal Power Systems	Utah Associated Municipal Power	Utah Associated Municipal Power	OS
9	Utah Associated Municipal Power Systems	Utah Associated Municipal Power	Utah Associated Municipal Power	AD
10	Utah Associated Municipal Power Systems			NF
11	Utah Associated Municipal Power Systems			AD
12	Utah Associated Municipal Power Systems			SFP
13	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	OS
14	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	AD
15	Warm Springs Power Enterprises	Warm Springs Power Enterprises	PGE	OS
16	Warm Springs Power Enterprises	Warm Springs Power Enterprises	PGE	AD
17	Westar Energy, Inc.			NF
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 Adm CO River	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	Accrual			
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
V11-1,2,8	Various	Various		938	938	1
V11-1,2,8	Various	Various		30	30	2
V11-1-3,5,6	Walla Walla Sub	Burbank Pumps	1	2,256	2,256	3
V11-1-3,5,6	Walla Walla Sub	Burbank Pumps	1			4
R.S. 286	Various	Various		19,994	19,994	5
R.S. 286	Various	Various		893	893	6
R.S. 67	Redmond Substation	Crooked River Pumps		9,430	9,430	7
R.S. 297	Various	Various	437	2,991,117	2,991,117	8
R.S. 297	Various	Various	445	270,539	270,539	9
V11-1-3,8	Various	Various		1,071	1,071	10
V11-1,2,8	Various	Various		2,005	2,005	11
V11-1-3,7	Various	Various		12,559	12,559	12
R.S. 637	Various	Various	104	610,193	610,193	13
R.S. 637	Various	Various	86	49,407	49,407	14
R.S. 591	Pelton Reregulating	Round Butte Sub		68,890	68,890	15
R.S. 591	Pelton Reregulating	Round Butte Sub		7,164	7,164	16
V11-1,2,8	Various	Various		334	334	17
R.S. 262	Various	Various	330	1,619,443	1,522,277	18
R.S. 262	Various	Various	330	169,375	162,424	19
R.S. 263	Various	Various		46,598	43,983	20
R.S. 263	Various	Various		4,111	3,863	21
R.S. 684	Dave Johnston Sub	Various				22
V11-1,2	Wyoming Distribution	Wyoming Distribution	1	9,372	9,372	23
V11-1,2,8	Various	Wyoming Distribution	1	4	4	24
V11-1,2,8	Various	Various		604	604	25
V11-1,2,7	Various	Various		135	135	26
				-43,811	-47,021	27
						28
						29
						30
						31
						32
						33
						34
			5,808	15,299,651	15,189,461	

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.
	5,839	246	6,085	1
				2
8,297		11,432	19,729	3
		934	934	4
		19,993	19,993	5
		893	893	6
10,516			10,516	7
14,645,235		3,703,057	18,348,292	8
		2,820,978	2,820,978	9
	3,677	497	4,174	10
		13,619	13,619	11
	67,688	9,395	77,083	12
2,979,862		514,494	3,494,356	13
		561,027	561,027	14
		109,725	109,725	15
		9,975	9,975	16
	4,132	174	4,306	17
2,317,779		550,000	2,867,779	18
		262,632	262,632	19
		46,279	46,279	20
		4,048	4,048	21
				22
37,871		40,268	78,139	23
		20,774	20,774	24
	4,269	178	4,447	25
	858	36	894	26
		-7,938,656	-7,938,656	27
				28
				29
				30
				31
				32
				33
				34
64,991,204	15,586,413	34,464,017	115,041,634	

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: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 2 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 2 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 2 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 3 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 3 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 3 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328 Line No.: 4 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 4 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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
2016 transmission and ancillary services.

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. Generation regulation and frequency response 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

2016 transmission and ancillary services.

Schedule Page: 328 Line No.: 7 Column: c

Avangrid Renewables, LLC and Utah Associated Municipal Power Systems

Schedule Page: 328 Line No.: 7 Column: d

Ancillary services under the Open Access Transmission Tariff (1st Revised Service Agreement 476) in effect until superseded.

Schedule Page: 328 Line No.: 7 Column: f

Long Hollow, WY Switching Station

Schedule Page: 328 Line No.: 7 Column: g

Long Hollow, WY Switching Station

Schedule Page: 328 Line No.: 7 Column: m

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 Line No.: 8 Column: c

Avangrid Renewables, LLC and Utah Associated Municipal Power Systems

Schedule Page: 328 Line No.: 8 Column: d

Ancillary services under the Open Access Transmission Tariff (1st Revised Service Agreement 476) in effect until superseded.

Schedule Page: 328 Line No.: 8 Column: f

Long Hollow, WY Switching Station

Schedule Page: 328 Line No.: 8 Column: g

Long Hollow, WY Switching Station

Schedule Page: 328 Line No.: 8 Column: m

2016 transmission and ancillary services.

Schedule Page: 328 Line No.: 9 Column: c

This footnote applies to all occurrences of "Nevada Power Company" on pages 328-330. Nevada Power Company is a wholly owned 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 Line No.: 9 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 279) terminating on April 30, 2019.

Schedule Page: 328 Line No.: 9 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 10 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 279) terminating on April 30, 2019.

Schedule Page: 328 Line No.: 10 Column: m

2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328 Line No.: 11 Column: d

Network transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 742) terminating no earlier than 12-months from notice by the customer.

Schedule Page: 328 Line No.: 11 Column: m

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 Line No.: 12 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 12 Column: d

Network transmission service under the Open Access Transmission Tariff (2nd Revised

Service Agreement 742) terminating no earlier than 12-months from notice by the customer.

Schedule Page: 328 Line No.: 12 Column: m

2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328 Line No.: 13 Column: d

Network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 505) terminating no earlier than 12-months from notice by the customer.

Schedule Page: 328 Line No.: 13 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.: 14 Column: d

Network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 505) terminating no earlier than 12-months from notice by the customer.

Schedule Page: 328 Line No.: 14 Column: m

2016 transmission and ancillary services. Charge for transmission services.

Schedule Page: 328 Line No.: 15 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 818) which terminated on December 31, 2016.

Schedule Page: 328 Line No.: 15 Column: m

2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328 Line No.: 16 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 16 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 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 Line No.: 17 Column: m

2016 transmission and ancillary services.

Schedule Page: 328 Line No.: 18 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 18 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 19 Column: a

This footnote applies to all occurrences of "Black Hills/Colorado Electric Utility Company" on pages 328-330. Complete name is Black Hills/Colorado Electric Utility Company, L.P.

Schedule Page: 328 Line No.: 19 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 19 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 19 Column: m

Transmission resale - purchase of point-to-point transmission. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 20 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 20 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 20 Column: m
2016 transmission and ancillary services.

Schedule Page: 328 Line No.: 21 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 21 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 21 Column: m
Transmission resale - purchase of point-to-point transmission. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 22 Column: d
Network transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 347) which terminated on December 31, 2017.

Schedule Page: 328 Line No.: 22 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 23 Column: d
Network transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 347) which terminated on December 31, 2017.

Schedule Page: 328 Line No.: 23 Column: m
2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328 Line No.: 24 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.: 24 Column: m
Transmission resale - purchase of point-to-point transmission. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 25 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.: 25 Column: m
2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328 Line No.: 26 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 26 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 26 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 27 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 27 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 27 Column: m
2016 transmission and ancillary services.

Schedule Page: 328 Line No.: 28 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 28 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 28 Column: m
Transmission resale - purchase of point-to-point transmission. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 29 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 29 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 29 Column: m
Transmission resale - purchase of point-to-point transmission. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 30 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 30 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 30 Column: m
Transmission resale - purchase of point-to-point transmission. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 31 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 31 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 31 Column: m
2016 transmission and ancillary services.

Schedule Page: 328 Line No.: 32 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 32 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 32 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 32 Column: m
2016 transmission and ancillary services.

Schedule Page: 328 Line No.: 33 Column: b

Capacity exchanged and operated by each transmission provider with no receipt or delivery of energy.

Schedule Page: 328 Line No.: 33 Column: c

Capacity exchanged and operated by each transmission provider with no receipt or delivery of energy.

Schedule Page: 328 Line No.: 33 Column: d

Legacy contract executed between PacifiCorp and Bonneville Power Administration ("BPA") concerning the exchange of transmission services over agreed-upon facilities ("Midpoint-Meridian Transmission Agreement", Rate Schedule 369). This agreement runs concurrently with the AC Intertie Agreement (Rate Schedule 368), which terminates when the facilities subject to that agreement are taken out of service. See also page 332, Transmission of electricity by others, in this Form No. 1.

Schedule Page: 328 Line No.: 34 Column: d

Legacy contract (3rd Revised Rate Schedule 237) executed between PacifiCorp and BPA for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Contract subject to terminate 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.: 34 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.1 Line No.: 1 Column: d

Legacy contract (3rd Revised Rate Schedule 237) executed between PacifiCorp and BPA for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Contract subject to terminate 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: 328.1 Line No.: 1 Column: m

2016 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 2 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (4th Revised Service Agreement 656) terminating on August 31, 2030.

Schedule Page: 328.1 Line No.: 2 Column: m

Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 3 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (4th Revised Service Agreement 656) terminating on August 31, 2030.

Schedule Page: 328.1 Line No.: 3 Column: m

2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.1 Line No.: 4 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: 328.1 Line No.: 4 Column: f

This footnote applies to all occurrences of "Bonneville Power Adm" on pages 328-330. Complete name is Bonneville Power Administration.

Schedule Page: 328.1 Line No.: 4 Column: m

Distribution voltage service charge. Primary delivery service. Regulation and frequency response service. Reactive supply and voltage control service. Operating reserve - spinning reserve service. Operating Reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 5 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: 328.1 Line No.: 5 Column: m

2016 transmission and ancillary services. Charge for transmission services.

Schedule Page: 328.1 Line No.: 6 Column: c

This footnote applies to all occurrences of "Benton REA" on pages 328-330. Complete name is Benton Rural Electric Association.

Schedule Page: 328.1 Line No.: 6 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: 328.1 Line No.: 6 Column: m

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.: 7 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: 328.1 Line No.: 7 Column: m

2016 transmission and ancillary services. Charge for transmission services.

Schedule Page: 328.1 Line No.: 8 Column: c

This footnote applies to all occurrences of "Umatilla Electric and Columbia" on pages 328-330. Complete name is Umatilla Electric Cooperative Association and Columbia Basin Electric Cooperative, Inc.

Schedule Page: 328.1 Line No.: 8 Column: d

Network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 538) terminating on September 30, 2028.

Schedule Page: 328.1 Line No.: 8 Column: m

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.: 9 Column: d

Network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 538) terminating on September 30, 2028.

Schedule Page: 328.1 Line No.: 9 Column: m

2016 transmission and ancillary services. Charge for transmission services.

Schedule Page: 328.1 Line No.: 10 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: 328.1 Line No.: 10 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: 328.1 Line No.: 10 Column: m

Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 11 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: 328.1 Line No.: 11 Column: m

2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.1 Line No.: 12 Column: d

Legacy contract (5th Revised Rate Schedule 368) executed between PacifiCorp and BPA for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Subject to termination upon mutual agreement.

Schedule Page: 328.1 Line No.: 12 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.1 Line No.: 13 Column: d

Legacy contract (5th Revised Rate Schedule 368) executed between PacifiCorp and BPA for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Subject to termination upon mutual agreement.

Schedule Page: 328.1 Line No.: 13 Column: m
2016 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 14 Column: d
Network transmission service and distribution delivery service under the Open Access Transmission Tariff (7th Revised Service Agreement 328) terminating on September 30, 2028.

Schedule Page: 328.1 Line No.: 14 Column: g
White Swan/Toppenish Substations

Schedule Page: 328.1 Line No.: 14 Column: m
Distribution voltage service charge. Primary delivery service. Regulation and frequency response service. Reactive supply and voltage control service. Operating reserve - spinning reserve service. Operating Reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 15 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: 328.1 Line No.: 15 Column: g
White Swan/Toppenish Substations

Schedule Page: 328.1 Line No.: 15 Column: m
2016 transmission and ancillary services. Charge for transmission services.

Schedule Page: 328.1 Line No.: 16 Column: d
Network transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 827) terminating on September 30, 2028.

Schedule Page: 328.1 Line No.: 16 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 17 Column: d
Network transmission service and distribution delivery service under the Open Access Transmission Tariff (2nd Revised Service Agreement 746) terminating on June 30, 2028.

Schedule Page: 328.1 Line No.: 17 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 18 Column: d
Network transmission service and distribution delivery service under the Open Access Transmission Tariff (2nd Revised Service Agreement 746) terminating on June 30, 2028.

Schedule Page: 328.1 Line No.: 18 Column: m
2016 annual transmission services true-up refunds and/or surcharge.

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: 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.: 20 Column: m
2016 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 21 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 21 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 21 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 21 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 22 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 22 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 22 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (1st Revised Service Agreement 747) terminating on June 30, 2028.

Schedule Page: 328.1 Line No.: 22 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 23 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 23 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 23 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (1st Revised Service Agreement 747) terminating on June 30, 2028.

Schedule Page: 328.1 Line No.: 23 Column: m

2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.1 Line No.: 24 Column: c

This footnote applies to all occurrences of “PUD No. 1 of Clark County” on pages 328-330. Complete name is Public Utility District No. 1 of Clark County.

Schedule Page: 328.1 Line No.: 24 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.: 24 Column: g

Chelatchie/View 115kV

Schedule Page: 328.1 Line No.: 24 Column: m

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.: 25 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.: 25 Column: g

Chelatchie/View 115kV

Schedule Page: 328.1 Line No.: 25 Column: m

2016 transmission and ancillary services. Charge for transmission 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

Scheduling, system control and dispatch service. Reactive supply and voltage control 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

2016 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 28 Column: d

Transmission service under the Open Access Transmission Tariff (10th Revised Service Agreement 299). Service provided pursuant to rules and regulations of Oregon Direct Access. Agreement terminates upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 28 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 29 Column: d

Transmission service under the Open Access Transmission Tariff (10th Revised Service Agreement 299). Service provided pursuant to rules and regulations of Oregon Direct Access. Agreement terminates upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 29 Column: m

2016 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 30 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 30 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 Line No.: 30 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 31 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 31 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 31 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 31 Column: m

2016 transmission and ancillary services.

Schedule Page: 328.1 Line No.: 32 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 32 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 32 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 32 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 33 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.1 Line No.: 33 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.1 Line No.: 33 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.
Schedule Page: 328.1 Line No.: 33 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.
Schedule Page: 328.1 Line No.: 34 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.1 Line No.: 34 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.1 Line No.: 34 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.
Schedule Page: 328.1 Line No.: 34 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.
Schedule Page: 328.2 Line No.: 1 Column: b
This footnote applies to all occurrences of “Clatskanie People's Utility Dist” on pages 328-330. Complete name is Clatskanie People's Utility District.
Schedule Page: 328.2 Line No.: 1 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 800) terminating on December 31, 2020.
Schedule Page: 328.2 Line No.: 1 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.
Schedule Page: 328.2 Line No.: 2 Column: 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: 328.2 Line No.: 2 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: 328.2 Line No.: 2 Column: m
Distribution voltage service charge. Meter interrogation services. Scheduling, system control and dispatch service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.
Schedule Page: 328.2 Line No.: 3 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: 328.2 Line No.: 3 Column: m
2016 transmission and ancillary services. Charge for transmission services.
Schedule Page: 328.2 Line No.: 4 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.2 Line No.: 4 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.2 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: 328.2 Line No.: 4 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 5 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 5 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 5 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 5 Column: m
2016 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 6 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 6 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 6 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 6 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 7 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 7 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 7 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 7 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 8 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 8 Column: d
Transmission resale service under the Open Access Transmission Tariff (Service Agreement 780). Termination upon mutual consent.

Schedule Page: 328.2 Line No.: 8 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.2 Line No.: 9 Column: c
This footnote applies to all occurrences of "PUD No. 2 of Grant County" on pages 328-330. Complete name is Public Utility District No. 2 of Grant County.

Schedule Page: 328.2 Line No.: 9 Column: d
Transmission resale service under the Open Access Transmission Tariff (Service Agreement 780). Termination upon mutual consent.

Schedule Page: 328.2 Line No.: 9 Column: m
2016 annual transmission services true-up refunds and/or surcharge.

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
Transmission resale - 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: 328.2 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

2016 transmission and ancillary services.

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

Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 711) terminating on November 30, 2018.

Schedule Page: 328.2 Line No.: 12 Column: m

2016 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 13 Column: d

Transmission service under the Open Access Transmission Tariff (Service Agreement 847). Service provided pursuant to rules and regulations of Oregon Direct Access. Agreement terminates upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 328.2 Line No.: 13 Column: m

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: 328.2 Line No.: 14 Column: d

Transmission service under the Open Access Transmission Tariff (Service Agreement 847). Service provided pursuant to rules and regulations of Oregon Direct Access. Agreement terminates upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 328.2 Line No.: 14 Column: m

2016 transmission and ancillary services. Charge for transmission services.

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: e

V11-1-3,5,6,8,11

Schedule Page: 328.2 Line No.: 15 Column: m

Unauthorized use of transmission service. 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.: 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: e
V11-1-3,5,6,8,11

Schedule Page: 328.2 Line No.: 16 Column: m
2016 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 17 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 17 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 17 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 17 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.2 Line No.: 18 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: 328.2 Line No.: 18 Column: m
Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.2 Line No.: 19 Column: d
Legacy contract (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: 328.2 Line No.: 19 Column: m
2016 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 20 Column: d
Service Agreement 761 executed between PacifiCorp and Foote Creek III, LLC (d/b/a Terra-Gen Operating, LLC) for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating on March 1, 2024.

Schedule Page: 328.2 Line No.: 20 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: 328.2 Line No.: 21 Column: d
Service Agreement 761 executed between PacifiCorp and Foote Creek III, LLC (d/b/a Terra-Gen Operating, LLC) for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating on March 1, 2024.

Schedule Page: 328.2 Line No.: 21 Column: m
2016 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 22 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 212) terminating on May 31, 2019.

Schedule Page: 328.2 Line No.: 22 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 23 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 212) terminating on May 31, 2019.

Schedule Page: 328.2 Line No.: 23 Column: m
2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.2 Line No.: 24 Column: b
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 24 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 24 Column: d

Legacy contract (Rate Schedule 257) executed between PacifiCorp and Idaho Power Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge for the Antelope Substation terminating coterminous with the Idaho Power Company and United States Department of Education Supply Agreement.

Schedule Page: 328.2 Line No.: 24 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.: 25 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 25 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 27 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 27 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 27 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 27 Column: m

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

2016 transmission and ancillary services.

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: 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.: 30 Column: m
Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.2 Line No.: 31 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.: 31 Column: m
2016 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 32 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 32 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 32 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 32 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 33 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 33 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 33 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 33 Column: m
2016 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 34 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 34 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 34 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 34 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.3 Line No.: 1 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 1 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 1 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 1 Column: m
2016 transmission and ancillary services.
Schedule Page: 328.3 Line No.: 2 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.3 Line No.: 2 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.3 Line No.: 2 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.
Schedule Page: 328.3 Line No.: 2 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.
Schedule Page: 328.3 Line No.: 3 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.3 Line No.: 3 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.3 Line No.: 3 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.
Schedule Page: 328.3 Line No.: 3 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.
Schedule Page: 328.3 Line No.: 4 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 733) terminating on November 30, 2023.
Schedule Page: 328.3 Line No.: 4 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.
Schedule Page: 328.3 Line No.: 5 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 733) terminating on November 30, 2023.
Schedule Page: 328.3 Line No.: 5 Column: m
2016 annual transmission services true-up refunds and/or surcharge.
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. Generation regulation and frequency response 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
2016 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. Generation regulation and frequency response service.

Schedule Page: 328.3 Line No.: 9 Column: b
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 9 Column: c
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 9 Column: d
Legacy contract (Rate Schedule 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. Terminated on December 31, 2017. See PacifiCorp, Docket No. ER07-882-000, et al, Settlement Agreement, Appendix 2 (filed November 21, 2007).

Schedule Page: 328.3 Line No.: 9 Column: f
Malin to Indian Springs line segment

Schedule Page: 328.3 Line No.: 9 Column: g
Malin to Indian Springs line segment

Schedule Page: 328.3 Line No.: 9 Column: m
Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

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 (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.: 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: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 11 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 11 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 11 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.3 Line No.: 12 Column: b
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 12 Column: c
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 12 Column: d
Legacy contract (1st Revised Rate Schedule 137) executed between PacifiCorp and Portland General Electric Company for transmission service over agreed-upon facilities and/or

subject to a sole-use or facilities charge for the Dalreed Substation, which terminated in December 2013.

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.

Schedule Page: 328.3 Line No.: 13 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.: 13 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. Rate Schedule 704.

Schedule Page: 328.3 Line No.: 13 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.3 Line No.: 14 Column: 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. Rate Schedule 704.

Schedule Page: 328.3 Line No.: 14 Column: m

2016 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 15 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.: 15 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.: 15 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 16 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 169) terminating on October 31, 2020.

Schedule Page: 328.3 Line No.: 16 Column: m

2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.3 Line No.: 17 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 700) terminating on March 31, 2022.

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 (3rd Revised Service Agreement 700) terminating on March 31, 2022.

Schedule Page: 328.3 Line No.: 18 Column: m

2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.3 Line No.: 19 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 701) terminating on March 31, 2022.

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 (3rd Revised Service Agreement 701) terminating on March 31, 2022.

Schedule Page: 328.3 Line No.: 20 Column: m
2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.3 Line No.: 21 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 702) terminating on March 31, 2022.

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 (3rd Revised Service Agreement 702) terminating on March 31, 2022.

Schedule Page: 328.3 Line No.: 22 Column: m
2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.3 Line No.: 23 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.: 23 Column: m
Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 24 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.: 24 Column: m
2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.3 Line No.: 25 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.: 25 Column: m
Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 26 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.: 26 Column: m
2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.3 Line No.: 27 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.: 27 Column: m
2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.3 Line No.: 28 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.: 28 Column: m
2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.3 Line No.: 29 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.: 29 Column: m
2016 annual transmission services true-up refunds and/or surcharge.

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. Regulation and frequency response 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

2016 transmission and ancillary services.

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. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.3 Line No.: 33 Column: a

This footnote applies to all occurrences of "PUD No. 1 of Cowlitz County" on pages 328-330. Complete name is Public Utility District No. 1 of Cowlitz County.

Schedule Page: 328.3 Line No.: 33 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: 328.3 Line No.: 33 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.: 34 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: 328.3 Line No.: 34 Column: m

2016 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

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 2 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 2 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 2 Column: m

2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.4 Line No.: 3 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.: 3 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 751) terminating on September 30, 2018.

Schedule Page: 328.4 Line No.: 3 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 4 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 751) terminating on September 30, 2018.

Schedule Page: 328.4 Line No.: 4 Column: m

2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.4 Line No.: 5 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 809) terminating on October 31, 2020.

Schedule Page: 328.4 Line No.: 5 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 6 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 809) terminating on October 31, 2020.

Schedule Page: 328.4 Line No.: 6 Column: m

2016 annual transmission services true-up refunds and/or surcharge.

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.: 8 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (9th Revised Service Agreement 791) terminating upon written notification.

Schedule Page: 328.4 Line No.: 9 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (9th Revised Service Agreement 791) terminating upon written notification.

Schedule Page: 328.4 Line No.: 10 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 10 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 10 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 10 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.4 Line No.: 11 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 11 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 11 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 11 Column: m
2016 transmission and ancillary services.

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
Transmission resale - 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: 328.4 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
2016 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 14 Column: a
This footnote applies to all occurrences of "Sierra Pacific Power Company" on pages 328-330. Sierra Pacific Power Company is a wholly owned 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.: 14 Column: b
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 14 Column: c
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 14 Column: d
Legacy contract (Rate Schedule 674) executed between PacifiCorp and Sierra Pacific Power Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating in September 2022.

Schedule Page: 328.4 Line No.: 14 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.: 15 Column: b
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 15 Column: c
Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 15 Column: d
Legacy contract (Rate Schedule 674) executed between PacifiCorp and Sierra Pacific Power Company for transmission service over agreed-upon facilities and/or subject to a sole-use

or facilities charge. Terminating in September 2022.

Schedule Page: 328.4 Line No.: 15 Column: m

2016 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 16 Column: d

Ancillary services under the Open Access Transmission Tariff.

Schedule Page: 328.4 Line No.: 16 Column: m

Generation regulation and frequency response service.

Schedule Page: 328.4 Line No.: 17 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 17 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 17 Column: d

Use of facilities agreement (Rate Schedule 298) 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: 328.4 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: 328.4 Line No.: 18 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 18 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 18 Column: e

V11-1-3,5,6,8,11

Schedule Page: 328.4 Line No.: 18 Column: m

Unauthorized use of transmission service. 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.: 19 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 19 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 19 Column: e

V11-1-3,5,6,8,11

Schedule Page: 328.4 Line No.: 19 Column: m

2016 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 20 Column: c

Complete name is Southern California Public Power Authority. Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 20 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.: 20 Column: m

Unauthorized use of transmission service.

Schedule Page: 328.4 Line No.: 21 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.: 21 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 22 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.: 22 Column: m
2016 annual transmission services true-up refunds and/or surcharge.

