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

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

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
PacifiCorp	**End of** 2011/Q2

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

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

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

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

The CPA Certification Statement should:

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

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

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

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

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

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

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

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

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

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent PacifiCorp	02 Year/Period of Report End of 2011/Q2
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 825 N.E. Multnomah, Suite 1900, Portland, OR 97232	
05 Name of Contact Person Henry E. Lay	06 Title of Contact Person Corporate Controller
07 Address of Contact Person *(Street, City, State, Zip Code)* 825 N.E. Multnomah, Suite 1900, Portland, OR 97232	

08 Telephone of Contact Person, *Including Area Code* (503) 813-6179	09 This Report Is (1) ☐ An Original (2) ☒ A Resubmission	10 Date of Report *(Mo, Da, Yr)* 07/02/2012

QUARTERLY CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name Douglas K. Stuver 02 Title Senior VP & Chief Financial Officer	03 Signature Douglas K. Stuver	04 Date Signed *(Mo, Da, Yr)* 07/02/2012

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

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	Important Changes During the Quarter	108-109	Resubmitted
2	Comparative Balance Sheet	110-113	Resubmitted
3	Statement of Income for the Quarter	114-117	Resubmitted
4	Statement of Retained Earnings for the Quarter	118-119	Resubmitted
5	Statement of Cash Flows	120-121	Resubmitted
6	Notes to Financial Statements	122-123	Resubmitted
7	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122 (a)(b)	
8	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	Resubmitted
9	Electric Plant In Service and Accum Provision For Depr by Function	208	
10	Transmission Service and Generation Interconnection Study Costs	231	
11	Other Regulatory Assets	232	
12	Other Regulatory Liabilities	278	
13	Elec Operating Revenues (Individual Schedule Lines 300-301)	300-301	
14	Regional Transmission Service Revenues (Account 457.1)	302	N/A
15	Electric Prod, Other Power Supply Exp, Trans and Distrib Exp	324	Resubmitted
16	Electric Customer Accts, Service, Sales, Admin and General Expenses	325	
17	Transmission of Electricity for Others	328-330	
18	Transmission of Electricity by ISO/RTOs	331	N/A
19	Transmission of Electricity by Others	332	
20	Deprec, Depl and Amort of Elec Plant (403,403.1,404,and 405) (except A	338	
21	Amounts Included in ISO/RTO Settlement Statements	397	N/A
22	Monthly Peak Loads and Energy Output	399	
23	Monthly Transmission System Peak Load	400	
24	Monthly ISO/RTO Transmission System Peak Load	400a	N/A

Schedule Page: 2 Line No.: 1 Column:

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

Schedule Page: 2 Line No.: 2 Column:

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

Schedule Page: 2 Line No.: 3 Column:

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

Schedule Page: 2 Line No.: 4 Column:

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

Schedule Page: 2 Line No.: 5 Column:

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

Schedule Page: 2 Line No.: 6 Column:

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

Schedule Page: 2 Line No.: 8 Column:

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

Schedule Page: 2 Line No.: 15 Column:

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

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) ☐ An Original (2) ☒ A Resubmission	07/02/2012	End of 2011/Q2

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.

Changes in Franchise Rights

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

State	Effective Date	Expiration Date	Fee
California (1)			
None			
Idaho (2)			
Montpelier	05/12/2011	05/12/2046	-
Ammon	06/08/2011	06/08/2041	3.0%
Oregon (3)			
None			
Utah (2)			
Panguitch	03/08/2011	03/08/2031	2.0%
Holladay	03/14/2011	03/14/2036	6.0%
Wasatch County	04/25/2011	09/28/2035	-
Centerville	06/07/2011	12/31/2016	5.0%
Hideout	06/22/2011	06/22/2021	6.0%
Washington (2)			
Dayton	02/21/2011	02/21/2021	6.0%
Wyoming (4)			
Lincoln County	06/22/2011	06/22/2036	-

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

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

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

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

ITEM 2.

For information on the resubmission, refer to Note 1 of Notes to Financial Statements in this Form 3-Q and Note 2 of Notes to Financial Statements in PacifiCorp's annual report on Form No. 1 for the year ended December 31, 2011.

ITEM 3.

Purchase or Sale of an Operating Unit

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

In March 2011, PacifiCorp entered into an agreement for the sale of the Snake Creek hydroelectric generating facility with Heber Light & Power Company. The sale will close after all regulatory approvals have been obtained. In April 2011, PacifiCorp filed for approval of the sale with the Oregon Public Utility Commission ("OPUC"), the California Public Utilities Commission ("CPUC") and the Wyoming Public Service Commission ("WPSC"). In July 2011, PacifiCorp received approval from the CPUC and the WPSC for the sale. Commission authorizations for the sale were as follows:

- CPUC - Advice Letter 439-E, effective July 28, 2011.
- WPSC - Docket No. 20000-395-EA-11, effective July 8, 2011, pursuant to open meeting action taken on July 8, 2011.

ITEM 4.

Important Leaseholds

None.

ITEM 5.

Important Extension or Reduction of Transmission System or Distribution Territory

None.

ITEM 6.

Financing Activities

Short-term Debt and Revolving Credit Facilities

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt. As of June 30, 2011, PacifiCorp had no short-term debt outstanding. As of December 31, 2010, PacifiCorp had $36 million of short-term debt outstanding at a weighted average interest rate of 0.3%.

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

- OPUC - Docket No. UF-4120, Order No. 98-158, dated April 16, 1998.
- Washington Utilities and Transportation Commission ("WUTC") - Docket No. UE-980404, dated April 8, 1998.
- Idaho Public Utilities Commission ("IPUC") - Case No. PAC-E-11-09, Order No. 32221, dated April 8, 2011, effective through April 30, 2016.
- FERC - Docket No. ES09-50-000, dated October 9, 2009, letter order effective January 1, 2010 through December 31, 2011.

Long-term Debt

In May 2011, PacifiCorp issued $400 million of 3.85% First Mortgage Bonds due June 15, 2021. The net proceeds are being used to fund capital expenditures, for the repayment of short-term debt and for general corporate purposes. State commission authorizations for this issuance were as follows:

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

PacifiCorp has regulatory authority from the OPUC and the IPUC to issue an additional $1.6 billion of long-term debt. PacifiCorp must make a notice filing with the WUTC prior to any future issuance.

As of June 30, 2011, PacifiCorp had $601 million of letters of credit available to provide credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $587 million plus interest. These letters of credit were fully available as of June 30, 2011 and expire periodically through September 22, 2012.

Common Equity

In January 2011, PacifiCorp declared a dividend of $275 million, which was paid to PPW Holdings LLC, a direct wholly owned subsidiary of MidAmerican Energy Holdings Company and PacifiCorp's direct parent company, on February 28, 2011. In March 2011, PacifiCorp declared a dividend of $275 million, which was paid to PPW Holdings LLC on April 20, 2011.

ITEM 7.

Changes in Articles of Incorporation or Amendments to Charter

None.

ITEM 8.

Estimated Annual Effect of Wage Scale Changes

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

Unions Represented	% Increase (1)	Effective Date(s)	Estimated Annual Financial Impact (2)
IBEW 57 Power Delivery (UT, ID & WY)	1.6%	1/26/2011	1,321,959
IBEW 57 Power Supply (UT, ID & WY)	1.6%	1/26/2011	622,877
WEW IBB S1978 (WY)	1.0%	3/24/2011	182,640
UWUA 197 (OR)	0.9%	5/26/2011	16,116
IBEW 57 Combustion Turbine (UT)	1.1%	5/26/2011	23,940
IBEW 57 Laramie (WY)	0.8%	6/26/2011	4,622
Total			$ 2,172,154

(1) This percentage increase represents the increase in wages for all effective dates during the calendar year as compared to the wage scale of the prior effective period.

(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.

Legal Proceedings

In addition to the discussion contained herein regarding updates to legal proceedings based upon significant changes that occurred subsequent to those disclosed in Important Changes During the Quarter/Year, Item 9 of PacifiCorp's annual report on Form No. 1 for the year ended December 31, 2010, also refer to Note 8 of Notes to Financial Statements included in this Form 3-Q for developments since December 31, 2010, which includes an update on the USA Power legal matter.

In December 2000, Wah Chang, a large industrial customer of PacifiCorp filed an action before the OPUC asserting that the rates set by a special tariff with PacifiCorp and approved by the OPUC were not just and reasonable due to alleged market manipulation during the energy crisis. In October 2001, the OPUC dismissed Wah Chang's petition and found that Wah Chang assumed the risk of price increases under the special tariff. Wah Chang petitioned the Circuit Court for Marion County, Oregon for review of the OPUC's order. In June 2002, the Circuit Court for Marion County, Oregon granted Wah Chang's motion for review and ordered the OPUC to reopen the record to allow Wah Chang the opportunity to present new evidence. In September 2009, the OPUC dismissed Wah Chang's petition and reaffirmed that the rates set by the special tariff were just and reasonable. In October 2009, Wah Chang filed with the Oregon Court of Appeals a petition for judicial review of the OPUC's September 2009 order denying Wah Chang relief. In July 2010, the Oregon Court of Appeals accepted judicial review.

In a separate but related proceeding, in December 2000, Wah Chang filed a complaint in the Circuit Court for Linn County, Oregon asserting that the OPUC-approved special tariff with PacifiCorp is subject to rescission based on theories of mutual mistake of fact, frustration of purpose and impracticability. In August 2002, the Circuit Court for Linn County, Oregon granted PacifiCorp's motion for summary judgment dismissing Wah Chang's complaint. In February 2004, the Circuit Court for Linn County, Oregon granted Wah Chang's motion to reopen the case to present additional evidence of alleged market manipulation. In December 2007, Wah Chang filed a second amended complaint seeking recovery of a portion of the costs paid under the special tariff based on various theories of legal relief, including partial rescission, unjust enrichment, and breach of duty of good faith and fair dealing. In August 2009, the Circuit Court for Linn County, Oregon granted Wah Chang's request to file a third amended complaint containing a claim for punitive damages. In April 2011, Wah Chang's claims were presented during a jury trial, and all claims, including the claim for punitive damages, were resolved in PacifiCorp's favor. Wah Chang did not appeal this outcome and the outcome had no impact on PacifiCorp's financial results.

ITEM 10.

Officer, Director, Security Holder and Associated Company Transactions

There have been no officer, director or security holder transactions during the six-month period ended June 30, 2011.

ITEM 11.
(Reserved)

ITEM 12.

Regulatory Matters

In addition to the discussion contained herein regarding updates to regulatory matters based upon material changes that occurred subsequent to those disclosed in Important Changes During the Quarter/Year, Item 12 of PacifiCorp's annual report on Form No. 1 for the year ended December 31, 2010, refer to Note 8 of Notes to Financial Statements in this Form 3-Q for additional regulatory matter updates.

FERC

As a result of a 2007 multi-party settlement with the FERC regarding long-term shared usage, coordinated operation and maintenance, and planning of certain 500-kV transmission lines, PacifiCorp agreed to file a Federal Power Act Section 205 rate change filing for its system-wide transmission service rates no later than June 1, 2011. In May 2011, PacifiCorp filed its Federal Power Act Section 205 rate case. In August 2011, the FERC issued an order in Docket Nos. ER11-3643-000 and ER11-3643-001 accepting, but suspending for a five-month period, the rates proposed in PacifiCorp’s May 2011 Federal Power Act Section 205 rate case filing due to material issues of fact. The FERC also ordered hearings to be held to address the issues raised by PacifiCorp’s Federal Power Act Section 205 rate case filing as well as issues raised by interveners to the proceeding. However, the FERC set the hearings in abeyance to allow the parties to negotiate a settlement. Although PacifiCorp’s proposed rates become effective December 25, 2011, they are subject to a final order to be issued by FERC following conclusion of settlement and hearing and, as such, are subject to refund pending the outcome of the proceeding.

State Regulatory Matters

Utah

In March 2009, PacifiCorp filed for an energy cost adjustment mechanism ("ECAM") with the Utah Public Service Commission ("UPSC"). The filing recommended that the UPSC adopt the mechanism to recover the difference between base net power costs set in the next Utah general rate case and actual net power costs. In February 2010, PacifiCorp filed an application with the UPSC seeking approval to defer the difference between the net power costs allowed by the UPSC's final order in PacifiCorp's 2009 general rate case and the actual net power costs incurred. Also in February 2010, the Utah Association of Energy Users filed a motion with the UPSC requesting deferral of incremental renewable energy credit ("REC") revenue in excess of the REC value utilized in Utah rates established by the 2009 general rate case. In July 2010, the UPSC issued an order approving a stipulation that would establish deferred accounts for both net power costs and REC revenues in excess of the levels currently included in rates, subject to the UPSC's final determination of the ratemaking treatment of the deferrals. In December 2010, the UPSC approved a separate stipulation that provides a $3 million monthly credit to customers effective January 1, 2011 that will be applied toward the UPSC's final decision. In March 2011, the UPSC issued its final order approving the use of an energy balancing account ("EBA") in Utah, which will begin at the conclusion of the general rate case described below. Under the EBA, which has been established as a four year pilot program, 70% of any difference between actual net power costs incurred and the amount of net power costs recovered through base rates, subject to certain other adjustments, are deferred during the calendar year. PacifiCorp must then file by March 15 of the following year to initiate collection or refund of the deferred balance. The UPSC did not address in its EBA order the ratemaking treatment of the deferred accounts for net power costs and REC revenues in excess of the levels included in rates since the 2009 general rate case. In April 2011, PacifiCorp filed a petition with the UPSC for clarification and reconsideration of certain aspects of the EBA order. In May 2011, the UPSC granted PacifiCorp's petition for reconsideration of the UPSC's decision to exclude financial swaps from the EBA. The UPSC denied reconsideration of the 70% sharing of incremental net power costs not in base rates and clarified that the final order does not preclude future consideration of balancing account treatment for REC sales. These issues are included in the settlement stipulation described in the following paragraph.