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.: 24 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 24 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 24 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 24 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 25 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 25 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 25 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 25 Column: m
2016 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 26 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 26 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 26 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 26 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 27 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 27 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 27 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 27 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 28 Column: 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
2016 transmission and ancillary services.

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
Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 568) terminating on April 30, 2029.

Schedule Page: 328.4 Line No.: 29 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.: 30 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 30 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 568) terminating on April 30, 2029.

Schedule Page: 328.4 Line No.: 30 Column: m
2016 annual transmission services true-up refunds and/or surcharge.

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: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 31 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 32 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 32 Column: m
2016 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 33 Column: a
This footnote applies to all occurrences of "Tri-State Generation & Trans." on pages 328-330. Complete name is Tri-State Generation and Transmission Association, Inc.

Schedule Page: 328.4 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 (7th Revised Service Agreement 628) terminating on June 30, 2021.

Schedule Page: 328.4 Line No.: 33 Column: m
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: 328.4 Line No.: 34 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 34 Column: d
Network transmission service under the Open Access Transmission Tariff (7th Revised Service Agreement 628) terminating on June 30, 2021.

Schedule Page: 328.4 Line No.: 34 Column: m
2016 transmission and ancillary services. Charge for transmission services.

Schedule Page: 328.5 Line No.: 1 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 1 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 1 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.5 Line No.: 1 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 2 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 2 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 2 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.5 Line No.: 3 Column: d
Network transmission service and distribution delivery service under the Open Access Transmission Tariff (2nd Revised Service Agreement 506) terminating upon written notification.

Schedule Page: 328.5 Line No.: 3 Column: m
Distribution voltage service charge. Primary delivery service. Scheduling, system control and dispatch service. Regulation and frequency response service. Reactive supply and voltage control service. Operating reserve - spinning reserve service. Operating Reserve - supplemental reserve service.

Schedule Page: 328.5 Line No.: 4 Column: d
Network transmission service and distribution delivery service under the Open Access Transmission Tariff (2nd Revised Service Agreement 506) terminating upon written notification.

Schedule Page: 328.5 Line No.: 4 Column: m
2016 annual transmission services true-up refunds and/or surcharge.

Schedule Page: 328.5 Line No.: 5 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.: 5 Column: d
Legacy contract (3rd Revised Rate Schedule 286) executed between PacifiCorp and United States Department of the Interior, Bureau of Reclamation Weber Basin Water Conservancy District for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge for energy deliveries at and below 138kV. Agreement terminates any time after April 1, 2040, with four years written notification.

Schedule Page: 328.5 Line No.: 5 Column: m
Energy consumption charge for deliveries at and below 138kV.

Schedule Page: 328.5 Line No.: 6 Column: d

Legacy contract (3rd Revised Rate Schedule 286) executed between PacifiCorp and United States Department of the Interior, Bureau of Reclamation Weber Basin Water Conservancy District for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge for energy deliveries at and below 138kV. Agreement terminates any time after April 1, 2040, with four years written notification.

Schedule Page: 328.5 Line No.: 6 Column: m

2016 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 7 Column: d

Legacy contract (3rd Amended Rate Schedule 67) executed between PacifiCorp and United States Department of the Interior, Bureau of Reclamation Crooked River Irrigation District for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Agreement terminates with one year written notice.

Schedule Page: 328.5 Line No.: 8 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.: 8 Column: d

Legacy contract executed between PacifiCorp and Utah Associated Municipal Power Systems for transmission service over agreed-upon facilities (4th Amended and Restated Transmission Service and Operating Agreement, 4th Revised Rate Schedule 297). Agreement subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.5 Line No.: 8 Column: m

Distribution voltage service charge. 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: 328.5 Line No.: 9 Column: d

Legacy contract executed between PacifiCorp and Utah Associated Municipal Power Systems for transmission service over agreed-upon facilities (4th Amended and Restated Transmission Service and Operating Agreement, 4th 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

2016 transmission and ancillary services. Charge for transmission services.

Schedule Page: 328.5 Line No.: 10 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 10 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 10 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.: 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

2016 transmission and ancillary services.

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
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

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
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
2016 transmission and ancillary services. Charge for transmission services.

Schedule Page: 328.5 Line No.: 15 Column: c
This footnote applies to all occurrences of "PGE" on pages 328-330. Complete name is Portland General Electric Company.

Schedule Page: 328.5 Line No.: 15 Column: d
Legacy contract (Rate Schedule 591) executed between PacifiCorp and Warm Springs Power Enterprises for transmission service over agreed-upon facilities and/or subject to sole-use or facilities charge. Terminating on January 31, 2032.

Schedule Page: 328.5 Line No.: 15 Column: m
Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.5 Line No.: 16 Column: d
Legacy contract (Rate Schedule 591) executed between PacifiCorp and Warm Springs Power Enterprises for transmission service over agreed-upon facilities and/or subject to sole-use or facilities charge. Terminating on January 31, 2032.

Schedule Page: 328.5 Line No.: 16 Column: m
2016 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 17 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 Line No.: 17 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.5 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: 328.5 Line No.: 17 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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 terminates 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 terminates upon three years after written notice and mutual consent.

Schedule Page: 328.5 Line No.: 19 Column: m

2016 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 138kV. Agreement terminates 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 138kV. Agreement terminates upon three years after written notice and mutual consent.

Schedule Page: 328.5 Line No.: 21 Column: m

2016 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 684) 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 (4th 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: b

This footnote applies to all occurrences of "Western Area Power Adm CO River" on pages 328-330. Complete name is Western Area Power Administration Colorado River Storage Project.

Schedule Page: 328.5 Line No.: 24 Column: d

Evergreen network transmission service under the Open Access Transmission Tariff (4th Revised Service Agreement 175).

Schedule Page: 328.5 Line No.: 24 Column: m

2016 annual transmission services true-up refunds and/or surcharge.

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: 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	AD					27,576	27,576
2	Arizona Public Service	LFP	420,980	420,980	1,992,497			1,992,497
3	Arizona Public Service	NF	13,095	13,095	86,775			86,775
4	Arizona Public Service	OS					138,930	138,930
5	Arizona Public Service	SFP	25,564	25,564	227,731			227,731
6	Ashland, City of	FNS	2,681	2,681		27,210		27,210
7	Avista Corporation	FNS	63,878	66,234	271,839			271,839
8	Avista Corporation	NF	10,435	10,435	56,881			56,881
9	Avista Corporation	SFP	20,256	20,256	77,901			77,901
10	Basin Elect. Power Coop	NF	5,158	5,158		7,685		7,685
11	Big Horn Rural Electric	OLF					165,790	165,790
12	Black Hills Power, Inc.	AD					973	973
13	Black Hills Power, Inc.	NF	39,517	39,517	39,517			39,517
14	Black Hills Power, Inc.	OS					45,922	45,922
15	Black Hills Power, Inc.	SFP	5,090	5,090	32,270			32,270
16	Bonneville Power Admin	AD					-14,618	-14,618
	TOTAL		19,890,671	20,178,368	132,002,190	2,608,462	-137,533	134,473,119

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Bonneville Power Admin	FNS	1,962,304	1,997,246	7,244,546			7,244,546
2	Bonneville Power Admin	LFP	5,694,786	5,796,191	67,482,018			67,482,018
3	Bonneville Power Admin	NF	48,892	49,763		298,364		298,364
4	Bonneville Power Admin	OLF	4,113,981	4,187,237	21,983,784		99,431	22,083,215
5	Bonneville Power Admin	OS	96,175	96,175		45,305	73,140	118,445
6	Bonneville Power Admin	SFP	484,492	493,119		2,187,310		2,187,310
7	CA Ind Sys Operator	AD					-86,828	-86,828
8	CA Ind Sys Operator	OS					1,496,789	1,496,789
9	CA Ind Sys Operator	SFP				41,158		41,158
10	Deseret Gen & Trans	LFP	159,229	159,229	4,225,309			4,225,309
11	Deseret Gen & Trans	NF	1,737	1,737	12,588			12,588
12	Flathead Elect Coop Inc	OS					70,077	70,077
13	Hermiston Gen Co L.P.	OS					196,857	196,857
14	Idaho Power Company	AD	-187	-187			-2,112	-2,112
15	Idaho Power Company	FNS			13,461			13,461
16	Idaho Power Company	LFP	4,406,666	4,467,600	14,211,252			14,211,252
	TOTAL		19,890,671	20,178,368	132,002,190	2,608,462	-137,533	134,473,119

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Idaho Power Company	NF	104,192	104,192	584,812			584,812
2	Idaho Power Company	OS					4,768	4,768
3	Idaho Power Company	SFP	4,080	4,080	12,912			12,912
4	LA Dept. of Water & Pwr	NF	4,066	4,066	34,958			34,958
5	LA Dept. of Water & Pwr	OS					4,868	4,868
6	Moon Lake Elect. Assoc.	FNS	22	22			277,886	277,886
7	Morgan City Corporation	LFP	12	12		1,430		1,430
8	Morgan Stanley C.G. Inc	SFP					-8,112	-8,112
9	Nevada Power Company	AD					-25,324	-25,324
10	Nevada Power Company	NF	108,400	108,400	539,730			539,730
11	Nevada Power Company	OS					79,558	79,558
12	Nevada Power Company	SFP	179,578	179,578	814,407			814,407
13	NorthWestern Corp.	NF	33,115	34,491	149,344			149,344
14	NorthWestern Corp.	OS					15,463	15,463
15	NorthWestern Corp.	SFP	36,040	36,040	156,107			156,107
16	Platte River Pwr Auth	LFP	205,796	205,796	849,642			849,642
	TOTAL		19,890,671	20,178,368	132,002,190	2,608,462	-137,533	134,473,119

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Platte River Pwr Auth	OS					18,889	18,889
2	Portland Gen. Electric	LFP	79,212	79,212	56,520			56,520
3	Portland Gen. Electric	OLF					1,001	1,001
4	Portland Gen. Electric	OS		3,441			5,498	5,498
5	Powerex Corporation	SFP					-1,225,758	-1,225,758
6	Public Service Co of CO	LFP	5,506	5,751	1,066,800			1,066,800
7	PUD No. 1 of Snohomish	SFP	2,000	2,000	4,000			4,000
8	Puget Sound Energy, Inc	SFP	31,132	31,132	40,115			40,115
9	Salt River Project	NF	3,315	3,315	9,888			9,888
10	Salt River Project	OS					1,211	1,211
11	Sierra Pacific Power Co	NF	162	162	893			893
12	Sierra Pacific Power Co	OS					121	121
13	Surprise Valley Electr.	AD					700	700
14	Surprise Valley Electr.	OLF					7,207	7,207
15	The Energy Authority	SFP					-53,094	-53,094
16	Tri-State Gen & Transm	LFP	13,283	13,527	1,066,800			1,066,800
	TOTAL		19,890,671	20,178,368	132,002,190	2,608,462	-137,533	134,473,119

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 2017/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	TRANSFER OF ENERGY Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Tri-State Gen & Transm	NF	22,663	22,663	199,597			199,597
2	Tri-State Gen & Transm	OS					18,098	18,098
3	Tucson Electric Power	NF	1,800	1,800	7,800			7,800
4	Tucson Electric Power	OS					675	675
5	Western Area Power Admn	AD					-9,540	-9,540
6	Western Area Power Admn	FNS	899,712	899,712	5,927,920			5,927,920
7	Western Area Power Admn	LFP	433,337	433,337	2,205,417			2,205,417
8	Western Area Power Admn	NF	144,357	144,357	303,180			303,180
9	Western Area Power Admn	OS					743,033	743,033
10	Western Area Power Admn	SFP	4,162	4,162	12,979			12,979
11	Westport Field Svc LLC	LFP					-3,273,199	-3,273,199
12	Accrual						1,066,591	1,066,591
13								
14								
15								
16								
	TOTAL		19,890,671	20,178,368	132,002,190	2,608,462	-137,533	134,473,119

Schedule Page: 332 Line No.: 1 Column: b
Settlement adjustment.

Schedule Page: 332 Line No.: 1 Column: g
Settlement adjustment.

Schedule Page: 332 Line No.: 2 Column: b
Arizona Public Service Company - contract termination dates: January 11, 2041 and the date that all generating plants comprising PacifiCorp resources associated with this agreement have been retired from service or interests transferred.

Schedule Page: 332 Line No.: 4 Column: b
Arizona Public Service Company - Legacy contract executed between PacifiCorp and Arizona Public Service Company concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Service Agreement between PacifiCorp and Arizona Public Service Company, Rate Schedule 436). The contract terminates October 31, 2020. See also page 328, Transmission of electricity for others, in this Form No. 1.

Schedule Page: 332 Line No.: 4 Column: g
Ancillary services. Settlement adjustment.

Schedule Page: 332 Line No.: 11 Column: b
Big Horn Rural Electric Company - contract termination date: March 10, 2018.

Schedule Page: 332 Line No.: 11 Column: g
Use of facilities.

Schedule Page: 332 Line No.: 12 Column: b
Settlement adjustment.

Schedule Page: 332 Line No.: 12 Column: g
Settlement adjustment.

Schedule Page: 332 Line No.: 14 Column: b
Ancillary services.

Schedule Page: 332 Line No.: 14 Column: g
Ancillary services.

Schedule Page: 332 Line No.: 16 Column: b
Settlement adjustment.

Schedule Page: 332 Line No.: 16 Column: g
Settlement adjustment.

Schedule Page: 332.1 Line No.: 2 Column: b
Bonneville Power Administration - contract termination dates: 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.: 4 Column: b
Bonneville Power Administration - contract termination dates: December 31, 2018; September 30, 2027 and evergreen.

Schedule Page: 332.1 Line No.: 4 Column: g
Use of facilities.

Schedule Page: 332.1 Line No.: 5 Column: b
Bonneville Power Administration - Legacy contract executed between PacifiCorp and Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities ("Midpoint-Meridian Transmission Agreement", Rate Schedule 369). This agreement runs concurrently with the AC Intertie Agreement (Rate Schedule 368), which terminates when the facilities subject to that agreement are taken out of service. See also page 328, Transmission of electricity for others, in this Form No. 1.

Schedule Page: 332.1 Line No.: 5 Column: g
Use of facilities.

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: g
Settlement adjustment.

Schedule Page: 332.1 Line No.: 8 Column: b
Ancillary services.

Schedule Page: 332.1 Line No.: 8 Column: g
Ancillary services.

Schedule Page: 332.1 Line No.: 10 Column: b
Deseret Generation and Transmission Co-operative - contract termination dates: January 1, 2018 and September 1, 2018.

Schedule Page: 332.1 Line No.: 12 Column: b
Use of facilities.

Schedule Page: 332.1 Line No.: 12 Column: g
Use of facilities.

Schedule Page: 332.1 Line No.: 13 Column: a
Hermiston Generating Company, L.P. operates the Hermiston Generating Plant, which is jointly owned. PacifiCorp owns 50% of the plant.

Schedule Page: 332.1 Line No.: 13 Column: b
Use of facilities.

Schedule Page: 332.1 Line No.: 13 Column: g
Use of facilities.

Schedule Page: 332.1 Line No.: 14 Column: b
Settlement adjustment.

Schedule Page: 332.1 Line No.: 14 Column: g
Settlement adjustment.

Schedule Page: 332.1 Line No.: 16 Column: b
Idaho Power Company - contract termination dates: April 1, 2025 and July 1, 2025.

Schedule Page: 332.2 Line No.: 2 Column: b
Ancillary services. Credit for unreserved use.

Schedule Page: 332.2 Line No.: 2 Column: g
Ancillary services. Credit for unreserved use.

Schedule Page: 332.2 Line No.: 4 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.: 5 Column: b
Ancillary services.

Schedule Page: 332.2 Line No.: 5 Column: g
Ancillary services.

Schedule Page: 332.2 Line No.: 6 Column: g
Use of facilities.

Schedule Page: 332.2 Line No.: 7 Column: b
Morgan City Corporation - contract termination date: Evergreen.

Schedule Page: 332.2 Line No.: 8 Column: a
Complete name is Morgan Stanley Capital Group, Inc.

Schedule Page: 332.2 Line No.: 8 Column: g
Revenues from sales on the secondary transmission market.

Schedule Page: 332.2 Line No.: 9 Column: a
This footnote applies to all occurrences of "Nevada Power Company" on page 332. Nevada Power Company is a wholly owned 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.: 9 Column: b
Settlement adjustment.

Schedule Page: 332.2 Line No.: 9 Column: g
Settlement adjustment.

Schedule Page: 332.2 Line No.: 11 Column: b
Ancillary services.

Schedule Page: 332.2 Line No.: 11 Column: g
Ancillary services.

Schedule Page: 332.2 Line No.: 14 Column: b
Ancillary services.

Schedule Page: 332.2 Line No.: 14 Column: g
Ancillary services.

Schedule Page: 332.2 Line No.: 16 Column: b
Platte River Power Authority - contract termination date: October 31, 2022.

Schedule Page: 332.3 Line No.: 1 Column: b
Ancillary services.

Schedule Page: 332.3 Line No.: 1 Column: g
Ancillary services.

Schedule Page: 332.3 Line No.: 2 Column: b
Portland General Electric Company - contract termination date: April 1, 2022.

Schedule Page: 332.3 Line No.: 3 Column: b
Portland General Electric Company - contract termination date: Upon two years written notice.

Schedule Page: 332.3 Line No.: 3 Column: g
Use of facilities.

Schedule Page: 332.3 Line No.: 4 Column: b
Ancillary services.

Schedule Page: 332.3 Line No.: 4 Column: g
Ancillary services.

Schedule Page: 332.3 Line No.: 5 Column: g
Revenues from sales on the secondary transmission market.

Schedule Page: 332.3 Line No.: 6 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.: 7 Column: a
This footnote applies to all occurrences of "PUD No. 1 of Snohomish" on page 332. Complete name is Public Utility District No. 1 of Snohomish County.

Schedule Page: 332.3 Line No.: 10 Column: b
Ancillary services.

Schedule Page: 332.3 Line No.: 10 Column: g
Ancillary services.

Schedule Page: 332.3 Line No.: 11 Column: a
This footnote applies to all occurrences of "Sierra Pacific Power Co" on page 332. Sierra Pacific Power Company is a wholly owned 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.: 12 Column: b
Ancillary services.

Schedule Page: 332.3 Line No.: 12 Column: g
Ancillary services.

Schedule Page: 332.3 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 332.3 Line No.: 13 Column: g
Settlement adjustment.

Schedule Page: 332.3 Line No.: 14 Column: b

Surprise Valley Electrification Corp. - contract termination date: Evergreen.

Schedule Page: 332.3 Line No.: 14 Column: g

Use of facilities.

Schedule Page: 332.3 Line No.: 15 Column: g

Revenues from sales on the secondary transmission market.

Schedule Page: 332.3 Line No.: 16 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.: 2 Column: b

Ancillary services.

Schedule Page: 332.4 Line No.: 2 Column: g

Ancillary services.

Schedule Page: 332.4 Line No.: 4 Column: b

Ancillary services.

Schedule Page: 332.4 Line No.: 4 Column: g

Ancillary services.

Schedule Page: 332.4 Line No.: 5 Column: b

Settlement adjustment.

Schedule Page: 332.4 Line No.: 5 Column: g

Settlement adjustment.

Schedule Page: 332.4 Line No.: 7 Column: b

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

Schedule Page: 332.4 Line No.: 9 Column: b

Western Area Power Administration - Legacy contract (Rate Schedule 684) executed between PacifiCorp and Western Area Power Administration concerning the exchange of transmission services over agreed-upon facilities. The contract terminates 50 years from execution. See also page 328, Transmission of electricity for others, in this Form No. 1.

Schedule Page: 332.4 Line No.: 9 Column: g

Ancillary services. Use of facilities.

Schedule Page: 332.4 Line No.: 11 Column: b

Westport Field Services, LLC - contract termination date: Evergreen.

Schedule Page: 332.4 Line No.: 11 Column: g

Reimbursement for third party services.

Schedule Page: 332.4 Line No.: 12 Column: g

Represents the difference between actual wheeling expenses for the period as reflected on the individual line items within this schedule and the accruals charged to Account 565, Transmission of electricity by others, during the period.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,115,015
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	Business & Economic Development and	
8	Corporate Memberships & Subscriptions:	
9	American Leadership of Oregon	5,000
10	American Wind Energy Association	25,000
11	American Wind Wildlife Institute	16,667
12	Associated Oregon Industries	28,840
13	Casper Area Chamber of Commerce	7,160
14	Clatsop Economic Development Resources	6,000
15	Economic Development for Central Oregon	8,000
16	Greater Portland Inc.	10,000
17	Greater Yakima Chamber of Commerce	5,000
18	Intermountain Electrical Association	9,000
19	Klamath County Economic Development Association	5,000
20	Laramie Chamber of Business Alliance	5,000
21	National Safety Council	6,035
22	Ogden-Weber Chamber of Commerce	6,000
23	Oregon Business Association	14,595
24	Oregon Business Council	30,438
25	Oregon Economic Development Association	10,000
26	Oregon Sports Authority	5,000
27	Oregon State University Pole Research Cooperative	15,000
28	Pacific Northwest Utilities Conference Committee	80,581
29	Redmond Economic Development, Inc.	7,000
30	Rocky Mountain Electrical League	18,000
31	Salt Lake Area Chamber of Commerce	27,600
32	Smart Electric Power Alliance	9,333
33	South Coast Development Council, Inc.	5,000
34	Southern Oregon Regional Economic Development, Inc.	5,500
35	University of Oregon	
36	Resource Assistance for Rural Environments	5,000
37	Utah Manufacturers Association	6,930
38	Utah Taxpayers Association	18,700
39	Utah Technology Council	12,000
40	Western Energy Supply and Transmission Associates	25,685
41	World Trade Center Utah	45,000
42	Yakima County Development Association	7,500
43	Other (Individually < $5,000)	148,880
44		
45	Directors' Fees - Regional Advisory Board	15,116
46	TOTAL	2,272,508

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
6	Rating Agency and Trustee Fees:	
7	The Bank of New York Mellon	127,210
8	Computershare Shareowner Services, LLC	17,433
9	CUSIP Global Services	605
10	Financial Industry Regulation Authority, Inc.	800
11	Fitch, Inc.	44,866
12	Moody's Investors Service, Inc.	121,002
13	Standard & Poor's Financial Services LLC	174,430
14	U.S. Bancorp	13,056
15		
16	General:	
17	Other	2,531
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46	TOTAL	2,272,508

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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			40,055,749		40,055,749
2	Steam Production Plant	271,454,306				271,454,306
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	35,017,010		305,969		35,322,979
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	126,926,939				126,926,939
7	Transmission Plant	106,515,411				106,515,411
8	Distribution Plant	148,951,203				148,951,203
9	Regional Transmission and Market Operation					
10	General Plant	38,785,821		1,035,064		39,820,885
11	Common Plant-Electric					
12	TOTAL	727,650,690		41,396,782		769,047,472

B. Basis for Amortization Charges

The Amortization of Limited-Term Electric Plant is based on straight-line amortization over the life of the asset.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	HYDRAULIC PROD.						
13	Klamath River						
14	330.20 CA/OR	41			-0.22		2.00
15	330.40 CA/OR	1			-1.36		2.00
16	331.00 CA/OR	15,749			10.88		2.00
17	332.00 CA/OR	37,051			9.18		2.00
18	333.00 CA/OR	18,013			6.69		2.00
19	334.00 CA/OR	16,185			7.98		2.00
20	335.00 CA/OR	183			5.02		2.00
21	336.00 CA/OR	2,595			7.14		2.00
22							
23							
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Schedule Page: 336 Line No.: 1 Column: d

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Functional Classification (a)	Ref. Line No. (Column)	Amort. of Ltd. Term Elec. Plt. (Acct 404) (d)
Intangible Plant	1(d)	$ 40,055,749
Less: Intangible mining plant(1)		3,147
Revised Intangible Plant		$ 40,052,602

(1) To adjust PacifiCorp's formula rate, per FERC Docket No. FA16-4-000 for amortization of mining assets related to production plant.

Schedule Page: 336 Line No.: 7 Column: b

Adjustment to PacifiCorp's formula rate under FERC Docket No. ER11-3643-000, Attachment H-1, is as follows:

Functional Classification (a)	Ref. Line No. (Column)	Depreciation Expense (Acct 403) (b)
Transmission Plant	7(b)	$ 106,515,411
Less: Prior period adjustment(1)		(262,575)
Revised Transmission Plant		$ 106,777,986

(1) To adjust PacifiCorp's formula rate, per FERC Docket No. FA16-4-000 for corrections to transmission depreciation expense for calendar years 2011 through 2016.

Schedule Page: 336 Line No.: 12 Column: b

Depreciation expense associated with transportation equipment is generally charged to operations and maintenance expense and construction work in progress. During the year ended December 31, 2017, depreciation expense associated with transportation equipment was $15,045,329.

Schedule Page: 336 Line No.: 12 Column: e

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

Schedule Page: 336 Line No.: 13 Column: a

The depreciation rate changes are for the Klamath hydroelectric system’s four mainstem dams (JC Boyle, Iron Gate, Copco No. 1 and Copco No. 2). For further discussion, refer to Note 13 of Notes to Financial Statements, in this Form No. 1.