In January 2011, PacifiCorp filed a general rate case with the UPSC requesting a rate increase of $232 million, or an average price increase of 14%. In June 2011, PacifiCorp filed its rebuttal testimony with the UPSC reducing the requested rate increase to $188 million, or an average price increase of 11%. In July 2011, PacifiCorp filed a settlement stipulation with the UPSC, which was approved by the UPSC in August 2011 and results in a $117 million rate increase, or an average price increase of 7%, effective September 21, 2011. The settlement stipulation also resolves all major dockets outstanding before the UPSC. Under the terms of the settlement stipulation, financial swaps will be included in the EBA and a collaborative process with Utah stakeholders may result in future modifications to PacifiCorp’s risk management and hedging policies. The settlement stipulation also concludes the ratemaking treatment of deferred accounts for net power costs and REC revenues in excess of the levels included in rates since the 2009 general rate case by providing for recovery of $60 million of deferred net power costs over a three-year period and for a credit to customers of $34 million (including carrying charges) associated with REC sales over a period of approximately nine months. The settlement stipulation also establishes a balancing account for prospective REC sales. The settlement stipulation also defers decisions regarding the ratemaking treatment associated with the Klamath hydroelectric system's four mainstem dams and relicensing and settlement costs as described in Note 8 to Notes to Financial Statements.

Oregon

In March 2011, PacifiCorp made its initial filing for the annual transition adjustment mechanism ("TAM") with the OPUC for an annual increase of $62 million to recover the anticipated net power costs forecasted for calendar year 2012. In July 2011, PacifiCorp filed updated net power costs, reflecting an increase in the overall request to $63 million, or an average price increase of 5%. The new rates will be effective January 1, 2012 and are subject to updates throughout the proceeding, which is scheduled to be completed in November 2011.

In October 2010, PacifiCorp filed its 2009 tax report under Oregon Senate Bill ("SB 408"). In January 2011, PacifiCorp entered into a stipulation with the OPUC staff and the Citizens' Utility Board of Oregon, whereby PacifiCorp, the OPUC staff and the Citizens' Utility Board of Oregon agreed to a surcharge of $13 million, plus interest. In April 2011, the OPUC issued an order adopting the stipulation without significant modification. The $13 million, plus interest, was recorded in earnings in the second quarter of 2011 and is being collected over a one-year period that began in June 2011.

In May 2011, Oregon Senate Bill 967 ("SB 967") was enacted into law. SB 967 immediately repealed and replaced SB 408, and as a result, PacifiCorp will no longer be required to file tax reports under SB 408. Among other matters, SB 967 directs the OPUC to consider the income tax component of rates when conducting ratemaking proceedings. The enactment of SB 967 did not impact PacifiCorp's financial results.

Wyoming

In April 2010, PacifiCorp filed an application with the WPSC requesting approval of a new ECAM to replace the existing power cost adjustment mechanism ("PCAM"). The PCAM concluded with the final deferral of net power costs in November 2010 and collection through March 2012. In February 2011, the WPSC issued an order approving an ECAM effective December 1, 2010, under which 70% of any difference between actual net power costs incurred and the amount of net power costs recovered through base rates, subject to certain other adjustments, are deferred as incurred during the calendar year. PacifiCorp must then file by March 15 of the following year to initiate collection or refund of the deferred balance beginning June 1.

In November 2010, PacifiCorp filed a general rate case with the WPSC requesting a rate increase of $98 million, or an average price increase of 17%. In May 2011, PacifiCorp filed its rebuttal testimony with the WPSC reducing the requested rate increase to $80 million. In June 2011, the WPSC approved a multi-party stipulation resulting in an annual rate increase of $62 million, or an average price increase of 11%. The stipulation also established a surcredit and a balancing account to pass on to or collect from customers any difference between the amount of the REC sales established in the surcredit and actual REC sales. The surcredit will be established annually based on PacifiCorp's forecasted REC sales and the difference between the surcredit and actual REC sales will be tracked in the balancing account. For 2011, the surcredit was set at $17 million, which reduced PacifiCorp's annual rate increase to $45 million, or an average price increase of 8%. The rates will be effective September 22, 2011.

In February 2011, PacifiCorp filed its final PCAM application with the WPSC requesting recovery of $16 million in deferred net power costs over the 12-month period ending March 31, 2012. PacifiCorp requested and received approval from the WPSC to implement an $11 million interim rate increase over the $5 million reflected in the tariff effective April 1, 2011, which will be in effect until the WPSC issues a final order.

Washington

In May 2010, PacifiCorp filed a general rate case with the WUTC requesting an annual increase of $57 million, or an average price increase of 21%. In November 2010, the requested annual increase was reduced to $49 million, or an average price increase of 18%. In March 2011, the WUTC issued a final order and clarification letter approving an annual increase of $33 million, or an average price increase of 12%, reduced in the first year by a customer bill credit of $5 million, or 2%, related to the sale of RECs expected during the rate year. The new rates were effective in April 2011. In April 2011, PacifiCorp filed a petition for reconsideration requesting the WUTC reconsider various items on the final order, including income tax and net power cost issues and the WUTC's conclusions with respect to rate of return. The WUTC staff also filed a petition for reconsideration. In May 2011, the WUTC denied the petitions for reconsideration filed by PacifiCorp and the WUTC staff.

In July 2011, PacifiCorp filed a general rate case with the WUTC requesting an annual increase of $13 million, or an average price increase of 4%, with an effective date no later than June 1, 2012.

Idaho

In May 2010, PacifiCorp filed a general rate case with the IPUC requesting an annual increase of $28 million, or an average price increase of 14%. In November 2010, the requested annual increase was reduced to $25 million, or an average price increase of 12%. In December 2010, the IPUC issued an interim order approving an annual increase of $14 million, or an average price increase of 7% with an effective date of December 28, 2010. In February 2011, the IPUC issued its final order with no revisions to the December 2010 increase. In March 2011, PacifiCorp petitioned the IPUC seeking reconsideration or rehearing on certain aspects of the order, including the IPUC's conclusion that 27% of PacifiCorp's Populus to Terminal transmission line investment is not currently used and useful and should be carried as plant held for future use. The Idaho-allocated share of 27% of the investment is approximately $13 million. In April 2011, the IPUC issued an order, accepting in part and rejecting in part, PacifiCorp's motion for reconsideration, resulting in no significant changes to the IPUC's initial order. In May 2011, PacifiCorp filed an appeal of the Populus to Terminal decision to the Idaho Supreme Court requesting a determination on the legality of the IPUC's decision to exclude 27% of the Populus to Terminal line as a result of its conclusion that the line is not fully used and useful.

In February 2011, PacifiCorp filed an ECAM application with the IPUC requesting recovery of $13 million in deferred net power costs. In March 2011, the IPUC issued an order approving recovery of $10 million beginning in 2011 and the remaining $3 million beginning in 2012. The rate change was effective April 1, 2011.

In May 2011, PacifiCorp filed a general rate case with the IPUC requesting an annual increase of $33 million, or an average price increase of 15%. If the schedule requested by PacifiCorp is approved by the IPUC, the new rates will be effective December 27, 2011.

California

In August 2011, PacifiCorp filed an application with the CPUC to increase rates pursuant to the energy cost adjustment clause. In the application, PacifiCorp requested a rate increase of $2 million, or an average price increase of 2%. If approved by the CPUC, the new rates will be effective January 1, 2012.

Hydroelectric Decommissioning

Condit Hydroelectric Facility - White Salmon River, Washington

In September 1999, a settlement agreement to remove the 14-megawatt ("MW") Condit hydroelectric facility was signed by PacifiCorp, state and federal agencies and non-governmental organizations. In early February 2005, the parties agreed to modify the settlement agreement, establishing a total cost to decommission not to exceed $21 million, excluding inflation. In October 2010, the Washington Department of Ecology issued a Clean Water Act 401 certificate, and in December 2010, the FERC issued a surrender order for project decommissioning modifying PacifiCorp's proposed decommissioning plans and directing a 2011 decommissioning. In January 2011, PacifiCorp filed a request for clarification and rehearing of the surrender order and a motion for stay with the FERC requesting reinstatement of PacifiCorp's decommissioning proposal. In April 2011, the FERC issued an order on rehearing, granting PacifiCorp nearly all of the changes it requested, but did not shorten the required agency consultation and FERC approval periods. In June 2011, PacifiCorp formally notified the FERC of its acceptance of the terms and conditions of the orders that govern the surrender of the project license. PacifiCorp commenced on-site decommissioning activities in June 2011 and dam breach is expected no later than November 2011.

Future Generation and Conservation

Integrated Resource Plan

As required by certain state regulations, PacifiCorp uses an Integrated Resource Plan ("IRP") to develop a long-term view of prudent future actions required to help ensure that PacifiCorp continues to provide reliable and cost-effective electric service to its customers. The IRP process identifies the amount and timing of PacifiCorp's expected future resource needs and an associated optimal future resource mix that accounts for planning uncertainty, risks, reliability impacts, state energy policies and other factors. The IRP is a coordinated effort with stakeholders in each of the six states where PacifiCorp operates. PacifiCorp files its IRP on a biennial basis and receives a formal notification in five states as to whether the IRP meets the commission's IRP standards and guidelines, referred to as acknowledgment. In March 2011, PacifiCorp filed its 2011 IRP with the state commissions. In June 2011, an addendum to the 2011 IRP with supplemental resource analysis was filed with the state commissions.

Requests for Proposals

PacifiCorp has issued a series of individual Requests for Proposals ("RFPs"), each of which focuses on a specific category of electric generation resources consistent with the IRP. The IRP and the RFPs provide for the identification and staged procurement of resources in future years to achieve a balance of load requirements and resources. As required by applicable laws and regulations, PacifiCorp files draft RFPs with the UPSC, the OPUC and the WUTC prior to issuance to the market. Approval by the UPSC, the OPUC or the WUTC may be required depending on the nature of the RFPs.

In October 2009, PacifiCorp filed a request for approval with the UPSC to re-issue the All Source RFP, which was previously suspended in April 2009. In October 2009 and November 2009, respectively, the UPSC and the OPUC approved resumption of the All Source RFP. The All Source RFP sought up to 1,500 MW on a system wide basis from projects with in-service dates from 2014 through 2016. In December 2009, the All Source RFP was issued to the market. As a result, PacifiCorp signed an engineer, procure and construct contract for the Lake Side 2 637-MW combined-cycle combustion turbine natural gas-fired generating facility ("Lake Side 2"), which is expected to be placed in service in June 2014. The Lake Side 2 generating facility will be constructed adjacent to PacifiCorp's Lake Side generating facility, which is located in Vineyard, Utah, about 40 miles south of Salt Lake City. In April 2011, the UPSC issued an order approving the construction of Lake Side 2. PacifiCorp has obtained all of the necessary construction permits and certificates, and in May 2011, PacifiCorp issued a notice to proceed with construction of the Lake Side 2 generating facility.

Environmental Laws and Regulations

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, renewable portfolio standards ("RPS"), 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. In addition to imposing continuing compliance obligations, these laws and regulations provide authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by the United States Environmental Protection Agency ("EPA") and various other state and local agencies. All such laws and regulations are subject to a range of interpretation, which may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and PacifiCorp is unable to predict the impact of the changing laws and regulations on its operations and financial results. PacifiCorp believes it is in material compliance with all applicable laws and regulations. Refer to Note 8 of Notes to Financial Statements in this Form 3-Q for additional information regarding certain environmental laws and regulations affecting PacifiCorp. The discussion below contains material developments since those disclosed in Important Changes During the Quarter/Year, Item 12 of PacifiCorp's annual report on Form No. 1 for the year ended December 31, 2010.