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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	6,305,547		6,305,547	
3	Rate Cases and Proceedings		599,034	599,034	
4					
5	Oregon Public Utility Commission:				
6	Annual Fee	4,009,002		4,009,002	
7	Rate Cases and Proceedings		649,367	649,367	
8	Deferred Intervenor Funding Grants (1)		244,998	244,998	410,913
9					
10	Wyoming Public Service Commission:				
11	Annual Fee	1,777,599		1,777,599	
12	Rate Cases and Proceedings		252,098	252,098	
13					
14	Washington Utilities and Transportation				
15	Commission:				
16	Annual Fee	684,019		684,019	
17	Rate Cases and Proceedings		18,424	18,424	
18					
19	Idaho Public Utilities Commission:				
20	Annual Fee	600,860		600,860	
21	Rate Cases and Proceedings		55,509	55,509	
22	Deferred Intervenor Funding Grants				26,865
23					
24	California Public Utilities Commission:				
25	Annual Fee	809		809	
26	Rate Cases and Proceedings		440,698	440,698	
27	Deferred Intervenor Funding Grants				40,605
28					
29	California Environmental Protection Agency:				
30	Industry Compliance Fee	54,046	18,485	72,531	
31					
32	Multi-State:				
33	Rate Cases and Proceedings		352,819	352,819	
34	Other Regulatory		1,303,025	1,303,025	
35					
36	Federal Energy Regulatory Commission:				
37	Annual Fee	1,932,452		1,932,452	
38	Annual Fee - Hydroelectric Plants	2,798,781		2,798,781	
39	Transmission Rate Cases		664,023	664,023	
40	Other Regulatory		92,209	92,209	
41					
42					
43					
44					
45					
46	TOTAL	18,163,115	4,690,689	22,853,804	478,383

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	6,305,547					2
Electric	928	599,034					3
							4
							5
Electric	928	4,009,002					6
Electric	928	649,367					7
Electric	928	244,998	369,593	928	244,998	535,508	8
							9
							10
Electric	928	1,777,599					11
Electric	928	252,098					12
							13
							14
							15
Electric	928	684,019					16
Electric	928	18,424					17
							18
							19
Electric	928	600,860					20
Electric	928	55,509					21
						26,865	22
							23
							24
Electric	928	809					25
Electric	928	440,698					26
			414			41,019	27
							28
							29
Electric	928	72,531					30
							31
							32
Electric	928	352,819					33
Electric	928	1,303,025					34
							35
							36
Electric	928	1,932,452					37
Electric	928	2,798,781					38
Electric	928	664,023					39
Electric	928	92,209					40
							41
							42
							43
							44
							45
		22,853,804	370,007		244,998	603,392	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 2017/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	A. Electric R, D & D Performed Internally:	
2	(3) Distribution	WestSmart Electric Vehicle Project
3	(6) Other	Utah Sustainable Transportation and Energy Plan
4	B. Electric R, D & D Performed Externally:	
5	(1) Research Support	Electric Power Research Institute
6		- Toxic Release Inventory reporting for power plants program
7	(2) Research Support	Edison Electric Institute
8		- Avian Power Line Interaction Committee
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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
10,634		580	10,634		2
	946,588		946,588		3
					4
					5
	18,000	557	18,000		6
					7
19,100	3,390		22,490		8
					9
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Schedule Page: 352 Line No.: 2 Column: b

PacifiCorp was selected for a $4 million grant from the U.S. Department of Energy to install, operate and collect data on plug-in electric vehicle charging stations located on 1,500 miles of interstate across Utah, Idaho and Wyoming. A component of this program related to research, development and demonstration activities is to manage and design an electric grid to handle widespread electric vehicle charging requirements in collaboration with the University of Utah.

Schedule Page: 352 Line No.: 3 Column: b

The Utah Sustainable Transportation and Energy Plan was signed into law in March 2016. The Utah legislation established a five-year pilot program to provide up to $10 million annually of mandated funding for electric vehicle infrastructure and clean coal research, and authorized funding at the Utah Public Service Commission's discretion for solar development, utility-scale battery storage and other innovative technology, economic development and air quality initiatives.

Schedule Page: 352 Line No.: 3 Column: e

Account 107, Construction work in progress
Account 557, Other expenses
Account 598, Maintenance of miscellaneous distribution plant
Account 908, Customer assistance expenses

Schedule Page: 352 Line No.: 8 Column: e

Account 920, Administrative and general salaries
Account 921, Office supplies and expenses

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	96,070,690		
4	Transmission	14,579,724		
5	Regional Market			
6	Distribution	34,891,621		
7	Customer Accounts	36,939,741		
8	Customer Service and Informational	6,340,864		
9	Sales			
10	Administrative and General	40,496,799		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	229,319,439		
12	Maintenance			
13	Production	44,957,770		
14	Transmission	12,054,482		
15	Regional Market			
16	Distribution	68,055,798		
17	Administrative and General	2,061,162		
18	TOTAL Maintenance (Total of lines 13 thru 17)	127,129,212		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	141,028,460		
21	Transmission (Enter Total of lines 4 and 14)	26,634,206		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	102,947,419		
24	Customer Accounts (Transcribe from line 7)	36,939,741		
25	Customer Service and Informational (Transcribe from line 8)	6,340,864		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	42,557,961		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	356,448,651		356,448,651
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 2017/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)	356,448,651		356,448,651
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	144,084,590		144,084,590
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	144,084,590		144,084,590
72	Plant Removal (By Utility Departments)			
73	Electric Plant	8,936,810		8,936,810
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	8,936,810		8,936,810
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock	5,060,730		5,060,730
79	Miscellaneous Other Income Deductions	326,837		326,837
80	Miscellaneous Non-Operating and Non-Utility	1,294,351		1,294,351
81	Charges to Affiliates	1,252,219		1,252,219
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	7,934,137		7,934,137
96	TOTAL SALARIES AND WAGES	517,404,188		517,404,188

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	7,206	1	575,953	579,398
3	Net Sales (Account 447)	(31,244)	(159,381)	(1,182,174)	(1,486,622)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	Energy Imbalance Market (Account 555)	(17,363,701)	(4,517,238)	(21,371,431)	(56,405,886)
8					
9					
10					
11					
12					
13					
14					
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41					
42					
43					
44					
45					
46	TOTAL	(17,387,739)	(4,676,618)	(21,977,652)	(57,313,110)

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				135,187,971	MWh	12,471,202
2	Reactive Supply and Voltage	112,304,158	MWh	7,252,695	125,440,482	MWh	8,180,383
3	Regulation and Frequency Response	92,323,097	MWh	34,424,818	112,174,892	MWh	42,716,246
4	Energy Imbalance				-6,164	MWh	42,000,131
5	Operating Reserve - Spinning	120,145,551	MWh	25,874,105	130,026,618	MWh	27,919,254
6	Operating Reserve - Supplement	120,145,551	MWh	29,309,025	128,181,773	MWh	31,354,173
7	Other						
8	Total (Lines 1 thru 7)	444,918,357		96,860,643	631,005,572		164,641,389

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	15,782	6	800	9,394	640	3,518		658	1,572
2	February	14,781	1	1900	8,387	496	3,518		949	1,431
3	March	13,966	1	800	8,032	474	3,518		587	1,355
4	Total for Quarter 1				25,813	1,610	10,554		2,194	4,358
5	April	12,994	3	800	7,330	357	3,625		357	1,325
6	May	14,874	30	1700	8,256	322	3,625		1,075	1,596
7	June	17,152	26	1700	9,942	390	3,783		1,127	1,910
8	Total for Quarter 2				25,528	1,069	11,033		2,559	4,831
9	July	18,381	6	1700	10,467	422	3,771		1,688	2,033
10	August	18,599	1	1700	10,596	409	3,771		1,802	2,021
11	September	16,812	5	1700	9,687	347	3,771		1,081	1,926
12	Total for Quarter 3				30,750	1,178	11,313		4,571	5,980
13	October	14,855	31	800	7,495	401	3,709		1,932	1,318
14	November	14,610	28	1800	7,929	405	3,614		1,283	1,379
15	December	15,521	21	1800	8,509	503	3,614		1,436	1,459
16	Total for Quarter 4				23,933	1,309	10,937		4,651	4,156
17	Total Year to Date/Year				106,024	5,166	43,837		13,97	19,325

Schedule Page: 400 Line No.: 1 Column: d
Pacific Standard Time

Schedule Page: 400 Line No.: 2 Column: d
Pacific Standard Time

Schedule Page: 400 Line No.: 3 Column: d
Pacific Standard Time

Schedule Page: 400 Line No.: 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
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Schedule Page: 400 Line No.: 9 Column: d
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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 2017 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 2017 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 2017 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 2017 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 2017 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 2017/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	55,249,822
3	Steam	39,882,510			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	181,928
5	Hydro-Conventional	4,729,189			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	7,036,569
7	Other	7,820,365			
8	Less Energy for Pumping	1,027	25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	52,431,037	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	125,390
10	Purchases	14,002,749	27	Total Energy Losses	3,879,854
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	66,473,563
12	Received	7,097,699			
13	Delivered	6,880,415			
14	Net Exchanges (Line 12 minus line 13)	217,284			
15	Transmission For Other (Wheeling)				
16	Received	15,299,651			
17	Delivered	15,189,461			
18	Net Transmission for Other (Line 16 minus line 17)	110,190			
19	Transmission By Others Losses	-287,697			
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	66,473,563			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	6,320,857	723,710	9,216	6	0800 PST
30	February	5,072,870	478,165	8,149	1	1900 PST
31	March	5,131,162	425,564	7,737	6	0800 PST
32	April	4,761,287	384,610	7,157	3	0800 PDT
33	May	5,038,770	475,709	8,097	30	1700 PDT
34	June	5,515,236	481,376	9,687	26	1700 PDT
35	July	6,234,323	376,466	10,210	6	1700 PDT
36	August	5,933,121	314,812	10,334	1	1700 PDT
37	September	5,276,521	584,651	9,454	5	1700 PDT
38	October	5,461,133	930,745	7,293	31	0800 PDT
39	November	5,567,453	967,853	7,643	7	1800 PST
40	December	6,160,830	892,908	8,336	12	1800 PST
41	TOTAL	66,473,563	7,036,569			

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 2017/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: Cholla (b)			Plant Name: Colstrip (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Steam			Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Full Outdoor			Conventional
3	Year Originally Constructed			1981			1984
4	Year Last Unit was Installed			1981			1986
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			414.00			155.61
6	Net Peak Demand on Plant - MW (60 minutes)			386			156
7	Plant Hours Connected to Load			7005			8626
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			395			148
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			0			0
12	Net Generation, Exclusive of Plant Use - KWh			1959086000			1011701000
13	Cost of Plant: Land and Land Rights			2635317			1788644
14	Structures and Improvements			65298661			62397134
15	Equipment Costs			480235453			170317233
16	Asset Retirement Costs			12055842			8150036
17	Total Cost			560225273			242653047
18	Cost per KW of Installed Capacity (line 17/5) Including			1353.2011			1559.3667
19	Production Expenses: Oper, Supv, & Engr			2989029			37798
20	Fuel			55172038			16459076
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			6508213			939932
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			194950			99981
26	Misc Steam (or Nuclear) Power Expenses			3020652			1335751
27	Rents			0			26275
28	Allowances			0			0
29	Maintenance Supervision and Engineering			2553299			205308
30	Maintenance of Structures			3638199			352811
31	Maintenance of Boiler (or reactor) Plant			5861377			2775921
32	Maintenance of Electric Plant			738311			1036493
33	Maintenance of Misc Steam (or Nuclear) Plant			2286359			421390
34	Total Production Expenses			82962427			23690736
35	Expenses per Net KWh			0.0423			0.0234
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	1181803	3401	0	639815	1513	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9161	128877	0	8464	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	44.923	87.951	0.000	22.772	75.090	0.000
41	Average Cost of Fuel per Unit Burned	46.432	87.951	0.000	25.547	75.090	0.000
42	Average Cost of Fuel Burned per Million BTU	2.534	16.249	2.546	1.509	12.771	1.518
43	Average Cost of Fuel Burned per KWh Net Gen	0.028	0.000	0.028	0.016	0.000	0.016
44	Average BTU per KWh Net Generation	11052.262	9.397	11061.659	10705.833	8.796	10714.629

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: Craig (d)	Plant Name: Dave Johnston (e)	Plant Name: Hayden (f)	Line No.
Steam	Steam	Steam	1
Outdoor Boiler	Semi-Outdoor	Outdoor Boiler	2
1979	1959	1965	3
1980	1972	1976	4
172.13	816.77	81.37	5
164	738	78	6
8446	8760	8760	7
0	0	0	8
165	754	77	9
0	0	0	10
0	192	0	11
1039894000	4519908000	493358000	12
137086	10449793	683069	13
38326776	159054652	17809571	14
182608586	865111333	95958746	15
35149	15604693	511486	16
221107597	1050220471	114962872	17
1284.5384	1285.8216	1412.8410	18
347685	229447	362783	19
20537501	49749399	13466029	20
0	0	0	21
1362848	3731263	1158843	22
0	0	0	23
0	0	0	24
577382	146	454030	25
1323712	14444350	329781	26
0	104424	116	27
0	0	0	28
686917	0	135741	29
412489	3574802	337142	30
5108240	9723784	1070282	31
2365240	7655968	105962	32
884872	1915029	423765	33
33606886	91128612	17844474	34
0.0323	0.0202	0.0362	35

(d) Coal	(d) Oil	(d) Composite	(e) Coal	(e) Oil	(e) Composite	(f) Coal	(f) Oil	(f) Composite	Line No.
Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
513901	138	0	3080133	18272	0	238649	404	0	38
9988	133820	0	8117	138000	0	11377	137269	0	39
42.308	126.581	0.000	15.607	80.831	0.000	53.304	85.000	0.000	40
39.671	126.581	0.000	15.672	80.831	0.000	56.189	85.000	0.000	41
1.986	22.516	2.000	0.965	13.946	0.993	2.469	14.746	2.479	42
0.020	0.000	0.020	0.011	0.000	0.011	0.027	0.000	0.027	43
9872.188	0.745	9872.933	11062.592	23.430	11086.022	11007.050	4.726	11011.776	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 2017/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: Hunter Unit No. 1 (b)			Plant Name: Hunter Unit No. 2 (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			1978			1980
4	Year Last Unit was Installed			1978			1980
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			457.73			294.46
6	Net Peak Demand on Plant - MW (60 minutes)			422			273
7	Plant Hours Connected to Load			7040			8456
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			418			269
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			0			0
12	Net Generation, Exclusive of Plant Use - KWh			2343429000			1951195000
13	Cost of Plant: Land and Land Rights			9688261			9688261
14	Structures and Improvements			64634246			54038841
15	Equipment Costs			380180978			246701517
16	Asset Retirement Costs			4718288			4718288
17	Total Cost			459221773			315146907
18	Cost per KW of Installed Capacity (line 17/5) Including			1003.2591			1070.2537
19	Production Expenses: Oper, Supv, & Engr			0			0
20	Fuel			47755005			37610792
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			5711337			4979270
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			-15522			4958
26	Misc Steam (or Nuclear) Power Expenses			775550			-4203669
27	Rents			769			495
28	Allowances			0			0
29	Maintenance Supervision and Engineering			0			0
30	Maintenance of Structures			2776466			1891968
31	Maintenance of Boiler (or reactor) Plant			6025451			3832525
32	Maintenance of Electric Plant			1802349			966729
33	Maintenance of Misc Steam (or Nuclear) Plant			74057			421979
34	Total Production Expenses			64905462			45505047
35	Expenses per Net KWh			0.0277			0.0233
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	1128456	1654	0	902386	917	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11139	138000	0	11317	138000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	42.202	0.000	0.000	41.595	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.894	13.723	1.899	1.838	14.313	1.841
43	Average Cost of Fuel Burned per KWh Net Gen	0.020	0.000	0.020	0.019	0.000	0.019
44	Average BTU per KWh Net Generation	10728.047	4.090	10732.137	10467.582	2.723	10470.305

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 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: Hunter Unit No. 3 (d)			Plant Name: Hunter - Total Plant (e)			Plant Name: Huntington (f)			Line No.
Steam			Steam			Steam			1
Outdoor Boiler			Outdoor Boiler			Outdoor Boiler			2
1983			1978			1974			3
1983			1983			1977			4
495.59			1247.78			996.00			5
489			1333			899			6
8622			8760			8760			7
0			0			0			8
471			1158			909			9
0			0			0			10
0			218			160			11
3134673000			7429297000			5399777000			12
10274569			29651091			2377564			13
92586505			211259592			124572764			14
447333401			1074215896			739936242			15
4718288			14154864			10531294			16
554912763			1329281443			877417864			17
1119.7013			1065.3172			880.9416			18
0			0			6773			19
60572842			145938639			138300998			20
0			0			0			21
6843697			17534304			12817667			22
0			0			0			23
0			0			0			24
-1998			-12562			0			25
1710569			-1717550			526805			26
11747			13011			7288			27
0			0			0			28
0			0			1917280			29
2750978			7419412			2164881			30
5562586			15420562			7106343			31
1113513			3882591			1071406			32
569179			1065215			874453			33
79133113			189543622			164793894			34
0.0252			0.0255			0.0305			35
Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
1424090	11069	0	3454932	13640	0	2479026	6323	0	38
11111	138000	0	11174	138000	0	11354	138000	0	39
0.000	0.000	0.000	42.072	81.669	0.000	55.886	79.902	0.000	40
41.898	0.000	0.000	41.918	81.669	0.000	55.585	79.902	0.000	41
1.885	14.127	1.910	1.876	14.091	1.888	2.448	13.785	2.455	42
0.019	0.000	0.019	0.019	0.000	0.019	0.026	0.000	0.026	43
10095.160	20.467	10115.627	10392.603	10.641	10403.244	10425.202	6.787	10431.989	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: Jim Bridger (b)			Plant Name: Naughton (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			1974			1963
4	Year Last Unit was Installed			1979			1971
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			1550.65			707.20
6	Net Peak Demand on Plant - MW (60 minutes)			1419			650
7	Plant Hours Connected to Load			8760			8745
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			1415			637
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			341			130
12	Net Generation, Exclusive of Plant Use - KWh			8749882000			4740158000
13	Cost of Plant: Land and Land Rights			1193761			1321031
14	Structures and Improvements			147284321			125020741
15	Equipment Costs			1242939604			669217841
16	Asset Retirement Costs			19611116			44905291
17	Total Cost			1411028802			840464904
18	Cost per KW of Installed Capacity (line 17/5) Including			909.9596			1188.4402
19	Production Expenses: Oper, Supv, & Engr			14143146			375609
20	Fuel			259330191			105045552
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			17041139			9655314
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			28814
26	Misc Steam (or Nuclear) Power Expenses			-23381682			9389463
27	Rents			362386			14350
28	Allowances			0			0
29	Maintenance Supervision and Engineering			801608			1699478
30	Maintenance of Structures			10731980			1267546
31	Maintenance of Boiler (or reactor) Plant			25402548			9847860
32	Maintenance of Electric Plant			7885317			3268113
33	Maintenance of Misc Steam (or Nuclear) Plant			2643576			1197315
34	Total Production Expenses			314960209			141789414
35	Expenses per Net KWh			0.0360			0.0299
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil	Composite	Coal	Gas	Composite
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	MCF	
38	Quantity (Units) of Fuel Burned	4930048	13549	0	2621288	79859	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9141	138000	0	9894	1048	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	47.977	78.900	0.000	39.576	6.625	0.000
41	Average Cost of Fuel per Unit Burned	52.385	78.900	0.000	39.872	6.625	0.000
42	Average Cost of Fuel Burned per Million BTU	2.850	13.613	2.859	2.015	6.323	2.022
43	Average Cost of Fuel Burned per KWh Net Gen	0.030	0.000	0.030	0.022	0.000	0.022
44	Average BTU per KWh Net Generation	10357.635	8.975	10366.610	10942.185	17.652	10959.837

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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: Wyodak (d)	Plant Name: Gadsby Steam (e)	Plant Name: Hermiston (f)	Line No.
Steam	Steam	Combined Cycle	1
Conventional	Outdoor	Outdoor	2
1978	1951	1996	3
1978	1955	1996	4
289.66	251.64	279.56	5
278	169	242	6
8301	664	6262	7
0	0	0	8
266	238	231	9
0	0	0	10
61	34	0	11
2022498000	28654000	1061583000	12
210526	1252090	842245	13
52154886	15117499	12843042	14
409007707	67795183	165061575	15
652977	1132809	407646	16
462026096	85297581	179154508	17
1595.0635	338.9667	640.8446	18
26487	32666	0	19
29859036	2396390	22408041	20
0	0	0	21
3791275	53650	0	22
0	0	0	23
0	0	0	24
-127650	0	5918655	25
2762651	3227923	0	26
13012	0	0	27
0	0	0	28
0	0	0	29
348031	160037	0	30
3955726	1412255	0	31
1018739	781417	0	32
152505	122608	0	33
41799812	8186946	28326696	34
0.0207	0.2857	0.0267	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Coal	Oil	Composite	Gas			Gas			36
Tons	Barrels		MCF			MCF			37
1563948	2557	0	606775	0	0	7867878	0	0	38
7978	138000	0	1045	0	0	1073	0	0	39
18.821	73.222	0.000	3.950	0.000	0.000	2.848	0.000	0.000	40
18.972	73.222	0.000	3.950	0.000	0.000	2.848	0.000	0.000	41
1.189	12.633	1.196	3.781	0.000	0.000	2.655	0.000	0.000	42
0.015	0.000	0.015	0.084	0.000	0.000	0.021	0.000	0.000	43
12337.637	7.327	12344.964	22117.994	0.000	0.000	7951.021	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: Blundell (b)			Plant Name: Chehalis (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam - Geothermal			Combined Cycle		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Indoor			Outdoor		
3	Year Originally Constructed	1984			2003		
4	Year Last Unit was Installed	2007			2003		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	38.10			593.30		
6	Net Peak Demand on Plant - MW (60 minutes)	35			508		
7	Plant Hours Connected to Load	8649			6243		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	32			477		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	22			18		
12	Net Generation, Exclusive of Plant Use - KWh	249033000			1758799000		
13	Cost of Plant: Land and Land Rights	41195596			3730527		
14	Structures and Improvements	8295869			24444973		
15	Equipment Costs	101773015			328350671		
16	Asset Retirement Costs	2391759			1030777		
17	Total Cost	153656239			357556948		
18	Cost per KW of Installed Capacity (line 17/5) Including	4032.9722			602.6579		
19	Production Expenses: Oper, Supv, & Engr	17354			143762		
20	Fuel	0			52097506		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	984550			0		
23	Steam From Other Sources	4677095			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			2021641		
26	Misc Steam (or Nuclear) Power Expenses	924734			676520		
27	Rents	8453			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	377114			42487		
31	Maintenance of Boiler (or reactor) Plant	262380			0		
32	Maintenance of Electric Plant	232221			2092496		
33	Maintenance of Misc Steam (or Nuclear) Plant	77804			0		
34	Total Production Expenses	7561705			57074412		
35	Expenses per Net KWh	0.0304			0.0325		
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	0	0	0	12249130	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	1094	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	4.253	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	4.253	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	3.887	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.030	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	7619.868	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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Plant Name: Gadsby Peakers (d)			Plant Name: Currant Creek (e)			Plant Name: Lake Side (f)			Line No.
Gas Turbine			Combined Cycle			Combined Cycle			1
Outdoor			Outdoor			Outdoor			2
2002			2005			2007			3
2002			2006			2007			4
181.05			566.90			591.30			5
120			517			534			6
1681			4928			4445			7
0			0			0			8
119			524			546			9
0			0			0			10
0			20			34			11
64160000			1193242000			1274053000			12
0			3403277			14532275			13
4273000			44179933			35496949			14
78567993			307026081			338261516			15
0			134848			0			16
82840993			354744139			388290740			17
457.5586			625.7614			656.6730			18
0			73480			58506			19
4456699			36667238			37855465			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
1024438			1878281			1999409			25
0			654236			555136			26
0			0			0			27
0			0			0			28
0			0			0			29
115269			345032			1151749			30
0			0			0			31
453332			1009880			482858			32
173016			22259			20061			33
6222754			40650406			42123184			34
0.0970			0.0341			0.0331			35
Gas			Gas			Gas			36
MCF			MCF			MCF			37
822711	0	0	8982278	0	0	9079239	0	0	38
1044	0	0	1038	0	0	1039	0	0	39
5.417	0.000	0.000	4.082	0.000	0.000	4.169	0.000	0.000	40
5.417	0.000	0.000	4.082	0.000	0.000	4.169	0.000	0.000	41
5.188	0.000	0.000	3.932	0.000	0.000	4.014	0.000	0.000	42
0.069	0.000	0.000	0.031	0.000	0.000	0.030	0.000	0.000	43
13387.936	0.000	0.000	7815.703	0.000	0.000	7402.135	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: Lake Side 2 (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combined Cycle					
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor					
3	Year Originally Constructed	2014					
4	Year Last Unit was Installed	2014					
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	655.20			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	612			0		
7	Plant Hours Connected to Load	6816			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	631			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	2066508000			0		
13	Cost of Plant: Land and Land Rights	16794626			0		
14	Structures and Improvements	53122743			0		
15	Equipment Costs	567951670			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	637869039			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	973.5486			0		
19	Production Expenses: Oper, Supv, & Engr	67614			0		
20	Fuel	60569093			0		
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	3084754			0		
26	Misc Steam (or Nuclear) Power Expenses	643908			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	1063129			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	429084			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	21803			0		
34	Total Production Expenses	65879385			0		
35	Expenses per Net KWh	0.0319			0.0000		
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	15135146	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1038	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.002	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.002	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.854	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.029	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	7604.104	0.000	0.000	0.000	0.000	0.000

Schedule Page: 402 Line No.: -1 Column: b

The Cholla Plant is operated by Arizona Public Service Company and is jointly owned. PacifiCorp owns 100% of Unit No. 4 and 49.53% of common facilities. Data reported on page 402 represents PacifiCorp's share.