Clean Air Standards

Clean Air Mercury Rule/Hazardous Air Pollutant Maximum Achievable Control Technology Standards

In March 2011, the EPA proposed a new rule that will require coal-fired generating facilities to reduce mercury emissions and other hazardous air pollutants through the establishment of a "Maximum Achievable Control Technology" standard rather than a cap-and-trade system. The public comment period closed August 4, 2011 and the final rule will be issued in November 2011. The proposed rule requires that new and existing coal-fired facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources are required to comply with the new standards within three years after the final rule is promulgated, with individual sources granted an additional year to complete installation of controls if approved by the permitting authority. Until the rule is final, PacifiCorp cannot fully determine the costs to comply with the requirements; however, PacifiCorp believes that its emission reduction projects completed to date or currently permitted or planned for installation, including scrubbers, baghouses and electrostatic precipitators are consistent with the EPA's proposed rules and will support PacifiCorp's ability to comply with the proposal's standards for acid gases and non-mercury metallic hazardous air pollutants. PacifiCorp anticipates having to take additional actions to reduce mercury emissions and otherwise comply with the proposal's standards. Incremental costs to install and maintain mercury emissions control equipment and additional emissions monitoring equipment at each of PacifiCorp's coal-fired generating facilities will increase the cost of providing service to customers.

Regional Haze

The EPA has initiated a regional haze program intended to improve visibility in designated federally protected areas ("Class I areas"). Some of PacifiCorp's generating facilities meet the threshold applicability criteria to be eligible units under the Clean Air Visibility Rules. In accordance with the federal requirements, states were required to submit State Implementation Plans ("SIPs") by December 2007 to demonstrate reasonable progress towards achieving natural visibility conditions in Class I areas by requiring emissions controls, known as best available retrofit technology, on sources constructed between 1962 and 1977 with emissions that are anticipated to cause or contribute to impairment of visibility. Utah submitted its SIP and suggested that the emissions reduction projects planned by PacifiCorp are sufficient to meet its initial emissions reduction requirements. Utah approved amendments to its SIP submittal in April 2011, and those amendments, along with its previous SIP submittal, await approval or further direction from the EPA. Wyoming submitted its regional haze SIP to the EPA in January 2011. PacifiCorp believes that its planned emissions reduction projects will satisfy the regional haze requirements in Utah and Wyoming. It is possible that additional controls may be required after the respective SIPs have been considered by the EPA or that the timing of installation of planned controls could change.

Climate Change

Greenhouse Gas Tailoring Rule

Effective January 2, 2011, power plants, among other facilities, were required to comply with the first phase of the Greenhouse Gas ("GHG") Tailoring Rule, which provides that any source that already has a Title V operating permit is required to have GHG provisions added to its permits upon renewal. In addition, the GHG Tailoring Rule provides that if projects at existing major sources result in an increase in emissions of GHG of at least 75,000 tons per year, such projects could trigger permitting requirements and the application of best available control technology to address GHG emissions. The second phase of the GHG Tailoring Rule took effect July 1, 2011 and broadened the scope of the sources that are required to obtain federal permits to limit GHGs to any new or modified sources that emit more than 100,000 tons per year of GHG, regardless of whether a major source air permit is required for any other pollutant regulated under the Clean Air Act.

New major sources are also required to undergo permitting and install the best available control technology if their GHG emissions exceed the applicable threshold. Several legal challenges have been filed to the EPA's final GHG Tailoring Rule in the United States Court of Appeals for the District of Columbia Circuit. The EPA issued GHG best available control technology guidance documents in an effort to provide permitting authorities guidance on how to conduct a best available control technology review for GHG. Permitting authorities are beginning to implement the GHG Tailoring Rule and determine what constitutes best available control technology for GHG. PacifiCorp is in the process of obtaining permits for certain existing facilities to install emissions reduction equipment to comply with the Regional Haze Rules and assessed the impacts of the projects on GHG emissions under the GHG Tailoring Rule. No GHG emissions limit is expected to be included in the permits. However, Lake Side 2 was subject to a best available control technology review and the permit includes a limit for carbon dioxide equivalent emissions. The GHG Tailoring Rule will result in the imposition of a permit limit for GHG emissions at certain facilities, which management believes will not have a material impact on PacifiCorp.

GHG New Source Performance Standards

Under the Clean Air Act, the EPA may establish emissions standards that reflect the degree of emission reductions achievable through the best technology that has been demonstrated, taking into consideration the cost of achieving those reductions and any non-air quality health and environmental impact and energy requirements. The EPA entered into a settlement agreement with a number of parties, including certain state governments and environmental groups, in December 2010 to promulgate emissions standards covering GHG by September 30, 2011, as amended, and issue final regulations by May 26, 2012. It is unclear what standards the EPA will establish for new and modified sources or what the guidelines will be for existing sources. Until the standards are proposed and finalized, the impact on PacifiCorp cannot be determined.

Regional and State Activities

Several states have promulgated or otherwise participate in state-specific or regional laws or initiatives to report or mitigate GHG emissions. These are expected to impact PacifiCorp and include:

- The Western Climate Initiative, a comprehensive regional effort to reduce GHG emissions by 15% below 2005 levels by 2020 through a cap-and-trade program that includes the electricity sector. The Western Climate Initiative includes the states of California, Montana, New Mexico, Oregon, Utah and Washington and the Canadian provinces of British Columbia, Manitoba, Ontario and Quebec. The state and provincial partners have agreed to begin reporting GHG emissions in 2011 for emissions that occurred in 2010. The first phase of the cap-and-trade program is scheduled to begin on January 1, 2012; however, only California, British Columbia and Quebec appear to be in a position to implement their programs in 2012.

- An executive order signed by California's governor in June 2005 would reduce GHG emissions in California to 2000 levels by 2010, to 1990 levels by 2020 and 80% below 1990 levels by 2050. The California Air Resources Board proposed regulations to adopt a GHG cap-and-trade program in October 2010; however, those regulations have not yet been finalized. In June 2011, the California Air Resources Board announced that while its cap-and-trade program is effective January 1, 2012, entities would not have a compliance obligation until 2013. In addition, California has adopted legislation that imposes a GHG emissions performance standard to all electricity generated within the state or delivered from outside the state that is no higher than the GHG emissions levels of a state-of-the-art combined-cycle natural gas-fired generating facility, as well as legislation that adopts an economy-wide cap on GHG emissions to 1990 levels by 2020.

Reporting

PacifiCorp voluntarily reported its GHG emissions to the California Climate Action Registry and currently reports to The Climate Registry. In September 2009, the EPA issued its final rule regarding mandatory GHG Reporting beginning January 1, 2010. Under GHG Reporting, suppliers of fossil fuels, manufacturers of vehicles and engines, and facilities that emit 25,000 metric tons or more per year of GHG are required to submit annual reports to the EPA. PacifiCorp is subject to this requirement and will submit its first report by September 30, 2011.

Federal Legislation

Legislation introduced in the 112^{th} Congress has been focused on repeal or delay of the EPA's ability to regulate GHG emissions. There is currently no federal legislation pending to regulate GHG emissions.

Renewable Portfolio Standards

In 2011, the California Legislature passed, and the governor signed, legislation to expand the state's RPS to require 20% of retail load to be procured from renewable resources by December 31, 2013, 25% by December 31, 2016 and 33% by December 31, 2020 and each year thereafter. The new law supersedes the California Air Resources Board 33% renewable electricity standard adopted pursuant to Executive Order S-21-09 in September 2009. The 2011 legislation expands the RPS to all California retail sellers, changes the flexible compliance mechanisms for retail sellers and limits the use of out-of-state renewable electricity generation to comply with the law.

Water Quality Standards

In March 2011, the EPA released a proposed rule under §316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The proposed rule establishes requirements for all power generating facilities that withdraw more than 2 million gallons per day, based on total design intake capacity, of water from waters of the United States and use at least 25% of the withdrawn water exclusively for cooling purposes. The proposed rule includes impingement (i.e., when fish and other organisms are trapped against screens when water is drawn into a facility's cooling system) mortality standards to be met through average impingement mortality or intake velocity design criteria and entrainment (i.e., when organisms are drawn into the facility) standards to be determined on a case-by-case basis. The standards are required to be met as soon as possible after the effective date of the final rule, but no later than eight years thereafter. The rule is required to be finalized by July 2012. PacifiCorp will be required to complete impingement and entrainment studies in 2013. The costs of compliance with the cooling water intake structure rule cannot be determined until the rule is final and the prescribed studies are conducted. In the event that PacifiCorp's existing intake structures require modification, the costs are not anticipated to be significant.

Coal Combustion Byproduct Disposal

In December 2008, an ash impoundment dike at the Tennessee Valley Authority's Kingston power plant collapsed after heavy rain, releasing a significant amount of fly ash and bottom ash, coal combustion byproducts, and water to the surrounding area. In light of this incident, federal and state officials have called for greater regulation of the storage and disposal of coal combustion byproducts. In May 2010, the EPA released a proposed rule to regulate the management and disposal of coal combustion byproducts, presenting two alternatives to regulation under the Resource Conservation and Recovery Act ("RCRA"). Under the first option, coal combustion byproducts would be regulated as special waste under RCRA Subtitle C and the EPA would establish requirements for coal combustion byproducts from the point of generation to disposition, including the closure of disposal units. Alternatively, the EPA is considering regulation under RCRA Subtitle D under which it would establish minimum nationwide standards for the disposal of coal combustion byproducts. Under both options, surface impoundments utilized for coal combustion byproducts would have to be cleaned and closed unless they could meet more stringent regulatory requirements; in addition, more stringent requirements would be implemented for new ash landfills and expansions of existing ash landfills. PacifiCorp operates 16 surface impoundments and six landfills that contain coal combustion byproducts. These ash impoundments and landfills may be impacted by the newly proposed regulation, particularly if the materials are regulated as hazardous or special waste under RCRA Subtitle C, and could pose significant additional costs associated with ash management and disposal activities at PacifiCorp's coal-fired generating facilities. The public comment period closed in November 2010. The EPA has indicated it does not intend to finalize the rule in 2011 and the substance of the final rule is not known. The impact of the proposed regulations on coal combustion byproducts cannot be determined at this time; however, PacifiCorp has begun developing surface impoundment and landfill compliance plan options to ensure that physical infrastructure decisions are aligned with the potential outcomes of the rulemaking.

Other

PacifiCorp expects that it will be allowed to recover the prudently incurred costs to comply with the environmental laws and regulations discussed above. PacifiCorp's planning efforts take into consideration the complexity of balancing factors such as: (1) pending environmental regulations and requirements to reduce emissions, address waste disposal, ensure water quality and protect wildlife; (2) avoidance of excessive reliance on any one generation technology; (3) costs and trade-offs of various resource options including energy efficiency, demand response programs and renewable generation; (4) state-specific energy policies, resource preferences and economic development efforts; (5) additional transmission investment to reduce power costs and increase efficiency and reliability of the integrated transmission system; and (6) keeping rates as affordable as possible. Due to the number of generating units impacted by environmental regulations, deferring installation of compliance-related projects is often not feasible or cost-effective and places PacifiCorp at risk of not having access to necessary capital, material and labor while attempting to perform major equipment installations in a compressed timeframe concurrent with other utilities across the country. Therefore, PacifiCorp has established installation schedules with permitting agencies that coordinate compliance timeframes with construction and tie-in of major environmental compliance projects as units are scheduled off-line for planned maintenance outages; these coordinated efforts reduce costs associated with replacement power and maintain system reliability.

Collateral and Contingent Features

PacifiCorp's senior secured and senior unsecured debt credit ratings are as follows:

	Fitch	Moody's	Standard & Poor's
Senior secured debt	A-	A2	A
Senior unsecured debt	BBB+	Baa1	A-
Outlook	Stable	Stable	Stable

Debt and preferred securities of PacifiCorp are rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of PacifiCorp's ability to, in general, meet the obligations of its issued debt or preferred securities. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

PacifiCorp has no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt and a change in ratings is not an event of default under the applicable debt instruments. PacifiCorp's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level in order to draw upon their availability. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities. Certain authorizations or exemptions by regulatory commissions for the issuance of securities are valid as long as PacifiCorp maintains investment grade ratings on senior secured debt. A downgrade below that level would necessitate new regulatory applications and approvals.

In accordance with industry practice, certain wholesale energy agreements, including derivative contracts, contain provisions that require PacifiCorp to maintain specific credit ratings on its unsecured debt from one or more of the three recognized credit rating agencies. These agreements, including 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 June 30, 2011, PacifiCorp's credit ratings from the three recognized credit rating agencies were investment grade. If all credit-risk-related contingent features or adequate assurance provisions for these agreements, including derivative contracts, had been triggered as of June 30, 2011, PacifiCorp would have been required to post $256 million 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. Refer to Note 4 of Notes to Financial Statements in this Form 3-Q for a discussion of PacifiCorp's collateral requirements specific to PacifiCorp's derivative contracts.

In July 2010, the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Reform Act"). The Reform Act reshapes financial regulation in the United States by creating new regulators, regulating new markets and firms and providing new enforcement powers to regulators. Virtually all major areas of the Reform Act, including collateral requirements on derivative contracts, will be the subject of regulatory interpretation and implementation rules requiring rulemaking proceedings that may take several years to complete.