Schedule Page: 402 Line No.: -1 Column: c

The Colstrip Plant is operated by Talen Montana, LLC and is jointly owned. PacifiCorp owns a 10.0% share of Colstrip Plant Unit Nos. 3 and 4. Data reported on page 402 represents PacifiCorp's share.

Schedule Page: 403 Line No.: -1 Column: d

The Craig Plant is operated by Tri-State Generation and Transmission Association, Inc. 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 reported on page 403, represents PacifiCorp's share.

Schedule Page: 403 Line No.: -1 Column: f

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 on page 403 represents PacifiCorp's share.

Schedule Page: 402 Line No.: 11 Column: b

PacifiCorp does not have employees at the Cholla Plant.

Schedule Page: 402 Line No.: 11 Column: c

PacifiCorp does not have employees at the Colstrip Plant.

Schedule Page: 403 Line No.: 11 Column: d

PacifiCorp does not have employees at the Craig Plant.

Schedule Page: 403 Line No.: 11 Column: f

PacifiCorp does not have employees at the Hayden Plant.

Schedule Page: 403 Line No.: 20 Column: d

Amount includes intercompany profits.

Schedule Page: 402.1 Line No.: -1 Column: b

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 on page 402.1 represents PacifiCorp's share. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this unit for calendar year 2017 were $1.4 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 402.1 Line No.: -1 Column: c

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 on page 402.1 represents PacifiCorp's share. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this unit for calendar year 2017 were $7.3 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 403.1 Line No.: -1 Column: e

Refer to plant statistics for each Hunter Unit Nos. 1, 2 and 3 on page 402.1 and 403.1.

Schedule Page: 402.1 Line No.: 11 Column: b

Refer to Hunter - Total Plant on page 403.1 for the average number of employees.

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: 402.2 Line No.: -1 Column: b

The Jim Bridger Plant is operated by PacifiCorp and is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 66.67% and 33.33%, respectively. Data reported on page 402.2 represents PacifiCorp's share. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this plant for calendar year

2017 were $28.3 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 402.2 Line No.: -1 Column: c

As a result of state permits, the state of Wyoming approved the Naughton Unit No. 3 (280 MW) to operate using coal-fuel generation until no later than January 30, 2019, at which point the unit would be closed or converted to natural gas fuel generation.

Schedule Page: 403.2 Line No.: -1 Column: d

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 reported on page 403.2 represents PacifiCorp's share. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this plant for calendar year 2017 were $3.9 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 403.2 Line No.: -1 Column: f

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 on page 403.2 represents PacifiCorp's share.

Schedule Page: 403.2 Line No.: 11 Column: f

PacifiCorp does not have employees at the Hermiston Plant.

Schedule Page: 402.2 Line No.: 20 Column: b

Amount includes intercompany profits.

Schedule Page: 402.3 Line No.: -1 Column: b

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.: 11 Column: d

Refer to the Gadsby Steam Plant on page 403.2 for the average number of employees.

Schedule Page: 402.4 Line No.: 11 Column: b

Refer to the Lake Side Plant on page 403.3 for the average number of employees.

Schedule Page: 402 Line No.: 36 Column: b2

Cholla - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: c2

Colstrip - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: d2

Craig - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: e2

Dave Johnston - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: f2

Hayden - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: b2

Hunter Unit No. 1 - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: c2

Hunter Unit No. 2 - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: d2

Hunter Unit No. 3 - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: e2

Hunter - Total Plant - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: f2

Huntington - Fuel oil is used for start-up purposes.

Schedule Page: 402.2 Line No.: 36 Column: b2

Jim Bridger - Fuel oil is used for start-up purposes.

Schedule Page: 402.2 Line No.: 36 Column: c2

Naughton - Natural gas is used for start-up purposes.

Schedule Page: 402.2 Line No.: 36 Column: d2

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 2017/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)	28	33
7	Plant Hours Connect to Load	5,707	6,218
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	107,722,000	138,290,000
13	Cost of Plant		
14	Land and Land Rights	107,019	20,914
15	Structures and Improvements	1,714,476	2,413,814
16	Reservoirs, Dams, and Waterways	2,948,598	2,954,724
17	Equipment Costs	5,356,751	10,478,625
18	Roads, Railroads, and Bridges	133,348	479,588
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	10,260,192	16,347,665
21	Cost per KW of Installed Capacity (line 20 / 5)	513.0096	605.4691
22	Production Expenses		
23	Operation Supervision and Engineering	18,117	24,833
24	Water for Power	0	0
25	Hydraulic Expenses	5,286	7,136
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	891,023	1,084,055
28	Rents	81,669	110,253
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	455	16,537
31	Maintenance of Reservoirs, Dams, and Waterways	39,049	34,615
32	Maintenance of Electric Plant	148,222	59,257
33	Maintenance of Misc Hydraulic Plant	18,660	27,474
34	Total Production Expenses (total 23 thru 33)	1,202,481	1,364,160
35	Expenses per net KWh	0.0112	0.0099

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 1927 Plant Name: Clearwater No. 1 (d)	FERC Licensed Project No. 1927 Plant Name: Clearwater No. 2 (e)	FERC Licensed Project No. 2420 Plant Name: Cutler (f)	Line No.
Run-of-River	Run-of-River	Storage	1
Outdoor	Outdoor	Conventional	2
1953	1953	1927	3
1953	1953	1927	4
15.00	26.00	30.00	5
12	20	30	6
7,698	8,171	8,353	7
			8
18	31	29	9
18	31	29	10
1	1	3	11
49,392,000	67,719,000	147,609,000	12
			13
0	0	3,511,105	14
1,504,709	2,504,227	4,006,226	15
5,184,972	14,779,679	10,610,438	16
1,407,702	2,202,026	14,698,730	17
50,817	250,151	570,519	18
0	0	0	19
8,148,200	19,736,083	33,397,018	20
543.2133	759.0801	1,113.2339	21
			22
17,976	39,723	120,721	23
510	884	0	24
37,083	64,277	107,672	25
0	0	0	26
252,581	440,824	1,250,710	27
58,385	101,201	45,766	28
0	0	0	29
30,652	57,681	3,203	30
5,376	9,046	12,593	31
105,472	48,052	16,582	32
46,041	79,804	341,873	33
554,076	841,492	1,899,120	34
0.0112	0.0124	0.0129	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 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 1927 Plant Name: Fish Creek (b)	FERC Licensed Project No. 20 Plant Name: Grace (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1952	1908
4	Year Last Unit was Installed	1952	1923
5	Total installed cap (Gen name plate Rating in MW)	11.00	33.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	10	29
7	Plant Hours Connect to Load	5,151	8,379
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	10	33
10	(b) Under the Most Adverse Oper Conditions	10	33
11	Average Number of Employees	1	3
12	Net Generation, Exclusive of Plant Use - Kwh	42,304,000	162,133,000
13	Cost of Plant		
14	Land and Land Rights	0	62,169
15	Structures and Improvements	1,764,228	2,499,425
16	Reservoirs, Dams, and Waterways	12,453,140	11,545,637
17	Equipment Costs	2,989,616	5,115,930
18	Roads, Railroads, and Bridges	533,015	415,291
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	17,739,999	19,638,452
21	Cost per KW of Installed Capacity (line 20 / 5)	1,612.7272	595.1046
22	Production Expenses		
23	Operation Supervision and Engineering	14,109	140,040
24	Water for Power	374	0
25	Hydraulic Expenses	27,194	37,208
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	280,680	1,385,201
28	Rents	42,816	28,203
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	23,896	25,355
31	Maintenance of Reservoirs, Dams, and Waterways	68,681	104,661
32	Maintenance of Electric Plant	18,850	47,047
33	Maintenance of Misc Hydraulic Plant	33,763	85,155
34	Total Production Expenses (total 23 thru 33)	510,363	1,852,870
35	Expenses per net KWh	0.0121	0.0114

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	85	31	6
8,375	6,767	8,199	7
			8
19	83	32	9
19	83	32	10
1	2	1	11
108,851,000	318,732,000	174,923,000	12
			13
341,617	25,845	0	14
7,918,010	3,674,365	2,934,578	15
15,439,589	15,705,505	15,809,631	16
3,159,410	15,374,678	6,717,856	17
1,095,742	883,836	488,877	18
0	0	0	19
27,954,368	35,664,229	25,950,942	20
1,553.0204	363.9950	811.2204	21
			22
1,410,092	404,012	37,970	23
0	0	1,088	24
4,758	8,021	79,086	25
0	0	0	26
819,672	731,479	560,955	27
73,502	38,978	124,517	28
0	0	0	29
168	22,773	65,483	30
35,000	106,514	9,257	31
122,755	63,986	13,052	32
16,794	35,479	98,190	33
2,482,741	1,411,242	989,598	34
0.0228	0.0044	0.0057	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 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 1927 Plant Name: Lemolo No. 2 (b)	FERC Licensed Project No. 935 Plant Name: Merwin (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage (Re-Reg)
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1956	1931
4	Year Last Unit was Installed	1956	1958
5	Total installed cap (Gen name plate Rating in MW)	38.50	136.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	34	149
7	Plant Hours Connect to Load	8,744	8,759
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	39	151
10	(b) Under the Most Adverse Oper Conditions	39	151
11	Average Number of Employees	1	1
12	Net Generation, Exclusive of Plant Use - Kwh	200,914,000	629,623,000
13	Cost of Plant		
14	Land and Land Rights	0	1,714,182
15	Structures and Improvements	6,295,884	110,019,724
16	Reservoirs, Dams, and Waterways	32,429,013	30,126,635
17	Equipment Costs	11,839,754	18,453,424
18	Roads, Railroads, and Bridges	1,820,580	4,075,878
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	52,385,231	164,389,843
21	Cost per KW of Installed Capacity (line 20 / 5)	1,360.6554	1,208.7488
22	Production Expenses		
23	Operation Supervision and Engineering	45,697	1,396,281
24	Water for Power	1,310	13,544
25	Hydraulic Expenses	95,180	731,151
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	537,719	557,639
28	Rents	149,856	150,463
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	81,106	21,119
31	Maintenance of Reservoirs, Dams, and Waterways	16,822	132,688
32	Maintenance of Electric Plant	7,959	236,130
33	Maintenance of Misc Hydraulic Plant	126,622	382,863
34	Total Production Expenses (total 23 thru 33)	1,062,271	3,621,878
35	Expenses per net KWh	0.0053	0.0058

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 1927 Plant Name: Toketee (d)	FERC Licensed Project No. 20 Plant Name: Oneida (e)	FERC Licensed Project No. 2630 Plant Name: Prospect No. 2 (f)	Line No.
Storage	Storage	Run-of-River	1
Conventional	Conventional	Conventional	2
1949	1915	1928	3
1950	1920	1928	4
42.50	30.00	32.00	5
44	22	36	6
8,203	8,760	8,363	7
			8
45	28	36	9
45	28	36	10
1	2	1	11
255,226,000	94,117,000	256,205,000	12
			13
0	283,870	105,168	14
4,242,910	2,266,749	3,871,989	15
12,834,762	8,438,236	34,596,701	16
5,554,799	9,835,782	7,064,649	17
488,933	584,173	325,100	18
0	0	0	19
23,121,404	21,408,810	45,963,607	20
544.0330	713.6270	1,436.3627	21
			22
52,263	116,634	235,489	23
1,446	0	9,453	24
105,071	33,825	2,620	25
0	0	0	26
613,830	578,092	697,684	27
165,699	24,879	65,627	28
0	0	266	29
93,170	458	49,004	30
10,043	4,176	94,337	31
189,699	80,138	176,641	32
130,452	95,982	245,596	33
1,361,673	934,184	1,576,717	34
0.0053	0.0099	0.0062	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 2017/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	14.45
6	Net Peak Demand on Plant-Megawatts (60 minutes)	17	13
7	Plant Hours Connect to Load	7,720	8,743
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	79,047,000	33,872,000
13	Cost of Plant		
14	Land and Land Rights	0	511,083
15	Structures and Improvements	2,207,793	750,045
16	Reservoirs, Dams, and Waterways	14,878,343	11,069,631
17	Equipment Costs	8,967,240	5,421,503
18	Roads, Railroads, and Bridges	599,269	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	26,652,645	17,752,262
21	Cost per KW of Installed Capacity (line 20 / 5)	1,480.7025	1,228.5302
22	Production Expenses		
23	Operation Supervision and Engineering	21,698	51,484
24	Water for Power	50,038	0
25	Hydraulic Expenses	44,500	15,785
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	274,297	328,935
28	Rents	70,063	11,690
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	37,130	2,730
31	Maintenance of Reservoirs, Dams, and Waterways	11,904	8,288
32	Maintenance of Electric Plant	72,534	56,340
33	Maintenance of Misc Hydraulic Plant	57,181	20,188
34	Total Production Expenses (total 23 thru 33)	639,345	495,440
35	Expenses per net KWh	0.0081	0.0146

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	255	166	6
7,184	6,736	7,116	7
			8
12	264	164	9
12	264	164	10
2	1	1	11
60,374,000	866,809,000	726,025,000	12
			13
0	17,910,160	8,363,013	14
4,314,742	72,656,734	17,506,231	15
89,746,004	47,489,944	32,833,984	16
2,634,437	24,733,104	16,919,245	17
2,089,012	1,133,091	2,033,298	18
0	0	0	19
98,784,195	163,923,033	77,655,771	20
8,980.3814	683.0126	579.5207	21
			22
13,056	2,377,457	1,376,535	23
374	23,901	13,345	24
103,639	1,573,432	720,398	25
0	0	0	26
430,626	260,645	447,516	27
42,816	265,523	148,251	28
0	0	0	29
24,857	34,035	25,927	30
91,726	171,734	427,346	31
90,640	164,173	238,183	32
33,763	640,118	368,488	33
831,497	5,511,018	3,765,989	34
0.0138	0.0064	0.0052	35

Schedule Page: 406 Line No.: -2 Column: b

In FERC Order No. P-14803-000 (issued March 15, 2018), articles pertaining to this hydroelectric plant were transferred from the Klamath (FERC License) Project No. 2082 to a new license for the Lower Klamath Project No. 14803. For further discussion, refer to Note 13 of Notes to Financial Statements, in this Form No. 1.

Schedule Page: 406 Line No.: -2 Column: c

In FERC Order No. P-14803-000 (issued March 15, 2018), articles pertaining to this hydroelectric plant were transferred from the Klamath (FERC License) Project No. 2082 to a new license for the Lower Klamath Project No. 14803. For further discussion, refer to Note 13 of Notes to Financial Statements, in this Form No. 1.

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.: -2 Column: d

In FERC Order No. P-14803-000 (issued March 15, 2018), articles pertaining to this hydroelectric plant were transferred from the Klamath (FERC License) Project No. 2082 to a new license for the Lower Klamath Project No. 14803. For further discussion, refer to Note 13 of Notes to Financial Statements, in this Form No. 1.

Schedule Page: 406.1 Line No.: -2 Column: e

In FERC Order No. P-14803-000 (issued March 15, 2018), articles pertaining to this hydroelectric plant were transferred from the Klamath (FERC License) Project No. 2082 to a new license for the Lower Klamath Project No. 14803. For further discussion, refer to Note 13 of Notes to Financial Statements, in this Form No. 1.

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	7.0	36,863,000	33,886,067
3	Bend		1913	1.11	1.0	2,295,000	2,037,208
4	Big Fork	2652	1910	4.15	4.6	21,447,000	8,124,876
5	Eagle Point		1957	2.81	2.8	18,371,000	1,947,821
6	East Side	2082	1924	3.20			1,991,695
7	Fall Creek	2082	1903	2.20	2.0	7,872,000	1,499,917
8	Granite		1896	2.00	1.3	7,476,000	5,238,307
9	Gunlock		1917	0.75	0.5	1,844,000	683,045
10	Last Chance		1983	1.73	1.2	3,725,000	2,924,738
11	Paris		1910	0.72	0.7	3,353,000	449,027
12	Pioneer	2722	1897	5.00	4.0	27,134,000	11,441,521
13	Prospect No. 1	2630	1912	3.76	4.6	21,106,000	5,334,832
14	Prospect No. 3	2337	1932	7.20	7.7	40,779,000	9,006,356
15	Prospect No. 4	2630	1944	1.00	0.9	4,599,000	2,409,792
16	Sand Cove		1926	0.80	0.4	1,530,000	939,208
17	Stairs	597	1895	1.00	1.2	5,643,000	1,933,999
18	Veyo		1920	0.50	0.2	257,000	897,832
19	Viva Naughton		1986	0.74	0.2	449,000	1,232,115
20	Wallowa Falls	308	1921	1.10	1.0	4,642,000	3,283,227
21	Weber	1744	1911	3.85	0.5	-68,000	3,632,216
22	West Side	2082	1908	0.60		-15,000	468,574
23	Keno Regulating Dam	2082					7,580,092
24	Upper Klamath Lake	2082					3,847,587
25	North Umpqua	1927					16,370,792
26							
27	Pumping Plant:						
28	Lifton		1917	-2.80	-2.0	-1,027,000	19,493,077
29							
30	Wind:						
31	Dunlap Ranch 1		2010	111.00	111.0	351,261,000	241,040,848
32	Foote Creek		1999	32.15	30.6	99,705,000	38,495,327
33	Glenrock		2008	99.00	99.0	268,269,000	203,042,484
34	Glenrock III		2009	39.00	39.0	99,455,000	88,385,577
35	Rolling Hills		2009	99.00	99.0	237,002,000	204,878,175
36	Goodnoe Hills		2008	94.00	94.0	191,917,000	185,160,600
37	Leaning Juniper 1		2006	100.00	99.0	155,685,000	178,836,133
38	Marengo		2007	140.40	135.0	315,543,000	242,067,319
39	Marengo II		2008	70.20	69.0	153,361,000	129,984,956
40	Seven Mile Hill		2008	99.00	99.0	334,363,000	201,990,458
41	Seven Mile Hill II		2008	19.50	19.5	66,294,000	42,717,449
42	High Plains		2009	99.00	99.0	279,904,000	220,137,775
43	McFadden Ridge I		2009	28.50	29.0	84,559,000	57,070,216
44							
45	Solar:						
46	Black Cap		2012	2.00	2.0	3,966,000	74,986

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
5,057,622	447,662		164,954	Water		2
1,835,323	54,490		11,295	Water		3
1,957,801	380,491		122,055	Water		4
693,175	257,819		91,527	Water		5
622,405	43,314		1,477	Water		6
681,780	102,365		90,437	Water		7
2,619,154	214,434		13,931	Water		8
910,727	36,806		50,041	Water		9
1,690,600	158,087		104,746	Water		10
623,649	76,151		21,504	Water		11
2,288,304	413,206		82,811	Water		12
1,418,838	137,719		185,624	Water		13
1,250,883	271,512		207,984	Water		14
2,409,792	49,598		32,149	Water		15
1,174,010	68,317		64,359	Water		16
1,933,999	222,518		11,120	Water		17
1,795,664	36,794		271,755	Water		18
1,665,020	221,186		18,639	Water		19
2,984,752	223,556		8,856	Water		20
943,433	331,838		13,294	Water		21
780,957	23,855		277	Water		22
	18,506		5,176			23
	251,579		54,239			24
						25
						26
						27
-6,961,813	231,596		68,118	Water		28
						29
						30
2,171,539	250,491		1,161,511	Wind		31
1,197,366	354,990		1,346,158	Wind		32
2,050,934	251,066		1,766,746	Wind		33
2,266,297	106,976		276,186	Wind		34
2,069,477	258,774		701,088	Wind		35
1,969,794	583,637		1,434,305	Wind		36
1,788,361	681,378		1,052,495	Wind		37
1,724,126	1,287,708		1,250,854	Wind		38
1,851,638	729,314		625,427	Wind		39
2,040,308	453,157		1,163,971	Wind		40
2,190,638	95,241		235,146	Wind		41
2,223,614	978,930		1,258,163	Wind		42
2,002,464	275,085		368,972	Wind		43
						44
						45
37,493	314,920			Solar		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.: 6 Column: a

The East Side plant was significantly curtailed pursuant to Section 6.2 of the Klamath Hydroelectric Settlement Agreement in FERC Docket No. P-2082-000.

Schedule Page: 410 Line No.: 22 Column: a

The West Side plant generation supplies station use and was significantly curtailed pursuant to Section 6.2 of the Klamath Hydroelectric Settlement Agreement in FERC Docket No. P-2082-000.

Schedule Page: 410 Line No.: 23 Column: a

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.: 24 Column: a

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.: 25 Column: a

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.: 28 Column: a

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.: 30 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.: 32 Column: a

The Foote Creek wind-powered generating facility is operated by PacifiCorp and is jointly owned by PacifiCorp and Eugene Water and Electric Board with an undivided interest of 78.79% and 21.21%, respectively. Data reported in line 32 represents PacifiCorp's share.

Schedule Page: 410 Line No.: 46 Column: a

PacifiCorp has an agreement with Citizens 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 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	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								
2	ALVEY, OR	DIXONVILLE 500kV, OR	500.00	500.00	Steel Tower	58.00		1
3	CAPTAIN JACK, OR	MALIN, OR	500.00	500.00	Steel Tower	7.00		1
4	DIXONVILLE, OR	MERIDIAN, OR	500.00	500.00	Steel Tower	74.00		1
5	KLAMATH CO-GEN, OR	CAPTAIN JACK, OR	500.00	500.00	Steel Tower	27.00		1
6	MALIN, OR	PG&E ROUND MTN, CA	500.00	500.00	Steel Tower	47.00		1
7	MERIDIAN, OR	KLAMATH CO-GEN, OR	500.00	500.00	Steel Tower	58.00		1
8	MIDPOINT, ID	MALIN, OR	500.00	500.00	Steel Tower	447.00		1
9	COLSTRIP 4, MT	SWITCHYARD, MT	500.00	500.00	Steel Tower	1.00		1
10	COLSTRIP, MT	BROADVIEW A, MT	500.00	500.00	Steel Tower	113.00		1
11	COLSTRIP, MT	BROADVIEW B, MT	500.00	500.00	Steel Tower	116.00		1
12	BROADVIEW, MT	TOWNSEND A, MT	500.00	500.00	Steel Tower	133.00		1
13	BROADVIEW, MT	TOWNSEND B, MT	500.00	500.00	Steel Tower	133.00		1
14	500kV costs and expenses							
15								
16	Subtotal 500kV					1,214.00		12
17								
18	90TH SOUTH, UT	CAMP WILLIAMS #3, UT	345.00	345.00	Steel - SP	11.00		1
19	90TH SOUTH, UT	CAMP WILLIAMS #4, UT	345.00	345.00			11.00	1
20	90TH SOUTH, UT	CAMP WILLIAMS #1, UT	345.00	345.00	Steel - SP	11.00		1
21	90TH SOUTH, UT	TERMINAL, UT	345.00	345.00			16.00	1
22	BEN LOMOND, UT	POPULUS #1, ID	345.00	345.00			82.00	1
23	BEN LOMOND, UT	POPULUS #2, ID	345.00	345.00	Steel - SP	86.00		1
24	BEN LOMOND, UT	CAMP WILLIAMS, UT	345.00	345.00	Steel - SP	69.00		1
25	BEN LOMOND, UT	TERMINAL #2, UT	345.00	345.00		47.00		1
26	BEN LOMOND, UT	TERMINAL #1, UT	345.00	345.00	Steel - SP		47.00	1
27	BORAH, ID	MIDPOINT #1, ID	345.00	345.00	Wood - H	83.00		1
28	BORAH, ID	MIDPOINT #2, ID	345.00	345.00	Wood - H	78.00		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	CLOVER, UT	OQUIRRH, UT	345.00	345.00	Steel Tower	100.00		1
34	CURRANT CREEK, UT	MONA, UT	345.00	345.00	Steel - SP	1.00		1
35	EMERY, UT	CAMP WILLIAMS, UT	345.00	345.00	Steel Tower	121.00		1
36					TOTAL	16,943.00	651.00	285

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 2017/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)	
								1
3-2250 AAC /91								2
3-1272 ACSR 36/1								3
3-1272 ACSR 36/1								4
3-1272 ACSR 54/19								5
3-1852 ACSR 51/27								6
3-1272 ACSR 54/19								7
3-1272 ACSR 36/1								8
795 KCM ACSR								9
795 ACSR 26/7								10
795 ACSR 26/7								11
795 ACSR 26/7								12
795 ACSR 26/7								13
	13,339,699	233,498,875	246,838,574	2,466	1,395,986	299,367	1,697,819	14
								15
	13,339,699	233,498,875	246,838,574	2,466	1,395,986	299,367	1,697,819	16
								17
								18
								19
1272 ACSR 45/7								20
1272 ACSR 45/7								21
1272 ACSR 45/7								22
1272 ACSR 45/7								23
1272 ACSR 45/7								24
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
1949 ACSR 45/7								33
954 ACSR 54/7								34
1272 ACSR 45/7								35
	240,598,562	3,482,303,031	3,722,901,593	505,147	16,871,564	2,161,509	19,538,220	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 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	EMERY, UT	HUNTINGTON, UT	345.00	345.00	Wood - H	20.00		1
2	EMERY, UT	SIGURD #1, UT	345.00	345.00	Steel - H	74.00		1
3	EMERY, UT	SIGURD #2, UT	345.00	345.00	Steel - H	75.00		1
4	FOUR CORNERS, NM	PINTO, UT	345.00	345.00	Wood - H	101.00		1
5	GOSHEN, ID	KINPORT, ID	345.00	345.00	Wood - H	41.00		1
6	HUNTINGTON, UT	HUNT PLANT 1, UT	345.00	345.00	Steel Tower	1.00		1
7	HUNTINGTON, UT	HUNT PLANT 2, UT	345.00	345.00	Steel Tower	1.00		1
8	HUNTINGTON, UT	PINTO, UT	345.00	345.00	Steel - SP	158.00		1
9	HUNTINGTON, UT	SPANISH FORK, UT	345.00	345.00	Steel Tower	78.00		1
10	JIM BRIDGER, WY	GOSHEN, ID	345.00	345.00	Steel Tower	226.00		1
11	JIM BRIDGER, WY	BORAH, ID	345.00	345.00	Steel Tower	240.00		1
12	JIM BRIDGER, WY	KINPORT, ID	345.00	345.00	Steel - SP	234.00		1
13	KINPORT, ID	MIDPOINT, ID	345.00	345.00	Steel - SP	113.00		1
14	MONA, UT	SIGURD #1, UT	345.00	345.00	Wood - H	69.00		1
15	MONA, UT	SIGURD #2, UT	345.00	345.00	Steel - SP		69.00	1
16	MONA, UT	HUNTINGTON, UT	345.00	345.00	Steel - SP	60.00		1
17	RED BUTTE, UT	SIGURD, UT	345.00	345.00	Steel - H	170.00		1
18	SIGURD, UT	UT/NV STATE LINE	345.00	345.00	Steel Tower	190.00		1
19	SPANISH FORK, UT	CAMP WILLIAMS, UT	345.00	345.00			35.00	1
20	TERMINAL, UT	BORAH, ID	345.00	345.00	Wood - H	138.00		1
21	TERMINAL, UT	BORAH, ID	345.00	345.00	Steel - SP		47.00	1
22	TERMINAL, UT	CAMP WILLIAMS #2, UT	345.00	345.00	Steel - SP	16.00	10.00	1
23	TERMINAL, UT	CAMP WILLIAMS, UT	345.00	345.00			23.00	1
24	345kV costs and expenses							
25								
26	Subtotal 345kV					2,758.00	382.00	41
27								
28	ALVEY, OR	DIXONVILLE, OR	230.00	230.00	Wood - H	59.00		1
29	ANTELOPE, ID	ANACONDA, MT	230.00	230.00	Wood - H	76.00		1
30	ANTELOPE, ID	LOST RIVER, ID	230.00	230.00	Wood - H	20.00		1
31	ARROWHEAD, WY	FIREHOLE, WY	230.00	230.00	Wood - H	9.00		1
32	ATLANTIC CITY, WY	COLUMBIA GENEVA, WY	230.00	230.00	Wood - H	1.00		1
33	BEN LOMOND, UT	NAUGHTON #1, WY	230.00	230.00	Wood - H	88.00		1
34	BEN LOMOND, UT	NAUGHTON #2, WY	230.00	230.00	Wood - H	88.00		1
35	BIRCH CREEK, UT	RAILROAD, WY	230.00	230.00	Wood - H	19.00		1
36					TOTAL	16,943.00	651.00	285

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)	
954 ACSR 45/7								1
954 ACSR 45/7								2
954 ACSR 54/7								3
795 ACSR 45/7								4
795 ACSR 26/7								5
2156 ACSR 8419								6
2156 ACSR 8419								7
795 ACSR 45/7								8
1272 ACSR 45/7								9
1272 ACSR 36/1								10
1272 ACSR 36/1								11
1272 ACSR 36/1								12
1272 ACSR 45/7								13
795 ACSR 45/7								14
954 ACSR 45/7								15
954 ACSR 54/7								16
2-954 ACSR 45/7								17
954 ACSR 54/7								18
1272 ACSR 45/7								19
2-954 ACSR 45/7								20
2-1272 ACSR 45/7								21
1272 ACSR 45/7								22
1272 ACSR 45/7								23
	152,630,901	1,661,158,141	1,813,789,042	42,067	2,062,367	524,766	2,629,200	24
								25
	152,630,901	1,661,158,141	1,813,789,042	42,067	2,062,367	524,766	2,629,200	26
								27
1272 ACSR 36/1								28
1272 ACSR 45/7								29
795 ACSR 45/7								30
795 ACSR 26/7								31
1272 ACSR 36/1								32
795 ACSR 26/7								33
795 ACSR 26/7								34
954 ACSR 54/7								35
	240,598,562	3,482,303,031	3,722,901,593	505,147	16,871,564	2,161,509	19,538,220	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 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	BITTER CREEK, WY	MONELL, WY	230.00	230.00	Wood - H	3.00		1
2	BRIDGER PUMP, WY	MANS FACE, WY	230.00	230.00	Wood - H	1.00		1
3	BUFFALO, WY	CASPER, WY	230.00	230.00	Wood - H	107.00		1
4	CASPER, WY	DAVE JOHNSTON, WY	230.00	230.00	Wood - H	36.00		1
5	CASPER, WY	RIVERTON, WY	230.00	230.00	Wood - H	110.00		1
6	CHAPPEL CREEK, WY	CRAVEN CREEK, WY	230.00	230.00	Steel - SP	30.00		1
7	CHAPPEL CREEK, WY	JONAH GAS, WY	230.00	230.00	Wood - H	32.00		1
8	CHAPPEL CREEK, WY	RILEY RIDGE, WY	230.00	230.00	Wood - H	29.00	6.00	1
9	CRAVEN CREEK, WY	PIONEER, WY	230.00	230.00	Wood - H	2.00		1
10	DAVE JOHNSTON, WY	SPENCE, WY	230.00	230.00	Wood - H	31.00		1
11	DAVE JOHNSTON, WY	WYODAK, WY	230.00	230.00	Wood - H	69.00		1
12	DIXONVILLE 500kV, OR	DIXONVILLE 230kV, OR	230.00	230.00	Wood - H	1.00		1
13	DIXONVILLE, OR	RESTON (BPA), OR	230.00	230.00	Wood - H	17.00		1
14	FAIRVIEW (BPA), OR	ISTHMUS, OR	230.00	230.00	Wood - H	12.00		1
15	FIREHOLE, WY	MONUMENT, WY	230.00	230.00	Wood - H	49.00		1
16	FRY, OR	BETHEL, OR	230.00	230.00	Wood - H	26.00		1
17	FRY, OR	ALVEY, OR	230.00	230.00	Wood - H	45.00		1
18	GLEN CANYON, AZ	SIGURD, UT	230.00	230.00	Wood - H	159.00		1
19	GONDER, UT - NV STATE	PAVANT, UT	230.00	230.00	Wood - H	98.00		1
20	DIXONVILLE, OR	GRANTS PASS, OR	230.00	230.00	Wood - H	62.00		1
21	HIGH PLAINS, WY	STANDPIPE, WY	230.00	230.00	Wood - H	38.00		1
22	HURRICANE, OR	WALLA WALLA, WA	230.00	230.00	Wood - H	78.00		1
23	JIM BRIDGER, WY	ROCK SPRINGS, WY	230.00	230.00	Wood - H	35.00		1
24	JIM BRIDGER, WY	SPENCE, WY	230.00	230.00	Wood - H	149.00		1
25	KLAMATH FALLS, OR	MALIN, OR	230.00	230.00	Wood - H	36.00		1
26	LIMA, WY	ROBERSON, WY	230.00	230.00	Wood - H	2.00		1
27	LONE PINE, OR	KLAMATH FALLS, OR	230.00	230.00	Wood - H	76.00		1
28	LONE PINE, OR	MERIDIAN #1, OR	230.00	230.00	Steel - SP	5.00		1
29	LONE PINE, OR	MERIDIAN #2, OR	230.00	230.00	Steel - SP	5.00		1
30	MCNARY (BPA), WA	WALLA WALLA, WA	230.00	230.00	Wood - H	56.00		1
31	MERIDIAN, OR	GRANTS PASS, OR	230.00	230.00	Wood - H	35.00		1
32	MONUMENT, WY	EXXON, WY	230.00	230.00	Wood - H	13.00		1
33	MONUMENT, WY	CRAVEN CREEK, WY	230.00	230.00	Wood - H	20.00		1
34	NAUGHTON, WY	TREASURETON, ID	230.00	230.00	Wood - H	80.00		1
35	NAUGHTON, WY	MONUMENT, WY	230.00	230.00	Wood - H	30.00		1
36					TOTAL	16,943.00	651.00	285

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
795 ACSR 26/7								1
1272 ACSR 36/1								2
1272 ACSR 36/1								3
								4
1272 ACSR 36/1								5
954 ACSR 54/7								6
1272 ACSR 45/7								7
1272 ACSR 45/7								8
1272 ACSR 45/7								9
1272 ACSR 45/7								10
1272 ACSR 36/1								11
1272 ACSR 36/1								12
795 ACSR 26/7								13
1272 ACSR 36/1								14
1272 ACSR 45/7								15
1272 ACSR 36/1								16
1272 ACSR 36/1								17
954 ACSR 45/7								18
795 ACSR 45/7								19
1272 ACSR 36/1								20
1272 ACSR 45/7								21
1272 ACSR 36/1								22
1272 ACSR 45/7								23
1272 ACSR 36/1								24
1272 ACSR 36/1								25
1272 ACSR 45/7								26
795 ACSR 26/7								27
1272 ACSR 54/19								28
1272 ACSR 36/1								29
1272 ACSR 36/1								30
1272 ACSR 36/1								31
1272 ACSR 36/1								32
1272 ACSR 45/7								33
1272 ACSR 45/7								34
1272 ACSR 36/1								35
	240,598,562	3,482,303,031	3,722,901,593	505,147	16,871,564	2,161,509	19,538,220	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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Line No.	DESIGNATION		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	NAUGHTON, WY	CRAVEN CREEK, WY	230.00	230.00	Wood - H	16.00		1
2	PALISADES SS, WY	BLUE RIM, WY	230.00	230.00	Wood - H	4.00		1
3	PAROWAN VALLEY, UT	SIGURD, UT	230.00	230.00	Wood - H	94.00		1
4	PAROWAN VALLEY, UT	WEST CEDAR, UT	230.00	230.00	Wood - H	26.00		1
5	PAVANT, UT	SIGURD, UT	230.00	230.00	Wood - H	43.00		1
6	POINT OF ROCKS, WY	DAVE JOHNSTON, WY	230.00	230.00	Wood - H	209.00		1
7	POMONA, WA	UNION GAP, WA	230.00	230.00	Wood - H	7.00		1
8	RIVERTON, WY	ROCK SPRINGS, WY	230.00	230.00	Wood - H	118.00		1
9	RIVERTON, WY	THERMOPOLIS, WY	230.00	230.00	Wood - H	51.00		1
10	ROCK SPRINGS, WY	FLAMING GORGE, UT	230.00	230.00	Wood - H	55.00		1
11	ROCK SPRINGS, WY	JIM BRIDGER, WY	230.00	230.00	Wood - H	35.00		1
12	ROCK SPRINGS, WY	MONUMENT, WY	230.00	230.00	Wood - H	41.00		1
13	SHERIDAN (MDU), WY	BUFFALO, WY	230.00	230.00	Wood - H	40.00		1
14	SHERIDAN (MDU), WY	YELLOWTAIL, MT	230.00	230.00	Wood - H	62.00		1
15	SHIRLEY BASIN, WY	DUNLAP RANCH, WY	230.00	230.00	Wood - H	12.00		1
16	SWIFT NO. 1, WA	SWIFT NO. 2, WA	230.00	230.00	Wood - H	2.00		1
17	SWIFT NO. 2, WA	WOODLAND (BPA) SS, WA	230.00	230.00	Wood - H	23.00		1
18	TALBOT, WA	MARENGO II, WA	230.00	230.00	Wood - H	7.00		1
19	TAP TO HANNA, OR	NICKEL MOUNTAIN, OR	230.00	230.00	Wood - H	9.00		1
20	THERMOPOLIS, WY	YELLOWTAIL, MT	230.00	230.00	Wood - H	176.00		1
21	TREASURETON, ID	BRADY, ID	230.00	230.00	Wood - H	66.00		1
22	TROUTDALE (BPA), OR	GRESHAM (PGE), OR	230.00	230.00	Steel Tower	6.00		1
23	TROUTDALE (BPA), OR	LINNEMAN (PGE), OR	230.00	230.00			7.00	1
24	UNION GAP, WA	MIDWAY (BPA), WA	230.00	230.00	Wood - H	39.00		1
25	WALLA WALLA, WA	LEWISTON (AVISTA), ID	230.00	230.00	Wood - H	45.00		1
26	WALLA WALLA, WA	WANAPUM (GPUD), WA	230.00	230.00	Wood - H	33.00		1
27	WANAPUM (GPUD), WA	POMONA, WA	230.00	230.00	Wood - H	37.00		1
28	WINDSTAR, WY	GLENROCK, WY	230.00	230.00	Wood - H	13.00		1
29	WYODAK, WY	BUFFALO, WY	230.00	230.00	Wood - H	69.00		1
30	YAMSAY (BPA), OR	KLAMATH FALLS, OR	230.00	230.00	Wood - H	63.00		1
31	230kV costs and expenses							
32								
33	Subtotal 230kV					3,338.00	13.00	73
34								
35	BIG GRASSY, ID	JEFFERSON, ID	161.00	161.00	Wood - H		21.00	1
36					TOTAL	16,943.00	651.00	285

TRANSMISSION LINE STATISTICS (Continued)

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1272 ACSR 36/1								6
1272 ACSR 36/1								7
1272 ACSR 36/1								8
1272 ACSR 36/1								9
1272 ACSR 36/1								10
1272 ACSR 36/1								11
1272 ACSR 36/1								12
795 ACSR 26/7								13
795 ACSR 26/7								14
795 ACSR 26/7								15
954 ACSR 45/7								16
954 ACSR 45/7								17
795 ACSR 26/7								18
795 ACSR 26/7								19
1272 ACSR 36/1								20
795 ACSR 26/7								21
954 ACSR 45/7								22
900 ACSR 54/7								23
954 ACSR 45/7								24
1272 ACSR 36/1								25
1272 ACSR 36/1								26
1272 ACSR 36/1								27
1272 ACSR 45/7								28
1272 ACSR 36/1								29
795 ACSR 26/7								30
	19,999,519	394,355,878	414,355,397	82,289	2,592,344	493,514	3,168,147	31
								32
	19,999,519	394,355,878	414,355,397	82,289	2,592,344	493,514	3,168,147	33
								34
250HH CU /7								35
	240,598,562	3,482,303,031	3,722,901,593	505,147	16,871,564	2,161,509	19,538,220	36

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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	ANTELOPE, ID	GOSHEN, ID	161.00	161.00	Wood - H	45.00		1
2	BONNEVILLE, ID	EAGLEROCK, ID	161.00	161.00	Wood - SP	9.00		1
3	EAGLEROCK, ID	GOSHEN, ID	161.00	161.00	Wood - H	15.00		1
4	GOSHEN, ID	GRACE, ID	161.00	161.00	Wood - H	57.00		1
5	GOSHEN, ID	JEFFERSON, ID	161.00	161.00	Wood - H		30.00	1
6	GOSHEN, ID	RIGBY, ID	161.00	161.00	Wood - H	31.00		1
7	GOSHEN, ID	SUGAR MILL, ID	161.00	161.00	Wood - SP	17.00		1
8	RIGBY, ID	JEFFERSON, ID	161.00	161.00	Wood - SP	18.00		1
9	SUGARMILL, ID	RIGBY, ID	161.00	161.00	Wood - SP	17.00		1
10	YELLOWTAIL, MT	RIMROCK, MT	161.00	161.00	Wood - H	46.00		1
11	161kV costs and expenses							
12								
13	Subtotal 161kV					255.00	51.00	11
14								
15	90TH SOUTH, UT	DUMAS #1, UT	138.00	138.00	Wood - H	12.00		1
16	90TH SOUTH, UT	DUMAS #2, UT	138.00	138.00	Wood - H	6.00		1
17	90TH SOUTH, UT	OQUIRRH, UT	138.00	138.00	Wood - SP	10.00		1
18	90TH SOUTH, UT	SANDY, UT	138.00	138.00	Steel - SP	1.00		1
19	ABAJO, UT	PINTO, UT	138.00	138.00	Wood - H	44.00		1
20	ABAJO, UT	RESOLUTE, UT	138.00	138.00	Wood - SP	10.00		1
21	AGRIUM, UT	THREEMILE KNOLL, ID	138.00	138.00	Wood - H	4.00		1
22	ANSCHTZ CO-GEN, WY	EVANSTON, WY	138.00	138.00	Wood - H	22.00		1
23	ANTELOPE, ID	SCOVILLE #1, ID	138.00	138.00	Wood - H	1.00		1
24	ANTELOPE, ID	SCOVILLE #2, ID	138.00	138.00	Wood - H	1.00		1
25	ASHGROVE, UT	CLOVER, UT	138.00	138.00	Wood - H	26.00		1
26	ASHLEY, UT	CARBON, UT	138.00	138.00	Wood - H	102.00		1
27	ASHLEY, UT	VERNAL, UT	138.00	138.00	Wood - H	12.00		1
28	BANGERTER, UT	OQUIRRH, UT	138.00	138.00	Wood - H		6.00	1
29	BARNEYS, UT	GRINDING, UT	138.00	138.00	Wood - SP	1.00		1
30	BDO, UT	BDO TAP, UT	138.00	138.00	Wood - SP	1.00		1
31	BEN LOMOND, UT	ANGEL, UT	138.00	138.00	Steel - SP	27.00		1
32	BEN LOMOND, UT	BRIGHAM CITY, UT	138.00	138.00	Wood - H	14.00		1
33	BEN LOMOND #1, UT	EL MONTE, UT	138.00	138.00	Steel - SP	14.00		1
34	BEN LOMOND #2, UT	EL MONTE, UT	138.00	138.00			13.00	1
35	BEN LOMOND, UT	HONEYVILLE, UT	138.00	138.00	Steel Tower	22.00		1
36					TOTAL	16,943.00	651.00	285

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.	
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)		
397.5 ACSR 26/7								1	
954 ACSR 45/7								2	
1272 ACSR 45/7								3	
250HH CU /7								4	
250HH CU /7								5	
397.5 ACSR 26/7								6	
795 AAC /37								7	
397.5 ACSR 26/7								8	
397.5 ACSR 26/7								9	
556.5 ACSR 26/7								10	
	623,996	25,670,863	26,294,859		101,066	3,212	104,278	11	
								12	
	623,996	25,670,863	26,294,859		101,066	3,212	104,278	13	
								14	
795 AAC /37								15	
795 AAC /37								16	
795 ACSR 26/7								17	
795 AAC /37								18	
397.5 ACSR 26/7								19	
795 ACSR 26/7								20	
397.5 ACSR 26/7								21	
795 ACSR 26/7								22	
397.5 ACSR 26/7								23	
397.5 ACSR 26/7								24	
397.5 ACSR 26/7								25	
397.5 ACSR 26/7								26	
397.5 ACSR 26/7								27	
								28	
1272 AAC /61								29	
397.5 ACSR 26/7								30	
397.5 ACSR 26/7								31	
1272 ACSR 45/7								32	
795 ACSR 45/7								33	
795 ACSR 45/7								34	
250 CUHD /12								35	
	240,598,562	3,482,303,031	3,722,901,593		505,147	16,871,564	2,161,509	36	19,538,220

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	BEN LOMOND, UT	SYRACUSE #1, UT	138.00	230.00	Steel Tower	7.00	13.00	1
2	BEN LOMOND, UT	SYRACUSE, UT	138.00	138.00	Steel Tower	25.00		1
3	BEN LOMOND, UT	W ZIRCONIUM, UT	138.00	138.00	Wood - SP	14.00		1
4	BEN LOMOND, UT	WHEELON, UT	138.00	138.00	Steel Tower	42.00		1
5	BONANZA, UT	CHAPITA, UT	138.00	138.00	Wood - H	9.00		1
6	BRIDGERLAND, UT	GREEN CANYON, UT	138.00	138.00	Wood - SP	16.00		1
7	BRIGHAM CITY, UT	WHEELON, UT	138.00	138.00	Wood - H	24.00		1
8	BUTLERVILLE, UT	90TH SOUTH, UT	138.00	138.00	Steel - SP	9.00		1
9	CAMERON, UT	MILFORD, UT	138.00	138.00	Wood - SP	25.00		1
10	CAMERON, UT	PAROWAN, UT	138.00	138.00	Wood - H	35.00		1
11	CAMERON, UT	SIGURD, UT	138.00	138.00	Wood - H	64.00		1
12	CANYON COMP, WY	STR 204, WY	138.00	138.00	Wood - H	12.00		1
13	CARBON, UT	HELPER #2, UT	138.00	138.00	Wood - H	2.00		1
14	CARBON, UT	MOAB, UT	138.00	138.00	Wood - H	120.00		1
15	CARBON, UT	SPANISH FORK #1, UT	138.00	138.00	Steel Tower	54.00		1
16	CARBON, UT	SPANISH FORK #2, UT	138.00	138.00	Steel Tower	52.00		1
17	CENTRAL (UAMPS) #2, UT	SAINT GEORGE, UT	138.00	138.00	Steel - SP	20.00		1
18	CENTRAL (UAMPS) #3, UT	SAINT GEORGE, UT	138.00	138.00	Steel - SP		20.00	1
19	CLEAR CREEK, WY	PAINTER, UT	138.00	138.00	Wood - SP	5.00		1
20	CLOVER, UT	BURRASTON PONDS	138.00	138.00	Wood - SP	2.00		1
21	CLOVER, UT	NEBO, UT	138.00	138.00	Wood - SP	8.00		1
22	COLUMBIA, UT	SUNNYSIDE, UT	138.00	138.00	Wood - H	2.00		1
23	COTTONWOOD, UT	HAMMER, UT	138.00	138.00	Wood - SP	5.00		1
24	COTTONWOOD, UT	MCCLELLAND, UT	138.00	138.00	Steel - SP	6.00		1
25	COTTONWOOD, UT	SILVER CREEK, UT	138.00	138.00	Wood - SP	29.00		1
26	CUTLER, UT	WHEELON, UT	138.00	138.00	Wood - SP	1.00		1
27	DRY CREEK, UT	SPANISH FORK, UT	138.00	138.00	Steel - SP	5.00		1
28	DUMAS, UT	WESTFIELD, UT	138.00	138.00	Wood - SP	18.00		1
29	DYNAMO, UT	TRI-CITY #1, UT	138.00	138.00	Steel - SP	2.00		1
30	DYNAMO, UT	TRI-CITY #2, UT	138.00	138.00			3.00	1
31	EAGLE MOUNTAIN, UT	PONY EXPRESS, UT	138.00	138.00	Wood - SP	10.00		1
32	EAST LAYTON, UT	105 TAP, UT	138.00	138.00	Steel - SP	15.00		1
33	EBAY TAP, UT	OQUIRRH, UT	138.00	138.00	Wood - SP	1.00		1
34	EL MONTE, UT	PIONEER, UT	138.00	138.00	Steel - SP	1.00		1
35	EL MONTE, UT	EAST BANK, UT	138.00	138.00	Steel - SP	4.00		1
36					TOTAL	16,943.00	651.00	285

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 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795 AAC /37								1
1272 ACSR 45/7								2
795 AAC /37								3
250 CUHD /12								4
795 ACSR 26/7								5
1272 ACSR 45/7								6
795 ACSR 26/7								7
795 AAC /37								8
397.5 ACSR 26/7								9
397.5 ACSR 26/7								10
397.5 ACSR 26/7								11
795 ACSR 26/7								12
556.5 ACSR 26/7								13
954 ACSR 54/7								14
795 ACSR 26/7								15
1272 ACSR 45/7								16
1272 ACSR 45/7								17
1272 ACSR 45/7								18
795 ACSR 26/7								19
397.5 ACSR 26/7								20
1272 ACSR 45/7								21
397.5 ACSR 26/7								22
795 AAC /37								23
795 AAC /37								24
397.5 ACSR 26/7								25
250 CUHD /12								26
1272 ACSR 45/7								27
795 ACSR 26/7								28
795 ACSR 26/7								29
795 ACSR 26/7								30
795 ACSR 26/7								31
795 ACSR 26/7								32
795 ACSR 26/7								33
1272 ACSR 45/7								34
1272 ACSR 45/7								35
	240,598,562	3,482,303,031	3,722,901,593	505,147	16,871,564	2,161,509	19,538,220	36