PacifiCorp is a party to derivative contracts, including over-the-counter derivative contracts. The Reform Act provides for extensive new regulation of over-the-counter derivative contracts and certain market participants, including imposition of mandatory clearing, exchange trading, capital and margin requirements for "swap dealers" and "major swap participants." The Reform Act provides certain exemptions from these regulations for commercial end-users that use derivatives to hedge and manage the commercial risk of their businesses. Although PacifiCorp generally does not enter into over-the-counter derivative contracts for purposes unrelated to hedging of commercial risk and does not believe it will be considered a swap dealer or major swap participant, the outcome of the rulemaking proceedings cannot be predicted and, therefore, the impact of the Reform Act on PacifiCorp's financial results cannot be determined at this time.

Other Information

Coal Mine Safety Disclosures Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act

The operation of PacifiCorp's coal mines and coal processing facilities is regulated by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 ("Mine Safety Act"). MSHA inspects PacifiCorp's coal mines and coal processing facilities on a regular basis and may issue citations, notices, orders, or any combination thereof, when it believes a violation has occurred under the Mine Safety Act. For citations, monetary penalties are assessed by MSHA. Citations, notices and orders can be contested and appealed and the severity and assessment of penalties may be reduced or, in some cases, dismissed through the appeal process.

The table below summarizes the total number of citations, notices and orders issued and penalties assessed by MSHA for each coal mine or coal processing facility operated by PacifiCorp under the indicated provisions of the Mine Safety Act during the three- and six-month periods ended June 30, 2011. Legal actions pending before the Federal Mine Safety and Health Review Commission, which are not exclusive to citations, notices, orders and penalties assessed by MSHA, are as of June 30, 2011. Closed or idled mines have been excluded from the table below as no citations, orders or notices were issued for such mines during the six-month period ended June 30, 2011. In addition, there were no fatalities at PacifiCorp's coal mines or coal processing facilities during the six-month period ended June 30, 2011.

	Mine Safety Act							
Coal Mine or Coal Processing Facility	**Section 104 Significant & Substantial Citations(1)**	**Section 104(b) Orders(2)**	**Section 104(d) Citations & Orders(3)**	**Section 110(b)(2) Citations(4)**	**Section 107(a) Imminent Danger Orders(5)**	**Section 104(e) Notice(6)**	**Total Value of Proposed MSHA Assessments (in thousands)**	**Legal Actions Pending**
Three-month period ended June 30, 2011								
Deer Creek	4	—	—	—	—	—	$ 12	11
Bridger (surface)	3	—	—	—	—	—	3	7
Bridger (underground)	22	1	—	—	—	—	41	16
Cottonwood Preparatory Plant	—	—	—	—	—	—	—	—
Wyodak Coal Crushing Facility	—	—	—	—	—	—	—	—
Six-month period ended June 30, 2011								
Deer Creek	7	—	—	—	—	—	$ 20	11
Bridger (surface)	6	—	—	—	—	—	9	7
Bridger (underground)	26	1	—	—	—	—	66	16
Cottonwood Preparatory Plant	1	—	—	—	—	—	—	—
Wyodak Coal Crushing Facility	—	—	—	—	—	—	—	—

(1) For alleged violations of a mining safety standard or regulation where there exists a reasonable likelihood that the hazard contributed to or will result in an injury or illness of a reasonably serious nature.

(2) For alleged failure to totally abate the subject matter of a Mine Safety Act section 104(a) citation within the period specified in the citation.

(3) For an alleged unwarrantable failure (i.e., aggravated conduct constituting more than ordinary negligence) to comply with a mining safety standard or regulation.

(4) For alleged flagrant violations (i.e., reckless or repeated failure to make reasonable efforts to eliminate a known violation of a mandatory health or safety standard that substantially and proximately caused, or reasonably caused, or reasonably could have been expected to cause, death or serious bodily injury).

(5) The total number of imminent danger orders (i.e., the existence of any condition or practice in a coal or other mine which could reasonably be expected to cause death or serious physical harm before such condition or practice can be abated).

(6) For a pattern, or the potential to have a pattern, of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the cause and effect of coal or other mine health or safety hazards.

ITEM 13.

Officer & Director Changes

PacifiCorp discloses information for its "named executive officers" consistent with Item 402 of Regulation S-K promulgated by the United States Securities and Exchange Commission in its Annual Report on Form 10-K. There have been no changes in officers or directors during the six-month period ended June 30, 2011.

ITEM 14.

Not applicable.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) ☐ An Original (2) ☒ A Resubmission	07/02/2012	End of 2011/Q2

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	22,494,657,036	22,017,833,818
3	Construction Work in Progress (107)	200-201	1,028,316,271	1,000,790,049
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		23,522,973,307	23,018,623,867
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	7,552,203,239	7,467,085,584
6	Net Utility Plant (Enter Total of line 4 less 5)		15,970,770,068	15,551,538,283
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		15,970,770,068	15,551,538,283
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		15,601,521	16,174,139
19	(Less) Accum. Prov. for Depr. and Amort. (122)		1,860,570	1,214,176
20	Investments in Associated Companies (123)		69,928	69,928
21	Investment in Subsidiary Companies (123.1)	224-225	206,255,692	211,124,799
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		84,158,850	84,517,252
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		5,477,018	4,236,855
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		5,904,320	9,400,334
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		315,606,759	324,309,131
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		8,259,252	3,930,954
36	Special Deposits (132-134)		714,146	603,868
37	Working Fund (135)		1,720	1,720
38	Temporary Cash Investments (136)		134,856,988	463,002
39	Notes Receivable (141)		352,481	351,089
40	Customer Accounts Receivable (142)		289,880,720	352,691,649
41	Other Accounts Receivable (143)		35,999,484	58,359,149
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		9,269,355	7,517,126
43	Notes Receivable from Associated Companies (145)		3,269,474	1,983,253
44	Accounts Receivable from Assoc. Companies (146)		13,615,346	13,686,414
45	Fuel Stock (151)	227	223,055,023	188,493,087
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	191,270,513	186,406,158
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

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)		87,672,774	392,882,811
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		12,559	6,674
60	Rents Receivable (172)		1,722,622	1,535,228
61	Accrued Utility Revenues (173)		214,855,971	205,559,000
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		52,111,172	123,801,642
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		5,904,320	9,400,334
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		1,242,476,570	1,513,838,238
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		34,637,124	33,300,472
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	135,566
72	Other Regulatory Assets (182.3)	232	1,734,854,643	1,737,446,767
73	Prelim. Survey and Investigation Charges (Electric) (183)		3,037,152	2,895,724
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		-214,513	0
77	Temporary Facilities (185)		89,720	90,676
78	Miscellaneous Deferred Debits (186)	233	77,816,003	86,478,095
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		10,559,055	11,446,745
82	Accumulated Deferred Income Taxes (190)	234	563,674,504	588,589,916
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,424,453,688	2,460,383,961
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		19,953,307,085	19,850,069,613

Schedule Page: 110 Line No.: 2 Column: c

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

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

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

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

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

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

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

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

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

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

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

As of June 30, 2011, Account 165 Prepayments included $58,066,731of income taxes receivable from MidAmerican Energy Holdings Company, PacifiCorp's indirect parent company.

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

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

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

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

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

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

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

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

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	end of 2011/Q2

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	3,417,945,896	3,417,945,896
3	Preferred Stock Issued (204)	250-251	40,733,100	40,733,100
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	1,102,229,981	1,102,229,981
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	41,284,560	41,284,560
11	Retained Earnings (215, 215.1, 216)	118-119	2,366,088,684	2,655,984,147
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	137,535,064	142,404,172
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-6,854,243	-6,961,899
16	Total Proprietary Capital (lines 2 through 15)		7,016,393,922	7,311,050,837
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	6,757,741,000	6,357,741,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		31,486	32,845
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		14,596,710	14,381,234
24	Total Long-Term Debt (lines 18 through 23)		6,743,175,776	6,343,392,611
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		55,279,102	55,883,528
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		6,485,000	8,499,000
29	Accumulated Provision for Pensions and Benefits (228.3)		431,433,952	493,432,168
30	Accumulated Miscellaneous Operating Provisions (228.4)		38,008,578	39,321,210
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		304,885,084	399,481,536
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		131,612,877	105,328,750
35	Total Other Noncurrent Liabilities (lines 26 through 34)		967,704,593	1,101,946,192
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	36,000,000
38	Accounts Payable (232)		481,864,437	448,570,314
39	Notes Payable to Associated Companies (233)		474	0
40	Accounts Payable to Associated Companies (234)		29,308,432	47,687,205
41	Customer Deposits (235)		39,824,509	39,611,243
42	Taxes Accrued (236)	262-263	81,248,327	48,501,673
43	Interest Accrued (237)		119,203,634	115,234,368
44	Dividends Declared (238)		512,462	512,462
45	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		14,611,505	16,433,946
48	Miscellaneous Current and Accrued Liabilities (242)		65,213,914	62,325,256
49	Obligations Under Capital Leases-Current (243)		1,286,632	1,369,860
50	Derivative Instrument Liabilities (244)		378,700,190	483,234,721
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		304,885,084	399,481,536
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		906,889,432	899,999,512
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		27,809,966	18,492,298
57	Accumulated Deferred Investment Tax Credits (255)	266-267	39,979,696	41,949,428
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	67,657,887	51,231,025
60	Other Regulatory Liabilities (254)	278	65,701,127	59,611,213
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	121,387,549	11,642,708
63	Accum. Deferred Income Taxes-Other Property (282)		3,320,044,435	3,330,234,891
64	Accum. Deferred Income Taxes-Other (283)		676,562,702	680,518,898
65	Total Deferred Credits (lines 56 through 64)		4,319,143,362	4,193,680,461
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		19,953,307,085	19,850,069,613

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

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

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	2,197,465,651	2,135,043,685	1,086,197,001	1,043,288,996
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,070,802,840	1,070,808,744	520,876,485	495,319,460
5	Maintenance Expenses (402)	320-323	224,689,840	218,683,014	113,480,380	112,862,439
6	Depreciation Expense (403)	336-337	270,422,973	247,832,634	135,041,167	125,264,921
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	22,721,566	17,232,216	11,306,029	8,585,811
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	2,761,985	2,756,408	1,380,993	1,380,993
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		135,566	2,368,654		1,081,162
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		271,261	-2,156,768	208,743	-1,542,444
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	74,242,159	63,912,330	36,142,624	32,019,859
15	Income Taxes - Federal (409.1)	262-263	-24,511,516	25,814,929	-82,810,350	-9,494,025
16	- Other (409.1)	262-263	-1,954,255	-2,652,186	-17,713,154	-7,384,308
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	281,586,854	294,925,038	209,273,203	192,921,096
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	147,165,282	225,299,355	58,492,436	127,728,844
19	Investment Tax Credit Adj. - Net (411.4)	266	-937,102	-937,102	-468,551	-468,551
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		164,750	2,422,551	45,013	372,500
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		7,323	32,157	3,662	32,157
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,772,909,462	1,710,898,162	868,183,782	822,477,226
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		424,556,189	424,145,523	218,013,219	220,811,770

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

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
2,197,465,651	2,135,043,685					2
						3
1,070,802,840	1,070,808,744					4
224,689,840	218,683,014					5
270,422,973	247,832,634					6
						7
22,721,566	17,232,216					8
2,761,985	2,756,408					9
135,566	2,368,654					10
						11
271,261	-2,156,768					12
						13
74,242,159	63,912,330					14
-24,511,516	25,814,929					15
-1,954,255	-2,652,186					16
281,586,854	294,925,038					17
147,165,282	225,299,355					18
-937,102	-937,102					19
						20
						21
164,750	2,422,551					22
						23
7,323	32,157					24
1,772,909,462	1,710,898,162					25
424,556,189	424,145,523					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		424,556,189	424,145,523	218,013,219	220,811,770
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		696,901	651,207	257,438	376,915
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		941,184	634,057	417,920	336,298
33	Revenues From Nonutility Operations (417)		20,838			
34	(Less) Expenses of Nonutility Operations (417.1)		57,486	30,483	33,274	23,107
35	Nonoperating Rental Income (418)		115,463	7,725	109,288	2,856
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-4,869,108	2,753,475	-6,290,441	2,133,720
37	Interest and Dividend Income (419)		4,102,179	2,666,088	2,949,587	1,367,502
38	Allowance for Other Funds Used During Construction (419.1)		21,838,679	41,826,788	10,436,789	20,123,520
39	Miscellaneous Nonoperating Income (421)		13,955,296	9,422,122	6,022,850	6,227,094
40	Gain on Disposition of Property (421.1)		361,822	1,787,645	214,343	349,424
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		35,223,400	58,450,510	13,248,660	30,221,626
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		22,736	7,039	4,267	272
44	Miscellaneous Amortization (425)		644,775	634,754	322,567	317,440
45	Donations (426.1)		1,372,444	1,421,816	709,856	727,611
46	Life Insurance (426.2)		-1,066,363	-284,891	-590,947	314,893
47	Penalties (426.3)		159,430	-589,518	160,495	63,561
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,128,678	1,031,949	566,528	471,251
49	Other Deductions (426.5)		12,648,072	14,104,189	4,842,031	10,235,516
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		14,909,772	16,325,338	6,014,797	12,130,544
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	122,522	190,905	72,192	91,030
53	Income Taxes-Federal (409.2)	262-263	7,357,932	14,705,718	3,427,492	6,499,018
54	Income Taxes-Other (409.2)	262-263	999,820	1,998,263	465,739	883,109
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	43,525,728	46,949,115	36,181,584	19,730,251
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	42,770,626	48,568,353	35,615,086	21,029,152
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		1,032,630	1,032,630	516,315	516,315
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		8,202,746	14,243,018	4,015,606	5,657,941
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		12,110,882	27,882,154	3,218,257	12,433,141
61	Interest Charges					
62	Interest on Long-Term Debt (427)		183,011,944	182,009,933	92,482,025	90,986,015
63	Amort. of Debt Disc. and Expense (428)		1,912,686	1,855,344	985,014	927,672
64	Amortization of Loss on Reaquired Debt (428.1)		887,690	1,224,335	443,845	610,306
65	(Less) Amort. of Premium on Debt-Credit (429)		1,359	1,359	679	679
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		-1,721	-16,812	-638	-9,284
68	Other Interest Expense (431)		6,192,627	4,949,868	4,053,569	2,572,571
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		11,592,753	23,519,201	5,574,583	11,532,878
70	Net Interest Charges (Total of lines 62 thru 69)		180,409,114	166,502,108	92,388,553	83,553,723
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		256,257,957	285,525,569	128,842,923	149,691,188
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)		256,257,957	285,525,569	128,842,923	149,691,188

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

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

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

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

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

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

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

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

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

Depreciation expense associated with transportation equipment is generally charged to operations and maintenance expense and construction work in progress. Depreciation expense associated with transportation equipment was $6,984,916 and $7,019,277 during the six-month periods ended June 30, 2011 and 2010, respectively, and $3,473,447 and $3,500,414 during the three-month periods ended June 30, 2011 and 2010, respectively.