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	EVANSTON, WY	RAILROAD, UT	138.00	138.00	Wood - SP	3.00		1
2	FORT DOUGLAS, UT	MCCLELLAND, UT	138.00	138.00	Wood - SP	3.00		1
3	FRANKLIN, ID	GREEN CANYON, UT	138.00	138.00	Wood - SP	25.00		1
4	FRANKLIN, ID	TREASURETON, ID	138.00	138.00	Wood - SP	10.00		1
5	GADSBY, UT	JORDAN, UT	138.00	138.00	Wood - SP	1.00		1
6	GADSBY, UT	TERMINAL, UT	138.00	138.00	Wood - SP	6.00		1
7	GADSBY, UT	THIRD WEST, UT	138.00	138.00	Wood - SP	1.00		1
8	GRAPHITE, UT	MOUNTAIN VIEW, UT	138.00	138.00	Wood - SP	1.00		1
9	GREEN CANYON, UT	NIBLEY, UT	138.00	138.00	Wood - SP	7.00		1
10	GREEN CANYON, UT	WHEELON, UT	138.00	138.00	Wood - SP	19.00		1
11	GRINDING, UT	OQUIRRH, UT	138.00	138.00	Wood - SP	7.00		1
12	GRINDING, UT	TOOELE, UT	138.00	138.00	Wood - SP	14.00		1
13	HALE, UT	MIDWAY, UT	138.00	138.00	Wood - H	19.00		1
14	HALE, UT	SPANISH FORK, UT	138.00	138.00	Wood - H	18.00		1
15	HALE, UT	TANNER, UT	138.00	138.00	Wood - H	7.00		1
16	HAMMER, UT	BUTLERVILLE, UT	138.00	138.00			2.00	1
17	HIGHLAND, UT	BULL RIVER (LEHI #5), UT	138.00	138.00	Wood - SP	5.00		1
18	HONEYVILLE, UT	LAMPO, UT	138.00	138.00	Wood - H	25.00		1
19	HONEYVILLE, UT	WHEELON, UT	138.00	138.00			14.00	1
20	HUNTINGTON, UT	MCFADDEN, UT	138.00	138.00	Wood - H	7.00		1
21	JERUSALEM, UT	NEBO, UT	138.00	138.00	Wood - H	26.00		1
22	JORDAN, UT	MCCLELLAND, UT	138.00	138.00	Wood - SP	5.00		1
23	JORDAN, UT	TERMINAL, UT	138.00	138.00	Wood - SP	6.00		1
24	JORDAN, UT	THIRD WEST, UT	138.00	138.00	Wood - SP	1.00		1
25	KEARNS, UT	TAYLORSVILLE, UT	138.00	138.00	Wood - SP	3.00		1
26	KEARNS, UT	WEST VALLEY, UT	138.00	138.00	Wood - SP	2.00		1
27	LONE PEAK, UT	CAMP WILLIAMS, UT	138.00	138.00			8.00	1
28	MCCLELLAND, UT	MIDVALLEY, UT	138.00	138.00	Wood - SP	6.00		1
29	MCFADDEN, UT	BLACKHAWK, UT	138.00	138.00	Wood - H	11.00		1
30	MID VALLEY, UT	90TH SOUTH, UT	138.00	138.00	Wood - H	9.00		1
31	MID VALLEY #2, UT	COTTONWOOD, UT	138.00	138.00	Wood - SP	3.00		1
32	MID VALLEY #1, UT	COTTONWOOD, UT	138.00	138.00	Wood - SP	5.00		1
33	MID VALLEY, UT	TAYLORSVILLE, UT	138.00	138.00	Wood - SP	4.00	2.00	1
34	MIDDLETON, UT	ST. GEORGE, UT	138.00	138.00	Wood - H	1.00		1
35	MOAB, UT	PINTO, UT	138.00	138.00	Wood - H	68.00		1
36					TOTAL	16,943.00	651.00	285

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)	
795 ACSR 26/7								1
								2
397.5 ACSR 26/7								3
795 ACSR 26/7								4
1272 ACSR 45/7								5
1272 ACSR 45/7								6
1272 AAC /61								7
397.5 ACSR 26/7								8
1272 ACSR 45/7								9
397.5 ACSR 26/7								10
795 ACSR 45/7								11
795 ACSR 45/7								12
397.5 ACSR 26/7								13
1272 ACSR 45/7								14
1272 ACSR 45/7								15
795 ACSR 26/7								16
1272 ACSR 45/7								17
397.5 ACSR 26/7								18
250 CUHD /12								19
397.5 ACSR 26/7								20
397.5 ACSR 26/7								21
795 AAC /37								22
1272 AAC/91								23
1272 AAC /61								24
795 ACSR 26/7								25
								26
1272 ACSR 45/7								27
795 AAC 26/7								28
795 AAC 26/7								29
1272 ACSR 45/7								30
								31
								32
1272 ACSR /61								33
397.5 ACSR 26/7								34
397.5 ACSR 26/7								35
	240,598,562	3,482,303,031	3,722,901,593	505,147	16,871,564	2,161,509	19,538,220	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 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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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	NAUGHTON, WY	CANYON COMP, WY	138.00	138.00	Wood - H	35.00		1
2	NAUGHTON, WY	PAINTER, WY	138.00	138.00	Wood - H	44.00		1
3	NEBO, UT	DRY CREEK, UT	138.00	138.00	Wood - H	33.00		1
4	NUCOR STEEL, UT	WHEELON, UT	138.00	138.00	Wood - H	10.00		1
5	ONEIDA, ID	OVID, UT	138.00	138.00	Wood - H	23.00		1
6	ONIEDA, ID	GRACE, ID	138.00	138.00	Wood - H	19.00		1
7	OQUIRRH, UT	BARNEY, UT	138.00	138.00	Wood - H	5.00		1
8	OQUIRRH, UT	BINGHAM CANYON, UT	138.00	138.00	Wood - H	8.00		1
9	OQUIRRH, UT	TOOELE, UT	138.00	138.00	Steel - SP	23.00		1
10	PAINTER, UT	RAILROAD, UT	138.00	138.00	Wood - H	7.00		1
11	PARRISH #105, UT	TERMINAL, UT	138.00	138.00	Steel - SP	14.00		1
12	PAROWAN, UT	WEST CEDAR, UT	138.00	138.00	Wood - H	21.00		1
13	PARRISH, UT	TAP TO SALT LAKE, UT	138.00	138.00	Steel - SP		8.00	1
14	PARRISH, UT	TERMINAL #1, UT	138.00	138.00	Steel - SP	16.00		1
15	PARRISH, UT	TERMINAL #2, UT	138.00	138.00			14.00	1
16	RAILROAD, UT	CANYON COMP, WY	138.00	138.00	Wood - H	17.00		1
17	RED BUTTE, UT	ST. GEORGE, UT	138.00	138.00	Steel - SP	1.00		1
18	RED BUTTE, UT	WEST CEDAR, UT	138.00	138.00	Wood - H	49.00		1
19	RIVERDALE, UT	EAST LAYTON, UT	138.00	138.00	Steel - SP		7.00	1
20	SHICK, UT	PARRISH, UT	138.00	138.00	Wood - H		10.00	1
21	SILVER CREEK, UT	RAILROAD, UT	138.00	138.00	Wood - SP	72.00		1
22	SILVER CREEK, UT	JORDANELLE, UT	138.00	138.00	Wood - SP	10.00		1
23	SPANISH FORK, UT	TANNER, UT	138.00	138.00	Wood - H	10.00		1
24	SUNRISE, UT	OQUIRRH, UT	138.00	138.00	Wood - SP		2.00	1
25	SYRACUSE, UT	ANGEL #1, UT	138.00	138.00			7.00	1
26	SYRACUSE, UT	CLEARFIELD SOUTH, UT	138.00	138.00	Steel - SP	5.00		1
27	SYRACUSE, UT	PARRISH, UT	138.00	138.00	Steel Tower	15.00		1
28	TAP TO ANGEL NORTH, UT	TAP TO PARRISH, UT	138.00	138.00	Wood - H	13.00		1
29	TAYLORSVILLE, UT	90TH SOUTH, UT	138.00	138.00	Wood - SP	6.00	2.00	1
30	TERMINAL, UT	KENNECOTT, UT	138.00	138.00	Steel - SP	9.00		1
31	TERMINAL, UT	MIDVALLEY #1, UT	138.00	138.00	Wood - H	7.00		1
32	TERMINAL, UT	MIDVALLEY #2, UT	138.00	138.00	Wood - H	7.00		1
33	TERMINAL, UT	ROWLEY, UT	138.00	138.00	Wood - H	53.00		1
34	TERMINAL, UT	TOOELE, UT	138.00	138.00	Wood - H	24.00	6.00	1
35	TERMINAL, UT	WEST VALLEY, UT	138.00	138.00	Wood - SP	7.00		1
36					TOTAL	16,943.00	651.00	285

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
795 AAC 26/7								2
795 AAC 26/7								3
397.5 ACSR 26/7								4
336.4 ACSR 26/7								5
250 CUHD /12								6
795 AAC 26/7								7
								8
1272 ACSR 45/7								9
1272 ACSR 45/7								10
795 AAC 45/7								11
397.5 ACSR 26/7								12
795 AAC 26/7								13
795 AAC 45/7								14
795 AAC 26/7								15
795 ACSR 26/7								16
1272 ACSR 45/7								17
397.5 ACSR 26/7								18
795 AAC 26/7								19
250 CUHD /12								20
1272 ACSR 45/7								21
795 AAC 26/7								22
1272 ACSR 45/7								23
								24
250 CUHD /12								25
1272 ACSR 45/7								26
1272 ACSR 45/7								27
795 AAC /37								28
795 AAC /37								29
795 AAC 26/7								30
1272 ACSR 45/7								31
1272 AAC /61								32
795 AAC /37								33
397.5 ACSR 26/7								34
								35
	240,598,562	3,482,303,031	3,722,901,593	505,147	16,871,564	2,161,509	19,538,220	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 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	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	THREEMILE KNOLL, ID	GRACE #1, ID	138.00	138.00	Wood - H	17.00		1
2	THREEMILE KNOLL, ID	GRACE #2, ID	138.00	138.00	Wood - H	17.00		1
3	THREEMILE KNOLL, ID	MONSANTO #1, ID	138.00	138.00	Wood - H	2.00		1
4	THREEMILE KNOLL, ID	MONSANTO #2, ID	138.00	138.00	Steel - SP	2.00		1
5	TIMP #1, UT	DYNAMO, UT	138.00	138.00	Steel - SP	2.00		1
6	TIMP #2, UT	DYNAMO, UT	138.00	138.00			2.00	1
7	TIMP, UT	HALE, UT	138.00	138.00	Steel - SP	4.00		1
8	TIMP, UT	SPANISH FORK, UT	138.00	138.00	Wood - H	23.00		1
9	TIMP, UT	VINEYARD, UT	138.00	138.00	Wood - SP	2.00		1
10	TREASURETON, ID	GRACE, ID	138.00	138.00	Steel Tower	25.00		1
11	TREASURETON, ID	GRACE #2, ID	138.00	138.00			25.00	1
12	TREASURETON, ID	ONEIDA, ID	138.00	138.00	Wood - H	6.00		1
13	TRI-CITY, UT	BANGERTER, UT	138.00	138.00	Wood - SP	6.00	12.00	1
14	TRI-CITY, UT	SUNRISE, ID	138.00	138.00	Wood - SP	22.00		1
15	TRI-CITY, UT	WESTFIELD, UT	138.00	138.00	Wood - H	15.00		1
16	WEST CEDAR, UT	THREE PEAKS, UT	138.00	138.00	Wood - SP	20.00		1
17	WEST VALLEY, UT	OQUIRRH, UT	138.00	138.00	Wood - H	9.00		1
18	WESTFIELD, UT	HALE, UT	138.00	138.00	Wood - H	13.00		1
19	WHEELON, UT	AMERICAN FALLS, ID	138.00	138.00	Wood - H	87.00		1
20	WHEELON #1, UT	TREASURETON, ID	138.00	138.00	Steel Tower	29.00		1
21	WHEELON #2, UT	TREASURETON, ID	138.00	138.00			29.00	1
22	WHEELON #3, UT	TREASURETON, ID	138.00	138.00	Wood - H	29.00		1
23	138kV costs and expenses							
24								
25	Subtotal 138kV					2,195.00	205.00	148
26								
27	All 115kV Lines					1,654.00		
28								
29	All 69kV Lines					2,913.00		
30								
31	All 57kV Lines					107.00		
32								
33	All 46kV Lines					2,509.00		
34								
35								
36					TOTAL	16,943.00	651.00	285

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 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.	
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses		
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)		
250 CUHD /12								1	
1272 ACSR 45/7								2	
1272 AAC /61								3	
1272 ACSR 45/7								4	
								5	
								6	
								7	
								8	
1272 ACSR 45/7								9	
250 CUHD /12								10	
250 CUHD /12								11	
250 CUHD /12								12	
								13	
								14	
1272 ACSR 45/7								15	
795 AAC 26/7								16	
								17	
795 AAC 26/7								18	
250 CUHD /12								19	
250 CUHD /12								20	
250 CUHD /12								21	
250 CUHD /12								22	
	28,822,078	398,735,335	427,557,413	184,213	1,398,326	126,413	1,708,952	23	
								24	
	28,822,078	398,735,335	427,557,413	184,213	1,398,326	126,413	1,708,952	25	
								26	
	5,213,526	199,149,305	204,362,831	61,789	2,572,646	490,114	3,124,549	27	
								28	
	8,325,019	287,574,032	295,899,051	82,334	3,914,504	188,040	4,184,878	29	
								30	
	52,655	12,152,288	12,204,943	3,516	55,891	9,930	69,337	31	
								32	
	11,591,169	270,008,314	281,599,483	46,473	2,778,434	26,153	2,851,060	33	
								34	
								35	
	240,598,562	3,482,303,031	3,722,901,593		505,147	16,871,564	2,161,509	36	19,538,220

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. For further discussion, see also page 328, Transmission of electricity for others, in this Form No. 1.

Schedule Page: 422 Line No.: 2 Column: a

The Alvey - Dixonville 500kV line is jointly owned by PacifiCorp and Bonneville Power Administration ("BPA"), each with an undivided interest of 50.0%. Plant cost reported for this line represents 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.: 4 Column: a

The Dixonville - Meridian 500kV line is jointly owned by PacifiCorp and BPA, each with an undivided interest of 50.0%. Plant cost reported for this line represents 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.: 8 Column: a

The Midpoint - Malin 500kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line designation is as follows:

Designation	PacifiCorp	Idaho Power Company
Hemingway – Summer Lake	78.0%	22.0%
Midpoint – Hemingway	63.0%	37.0%

Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422 Line No.: 9 Column: a

The Colstrip 4 - Switchyard 500kV line is jointly owned by PacifiCorp, NorthWestern Corporation, Puget Sound Energy, Avista Corporation and Portland General Electric Company, in which PacifiCorp owns 6.8% of the line. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422 Line No.: 10 Column: a

The Colstrip - Broadview A 500kV line is jointly owned by PacifiCorp, NorthWestern Corporation, Puget Sound Energy, Avista Corporation and Portland General Electric Company, in which PacifiCorp owns 6.8% of the line. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp's share.

Schedule Page: 422 Line No.: 11 Column: a

The Colstrip - Broadview B 500kV line is jointly owned by PacifiCorp, NorthWestern Corporation, Puget Sound Energy, Avista Corporation and Portland General Electric Company, in which PacifiCorp owns 6.8% of the line. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp's share.

Schedule Page: 422 Line No.: 12 Column: a

The Broadview - Townsend A 500kV line is jointly owned by PacifiCorp, NorthWestern Corporation, Puget Sound Energy, Avista Corporation and Portland General Electric Company, in which PacifiCorp owns 8.1% of the line. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp's share.

Schedule Page: 422 Line No.: 13 Column: a

The Broadview - Townsend B 500kV line is jointly owned by PacifiCorp, NorthWestern Corporation, Puget Sound Energy, Avista Corporation and Portland General Electric Company, in which PacifiCorp owns 8.1% of the line. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp's share.

Schedule Page: 422 Line No.: 18 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422 Line No.: 19 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422 Line No.: 27 Column: a

The Borah - Midpoint #1 345kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line designation Borah - Adelaide - Midpoint #1 is as follows: PacifiCorp 35.6%, Idaho Power Company 64.4%. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422 Line No.: 28 Column: a

The Borah - Midpoint #2 345kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line designation Borah - Adelaide - Midpoint #2 is as follows: PacifiCorp 35.6%, Idaho Power Company 64.4%. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422.1 Line No.: 5 Column: a

The Goshen - Kinport 345kV line is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 81.7% and 18.3%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422.1 Line No.: 10 Column: a

The Jim Bridger - Goshen 345kV line is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 70.8% and 29.2%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422.1 Line No.: 11 Column: a

The Jim Bridger - Borah 345kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line designation is as follows:

Designation	PacifiCorp	Idaho Power Company
Jim Bridger – Populus #1	70.8%	29.2%
Populus – Borah #1	70.8%	29.2%

Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422.1 Line No.: 12 Column: a

The Jim Bridger - Kinport 345kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line designation is as follows:

Designation	PacifiCorp	Idaho Power Company
Jim Bridger – Populus #2	70.8%	29.2%
Populus – Kinport	70.8%	29.2%

Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422.1 Line No.: 13 Column: a

The Kinport - Midpoint 345kV line is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 26.8% and 73.2%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422.2 Line No.: 4 Column: a

A 1.5 mile segment of the Casper - Dave Johnston 230kV line is jointly owned by PacifiCorp and Black Hills Power with an undivided interest of 43.75% and 56.25%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp's share.

Schedule Page: 422.2 Line No.: 4 Column: i

1557 ACSS/TW 45/7

Schedule Page: 422.2 Line No.: 19 Column: a

Complete name is Gonder (NV Energy), UT - NV State

Schedule Page: 422.2 Line No.: 22 Column: a

The Hurricane - Walla Walla 230kV line is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 59.2% and 40.8%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422.3 Line No.: 35 Column: a

The Big Grassy - Jefferson 161kV line is jointly owned by PacifiCorp and Idaho Power company with an undivided interest of 62.2% and 37.8%, respectively. Plant costs and operation and maintenance costs reported for this line represents PacifiCorp's share.

Schedule Page: 422.4 Line No.: 1 Column: a

The Antelope - Goshen 161kV line is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 78.1% and 21.9%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp's share.

Schedule Page: 422.4 Line No.: 5 Column: a

The Goshen - Jefferson 161kV line is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 62.2% and 37.8%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp's share.

Schedule Page: 422.4 Line No.: 23 Column: a

The Antelope - Scoville #1 138kV line is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 33.3% and 66.7%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp's share.

Schedule Page: 422.4 Line No.: 24 Column: a

The Antelope - Scoville #2 138kV line is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 33.3% and 66.7%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp's share.

Schedule Page: 422.4 Line No.: 28 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.5 Line No.: 17 Column: a

The Central - Saint George 138kV line is jointly owned by PacifiCorp and Utah Associated Municipal Power Systems with an undivided interest of 54.62% and 45.38%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp's share.

Schedule Page: 422.5 Line No.: 18 Column: a

See footnote on page 422.5, line no. 17, column (a)

Schedule Page: 422.5 Line No.: 20 Column: b

Complete name is Burraston Ponds Metering, UT

Schedule Page: 422.6 Line No.: 2 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 26 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 31 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 32 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 8 Column: b

Complete name is Bingham Canyon (KCC), UT

Schedule Page: 422.7 Line No.: 8 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 24 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 35 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 5 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 6 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 7 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 8 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 13 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 14 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 17 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 19 Column: a

The Wheelon - American Falls 138kV line is jointly owned by PacifiCorp and Idaho Power Company. Ownership of the line designation American Falls - Malad is as follows: PacifiCorp 96.4%, Idaho Power Company 3.6%. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp's share.

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 2017/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	SILVER CREEK, UT	CROYDON, UT	34.00	Wood - SP	14.00	1	1
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		34.00		14.00	1	1

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
1272	ACSR	Vertical 5'	138	3,520,713	7,750,172	11,208,103		22,478,988	1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
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									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				3,520,713	7,750,172	11,208,103		22,478,988	44

Schedule Page: 424 Line No.: 1 Column: a
Lines added to the designation from Silver Creek, Utah to Railroad, Utah

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 2017/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	

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 2017/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	69.00	
8	YREKA SUB	T/D-UNATTENDED	115.00	12.47	69.00
9	TOTAL		230.00	81.47	69.00
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	TOTAL		690.00	391.00	12.47
18	Number of Substations-5				
19					
20	IDAHO				
21	ALEXANDER	DISTRIBUTION-UNATTEN	46.00	12.47	
22	AMMON	DISTRIBUTION-UNATTEN	69.00	12.47	
23	ANDERSON	DISTRIBUTION-UNATTEN	69.00	12.47	
24	ARCO	DISTRIBUTION-UNATTEN	69.00	12.47	
25	ARIMO	DISTRIBUTION-UNATTEN	46.00	12.47	
26	BANCROFT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	BELSON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	BERENICE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	CAMAS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	CANYON CREEK SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
31	CHESTERFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	CLEMENTS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	CLIFTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	COVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	DOWNEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	DUBOIS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	EASTMONT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	EGIN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	EIGHT MILE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	GEORGETOWN 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 2017/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
4	3					2
4	3					3
323	99					4
						5
						6
35	4					7
95	2					8
130	6					9
						10
						11
500	2					12
51	4					13
5	3					14
19	3					15
150	2					16
725	14					17
						18
						19
						20
4	1					21
14	1					22
20	1					23
6	1					24
7	1					25
4	1					26
12	1					27
10	1					28
14	1					29
20	1					30
5	1					31
5	1					32
4	1					33
6	1					34
5	1					35
12	1					36
14	1					37
14	1					38
4	1					39
6	1					40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	GRACE CITY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	HAMER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	HAYES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	HENRY SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
5	HOLBROOK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	HOOPES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	HORSLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	IDAHO FALLS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	INDIAN CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	JEFFCO SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
11	KETTLE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
12	LAVA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	LUND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	MCCAMMON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	MENAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	MERRILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	MILLER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	MONTPELIER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	MOODY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	NEWDALE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	OSGOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	PRESTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	RAYMOND SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	RENO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	REXBURG SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	RIRIE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	ROBERTS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	RUBY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	SAND CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	SANDUNE SUB	DISTRIBUTION-UNATTEN	67.00	24.90	
31	SHELLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	SMITH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	SOUTH FORK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	SPUD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	ST. CHARLES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	SUGAR CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	SUNNYDELL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	TANNER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	TARGHEE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	THORNTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
5	1					1
14	1					2
9	1					3
1	1					4
6	1					5
9	1					6
4	1					7
20	1					8
3	1					9
22	1					10
14	1					11
6	1					12
5	1					13
3	1					14
10	1					15
20	1					16
5	1					17
8	1					18
14	1					19
20	1					20
20	1					21
12	1					22
2	1					23
20	1					24
32	2					25
9	1					26
8	1					27
7	1					28
40	2					29
30	1					30
20	1					31
20	1					32
14	1					33
8	1					34
5	1					35
12	1					36
13	1					37
4	1					38
4	1					39
7	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 2017/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	UCON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	WATKINS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	WEBSTER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	WESTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	WINDSPER SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
6	TOTAL		4000.00	867.43	
7	Number of Substations-65				
8					
9	CINDER BUTTE SUB	T/D-UNATTENDED	161.00	12.47	
10	MALAD SUB	T/D-UNATTENDED	138.00	69.00	12.47
11	MUD LAKE SUB	T/D-UNATTENDED	69.00	12.47	
12	RIGBY SUB	T/D-UNATTENDED	161.00	12.47	69.00
13	SAINT ANTHONY SUB	T/D-UNATTENDED	69.00	46.00	12.47
14	TOTAL		598.00	152.41	93.94
15	Number of Substations-5				
16					
17	AMPS SUB	TRANSMISSION-UNATTEN	230.00	69.00	12.47
18	ANTELOPE SUB	TRANSMISSION-UNATTEN	230.00	161.00	13.80
19	ASHTON PLANT	TRANSMISSION-UNATTEN	46.00	12.47	2.40
20	BIG GRASSY SUB	TRANSMISSION-UNATTEN	161.00	69.00	
21	BONNEVILLE SUB	TRANSMISSION-UNATTEN	161.00	69.00	
22	CONDA SUB	TRANSMISSION-UNATTEN	138.00	46.00	
23	FISH CREEK SUB	TRANSMISSION-UNATTEN	161.00	46.00	
24	FRANKLIN SUB	TRANSMISSION-UNATTEN	138.00	46.00	
25	GOSHEN SUB	TRANSMISSION-UNATTEN	345.00	161.00	69.00
26	GRACE SUB	TRANSMISSION-UNATTEN	161.00	138.00	12.50
27	JEFFERSON SUB	TRANSMISSION-UNATTEN	161.00	69.00	
28	MIDPOINT SUB	TRANSMISSION-UNATTEN	500.00	345.00	
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	WESTWOOD SUB	TRANSMISSION-UNATTEN	161.00	13.20	
35	TOTAL		3605.00	1704.67	225.17
36	Number of Substations-18				
37					
38	MONTANA				
39	BROADVIEW SUB	TRANSMISSION-UNATTEN	500.00	230.00	
40	COLSTRIP SUB	TRANSMISSION-UNATTEN	500.00	230.00	

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
7	1					1
14	1					2
20	1					3
4	1					4
20	1					5
736	67					6
						7
						8
30	1					9
39	4	1				10
14	1					11
189	4					12
40	2					13
312	12	1				14
						15
						16
75	1					17
250	1					18
15	1					19
67	1					20
67	1					21
67	1					22
25	3					23
75	1					24
908	4					25
217	2					26
233	3					27
1500	1	1				28
30	1					29
76	2					30
168	3					31
775	2					32
533	2					33
30	1					34
5111	31	1				35
						36
						37
						38
32	2					39
68	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 2017/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	YELLOWTAIL SUB	TRANSMISSION-UNATTEN	230.00	161.00	
2	TOTAL		1230.00	621.00	
3	Number of Substations-3				
4					
5	OREGON				
6	26TH STREET	DISTRIBUTION-UNATTEN	20.80	4.16	
7	35TH STREET	DISTRIBUTION-UNATTEN	20.80	2.40	
8	AGNESS AVE	DISTRIBUTION-UNATTEN	115.00	12.47	
9	ALDERWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	ARLINGTON	DISTRIBUTION-UNATTEN	69.00	12.47	
11	ATHENA	DISTRIBUTION-UNATTEN	69.00	12.47	
12	BANDON TIE SUB	DISTRIBUTION-UNATTEN	20.80	12.47	
13	BEACON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	BEALL LANE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
15	BEATTY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	BELKNAP SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
17	BLALOCK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	BLOSS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
19	BLY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	BOISE CASCADE SUB	DISTRIBUTION-UNATTEN	69.00	11.00	
21	BONANZA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	BOND STREET SUB	DISTRIBUTION-UNATTEN	69.00	12.50	
23	BROOKHURST SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
24	BROWNSVILLE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
25	BRYANT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	BUCHANAN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
27	BUCKAROO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	CAMPBELL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
29	CANNON BEACH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
30	CANYONVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
31	CARNES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	CASEBEER SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
33	CAVEMAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
34	CHERRY LANE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	CHILOQUIN MARKET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	CHINA HAT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	CIRCLE BLVD SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
38	CLEVELAND AVE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	CLOAKE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
40	COBURG SUB	DISTRIBUTION-UNATTEN	69.00	20.80	

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 2017/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)	
100	1					1
200	5					2
						3
						4
						5
5	1					6
30	6					7
25	1					8
45	2					9
5	1					10
9	1					11
8	3	1				12
11	3					13
25	1					14
6	1					15
40	2					16
2	3					17
32	2					18
8	3					19
3	1					20
8	3					21
25	1					22
50	2					23
13	1					24
34	2					25
45	2					26
34	2					27
20	2					28
13	1					29
25	1					30
9	3					31
20	1					32
45	2					33
25	1					34
9	3					35
25	1					36
80	2					37
45	2					38
20	1					39
10	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 2017/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	COLISEUM SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
2	COLUMBIA SUB	DISTRIBUTION-UNATTEN	115.00	12.47	57.00
3	COOS RIVER SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
4	COQUILLE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
5	CREEK SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
6	CROOKED RIVER RANCH SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
7	CROWFOOT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
8	CULLY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
9	CULVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	DAIRY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	DALLAS SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
12	DALREED SUB	DISTRIBUTION-UNATTEN	230.00	34.40	
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	GLENDALE SUB	DISTRIBUTION-UNATTEN	230.00	12.47	
26	GLENEDEN SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
27	GLIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
28	GOLD HILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	GORDON HOLLOW SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	GOSHEN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
31	GRANT STREET SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
32	GREEN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	GRIFFIN CREEK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
34	HAMAKER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	HARRISBURG SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
36	HENLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	HERMISTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	HILLVIEW SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
39	HINKLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	HOLLADAY 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 2017/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)	
9	2					1
55	2	1				2
20	1					3
40	2					4
5	1					5
25	2					6
20	1					7
25	1					8
13	1					9
25	1					10
50	2					11
95	4					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
25	2					25
6	1					26
12	1					27
11	3					28
6	1					29
20	1					30
45	2					31
25	1					32
20	1					33
8	3					34
13	1					35
6	3					36
40	1					37
45	2					38
20	1					39
75	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 2017/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	HOLLYWOOD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	HOOD RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	HORNET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	HUMBUG CREEK SUB	DISTRIBUTION-UNATTEN	67.00	12.50	
5	HUNTERS CIRCLE TEMP SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	ILLAHEE FLATS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
7	INDEPENDENCE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
8	JACKSONVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
9	JEFFERSON SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
10	JEROME PRAIRIE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
11	JORDAN POINT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
12	JOSEPH SUB	DISTRIBUTION-UNATTEN	20.80	12.47	
13	JUNCTION CITY SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
14	KENWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
15	KILLINGWORTH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	KNAPPA SVENSEN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
17	LAKEPORT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	LANCASTER SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
19	LEBANON SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
20	LINCOLN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
21	LOCKHART SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
22	LYONS SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
23	MADRAS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	MALLORY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
25	MARYS RIVER SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
26	MEDCO SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
27	MEDFORD	DISTRIBUTION-UNATTEN	115.00	12.47	
28	MERLIN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
29	MERRILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	MINAM SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	MODOC SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	MURDER CREEK SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
33	MYRTLE CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	MYRTLE POINT SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
35	NELSCOTT SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
36	NEW DESCHUTES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	NEW O'BRIEN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
38	OAK KNOLL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
39	OAKLAND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
40	OREMET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
50	2					1
40	2					2
20	1					3
9	1					4
12	1					5
2	1					6
20	1					7
75	2					8
12	1					9
20	1					10
20	1					11
6	1	1				12
22	2					13
3	3					14
40	2					15
6	1					16
50	2					17
12	3					18
40	2					19
105	3					20
40	2					21
25	2					22
25	2					23
25	1					24
20	1					25
20	1					26
67	8					27
45	2					28
17	6					29
	1					30
6	3					31
100	4					32
14	1					33
9	1					34
4	1					35
25	1					36
9	1					37
45	2					38
8	1					39
75	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 2017/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	OVERPASS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	PALLETTE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
3	PARK STREET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	PARKROSE SUB	DISTRIBUTION-UNATTEN	120.00	13.20	
5	PENDLETON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	PILOT ROCK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	POWELL BUTTE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
8	PRINEVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
9	PROVOLT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	QUEEN AVE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
11	RED BLANKET SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
12	REDMOND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
13	RIDDLE VENEER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	ROGUE RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
15	ROSEBURG SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
16	ROSS AVE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	ROXY ANN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	RUCH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	RUNNING Y SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
20	RUSSELLVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
21	SCENIC SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
22	SCIO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	SEASIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
24	SELMA SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
25	SHASTA WAY SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
26	SHEVLIN PARK SUB	DISTRIBUTION-UNATTEN	69.00	12.50	
27	SIMTAG BOOSTER PUMP	DISTRIBUTION-UNATTEN	34.50	4.16	
28	SOUTH DUNES SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
29	SOUTHGATE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
30	SPRAGUE RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	STATE STREET SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
32	STAYTON SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
33	STEAMBOAT SUB	DISTRIBUTION-UNATTEN	115.00	7.20	
34	STEVENS ROAD SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
35	SUTHERLIN SUB	DISTRIBUTION-UNATTEN	115.00	12.00	
36	SWEET HOME SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
37	TAKELMA SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
38	TALENT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
39	TEXUM SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	TILLER 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 2017/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)	
45	2					1
1	1	1				2
40	2					3
37	2					4
46	7	1				5
22	2					6
12	1					7
50	2					8
11	3					9
50	2					10
2	3					11
50	2					12
25	1					13
25	2					14
50	2					15
9	3					16
25	1					17
9	1					18
9	1					19
45	2					20
70	3					21
8	1					22
40	2					23
9	1					24
2	3					25
25	1					26
19	2					27
9	1					28
20	1					29
7	3					30
40	2					31
55	2					32
	1					33
50	2					34
25	1					35
42	2					36
12	1					37
50	2					38
25	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 2017/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	TOLO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	TURKEY HILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	UMAPINE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	UMATILLA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	VERNON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	VILAS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
7	VILLAGE GREEN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
8	VINE STREET SUB	DISTRIBUTION-UNATTEN	67.00	21.80	
9	WALLOWA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	WARM SPRINGS SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
11	WARRENTON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
12	WASCO SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
13	WECOMA BEACH SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
14	WESTON SUB	DISTRIBUTION-UNATTEN	70.60	13.09	
15	WESTSIDE HYDRO/SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	WEYERHAUSER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	WHITE CITY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	WILLOW COVE SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
19	WINSTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	YEW AVENUE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
21	YOUNGS BAY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
22	TOTAL		15451.27	2482.29	195.00
23	Number of Substations-176				
24					
25	ALBINA SUB	T/D-UNATTENDED	115.00	12.47	69.00
26	APPLEGATE SUB	T/D-UNATTENDED	115.00	69.00	12.47
27	ASHLAND SUB	T/D-UNATTENDED	115.00	12.47	7.20
28	BEND PLANT SUB	T/D-UNATTENDED	69.00	13.09	12.47
29	CAVE JUNCTION SUB	T/D-UNATTENDED	115.00	12.47	69.00
30	HAZELWOOD SUB	T/D-UNATTENDED	115.00	69.00	12.47
31	KNOTT SUB	T/D-UNATTENDED	115.00	12.47	57.00
32	MILE HI SUB	T/D-UNATTENDED	115.00	69.00	12.47
33	PILOT BUTTE SUB	T/D-UNATTENDED	230.00	69.00	12.47
34	RIDDLE SUB	T/D-UNATTENDED	115.00	69.00	
35	SAGE ROAD SUB	T/D-UNATTENDED	115.00	12.47	
36	WINCHESTER SUB	T/D-UNATTENDED	115.00	12.47	69.00
37	TOTAL		1449.00	432.91	333.55
38	Number of Substations-12				
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
11	1					1
13	3					2
20	1					3
25	2					4
50	2					5
25	1					6
40	2					7
30	1					8
7	1					9
12	3					10
25	2					11
2	3					12
3	1					13
25	1					14
22	9					15
40	2					16
60	3					17
28	3					18
22	3					19
25	1					20
37	2					21
4562	332	5				22
						23
						24
177	9					25
65	2					26
20	1					27
31	3					28
70	2					29
106	3					30
162	5					31
39	4					32
400	4					33
75	2					34
40	2					35
75	5					36
1260	42					37
						38
						39
						40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	LEMOLO #1 HYDRO	TRANSMISSION-ATTENDE	11.50	12.50	
2	CALAPOOYA SUB	TRANSMISSION-UNATTEN	230.00	69.00	
3	CHILOQUIN SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
4	COLD SPRINGS SUB	TRANSMISSION-UNATTEN	230.00	69.00	2.40
5	COVE SUB	TRANSMISSION-UNATTEN	230.00	69.00	
6	DIAMOND HILL SUB	TRANSMISSION-UNATTEN	230.00	69.00	
7	DIXONVILLE 115/230 SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
8	DIXONVILLE 500 SUB	TRANSMISSION-UNATTEN	500.00	230.00	
9	FISH HOLE SUB	TRANSMISSION-UNATTEN	115.00	69.00	
10	FRY SUB	TRANSMISSION-UNATTEN	230.00	115.00	
11	GRANTS PASS SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
12	HURRICANE SUB	TRANSMISSION-UNATTEN	230.00	69.00	2.40
13	ISTHMUS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
14	KENNEDY SUB	TRANSMISSION-UNATTEN	69.00	57.00	
15	KLAMATH FALLS SUB	TRANSMISSION-UNATTEN	230.00	69.00	
16	LONE PINE SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
17	MALIN SUB	TRANSMISSION-UNATTEN	500.00	230.00	69.00
18	MERIDIAN SUB	TRANSMISSION-UNATTEN	500.00	230.00	
19	MONPAC SUB	TRANSMISSION-UNATTEN	115.00	69.00	
20	NICKEL MOUNTAIN SUB	TRANSMISSION-UNATTEN	230.00	115.00	
21	PARRISH GAP SUB	TRANSMISSION-UNATTEN	230.00	69.00	12.47
22	PONDEROSA SUB	TRANSMISSION-UNATTEN	230.00	115.00	
23	PROSPECT CENTRAL SUB	TRANSMISSION-UNATTEN	115.00	69.00	
24	ROBERTS CREEK SUB	TRANSMISSION-UNATTEN	115.00	69.00	
25	ROUNDUP SUB - BPA	TRANSMISSION-UNATTEN	230.00	69.00	
26	SANTIAM TIE - BPA	TRANSMISSION-UNATTEN	230.00	69.00	
27	SNOW GOOSE SUB	TRANSMISSION-UNATTEN	525.00	230.00	34.50
28	TROUTDALE SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
29	TUCKER SUB	TRANSMISSION-UNATTEN	115.00	69.00	
30	WHETSTONE SUB	TRANSMISSION-UNATTEN	230.00	115.00	12.47
31	TOTAL		7050.50	3105.50	478.24
32	Number of Substations-30				
33					
34	UTAH				
35	106TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
36	118TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
37	23RD ST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	70TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
39	ALTAVIEW SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	AMALGA 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 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
2	3					1
87	2					2
119	4					3
66	2					4
67	3					5
75	1					6
343	6					7
650	3	1				8
7	3					9
500	2					10
473	5					11
29	2					12
250	1					13
33	1					14
251	6	1				15
733	10					16
775	4	1				17
1300	6	1				18
50	1					19
114	1					20
150	1					21
500	2					22
30	3					23
50	1					24
67	2					25
75	1					26
650	1	1				27
500	3					28
100	2					29
250	1					30
8296	83	5				31
						32
						33
						34
30	1					35
30	1					36
12	1					37
30	1					38
45	2					39
11	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	AMERICAN FORK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
2	ARAGONITE	DISTRIBUTION-UNATTEN	46.00	7.20	
3	AURORA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	BANGERTER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
5	BEAR RIVER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	BENJAMIN SUB	DISTRIBUTION-UNATTEN	46.20	12.47	
7	BINGHAM SUB	DISTRIBUTION-UNATTEN	46.00	7.62	
8	BLUE CREEK	DISTRIBUTION-UNATTEN	46.00	12.47	
9	BLUFF SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	BLUFFDALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	BOTHWELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	BRIAN HEAD SUB	DISTRIBUTION-UNATTEN	34.50	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	69.00	7.20	
22	CARBONVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	CARLISLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
24	CASTO SUB	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	69.00	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	138.00	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	12.47	
40	COPPER HILLS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
30	1					1
1	1					2
3	1					3
50	2					4
17	2					5
4	1					6
25	1					7
2	3					8
1	3					9
9	1					10
4	1					11
14	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
22	1					35
30	1					36
106	4					37
1	3					38
30	1					39
30	1					40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	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	12.47	
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	69.00	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	12.47	
40	GORDON AVENUE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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
14	1	2				38
30	1					39
30	1					40

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	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	HERRIMAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
9	HIGHLAND DIST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	HOGGARD SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
11	HOLDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	HOLLADAY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	HUNTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	HUNTINGTON CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
15	IRON MOUNTAIN SUB	DISTRIBUTION-UNATTEN	34.50	7.20	
16	IRONTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	IVINS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	JORDAN NARROWS SUB	DISTRIBUTION-UNATTEN	46.00	2.40	
19	JORDAN PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
20	JORDANELLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
21	JUAB SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	JUNCTION SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	KAIBAB SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	KAMAS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	KEARNS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
26	KENSINGTON SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
27	KYUNE SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
28	LAKE PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
29	LAYTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	LEGRANDE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	LEWISTON SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
32	LINCOLN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	LINDON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	LISBON SUB	DISTRIBUTION-UNATTEN	70.60	12.47	
35	LOAFER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	LOGAN CANYON SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
37	LONE TREE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
38	LOWER BEAVER SUB	DISTRIBUTION-UNATTEN	46.00	6.60	
39	LYNNDYL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	MAESER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
2	1					1
50	2					2
23	1					3
11	2					4
60	2					5
3	1					6
3	3					7
30	1					8
25	1					9
50	2					10
4	1					11
32	2					12
22	1					13
12	2					14
1	1					15
2	1					16
22	1					17
13	2					18
30	1					19
30	1					20
4	1					21
3	1					22
5	1					23
7	1					24
60	2					25
7	1					26
	1					27
53	2					28
40	2					29
2	1					30
22	1					31
20	1					32
20	1					33
3	1					34
	1					35
1	1					36
20	1					37
1	1					38
4	1					39
12	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	MAGNA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
2	MANILA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
3	MANTUA SUB	DISTRIBUTION-UNATTEN	44.00	12.47	
4	MAPLETON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	MARRIOTT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	MARYSVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	MATHIS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	MCCORNICK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	MCKAY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	MEADOWBROOK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	46.00
11	MEDICAL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	MIDLAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
13	MIDVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	MILFORD SUB	DISTRIBUTION-UNATTEN	138.00	46.00	
15	MILFORD TV SUB	DISTRIBUTION-UNATTEN	46.00	13.20	
16	MINERSVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	MOAB CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	MOORE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	MORGAN SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
20	MORONI SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	MOUNTAIN DELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	MOUNTAIN GREEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	MYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	NEW HARMONY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	NEWGATE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	NEWTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	NIBLEY SUB	DISTRIBUTION-UNATTEN	138.00	24.90	
28	NORTH BENCH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	NORTH FIELDS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	NORTH LOGAN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	NORTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	NORTH SALT LAKE SUB	DISTRIBUTION-UNATTEN	46.00	13.20	
33	NORTHEAST SUB	DISTRIBUTION-UNATTEN	46.00	12.50	
34	NORTHRIDGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	OAKLAND AVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	OAKLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	OLYMPUS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	OPHIR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	ORANGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	ORANGEVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
30	1					1
22	1					2
2	1					3
14	1					4
20	1					5
3	1					6
9	1					7
6	1					8
20	1					9
42	2					10
57	4					11
30	1					12
25	1					13
89	2					14
	1					15
2	1					16
19	2					17
3	1					18
7	2					19
6	1					20
5	1					21
6	1					22
6	1					23
7	1					24
20	1					25
5	1					26
14	1					27
25	1					28
2	1					29
25	1					30
22	1					31
25	1					32
45	2					33
14	1					34
24	2					35
6	1					36
22	1					37
3	1					38
20	1					39
14	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	OREM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	PACK CREEK RESERVOIR	DISTRIBUTION-UNATTEN	46.00	12.47	
3	PANGUITCH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	PARIETTE SUB	DISTRIBUTION-UNATTEN	69.00	24.94	
5	PARK CITY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	PARKSIDE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
7	PARKWAY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	PARLEYS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	PELICAN POINT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	PINE CANYON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
11	PINE CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	PINNACLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	PLAIN CITY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
14	PLEASANT GROVE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
15	PLEASANT VIEW SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	PONY EXPRESS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
17	PORTER ROCKWELL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
18	PROMONTORY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	QUAIL CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	QUARRY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
21	QUICHAPA SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
22	RAINS SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
23	RANDOLPH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	RASMUSON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	RATTLESNAKE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
26	RED MOUNTAIN SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
27	REDWOOD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	RESEARCH PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	RICH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	RICHFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	RICHMOND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	RIDGELAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
33	RITER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	ROCK CANYON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	ROCKVILLE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
36	ROCKY POINT	DISTRIBUTION-UNATTEN	138.00	13.20	
37	ROSE PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	ROYAL SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
39	SALINA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	SANDY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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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)	
48	2					1
4	1					2
5	1					3
14	1					4
42	2					5
60	2					6
50	2					7
16	2					8
6	1					9
55	2					10
2	1					11
14	1					12
22	1					13
25	1					14
14	1					15
60	2					16
30	1					17
2	1					18
4	1					19
60	2					20
4	1					21
15	1					22
2	1					23
1	3					24
14	1					25
12	1					26
45	2					27
45	2					28
5	1					29
22	2					30
11	1					31
40	2					32
20	1					33
5	1					34
4	1					35
30	1					36
24	3					37
	3					38
11	1					39
60	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 2017/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	SARATOGA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
2	SCIPIO SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	SCOFIELD RESERVOIR SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
4	SCOFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	SECOND STREET SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	SEGO CANYON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	SEVEN MILE SUB	DISTRIBUTION-UNATTEN	68.68	7.20	
8	SHARON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	SHIVWITS SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
10	SHORELINE SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
11	SIXTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	SKULL VALLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	SKYPARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	12.47
14	SNARR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	SNOWVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	SNYDERVILLE SUB	DISTRIBUTION-UNATTEN	138.00	46.00	
17	SOLDIER SUMMIT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	SOUTH JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
19	SOUTH MILFORD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	SOUTH MOUNTAIN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
21	SOUTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	SOUTH PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
23	SOUTH WEBER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
24	SOUTHWEST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	SPANISH VALLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	SPRINGDALE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
27	ST. JOHNS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	STANSBURY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	SUMMIT CREEK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
30	SUMMIT PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	SUNRISE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
32	SUTHERLAND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	TAMARISK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
34	TAYLOR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	THIEF CREEK SUB	DISTRIBUTION-UNATTEN	138.00	24.90	
36	THIRD WEST SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
37	THIRTEENTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	TOOELE DEPOT SUB	DISTRIBUTION-UNATTEN	46.00	12.50	
39	TOQUERVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	34.50
40	UINTAH 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 2017/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)	
60	2					1
1	3					2
1	1					3
1	3					4
13	2					5
14	1					6
	1					7
20	1					8
6	1					9
60	2					10
20	1					11
2	1					12
40	1					13
40	2					14
5	1					15
127	3					16
12	1					17
60	2					18
28	2					19
60	2					20
25	1					21
30	1					22
22	1					23
22	2					24
6	1					25
4	1					26
4	1					27
20	1					28
14	1					29
7	1					30
60	2					31
6	1					32
20	1					33
14	1					34
14	1					35
100	2					36
22	1					37
25	1					38
34	2					39
39	2					40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	UNION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	VALLEY CENTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	VERMILLION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	VERNAL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	VICKERS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	VINEYARD SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
7	WALLSBURG SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	WALNUT GROVE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
9	WARREN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
10	WASATCH STATE PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	WASHAKIE SUB	DISTRIBUTION-UNATTEN	138.00	4.16	
12	WELBY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	WELFARE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	WEST COMMERCIAL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	WEST JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
16	WEST OGDEN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
17	WEST POINT SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
18	WEST ROY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	WEST TEMPLE SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
20	WESTWATER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	WHITE ROCK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
22	WILLOWCREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	WILLOWRIDGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	WINCHESTER HILLS SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
25	WINKLEMAN SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
26	WOLF CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	WOOD CROSS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	WOODRUFF SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	TOTAL		20214.28	3539.55	105.44
30	Number of Substations-274				
31					
32	90TH SOUTH SUB	T/D-UNATTENDED	345.00	138.00	12.47
33	ANGEL SUB	T/D-UNATTENDED	138.00	12.47	46.00
34	BDO SUB	T/D-UNATTENDED	138.00	12.47	
35	BUTLERVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47
36	CENTENNIAL SUB	T/D-UNATTENDED	138.00	12.47	
37	COTTONWOOD SUB	T/D-UNATTENDED	138.00	12.47	46.00
38	DECADE SUB	T/D-UNATTENDED	138.00	12.47	
39	DUMAS SUB	T/D-UNATTENDED	138.00	12.47	
40	EMMA PARK SUB	T/D-UNATTENDED	138.00	12.47	