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

Generally, PacifiCorp records depreciation 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. Payroll taxes were $22,645,302 and $22,092,341 during the six-month periods ended June 30, 2011 and 2010, respectively, and $10,306,805 and $10,473,980 during the three-month periods ended June 30, 2011 and 2010, respectively.

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

The following presents PacifiCorp's total income tax expense during the three- and six-month periods ended June 30, 2011 and 2010. Individual expenses are referenced back to the respective line number on pages 114 - 117.

Line No.		Six-Month Periods Ended June 30, 2011	Six-Month Periods Ended June 30, 2010	Three-Month Periods Ended June 30, 2011	Three-Month Periods Ended June 30, 2010
15	Income Taxes - Federal (409.1)	$ (24,511,516)	$ 25,814,929	$ (82,810,350)	$ (9,494,025)
16	- Other (409.1)	(1,954,255)	(2,652,186)	(17,713,154)	(7,384,308)
17	Provision for Deferred Income Taxes (410.1)	281,586,854	294,925,038	209,273,203	192,921,096
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	147,165,282	225,299,355	58,492,436	127,728,844
19	Investment Tax Credit Adj. - Net (411.4)	(937,102)	(937,102)	(468,551)	(468,551)
53	Income Taxes-Federal (409.2)	7,357,932	14,705,718	3,427,492	6,499,018
54	Income Taxes-Other (409.2)	999,820	1,998,263	465,739	883,109
55	Provision for Deferred Income Taxes (410.2)	43,525,728	46,949,115	36,181,584	19,730,251
56	(Less) Provision for Deferred Income Taxes-Cr (411.2)	42,770,626	48,568,353	35,615,086	21,029,152
58	(Less) Investment Tax Credits (420)	1,032,630	1,032,630	516,315	516,315
	Total Income Tax Expense	$ 115,098,923	$ 105,903,437	$ 53,732,126	$ 53,412,279

Account 409.1, Income taxes and footnote amended in accordance with FERC Order No. AC11-132.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		2,652,408,336	2,103,304,579
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		261,127,065	282,772,094
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24	Preferred Stock, various series and rates	238	-1,024,923	(1,033,409)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-1,024,923	(1,033,409)
30	Dividends Declared-Common Stock (Account 438)			
31	Common stock	238	-549,997,605	
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-549,997,605	
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,362,512,873	2,385,043,264
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		3,575,811	3,575,811
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		3,575,811	3,575,811
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,366,088,684	2,388,619,075
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

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

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

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

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

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

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

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

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

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

Outstanding shares on preferred stock as of June 30, 2011 and dividends on preferred stock during the six-month period ended June 30, 2011 were as follows:

	Shares	Dividend
4.52% Serial Preferred	2,065	$ 4,667
4.56% Serial Preferred	81,326	185,423
4.72% Serial Preferred	65,854	155,415
5.00% Serial Preferred	41,908	104,770
5.40% Serial Preferred	65,959	178,089
6.00% Serial Preferred	5,930	17,790
7.00% Serial Preferred	18,046	63,161
5.00% Preferred	126,243	315,608
	407,331	$1,024,923

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

Outstanding shares on preferred stock as of June 30, 2010 and dividends on preferred stock during the six-month period ended June 30, 2010 were as follows:

	Shares	Dividend
4.52% Serial Preferred	2,065	$ 4,667
4.56% Serial Preferred	81,326	189,146
4.72% Serial Preferred	65,854	160,178
5.00% Serial Preferred	41,908	104,770
5.40% Serial Preferred	65,959	178,089
6.00% Serial Preferred	5,930	17,790
7.00% Serial Preferred	18,046	63,161
5.00% Preferred	126,243	315,608
	407,331	$1,033,409

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

For information regarding common stock dividends declared, refer to Important Changes During the Quarter/Year, Item 6 and Note 9 of Notes to Financial Statements in this Form 3-Q.

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

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

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

See footnote for column (c) line 47.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

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)	256,257,957	285,525,569
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	278,095,542	255,934,603
5	Amortization:	26,535,153	20,835,264
6			
7	Unrealized (Gains)/Losses on Derivative Contracts	-1,989,676	3,138,678
8	Deferred Income Taxes (Net)	135,176,674	68,006,445
9	Investment Tax Credit Adjustment (Net)	-1,969,732	-1,969,732
10	Net (Increase) Decrease in Receivables	84,979,086	106,970,528
11	Net (Increase) Decrease in Inventory	-39,426,291	-22,802,499
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	30,526,225	-103,495,437
14	Net (Increase) Decrease in Other Regulatory Assets	-14,131,342	22,477,072
15	Net Increase (Decrease) in Other Regulatory Liabilities	-5,044,951	-7,365,416
16	(Less) Allowance for Other Funds Used During Construction	21,838,679	41,826,788
17	(Less) Undistributed Earnings from Subsidiary Companies	-4,869,108	2,753,475
18	Amounts Due To/From Affiliates (Net)	284,591,309	245,757,111
19	Derivative Collateral (Net)	18,226,008	-59,918,405
20	Other Operating Activities:	8,706,145	8,710,987
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,043,562,536	777,224,505
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-734,161,628	-917,810,169
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	-21,838,679	-41,826,788
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-712,322,949	-875,983,381
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	363,967	2,052,689
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-1,286,664	-6,055,250
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other Investing Activities:	-420,291	1,497,120
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-713,665,937	-878,488,822
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	396,535,186	
62	Preferred Stock		
63	Common Stock		
64	Equity Contribution		100,000,000
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	396,535,186	100,000,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		-560,528
75	Common Stock		
76	Other (provide details in footnote):		
77	Repayment of Capital Lease Obligations	-687,653	-1,082,693
78	Net Decrease in Short-Term Debt (c)	-35,999,320	
79			
80	Dividends on Preferred Stock	-1,024,923	-1,041,895
81	Dividends on Common Stock	-549,997,605	
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-191,174,315	97,314,884
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	138,722,284	-3,949,433
87			
88	Cash and Cash Equivalents at Beginning of Period	4,395,676	86,208,704
89			
90	Cash and Cash Equivalents at End of period	143,117,960	82,259,271

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

Includes depreciation expense associated with transportation equipment and capital lease assets of $7,672,569 and $8,101,969 during the six-month periods ended June 30, 2011 and 2010, respectively.

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

	Six-Month Periods Ended June 30, 2011	2010
Amortization of software development & other intangibles	$ 22,721,566	$ 17,232,216
Amortization of hydroelectric relicensing costs	644,775	634,754
Amortization of electric plant acquisition adjustments	2,761,985	2,756,408
Amortization of regulatory assets	406,827	211,886
	$ 26,535,153	$ 20,835,264

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

	Six-Month Periods Ended June 30, 2011	2010
Coal & steam depreciation & depletion included in cost of fuel	$ 5,921,924	$ 6,996,442
(Gain)/loss on sale of property	(365,388)	(1,996,268)
Write-off of assets under construction	1,165,357	1,815,435
Other	1,984,252	1,895,378
	$ 8,706,145	$ 8,710,987

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

Certain amounts in the prior period financial statements have been reclassified to conform to the current period presentation.

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

Represents proceeds from disposal of fixed assets.

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

Represents proceeds from disposal of fixed assets.

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

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

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

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

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

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

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

	Six-Month Periods Ended June 30, 2011	2010
Other investments/special funds	$ 842,917	$ 2,052,621
Temporary facilities	956	4,784
Restricted cash	(1,264,164)	(560,285)
	$ (420,291)	$ 1,497,120

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

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

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

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

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

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

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

Schedule Page: 120 Line No.: 90 Column: b

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

Schedule Page: 120 Line No.: 90 Column: c

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

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) ☐ An Original (2) ☒ A Resubmission	07/02/2012	End of 2011/Q2

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.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

PACIFICORP
NOTES TO FINANCIAL STATEMENTS
(Unaudited)

(1) General

PacifiCorp is a United States regulated electric company serving 1.7 million retail customers, including residential, commercial, industrial and other customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp owns, or has interests in, a number of thermal, hydroelectric, wind-powered and geothermal generating facilities, as well as electric transmission and distribution assets. PacifiCorp also buys and sells electricity on the wholesale market with public and private utilities, energy marketing companies, financial institutions and incorporated municipalities. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp's subsidiaries support its electric utility operations by providing coal mining and environmental remediation services. PacifiCorp is an indirect subsidiary of MidAmerican Energy Holdings Company ("MEHC"), a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

Restatement

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

In accordance with the order, PacifiCorp has resubmitted its previously filed 2011 Forms 3-Q in order to restate the 2011 and 2010 information on the basis required in the order. For additional information on the restatement, refer to Note 2 of Notes to Financial Statements in PacifiCorp's annual report on Form No. 1 for the year ended December 31, 2011.

Basis of Presentation

These unaudited 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. These unaudited financial statements do not include all of the disclosures required by the FERC and GAAP for annual financial statements. Management believes the unaudited financial statements contain all adjustments (consisting only of normal recurring adjustments) considered necessary for the fair presentation of the financial statements as of June 30, 2011 and for the six-month periods ended June 30, 2011 and 2010. The results of operations for the three- and six-month periods ended June 30, 2011 are not necessarily indicative of the results to be expected for the full year.

The following are the significant differences between the FERC accounting and reporting standards and GAAP.

Investments in Subsidiaries

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

Costs of Removal

Estimated removal costs that are recovered through approved depreciation rates, but that do not meet the requirements of a legal asset retirement obligation are reflected in the cost of removal regulatory liability under GAAP and as accumulated depreciation under the FERC accounting and reporting standards.

Income Taxes

Accumulated deferred income taxes are classified as current and non-current on the balance sheet for GAAP. Under the FERC accounting and reporting standards, accumulated deferred income taxes are classified as gross non-current assets and gross non-current liabilities. Additionally, there are certain presentational differences between FERC and GAAP for amounts related to unrecognized tax benefits associated with temporary differences in accordance with FERC Docket No. AI07-2-000, "Accounting and Financial Reporting for Uncertainty in Income Taxes."

Interest and penalties on income taxes for GAAP are classified as income tax expense. All such amounts are classified as interest income, interest expense and penalties under the FERC accounting and reporting standards.

Unrealized Gains and Losses on Derivative Instruments

Under the FERC accounting and reporting standards, unrealized gains and losses on derivative instruments that are not recorded as a net regulatory asset or accumulated other comprehensive income ("AOCI") are presented on a gross basis on the Statement of Income as miscellaneous nonoperating income for unrealized gains and as other deductions for unrealized losses in accordance with FERC Order 627, "Accounting and Reporting of Financial Instruments, Comprehensive Income, Derivatives and Hedging Activities." For GAAP, unrealized gains and losses on energy derivative contracts not held for trading purposes and that are not recorded as a net regulatory asset or AOCI are presented on the Statement of Income as revenues for sales contracts and as energy costs and operating expense for purchase and financial swap energy contracts.

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 unaudited financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. Actual results may differ from the estimates used in preparing the unaudited financial statements. Note 2 of Notes to Financial Statements included in PacifiCorp's annual report on Form No. 1 for the year ended December 31, 2010 describes the most significant accounting policies used in the preparation of the financial statements. There have been no significant changes in PacifiCorp's assumptions regarding significant accounting estimates and policies during the six-month period ended June 30, 2011.

(2) New Accounting Pronouncements

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

In January 2010, the FASB issued ASU No. 2010-06, which amends FASB ASC Topic 820, "Fair Value Measurements and Disclosures." ASU No. 2010-06 requires disclosure of (a) the amount of significant transfers into and out of Levels 1 and 2 of the fair value hierarchy and the reasons for those transfers and (b) gross presentation of purchases, sales, issuances and settlements in the Level 3 fair value measurement rollforward. This guidance clarifies that existing fair value measurement disclosures should be presented for each class of assets and liabilities. The existing disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements have also been clarified to ensure such disclosures are presented for the Levels 2 and 3 fair value measurements. PacifiCorp adopted this guidance as of January 1, 2010, with the exception of the disclosure requirement to present purchases, sales, issuances and settlements gross in the Level 3 fair value measurement rollforward, which PacifiCorp adopted as of January 1, 2011. The adoption of this guidance did not have a material impact on PacifiCorp's disclosures included within Notes to Financial Statements.

(3) Fair Value Measurements

The carrying value of PacifiCorp's cash, certain cash equivalents, receivables, 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 June 30, 2011					
Assets:					
Commodity derivatives	$ -	$ 162	$ -	$ (110)	$ 52
Investments in available-for-sale securities - Money market mutual funds(2)	137	-	-	-	137
	$ 137	$ 162	$ -	$ (110)	$ 189
Liabilities - Commodity derivatives	$ -	$ (358)	$ (240)	$ 219	$ (379)
As of December 31, 2010					
Assets:					
Commodity derivatives	$ -	$ 263	$ 5	$ (145)	$ 123
Investments in available-for-sale securities - Money market mutual funds(2)	2	-	-	-	2
	$ 2	$ 263	$ 5	$ (145)	$ 125
Liabilities - Commodity derivatives	$ -	$ (405)	$ (350)	$ 272	$ (483)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $109 million and $127 million as of June 30, 2011 and December 31, 2010, respectively.

(2) Amounts are included in other special funds and temporary cash investments on the Comparative Balance Sheet. The fair value of these money market mutual funds approximates cost.

Derivative contracts are recorded on the Comparative Balance Sheet as either assets or liabilities and are stated at 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 4 for further discussion regarding PacifiCorp's risk management and hedging activities.

Contracts with explicit or embedded optionality are valued by separating each contract into its physical and financial forward, swap and option components. Forward and swap components are valued against the appropriate forward price curve. Option components are valued using Black-Scholes-type models, such as European option, spread option and best-of option, with the appropriate forward price curve and other inputs.

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

The following table reconciles the beginning and ending balances of PacifiCorp's commodity derivative assets and liabilities measured at fair value on a recurring basis using significant Level 3 inputs (in millions):

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2011	**2010**	**2011**	**2010**
Beginning balance	$ (351)	$ (409)	$ (345)	$ (380)
Changes in fair value recognized in net regulatory assets	94	(21)	79	(52)
Settlements	17	24	26	26
Ending balance	$ (240)	$ (406)	$ (240)	$ (406)

PacifiCorp's long-term debt is carried at cost on the financial statements. The fair value of PacifiCorp's long-term debt has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of PacifiCorp's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of PacifiCorp's long-term debt (in millions):

	As of June 30, 2011		As of December 31, 2010	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
Long-term debt	$ 6,743	$ 7,472	$ 6,344	$ 7,086

(4) Risk Management and Hedging Activities

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

PacifiCorp has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, PacifiCorp uses commodity derivative contracts, including forwards, futures, 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 Note 3 for additional information on derivative contracts.

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

	Derivative Assets		Derivative Liabilities		
	Current	Noncurrent	Current	Noncurrent	Total
As of June 30, 2011					
Not designated as hedging contracts (1)(2):					
Commodity assets	$ 67	$ 9	$ 61	$ 25	$ 162
Commodity liabilities	(19)	(3)	(228)	(348)	(598)
Total	48	6	(167)	(323)	(436)
Total derivatives	48	6	(167)	(323)	(436)
Cash collateral (payable) receivable	(2)	-	93	18	109
Total derivatives – net basis	$ 46	$ 6	$ (74)	$ (305)	$ (327)
As of December 31, 2010					
Not designated as hedging contracts (1)(2):					
Commodity assets	$ 185	$ 13	$ 34	$ 36	$ 268
Commodity liabilities	(62)	(4)	(213)	(476)	(755)
Total	123	9	(179)	(440)	(487)
Total derivatives	123	9	(179)	(440)	(487)
Cash collateral (payable) receivable	(9)	-	95	41	127
Total derivatives – net basis	$ 114	$ 9	$ (84)	$ (399)	$ (360)

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

(2) PacifiCorp's commodity derivatives not designated as hedging contracts are generally included in rates and as of June 30, 2011 and December 31, 2010, a net regulatory asset of $438 million and $487 million, respectively, was recorded related to the net derivative liability of $436 million and $487 million, respectively.

Not Designated as Hedging Contracts

For PacifiCorp's commodity derivatives not designated as hedging contracts, the settled amount is generally included in rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in rates are recorded as net regulatory assets. The following table reconciles the beginning and ending balances of PacifiCorp's net regulatory assets and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in net regulatory assets, as well as amounts reclassified to earnings (in millions):

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2011	2010	2011	2010
Beginning balance	$ 505	$ 429	$ 487	$ 367
Changes in fair value recognized in net regulatory assets	(64)	41	(66)	73
Net gains reclassified to earnings - operating revenues	2	20	10	41
Net (losses) gains reclassified to earnings - operation expenses	(5)	(8)	7	1
Ending balance	$ 438	$ 482	$ 438	$ 482

For PacifiCorp's derivatives not designated as hedging contracts and for which changes in fair value are not recorded as a net regulatory asset, unrealized gains and losses are recognized on the Statement of Income as miscellaneous nonoperating income for unrealized gains and as other deductions for unrealized losses. During the three- and six-month periods ended June 30, 2011 and 2010, these amounts were not material.

Designated as Hedging Contracts

PacifiCorp uses derivative contracts accounted for as cash flow hedges to hedge electricity and natural gas commodity prices. Realized gains and losses on hedges and hedge ineffectiveness are recognized in income as operating revenues or operation expenses depending upon the nature of the item being hedged. For the three- and six-month periods ended June 30, 2011 and 2010, hedge ineffectiveness was insignificant. As of June 30, 2011 and December 31, 2010, PacifiCorp had no derivative contracts designated as cash flow hedges.

Derivative Contract Volumes

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

	Unit of Measure	June 30, 2011	December 31, 2010
Commodity contracts:			
Electricity sales	Megawatt hours	(10)	(13)
Natural gas purchases	Decatherms	127	159
Fuel oil purchases	Gallons	8	16

Credit Risk

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

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

Collateral and Contingent Features

In accordance with industry practice, certain wholesale derivative contracts contain provisions that require PacifiCorp to maintain specific credit ratings from one or more of the major credit rating agencies on its unsecured debt. These derivative contracts may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" in the event of a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. As of June 30, 2011, PacifiCorp's credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of PacifiCorp's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $403 million and $448 million as of June 30, 2011 and December 31, 2010, respectively, for which PacifiCorp had posted collateral of $111 million and $136 million, respectively. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of June 30, 2011 and December 31, 2010, PacifiCorp would have been required to post $166 million and $129 million, respectively, of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation or other factors.

(5) Recent Debt Transactions

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

(6) Employee Benefit Plans

Net periodic benefit cost for the pension and other postretirement benefit plans included the following components (in millions):

	Three Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2011	**2010**	**2011**	**2010**
Pension:				
Service cost(1)	$ 3	$ 3	$ 5	$ 6
Interest cost	16	16	32	33
Expected return on plan assets	(19)	(19)	(37)	(37)
Net amortization	7	6	14	12
Net amortization of regulatory deferrals	(3)	(2)	(5)	(5)
Net periodic benefit cost	$ 4	$ 4	$ 9	$ 9
Other postretirement:				
Service cost(1)	$ 2	$ 2	3	$ 3
Interest cost	8	8	16	16
Expected return on plan assets	(8)	(8)	(15)	(15)
Net amortization	5	3	9	7
Net periodic benefit cost	$ 7	$ 5	$ 13	$ 11

(1) Service cost excludes $3 million of contributions to joint trust union plans during each of the three-month periods ended June 30, 2011 and 2010. Service cost excludes $6 million of contributions to joint trust union plans during each of the six-month periods ended June 30, 2011 and 2010.

Employer contributions to the pension, other postretirement benefit and joint trust union plans are expected to be $71 million, $28 million and $12 million, respectively, during 2011. As of June 30, 2011, $53 million, $14 million and $6 million of contributions had been made to the pension, other postretirement benefit and joint trust union plans, respectively.

(7) Income Taxes

The effective tax rate was 29% for the three-month period ended June 30, 2011 compared to 26% for 2010. The increase in PacifiCorp's effective tax rate for the three-month period ended June 30, 2011 was primarily due to the impact of lower allowance for equity funds in the current period, partially offset by the impact of production tax credits associated with PacifiCorp's wind-powered generating facilities.

The effective tax rate was 31% for the six-month period ended June 30, 2011 compared to 27% for 2010. The increase in PacifiCorp's effective tax rate for the six-month period ended June 30, 2011 was primarily due to the impact of lower allowance for equity funds in the current period and certain other effects of ratemaking in the first quarter of 2011, partially offset by the impact of production tax credits associated with PacifiCorp's wind-powered generating facilities.

(8) Commitments and Contingencies

Legal Matters

PacifiCorp is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. PacifiCorp does not believe that such normal and routine litigation will have a material impact on its financial results. PacifiCorp is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties and other costs in substantial amounts and are described below.

USA Power

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

FERC Investigation

During 2007, the Western Electricity Coordinating Council ("WECC") audited PacifiCorp's compliance with several of the reliability standards developed by the North American Electric Reliability Corporation ("NERC"). In April 2008, PacifiCorp received notice of a preliminary non-public investigation from the FERC and the NERC to determine whether an outage that occurred in PacifiCorp's transmission system in February 2008 involved any violations of reliability standards. In November 2008, PacifiCorp received preliminary findings from the FERC staff regarding its non-public investigation into the February 2008 outage. Also in November 2008, in conjunction with the reliability standards review, the FERC assumed control of certain aspects of the WECC's 2007 audit. PacifiCorp has engaged in discussions with FERC staff regarding findings related to the non-public investigation, which includes the WECC's findings that are now being processed by the FERC. PacifiCorp does not believe that the outcome of the non-public investigation will have a material impact on its financial results.

Environmental Laws and Regulations

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

Hydroelectric Relicensing

PacifiCorp's hydroelectric portfolio consists of 46 generating facilities with an aggregate facility net owned capacity of 1,161 megawatts. The FERC regulates 98% of the net capacity of this portfolio through 16 individual licenses, which have terms of 30 to 50 years. PacifiCorp expects to incur ongoing operating and maintenance expense and capital expenditures associated with the terms of its renewed hydroelectric licenses and settlement agreements, including natural resource enhancements. PacifiCorp's Klamath hydroelectric system is currently operating under annual licenses. Substantially all of PacifiCorp's remaining hydroelectric generating facilities are operating under licenses that expire between 2030 and 2058.

Klamath Hydroelectric System - Klamath River, Oregon and California

In February 2010, PacifiCorp, the United States Department of the Interior, the United States Department of Commerce, the State of California, the State of Oregon and various other governmental and non-governmental settlement parties signed the Klamath Hydroelectric Settlement Agreement ("KHSA"). Among other things, the KHSA provides that the United States Department of the Interior conduct scientific and engineering studies to assess whether removal of the Klamath hydroelectric system's four mainstem dams is in the public interest and will advance restoration of the Klamath Basin's salmonid fisheries. If it is determined that dam removal should proceed, dam removal is expected to commence no earlier than 2020.

Under the KHSA, PacifiCorp and its customers are protected from uncapped dam removal costs and liabilities. For dam removal to occur, federal legislation consistent with the KHSA must be enacted to provide, among other things, protection for PacifiCorp from all liabilities associated with dam removal activities. If Congress does not enact legislation, then PacifiCorp will resume relicensing at the FERC. In addition, the KHSA limits PacifiCorp's contribution to dam removal costs to no more than $200 million, of which up to $184 million would be collected from PacifiCorp's Oregon customers with the remainder to be collected from PacifiCorp's California customers. An additional $250 million for dam removal costs is expected to be raised through a California bond measure or other appropriate State of California financing mechanism. If dam removal costs exceed $200 million and if the State of California is unable to raise the additional funds necessary for dam removal costs, sufficient funds would need to be provided by an entity other than PacifiCorp in order for the KHSA and dam removal to proceed.