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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)	
50	2					1
22	1					2
3	1					3
33	2					4
2	1					5
30	1					6
13	1					7
30	1					8
30	1					9
2	3					10
14	1					11
42	2					12
10	1					13
22	1					14
28	1					15
60	2					16
40	1					17
25	1					18
60	3					19
5	1					20
30	1					21
1	1					22
14	1					23
4	1					24
	1					25
6	1					26
20	1					27
2	1					28
5743	375	2				29
						30
						31
1572	5					32
135	3					33
30	1					34
205	4					35
40	2					36
289	7					37
60	2					38
60	2					39
8	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	GROW SUB	T/D-UNATTENDED	138.00	12.47	46.00
2	HALE SUB	T/D-UNATTENDED	138.00	46.00	12.47
3	HIGHLAND SUB	T/D-UNATTENDED	138.00	12.47	46.00
4	JORDAN SUB	T/D-UNATTENDED	138.00	46.00	12.47
5	JUDGE SUB	T/D-UNATTENDED	46.00	12.47	
6	MCCLELLAND SUB	T/D-UNATTENDED	138.00	46.00	12.47
7	MORTON COURT SUB	T/D-UNATTENDED	138.00	12.47	
8	OQUIRRH SUB	T/D-UNATTENDED	345.00	46.00	138.00
9	PARRISH SUB	T/D-UNATTENDED	138.00	12.47	46.00
10	PIONEER PLANT	T/D-UNATTENDED	138.00	12.47	
11	RIVERDALE SUB	T/D-UNATTENDED	138.00	46.00	12.47
12	SEVIER SUB	T/D-UNATTENDED	138.00	46.00	12.47
13	SILVER CREEK SUB	T/D-UNATTENDED	138.00	12.47	46.00
14	SOUTHEAST SUB	T/D-UNATTENDED	138.00	12.47	46.00
15	SYRACUSE SUB	T/D-UNATTENDED	345.00	138.00	46.00
16	TAYLORSVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47
17	TERMINAL SUB	T/D-UNATTENDED	345.00	46.00	138.00
18	TIMP SUB	T/D-UNATTENDED	138.00	46.00	12.47
19	TOOELE SUB	T/D-UNATTENDED	138.00	46.00	12.47
20	TRI CITY SUB	T/D-UNATTENDED	138.00	12.47	
21	WEST VALLEY SUB	T/D-UNATTENDED	138.00	12.47	
22	WESTFIELD SUB	T/D-UNATTENDED	138.00	12.47	
23	TOTAL		5014.00	1006.46	768.70
24	Number of Substations-31				
25					
26	EMERY SUB	TRANSMISSION-ATTENDE	345.00	138.00	69.00
27	GADSBY SUB	TRANSMISSION-ATTENDE	138.00	46.00	
28	ABAJO SUB	TRANSMISSION-UNATTEN	138.00	69.00	
29	ASHLEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
30	BARNEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
31	BEN LOMOND SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
32	BLACK ROCK SUB	TRANSMISSION-UNATTEN	230.00	69.00	
33	BLACKHAWK SUB	TRANSMISSION-UNATTEN	138.00	69.00	46.00
34	CAMERON SUB	TRANSMISSION-UNATTEN	138.00	46.00	
35	CAMP WILLIAMS SUB	TRANSMISSION-UNATTEN	345.00	138.00	12.47
36	CLOVER SUB	TRANSMISSION-UNATTEN	345.00	138.00	14.40
37	COLUMBIA SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
38	CRANER FLAT SUB	TRANSMISSION-UNATTEN	138.00	12.47	
39	CROYDON SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
40	CUTLER SUB	TRANSMISSION-UNATTEN	138.00	46.00	

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.
72	3					1
114	2					2
97	2					3
164	2					4
22	1					5
340	3					6
65	2					7
835	4	1				8
97	2					9
30	1					10
180	3					11
34	4					12
100	2					13
50	2					14
1300	6					15
358	4					16
1108	6	2				17
130	2					18
249	3					19
30	1					20
30	1					21
20	1					22
7824	84	3				23
						24
						25
783	13					26
318	2					27
67	1					28
133	2					29
100	1					30
1813	5					31
75	1					32
100	2					33
25	4					34
169	2					35
448	1					36
71	2					37
40	2					38
81	2					39
50	1					40

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	EL MONTE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
2	GARKANE SUB	TRANSMISSION-UNATTEN	69.00	46.00	
3	GREEN CANYON SUB	TRANSMISSION-UNATTEN	138.00	46.00	
4	GRINDING SUB	TRANSMISSION-UNATTEN	138.00	13.80	
5	HELPER SUB	TRANSMISSION-UNATTEN	138.00	46.00	
6	HONEYVILLE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
7	HORSESHOE SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
8	HUNTINGTON SUB	TRANSMISSION-UNATTEN	345.00	138.00	24.90
9	JERUSALEM SUB	TRANSMISSION-UNATTEN	138.00	46.00	
10	LAMPO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
11	MATHINGTON SUB	TRANSMISSION-UNATTEN	138.00	46.00	13.20
12	MCFADDEN SUB	TRANSMISSION-UNATTEN	138.00	46.00	
13	MIDDLETON SUB	TRANSMISSION-UNATTEN	138.00	69.00	34.50
14	MIDVALLEY SUB	TRANSMISSION-UNATTEN	345.00	138.00	
15	MIDWAY CITY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
16	MINERAL PRODUCTS SUB	TRANSMISSION-UNATTEN	69.00	46.00	
17	MOAB SUB	TRANSMISSION-UNATTEN	138.00	69.00	
18	NEBO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
19	PAROWAN VALLEY SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
20	PAVANT SUB	TRANSMISSION-UNATTEN	230.00	46.00	
21	PINTO SUB	TRANSMISSION-UNATTEN	345.00	138.00	69.00
22	RED BUTTE SUB	TRANSMISSION-UNATTEN	345.00	138.00	
23	SIGURD SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
24	SMITHFIELD SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
25	SPANISH FORK SUB	TRANSMISSION-UNATTEN	345.00	138.00	46.00
26	ST GEORGE SUB	TRANSMISSION-UNATTEN	138.00	16.50	
27	THREE PEAKS SUB	TRANSMISSION-UNATTEN	345.00	138.00	
28	WEST CEDAR SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
29	TOTAL		8441.00	3377.77	724.35
30	Number of Substations-43				
31					
32	WASHINGTON				
33	ATTALIA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	BOWMAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	CASCADE KRAFT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	4.16
36	CLINTON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
37	DAYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	DODD ROAD SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
39	GRANDVIEW SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
40	HOPLAND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (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.
312	3					1
33	1					2
67	2					3
225	3					4
142	2					5
35	1					6
80	2					7
270	4					8
67	1					9
75	1					10
160	5	1				11
45	1					12
141	4					13
900	2					14
67	1					15
12	1					16
67	1					17
67	1					18
138	2					19
133	2					20
258	3					21
414	2					22
1124	6					23
63	2					24
1017	5					25
100	3	1				26
450	1					27
262	3					28
10997	106	2				29
						30
						31
						32
25	1					33
45	2					34
118	6					35
25	1					36
23	2					37
25	4					38
42	2					39
50	2					40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	NACHES SUB	DISTRIBUTION-UNATTEN	115.00	12.00	
2	NOB HILL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
3	NORTH PARK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	ORCHARD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
5	PACIFIC SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
6	POMEROY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	PROSPECT POINT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	PUNKIN CENTER SUB	DISTRIBUTION-UNATTEN	116.00	13.20	
9	RIVER ROAD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	SELAH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
11	SULPHUR CREEK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
12	SUNNYSIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
13	TIETON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	34.50
14	TOPPENISH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
15	TOUCHET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	VOELKER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
17	WAITSBURG SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	WAPATO SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
19	WENAS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
20	WHITE SWAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
21	WILEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
22	TOTAL		2922.00	370.22	107.66
23	Number of Substations-29				
24					
25	CENTRAL SUB	T/D-UNATTENDED	69.00	12.47	
26	MILL CREEK SUB	T/D-UNATTENDED	69.00	12.47	
27	UNION GAP SUB	T/D-UNATTENDED	230.00	115.00	12.47
28	TOTAL		368.00	139.94	12.47
29	Number of Substations-3				
30					
31	DRY GULCH SUB - AVISTA	TRANSMISSION-UNATTEN	115.00	69.00	
32	OUTLOOK SUB	TRANSMISSION-UNATTEN	230.00	115.00	
33	PASCO SUB	TRANSMISSION-UNATTEN	115.00	69.00	7.20
34	POMONA HEIGHTS SUB	TRANSMISSION-UNATTEN	230.00	115.00	13.20
35	WALLA WALLA 230KV SUB	TRANSMISSION-UNATTEN	230.00	69.00	
36	WALLULA SUB	TRANSMISSION-UNATTEN	230.00	69.00	
37	WINE COUNTRY SUB	TRANSMISSION-UNATTEN	230.00	115.00	
38	TOTAL		1380.00	621.00	20.40
39	Number of Substations-7				
40					

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	1					1
42	2					2
45	2					3
50	2					4
28	3					5
9	1					6
40	2					7
44	3					8
76	5					9
45	2					10
25	1					11
45	2					12
29	2					13
50	2					14
6	1					15
25	1					16
9	1					17
45	2					18
25	2					19
22	2					20
45	2					21
1083	61					22
						23
						24
14	1					25
45	2					26
595	5					27
654	8					28
						29
						30
20	1					31
125	1					32
39	9					33
325	3					34
300	2					35
120	2					36
250	1					37
1179	19					38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	WYOMING				
2	ANTELOPE MINE SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
3	ARROWHEAD SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
4	ASTLE STREET	DISTRIBUTION-UNATTEN	34.50	13.20	
5	BAILEY DOME SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
6	BAR NUNN	DISTRIBUTION-UNATTEN	115.00	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	BYRON SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
14	CASSA SUB	DISTRIBUTION-UNATTEN	57.00	20.80	12.47
15	CENTER STREET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
16	CHAPMAN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	CHUKAR SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
18	CHURCH AND DWIGHT SUB	DISTRIBUTION-UNATTEN	34.50	0.48	
19	COKEVILLE SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
20	COLUMBIA-GENEVA SUB	DISTRIBUTION-UNATTEN	230.00	13.80	
21	COMMUNITY PARK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
22	CROOKS GAP SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
23	DEER CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	DJ COAL MINE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
25	DOUGLAS SUB	DISTRIBUTION-UNATTEN	57.00	4.16	
26	DRY FORK SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
27	ELK BASIN SUB	DISTRIBUTION-UNATTEN	34.50	7.20	
28	EMIGRANT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
29	EVANS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
30	EVANSTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
31	FORT CASPER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	FORT SANDERS SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
33	FRANNIE SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
34	FRONTIER SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
35	GARLAND SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
36	GLENDO SUB	DISTRIBUTION-UNATTEN	57.00	4.16	
37	GRASS CREEK SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
38	GREAT DIVIDE SUB	DISTRIBUTION-UNATTEN	115.00	34.50	
39	GREYBULL SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
40	HANNA SUB	DISTRIBUTION-UNATTEN	34.50	12.47	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
25	1					2
150	2					3
13	1					4
2	1					5
30	1					6
25	1					7
7	1					8
14	1					9
150	2					10
73	4					11
25	1					12
2	3					13
2	6					14
12	1					15
4	1					16
1	3					17
1	1					18
4	1					19
45	2					20
50	2					21
5	3					22
9	1					23
12	1					24
6	1					25
9	1					26
5	1					27
12	1					28
9	1					29
40	2					30
28	1					31
20	1					32
50	2					33
6	1					34
45	2					35
1	3					36
25	1					37
20	1					38
3	1					39
6	1					40

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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	JACKALOPE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	KEMMERER SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
3	KIRBY CREEK PUMPING STATION	DISTRIBUTION-UNATTEN	34.50	2.40	
4	KIRBY CREEK SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
5	LANDER SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
6	LARAMIE SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
7	LATHAM SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
8	LINCH SUB	DISTRIBUTION-UNATTEN	69.00	13.80	
9	LITTLE MOUNTAIN SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
10	LOVELL SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
11	MILL IRON SUB	DISTRIBUTION-UNATTEN	34.50	13.80	
12	MILLS SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
13	MURPHY DOME SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
14	NUGGETT SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
15	OPAL SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
16	ORIN SUB	DISTRIBUTION-UNATTEN	57.00	7.20	
17	ORPHA SUB	DISTRIBUTION-UNATTEN	57.00	7.20	
18	PARADISE SUB	DISTRIBUTION-UNATTEN	69.00	25.00	
19	PARCO SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
20	PINEDALE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
21	PITCHFORK SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
22	POISON SPIDER SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
23	POLECAT SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
24	RAINBOW SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
25	RAVEN SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
26	RED BUTTE SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
27	REFINERY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
28	SAGE HILL SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
29	SHOSHONI SUB	DISTRIBUTION-UNATTEN	34.50	2.40	
30	SLATE CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	SOUTH CODY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
32	SOUTH ELK BASIN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
33	SOUTH TRONA SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
34	SPRING CREEK SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
35	SVILAR SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
36	TEN MILE STEP DOWN SUB	DISTRIBUTION-UNATTEN	34.50	12.50	
37	TEN MILE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
38	THERMOPOLIS TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
39	THUNDER CREEK SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
40	VETERANS SUB	DISTRIBUTION-UNATTEN	34.50	13.20	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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
14	1					2
3	3					3
2	3					4
25	2					5
50	2					6
25	1					7
12	1					8
20	1					9
4	1					10
12	1					11
1	3					12
5	1					13
	1					14
8	1					15
1	1					16
3	3					17
30	1					18
5	1					19
20	1					20
16	9	2				21
3	1					22
2	3					23
12	1					24
200	2					25
30	1					26
45	2					27
6	1					28
2	3					29
1	1					30
14	3	1				31
2	6					32
150	2					33
28	1					34
2	3					35
5	1					36
12	1					37
5	1					38
9	1					39
25	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 2017/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	WAPA THERMOPOLIS	DISTRIBUTION-UNATTEN	115.00	34.50	
2	WERTZ-SINCLAIR SUB	DISTRIBUTION-UNATTEN	57.00	4.16	12.50
3	WEST ADAMS SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
4	WESTVACO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
5	WORLAND TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
6	WYOPO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
7	TOTAL		7875.44	1378.71	38.17
8	Number of Substations-85				
9					
10	BUFFALO SUB	T/D-UNATTENDED	230.00	20.80	
11	ELK HORN SUB	T/D-UNATTENDED	115.00	12.47	
12	FIREHOLE SUB	T/D-UNATTENDED	230.00	34.50	
13	HILLTOP SUB	T/D-UNATTENDED	115.00	34.50	20.80
14	LABARGE SUB	T/D-UNATTENDED	69.00	24.90	
15	POINT OF ROCKS SUB	T/D-UNATTENDED	230.00	34.50	
16	RIVERTON 230 SUB	T/D-UNATTENDED	230.00	12.47	34.50
17	YELLOWCAKE SUB	T/D-UNATTENDED	230.00	34.50	
18	TOTAL		1449.00	208.64	55.30
19	Number of Substations-8				
20					
21	DAVE JOHNSTON PLANT/SUB	TRANSMISSION-ATTENDE	230.00	115.00	69.00
22	JIM BRIDGER 345KV SUB	TRANSMISSION-ATTENDE	345.00	230.00	34.50
23	NAUGHTON SUB	TRANSMISSION-ATTENDE	230.00	138.00	69.00
24	BAIROIL SUB	TRANSMISSION-UNATTEN	115.00	34.50	57.00
25	CASPER SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
26	CHAPPEL CREEK SUB	TRANSMISSION-UNATTEN	230.00	69.00	
27	CHIMNEY BUTTE SUB	TRANSMISSION-UNATTEN	230.00	69.00	
28	FOOTE CREEK WIND FARM	TRANSMISSION-UNATTEN	230.00	34.50	
29	GLENDO AUTO SUB	TRANSMISSION-UNATTEN	69.00	57.00	
30	MANSFACE SUB	TRANSMISSION-UNATTEN	230.00	34.50	
31	MIDWEST SUB	TRANSMISSION-UNATTEN	230.00	69.00	34.50
32	MINERS SUB	TRANSMISSION-UNATTEN	230.00	34.50	9.70
33	MUSTANG SUB	TRANSMISSION-UNATTEN	230.00	115.00	
34	OREGON BASIN SUB	TRANSMISSION-UNATTEN	230.00	69.00	34.50
35	PLATTE SUB	TRANSMISSION-UNATTEN	230.00	115.00	34.50
36	RAILROAD SUB	TRANSMISSION-UNATTEN	230.00	138.00	
37	ROCK SPRINGS 230 SUB	TRANSMISSION-UNATTEN	230.00	34.50	
38	SAGE SUB	TRANSMISSION-UNATTEN	69.00	46.00	
39	STANDPIPE SUB	TRANSMISSION-UNATTEN	230.00	12.47	
40	THERMOPOLIS SUB	TRANSMISSION-UNATTEN	230.00	115.00	

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 2017/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
2	6					2
3	1					3
25	1					4
5	1					5
20	1	1				6
1860	148	4				7
						8
						9
20	1					10
25	1					11
50	2					12
45	2	1				13
8	6					14
25	1					15
76	4					16
25	1					17
274	18	1				18
						19
						20
303	3	1				21
703	7					22
661	4					23
53	3					24
575	4					25
75	1					26
75	1					27
196	2					28
8	1	1				29
20	1					30
157	3					31
20	1					32
100	1					33
100	2					34
140	3					35
400	1					36
50	2					37
22	1					38
75	1					39
84	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 2017/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	TOTAL		4278.00	1644.97	411.70
2	Number of Substations-20				
3					
4	CALIFORNIA				
5	Distribution - 42				
6	T/D - 2				
7	Transmission - 5				
8					
9	IDAHO				
10	Distribution - 65				
11	T/D - 5				
12	Transmission - 18				
13					
14	MONTANA				
15	Transmission - 3				
16					
17	OREGON				
18	Distribution - 176				
19	T/D - 12				
20	Transmission - 30				
21					
22	UTAH				
23	Distribution - 274				
24	T/D - 31				
25	Transmission - 43				
26					
27	WASHINGTON				
28	Distribution - 29				
29	T/D - 3				
30	Transmission - 7				
31					
32	WYOMING				
33	Distribution - 85				
34	T/D - 8				
35	Transmission - 20				
36					
37	ALL STATES				
38	Distribution - 671				
39	T/D - 61				
40	Transmission - 126				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
3817	43	2				1
						2
						3
						4
323						5
130						6
725						7
						8
						9
736						10
312						11
5111						12
						13
						14
200						15
						16
						17
4562						18
1260						19
8296						20
						21
						22
5743						23
7824						24
10997						25
						26
						27
1083						28
654						29
1179						30
						31
						32
1860						33
274						34
3817						35
						36
						37
14307						38
10454						39
30325						40

Schedule Page: 426.3 Line No.: 18 Column: a

The Antelope 230kV Substation is jointly owned by PacifiCorp and Idaho Power Company. Ownership and operations and maintenance costs vary by type of asset as defined in the Joint Ownership and Operating Agreement.

Schedule Page: 426.3 Line No.: 20 Column: a

The Big Grassy 161kV Substation is jointly owned by PacifiCorp and Idaho Power Company. Ownership and operations and maintenance costs vary by type of asset as defined in the Joint Ownership and Operating Agreement.

Schedule Page: 426.3 Line No.: 25 Column: a

The Goshen 345kV Substation is jointly owned by PacifiCorp and Idaho Power Company. Ownership and operations and maintenance costs vary by type of asset as defined in the Joint Ownership and Operating Agreement.

Schedule Page: 426.3 Line No.: 27 Column: a

The Jefferson 161kV Substation is jointly owned by PacifiCorp and Idaho Power Company. Ownership and operations and maintenance costs vary by type of asset as defined in the Joint Ownership and Operating Agreement.

Schedule Page: 426.3 Line No.: 28 Column: a

The Midpoint 500kV Substation is jointly owned by PacifiCorp and Idaho Power Company. Ownership and operations and maintenance costs vary by type of asset as defined in the Joint Ownership and Operating Agreement.

Schedule Page: 426.3 Line No.: 28 Column: g

Represents one 3-phase bank

Schedule Page: 426.3 Line No.: 32 Column: a

The Threemile Knoll 345kV Substation is jointly owned by PacifiCorp and Idaho Power Company. Ownership and operations and maintenance costs vary by type of asset as defined in the Joint Ownership and Operating Agreement.

Schedule Page: 426.3 Line No.: 39 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.: 40 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.: 8 Column: a

The Dixonville 500kV Substation is jointly owned by PacifiCorp and Bonneville Power Administration ("BPA"), each with an undivided interest of 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.: 12 Column: a

The Hurricane 230kV Substation is jointly owned by PacifiCorp and Idaho Power Company. Ownership and operations and maintenance costs vary by type of asset as defined in the Joint Ownership and Operating Agreement.

Schedule Page: 426.9 Line No.: 17 Column: a

The Malin 500kV Substation is jointly owned by PacifiCorp, BPA and Portland General Electric Company. Ownership and operations and maintenance costs vary by type of asset as defined in the operation and maintenance agreement.

Schedule Page: 426.9 Line No.: 18 Column: a

The Meridian 500kV Substation is jointly owned by PacifiCorp and BPA, each with an undivided interest of 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.: 25 Column: a

The Roundup 230kV Substation property is owned by PacifiCorp and BPA. Operation and maintenance costs vary by type of asset with responsibility for performance as defined in the facility sharing agreement.

Schedule Page: 426.9 Line No.: 26 Column: a

The Santiam Tie 230kV Substation property is owned by PacifiCorp and BPA. Operation and maintenance costs vary by type of asset with responsibility for performance as defined in the facility sharing agreement.

Schedule Page: 426.19 Line No.: 31 Column: a

The Dry Gulch 115kV Substation property is owned by PacifiCorp and Avista Corporation. Operation and maintenance costs vary by type of asset with responsibility for performance as defined in the facility sharing agreement.

Schedule Page: 426.19 Line No.: 35 Column: a

The Walla Walla 230kV Substation is jointly owned by PacifiCorp and Idaho Power Company. Ownership and operations and maintenance costs vary by type of asset as defined in the Joint Ownership and Operating Agreement.

Schedule Page: 426.22 Line No.: 21 Column: a

The Dave Johnston 230kV Substation is jointly owned by PacifiCorp and Black Hills Power with an undivided interest of 85.0% and 15.0%, respectively. 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.: 22 Column: a

The Jim Bridger 345kV Substation is jointly owned by PacifiCorp and Idaho Power Company. Ownership and operations and maintenance costs vary by type of asset as defined in the Joint Ownership and Operating Agreement.

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 2017/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	Bridger Coal Company	151,501	172,858,805
3	Coal purchases	Trapper Mining Inc.	151,501	15,625,033
4	Administrative services under the IASA	BHE		5,952,892
5	Administrative services under the IASA	MEC		3,469,506
6	Administrative services under the IASA	BHE U.S. Transmission, LLC	107,426.5,923	774,375
7	Administrative services under the IASA	MHC Inc.	426.5,923	337,353
8	Administrative services under the IASA	Kern River Gas Transmission Company	923	1,355
9	Gas transportation services and encroachment			
10	agreement for Sigurd to Red Butte	Kern River Gas Transmission Company	547,593	3,080,346
11	Rail services and right-of-way fees	BNSF Railway Company	107,501,507,567,589	35,118,660
12	Employee relocation services	HomeServices of America, Inc.		1,491,577
13	Banking services and financial transactions			
14	related to energy hedging activity	Wells Fargo & Company		1,903,997
15	Banking services	U.S. Bancorp		414,545
16	Computer hardware and software and computer			
17	systems maintenance and support services	IBM		3,585,236
18	Lubricating oil and grease products	Phillips 66 Company		897,207
19				
20	Non-power Goods or Services Provided for Affiliate			
21	Information technology and administrative	Bridger Coal Company	501,557,931	1,118,025
22	support services			
23	Administrative services under the IASA	MEC		942,339
24	Administrative services under the IASA	BHE U.S. Transmission, LLC		260,261
25	Operational support services	MEC	580	878,532
26	Finance support and employee benefits	Interwest Mining Company	557	271,111
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Schedule Page: 429 Line No.: 4 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. Nine 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 and regulatory groups. The legislative and 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 and 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.

Plant: This allocator distributes costs of managing the corporate insurance function based on assets for each affiliate.

Schedule Page: 429 Line No.: 4 Column: c

Accounts charged from BHE: 107, 426.4, 426.5 and 923.

Schedule Page: 429 Line No.: 4 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.: 5 Column: b

This footnote applies to all occurrences of "MEC" on page 429. Complete name is MidAmerican Energy Company.

Schedule Page: 429 Line No.: 5 Column: c

Accounts charged from MEC: 107, 426.4, 426.5 and 923.

Schedule Page: 429 Line No.: 5 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.: 6 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.: 7 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.: 8 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.: 11 Column: d

Non-power goods or services provided by BNSF Railway Company are as follows:

$35,067,803 Rail services
50,857 Right-of-way fees
$35,118,660

Included in the rail services are amounts related to a jointly-owned plant that are paid indirectly to BNSF Railway Company.

Schedule Page: 429 Line No.: 12 Column: c

Accounts charged from HomeServices of America, Inc.: 506, 535, 539, 548, 557, 561.2, 580, 581, 590, 592, 901, 903, 908 and 921.

Schedule Page: 429 Line No.: 14 Column: c

Accounts charged from Wells Fargo & Company: 228.3, 419, 426.5, 427, 431, 501, 547, 903, 923 and 928.

Schedule Page: 429 Line No.: 14 Column: d

Non-power goods or services provided by Wells Fargo & Company are as follows:

$1,128,574 Banking services
775,423 Financial transactions related to energy hedging activity
$1,903,997

Schedule Page: 429 Line No.: 15 Column: c

Accounts charged from U.S. Bancorp: 419, 427, 431, 537, 557, 903, 920, 923, 928 and 930.2.

Schedule Page: 429 Line No.: 17 Column: b

This footnote applies to all occurrences of "IBM" on page 429. Complete name is International Business Machines Corporation.

Schedule Page: 429 Line No.: 17 Column: c

Accounts charged from IBM: 107, 165, 903, 921, 923 and 935.

Schedule Page: 429 Line No.: 18 Column: c

Accounts charged from Phillips 66 Company: 154, 500, 501, 502, 506, 511, 512, 513, 514, 535, 539, 548, 552, 553, 562, 571, 582, 583, 592 and 593.

Schedule Page: 429 Line No.: 23 Column: c

Accounts charged to MEC: 556, 557, 580, 588, 920 and 921.

Schedule Page: 429 Line No.: 23 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.: 24 Column: c

Accounts charged to BHE U.S. Transmission, LLC: 557, 560, 580, 588, 920 and 921.

Schedule Page: 429 Line No.: 24 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.

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