PacifiCorp has begun collection of surcharges from Oregon customers for their share of dam removal costs, as approved by the Oregon Public Utility Commission ("OPUC") and is depositing the proceeds in a trust account maintained by the OPUC. In May 2011, the California Public Utilities Commission ("CPUC") approved the collection of surcharges from California customers beginning at a future date to be determined through a tariff filing. In June 2011, the tariff filing was completed and new rates will be effective upon the establishment of two trust accounts.

As of June 30, 2011 and December 31, 2010, the net book value of PacifiCorp's Klamath hydroelectric system's four mainstem dams and the associated relicensing and settlement costs was $121 million and $125 million, respectively. During 2010 and 2011, PacifiCorp received approvals from the OPUC, the CPUC and the Wyoming Public Service Commission to depreciate the Klamath hydroelectric system's four mainstem dams and the associated relicensing and settlement costs through the expected dam removal date. The depreciation rate changes were effective January 1, 2011 and will allow for full depreciation of the assets by December 2019. PacifiCorp is seeking similar approval in Idaho and expects to seek approval in the next Washington general rate case. As part of the July 2011 Utah general rate case settlement stipulation, PacifiCorp and the other parties to the settlement stipulation proposed to defer a decision regarding the acceleration of the depreciation rates for the Klamath hydroelectric system's four mainstem dams to a future rate proceeding, at which time the associated relicensing and settlement costs would be addressed. In August 2011, the Utah Public Service Commission approved the general rate case settlement stipulation.

FERC Issues

Northwest Refund Case

In June 2003, the FERC terminated its proceeding relating to the possibility of requiring refunds for wholesale spot-market bilateral sales in the Pacific Northwest between December 2000 and June 2001. The FERC concluded that ordering refunds would not be an appropriate resolution of the matter. In November 2003, the FERC issued its final order denying rehearing. Several market participants, excluding PacifiCorp, filed petitions in the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit") for review of the FERC's final order. In August 2007, the Ninth Circuit concluded that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and its potential ties to the Pacific Northwest, and that the FERC should not have excluded from the Pacific Northwest refund proceeding purchases of energy in the Pacific Northwest spot market made by the California Energy Resources Scheduling ("CERS") division of the California Department of Water Resources. Without issuing the mandate order, the Ninth Circuit remanded the case to the FERC to (a) address the new market manipulation evidence in detail and account for it in any future orders regarding the award or denial of refunds in the proceedings; (b) include sales to CERS in its analysis; and (c) further consider its refund decision in light of related, intervening opinions of the court. The Ninth Circuit offered no opinion on the FERC's findings based on the record established by the administrative law judge and did not rule on the merits of the FERC's November 2003 decision to deny refunds. In April 2009, the Ninth Circuit issued a formal mandate order, completing the remand of the case to the FERC, which has not yet undertaken further action. PacifiCorp cannot predict the future course of this proceeding and its impact on its financial results, if any, at this time.

Purchase Obligations

In May 2011, PacifiCorp issued a notice to proceed with the engineering, procurement and construction contract for the 637-MW Lake Side 2 combined-cycle combustion turbine natural gas-fired generating facility. The notice to proceed resulted in purchase obligations for the years ending December 31 of approximately $181 million in 2011, $206 million in 2012, $126 million in 2013 and $8 million in 2014.

(9) Common Equity

In March 2011, PacifiCorp declared a dividend of $275 million, which was paid to PPW Holdings LLC, a direct wholly owned subsidiary of MEHC and PacifiCorp's direct parent company, on April 20, 2011.

In January 2011, PacifiCorp declared a dividend of $275 million, which was paid to PPW Holdings LLC on February 28, 2011.

Appropriated Retained Earnings

In accordance with the requirements of certain hydroelectric relicensing projects, as of June 30, 2011 and December 31, 2010, PacifiCorp had $4 million in appropriated retained earnings – amortization reserve, federal.

(10) Components of Accumulated Other Comprehensive Income (Loss), Net

Accumulated other comprehensive income (loss), net is included in proprietary capital on the Comparative Balance Sheet and consisted of unrecognized amounts on retirement benefits of $7 million, net of tax of $4 million, as of June 30, 2011 and December 31, 2010.

(11) Supplemental Cash Flows Information

The summary of supplemental cash flows information for the six-month periods ended June 30 is as follows (in millions):

	2011	2010
Interest paid, net of amounts capitalized	$ 174	$ 163
Income taxes received, net	$ (306)	$ (211)
Supplemental disclosure of non-cash investing and financing activities:		
Utility plant additions in accounts payable	$ 191	$ 164
Utility plant additions acquired under capital lease obligations	$ -	$ -

Cash and cash equivalents consist of the following amounts as of June 30 (in millions):

	2011	2010
Cash (131)	$ 8	$ 7
Working funds (135)	-	-
Temporary cash investments (136)	135	75
Total cash and cash equivalents	$ 143	$ 82

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 07/02/2012	Year/Period of Report End of 2011/Q2

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(5,819,577)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				76,320
4	Total (lines 2 and 3)				76,320
5	Balance of Account 219 at End of Preceding Quarter/Year				(5,743,257)
6	Balance of Account 219 at Beginning of Current Year				(6,961,899)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				107,656
9	Total (lines 7 and 8)				107,656
10	Balance of Account 219 at End of Current Quarter/Year				(6,854,243)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(5,819,577)		
2		(1,070,326)	(1,070,326)		
3		6,014,042	6,090,362		
4		4,943,716	5,020,036	285,525,569	290,545,605
5		4,943,716	(799,541)		
6			(6,961,899)		
7		(741,398)	(741,398)		
8		741,398	849,054		
9			107,656	256,257,957	256,365,613
10			(6,854,243)		

Schedule Page: 122(a)(b) Line No.: 5 Column: e

Unrecognized amounts on retirement benefits of ($9,256,000) less tax of $3,512,743 netting to ($5,743,257).

Schedule Page: 122(a)(b) Line No.: 5 Column: g

Unrealized gain on derivative contracts designated as cash flow hedges of $7,967,437 less tax of ($3,023,721) netting to $4,943,716.

Schedule Page: 122(a)(b) Line No.: 10 Column: e

Unrecognized amounts on retirement benefits of ($11,046,499) less tax of $4,192,256 netting to ($6,854,243).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	22,155,193,716	22,155,193,716
4	Property Under Capital Leases	65,393,121	65,393,121
5	Plant Purchased or Sold		
6	Completed Construction not Classified	94,899,516	94,899,516
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	22,315,486,353	22,315,486,353
9	Leased to Others		
10	Held for Future Use	19,995,175	19,995,175
11	Construction Work in Progress	1,028,316,271	1,028,316,271
12	Acquisition Adjustments	159,175,508	159,175,508
13	Total Utility Plant (8 thru 12)	23,522,973,307	23,522,973,307
14	Accum Prov for Depr, Amort, & Depl	7,552,203,239	7,552,203,239
15	Net Utility Plant (13 less 14)	15,970,770,068	15,970,770,068
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	6,959,428,424	6,959,428,424
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	488,167,565	488,167,565
22	Total In Service (18 thru 21)	7,447,595,989	7,447,595,989
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	104,607,250	104,607,250
33	Total Accum Prov (equals 14) (22,26,30,31,32)	7,552,203,239	7,552,203,239

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
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					31
					32
					33

Schedule Page: 200 Line No.: 10 Column: c

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

Schedule Page: 200 Line No.: 18 Column: c

Depreciation is comprised of:

Depreciation	$6,920,138,994
Depletion	39,289,430
Total	$6,959,428,424

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

ELECTRIC PLANT IN SERVICE AND ACCUMULATED PROVISION FOR DEPRECIATION BY FUNCTION

1. Report below the original cost of plant in service by function. In addition to Account 101, include Account 102, and Account 106. Report in column (b) the original cost of plant in service and in column(c) the accumulated provision for depreciation and amortization by function.

Line No.	Item (a)	Plant in Service Balance at End of Quarter (b)	Accumulated Depreciation and Amortization Balance at End of Quarter (c)
1	Intangible Plant	877,394,509	448,078,620
2	Steam Production Plant	6,129,811,838	2,478,576,835
3	Nuclear Production Plant		
4	Hydraulic Production - Conventional	671,277,744	269,689,692
5	Hydraulic Production - Pumped Storage		
6	Other Production	3,314,209,861	435,879,273
7	Transmission	4,455,084,856	1,196,033,543
8	Distribution	5,564,334,919	2,123,463,309
9	Regional Transmission and Market Operation		
10	General	1,237,979,505	487,047,330
11	TOTAL (Total of lines 1 through 10)	22,250,093,232	7,438,768,602

Name of Respondent PacifiCorp	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 07/02/2012	Year/Period of Report End of 2011/Q2

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Aref 600000	4,419	561.6	4,419	456
3	Aref 618363	152	561.6	152	456
4	Aref 645170	10,648	561.6	10,648	456
5	Aref 654674	19,859	561.6	19,859	456
6	Aref 676490	8,095	561.6	8,095	456
7	Aref 686257	11,556	561.6	11,556	456
8	Aref 688430	4,230	561.6	4,230	456
9	Aref 690566	4,749	561.6	4,749	456
10	Aref 690831	8,944	561.6	8,944	456
11	Aref 637974	122	561.6		
12	Aref 637977	243	561.6		
13	Aref 648013	1,962	561.6		
14	Aref 675661	3,990	561.6		
15	Aref 675662	3,990	561.6		
16	Aref 675663	4,066	561.6		
17	Aref 675664	3,762	561.6		
18	Aref 675665	3,458	561.6		
19	Aref 680400	1,093	561.6		
20	Aref 683060	2,739	561.6		
21	**Generation Studies**				
22	GIQ0187	14	561.7	14	456
23	GIQ0187-189	1,006	561.7	1,006	456
24	GIQ0188	14	561.7	14	456
25	GIQ0189	14	561.7	14	456
26	GIQ0190	227	561.7	227	456
27	GIQ0193	14	561.7	14	456
28	GIQ0230	76	561.7	76	456
29	GIQ0255	14,061	561.7	14,061	456
30	GIQ0256	120	561.7	120	456
31	GIQ0260-263	765	561.7	765	456
32	GIQ0289	(74)	561.7	(74)	456
33	GIQ0290	1,297	561.7	1,297	456
34	GIQ0291	1,414	561.7	1,414	456
35	GIQ0292	5,714	561.7	5,714	456
36	GIQ0295	941	561.7	941	456
37	GIQ0299	2,868	561.7	2,868	456
38	GIQ0303	60	561.7	60	456
39	GIQ0306	4,413	561.7	4,413	456
40	GIQ0310	2,549	561.7	2,549	456

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 07/02/2012	Year/Period of Report End of 2011/Q2

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Aref 704328	350	561.6		
3	Aref 659527	3,728	561.6		
4	Aref 673963	3,636	107		
5	Aref 659527	2,283	107		
6	Aref 681628	3,484	107		
7	Aref 684287	3,211	107		
8	Aref 686836	3,393	107		
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0311	11,410	561.7	11,410	456
23	GIQ0313	1,683	561.7	1,683	456
24	GIQ0314	2,620	561.7	2,620	456
25	GIQ0315	7,918	561.7	7,918	456
26	GIQ0316	2,345	561.7	2,345	456
27	GIQ0322	16,329	561.7	16,329	456
28	GIQ0323	7,579	561.7	7,579	456
29	GIQ0324	6,044	561.7	6,044	456
30	GIQ0326	15,924	561.7	15,924	456
31	GIQ0332	8,021	561.7	8,021	456
32	GIQ0333	8,159	561.7	8,159	456
33	GIQ0334	80	561.7	80	456
34	GIQ0335	3,613	561.7	3,613	456
35	GIQ0341	2,675	561.7	2,675	456
36	GIQ0345	282	561.7	282	456
37	GIQ0346	185	561.7	185	456
38	GIQ0347	2,460	561.7	2,460	456
39	GIQ0348	5,307	561.7	5,307	456
40	GIQ0349	2,774	561.7	2,774	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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11					
12					
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14					
15					
16					
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19					
20					
21	**Generation Studies**				
22	GIQ0350	7,413	561.7	7,413	456
23	GIQ0351	28,562	561.7	28,562	456
24	GIQ0352	1,555	561.7	1,555	456
25	GIQ0353	1,425	561.7	1,425	456
26	GIQ0354	6,781	561.7	6,781	456
27	GIQ0355	720	561.7	720	456
28	GIQ0356	9,993	561.7	9,993	456
29	GIQ0357	9,238	561.7	9,238	456
30	GIQ0358	707	561.7	707	456
31	GIQ0359	15,109	561.7	15,109	456
32	GIQ0360	14,838	561.7	14,838	456
33	GIQ0361	1,135	561.7	1,135	456
34	GIQ0362	955	561.7	955	456
35	GIQ0363	4,275	561.7	4,275	456
36	GIQ0364	18,464	561.7	18,464	456
37	GIQ0365	4,427	561.7	4,427	456
38	GIQ0366	13,424	561.7	13,424	456
39	GIQ0367	21,202	561.7	21,202	456
40	GIQ0368	5,334	561.7	5,334	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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6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0369	1,013	561.7	1,013	456
23	GIQ0370	3,968	561.7	3,968	456
24	GIQ0371	1,517	561.7	1,517	456
25	GIQ0372	8,949	561.7	8,949	456
26	GIQ0373	3,460	561.7	3,460	456
27	GIQ0374	12,023	561.7	12,023	456
28	GIQ0375	10,331	561.7	10,331	456
29	GIQ0376	6,226	561.7	6,226	456
30	GIQ0377	15,179	561.7	15,179	456
31	GIQ0378	12,983	561.7	12,983	456
32	GIQ0379	1,506	561.7	1,506	456
33	GIQ0380	1,481	561.7	1,481	456
34	GIQ0381	1,418	561.7	1,418	456
35	GIQ0382	1,570	561.7	1,570	456
36	GIQ0383	1,546	561.7	1,546	456
37	GIQ0384	3,773	561.7	3,773	456
38	GIQ0385	5,219	561.7	5,219	456
39	GIQ0386	4,144	561.7	4,144	456
40	GIQ0387	2,562	561.7	2,562	456

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

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	GIQ0388	622	561.7	622	456
23	GIQ0389	1,940	561.7	1,940	456
24	GIQ0390	498	561.7	498	456
25	Pre-Queue	587	561.7	588	456
26	Accruals - Customer Studies	1,730	561.7		
27	GIQ1256	25,787	561.7		
28	GIQ1293	5,308	561.7		
29	GIQ0301	2,751	107		
30	GIQ1256	4,486	107		
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 07/02/2012	Year/Period of Report End of 2011/Q2

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	DSM Regulatory Asset - CA	(3,543,587)	300,225	908	446,059	-3,689,421
2	DSM Regulatory Asset - ID	4,760,298	589,823	908	1,171,884	4,178,237
3	DSM Regulatory Asset - UT	(1,791,451)	8,365,637	908, 431	11,716,496	-5,142,310
4	DSM Regulatory Asset - WA	(546,412)	2,937,801	908	1,970,422	420,967
5	DSM Regulatory Asset - WY	(3,365,606)	784,583	908, 431	26,510	-2,607,533
6	DSM Regulatory Asset - OR	17,911	2,964			20,875
7	DSM Regulatory Assets - Accruals	4,618,592	233,383			4,851,975
8	Alternative Rate for Energy (CARE) - CA	299,581	11,012	142	131,397	179,196
9	2006 Transition Plan - OR (3)	2,372,818	10,658	920	491,935	1,891,541
10	2006 Transition Plan - CA (1)	178,218		920	44,555	133,663
11	Deferred Income Taxes Electric	472,644,174		282, 283	25,610,830	447,033,344
12	Deferral of Interest on Uncertain Tax Positions- UT	1,925,273	238,016			2,163,289
13	Deferral of Interest on Uncertain Tax Positions- WY	518,115	64,575			582,690
14	Deferral of Interest on Uncertain Tax Positions- ID	264,654	32,982			297,636
15	Tax Revenue Requirement Adjustment - WY	99,955				99,955
16	Deferred Excess Net Power Costs - OR	2,390,833	9,683	555	894,664	1,505,852
17	Deferred Excess Net Power Costs/ECAC - CA	1,918,018	26,576	555	242,168	1,702,426
18	Deferred Excess Net Power Costs - WY 2009	286,230	12	555	286,242	
19	Deferred Excess Net Power Costs - WY 2010	14,565,096		555	6,307,810	8,257,286
20	Deferred Excess Net Power Costs - WY 2011	10,862,650	5,899,259			16,761,909
21	Deferred Excess Net Power Costs - WA Hydro (3)	2,159,781	39,243	555	432,318	1,766,706
22	Deferred Excess Net Power Costs - ID 2009	228,618		555	228,618	
23	Deferred Excess Net Power Costs - ID 2010	12,799,355	302,806	555	1,862,539	11,239,622
24	Deferred Excess Net Power Costs - ID 2011	3,685,300	5,094,626			8,779,926
25	Environmental Costs (10)	8,537,648	694,687	925	391,036	8,841,299
26	Environmental Costs - WA (10)	(668,578)	28,151	925	50,711	-691,138
27	Reg Asset - Environmental Costs	10,590,149	243,148			10,833,297
28	Cholla Plant Transaction Costs (26)	5,944,671	45,948	557	280,606	5,710,013
29	Washington Colstrip #3 (22)	513,212		456	13,047	500,165
30	Frozen Mark-to-Market		20,971,832			20,971,832
31	Derivative Net Regulatory Asset	506,646,912			68,432,040	438,214,872
32	Asset Retirement Obligations Regulatory Difference	70,473,868	28,072,803	230	1,884,914	96,661,757
33	Pension/Other Postretirement	586,086,875			9,365,063	576,721,812
34	RTO Grid West N/R - OR (3)	627,878	2,916	904	92,926	537,868
35	RTO Grid West N/R - ID (5)	20,372		904	6,791	13,581
36	Deferred Independent Evaluator Fee - UT	28,212	7,326			35,538
37	Deferred Independent Evaluator Fee - OR (1)	252,643		557	404,271	-151,628
38	Deferred Intervenor Funding Grants - ID	73,477		928	4,925	68,552
39	Deferred Intervenor Funding Grants - OR	160,719	75,524			236,243
40	BPA Idaho Balancing Account	3,362,752	249,819			3,612,571
41	BPA Oregon Balancing Account		1,825,644			1,825,644
42	Renewable Adjustment Clause - OR (1)	348,590	1,413		130,212	219,791
43	REC & SO2 Revenue Requirement - WY		1,982,106			1,982,106
44	TOTAL	1,779,058,234	98,351,308		142,554,899	1,734,854,643

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Goodnoe Hills Settlement - WY (24)	483,437		930.2	5,312	478,125
2	Lake Side Settlement - WY (38)	998,115		930.2	6,979	991,136
3	SB 408 Regulatory Asset - OR (1)	(6,479)	15,636,459		1,252,469	14,377,511
4	SB 408 Regulatory Asset - MCBIT	(87,268)	84,900	431, 426.5	101,083	-103,451
5	Chehalis Generating Facility Deferral - WA (6)	14,250,000			750,000	13,500,000
6	Powerdale Decommissioning - ID (10)	312,389	10,305	407.3	7,844	314,850
7	Powerdale Decommissioning - OR (1.5)	379,243		407.3	113,773	265,470
8	Powerdale Decommissioning - WA (3)	851,788		407.3	70,982	780,806
9	Powerdale Decommissioning - WY (1)	17,196		407.3	17,196	
10	Powerdale Decommissioning - CA (2)	60,828		407.3	9,253	51,575
11	Deferred Advertising Costs - WY	52,198				52,198
12	Major Plant Additions Deferral - UT	11,718,447	191,436		5,741,203	6,168,680
13	Major Plant Additions Balancing - UT	4,327,380	425,465			4,752,845
14	Solar Feed-In Tariff Deferral - OR	333,373	253,274		4,606	582,041
15	Solar Feed-In Tariff Deferral - CA		15,428		48,914	-33,486
16	Tax Adj. on Postretirement Benefits - CA	353,909		410.1, 283	26,678	327,231
17	Tax Adj. on Postretirement Benefits - ID	772,635		410.1, 283	42,790	729,845
18	Tax Adj. on Postretirement Benefits - OR	4,265,060		410.1, 283	186,678	4,078,382
19	Tax Adj. on Postretirement Benefits - UT	5,528,360		410.1, 283	327,922	5,200,438
20	Tax Adj. on Postretirement Benefits - WY	2,198,420		410.1, 283	207,709	1,990,711
21	Storm Damage Deferral - CA	960,134		924	295,771	664,363
22	Deferral Overburden Cost - ID	289,130	228,699	501	111,408	406,421
23	Deferral Overburden Cost - WY	788,007	633,387	501	305,340	1,116,054
24	Regulatory Assets - Reclassifications	9,864,118	1,726,774			11,590,892
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
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38						
39						
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41						
42						
43						
44	TOTAL	1,779,058,234	98,351,308		142,554,899	1,734,854,643

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

Weighted average remaining life is 33 years. Represents the ratemaking treatment of income tax benefits related to certain property-related basis differences and other various differences that will be recovered from or returned to PacifiCorp's customers in most state jurisdictions.

Schedule Page: 232 Line No.: 16 Column: a

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

Schedule Page: 232 Line No.: 17 Column: a

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

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

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

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

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

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

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

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

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

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

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

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

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

Schedule Page: 232 Line No.: 31 Column: a

Weighted average remaining life is 4 years.

Schedule Page: 232 Line No.: 31 Column: d

Account 421, Miscellaneous nonoperating income
Account 426.5, Other deductions
Account 182.3, Other regulatory assets

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

Weighted average remaining life is 9 years. Substantially represents amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in rates when recognized.

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

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

Schedule Page: 232 Line No.: 42 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.: 5 Column: d

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

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

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

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

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

Schedule Page: 232.1 Line No.: 15 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.: 24 Column: f

The following schedule summarizes regulatory assets reclassifications:

	As of June 30, 2011
Reclassified from Regulatory Assets to Regulatory Liabilities:	
DSM Regulatory Asset - CA	$ 3,689,421
DSM Regulatory Asset - WY	2,607,533
DSM Regulatory Asset - UT	5,142,310
Deferred Independent Evaluator Fee - OR (1)	151,628
	$ 11,590,892

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Investment Tax Credit Regulatory Liability	19,091,853	190	253,493		18,838,360
2	Income Tax Reg. Liab.- WA Flow Through	9,910,469				9,910,469
3	Gain on Sale of Assets - OR	86,636		17,885	389	69,140
4	Injuries & Damages Reserve - OR				62,118	62,118
5	Property Insurance Reserve - OR				1,251,309	1,251,309
6	Property Insurance Reserve - ID	3,506			32,601	36,107
7	Property Insurance Reserve - UT	57,856			414,994	472,850
8	Property Insurance Reserve - WY	9,403			87,453	96,856
9	SMUD Revenue Imputation (11)	8,772,752	440, 442	222,622	14,122	8,564,252
10	Utah Home Energy Lifeline	265,653	142	1,241,750	983,416	7,319
11	BPA Washington Balancing Account	1,806,760			4,188	1,810,948
12	BPA Oregon Balancing Account	615,890	440, 442	2,441,534	1,825,644	
13	Asset Retirement Obligations Reg. Difference	4,388,914	230	47,396	32,906	4,374,424
14	Washington Low Income Program	(92,768)	142	240,947	339,930	6,215
15	Misc. Regulatory Liabilities - OR	192,605	142	15		192,590
16	Blue Sky - OR	827,847	456	125,205	701,819	1,404,461
17	Blue Sky - WA	70,190	456	20,604	40,399	89,985
18	Blue Sky - CA	32,131	456	7,378	17,581	42,334
19	Blue Sky - UT	1,259,932	456	355,134	661,520	1,566,318
20	Blue Sky - ID	9,022	456	7,218	13,837	15,641
21	Blue Sky - WY	120,237	456	61,572	51,118	109,783
22	OR Energy Conservation Charge	2,306,875	456	5,665,345	5,150,904	1,792,434
23	Renewable Energy Credit Sales Deferral - OR	3,651,514	456	358,923	17,386	3,309,977
24	Renewable Energy Credit Sales Deferral - WA			795,704	832,815	37,111
25	Renewable Energy Credit Sales Deferral - WY	2,318,268	456	2,318,268		
26	Renewable Energy Credit Sales Deferral - ID	(419,154)			419,154	
27	Tax Revenue Requirement Adj. - UT	49,234				49,234
28	Regulatory Liability - Reclassifications	9,864,118			1,726,774	11,590,892
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	65,199,743		14,180,993	14,682,377	65,701,127

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

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

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

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

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

The following schedule summarizes regulatory liabilities reclassifications:

	As of June 30, 2011
Reclassified from Regulatory Assets to Regulatory Liabilities:	
DSM Regulatory Asset - CA	$ 3,689,421
DSM Regulatory Asset - WY	2,607,533
DSM Regulatory Asset - UT	5,142,310
Deferred Independent Evaluator Fee - OR (1)	151,628
	$ 11,590,892

Name of Respondent PacifiCorp	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 07/02/2012	Year/Period of Report End of 2011/Q2

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	723,718,918	
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	606,802,951	
5	Large (or Ind.) (See Instr. 4)	531,451,853	
6	(444) Public Street and Highway Lighting	10,140,439	
7	(445) Other Sales to Public Authorities	9,225,852	
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,881,340,013	
11	(447) Sales for Resale	159,057,977	
12	TOTAL Sales of Electricity	2,040,397,990	
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	2,040,397,990	
15	Other Operating Revenues		
16	(450) Forfeited Discounts	4,397,608	
17	(451) Miscellaneous Service Revenues	3,092,933	
18	(453) Sales of Water and Water Power	83,233	
19	(454) Rent from Electric Property	10,021,788	
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	102,660,935	
22	(456.1) Revenues from Transmission of Electricity of Others	36,811,164	
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	157,067,661	
27	TOTAL Electric Operating Revenues	2,197,465,651	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

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
7,861,367				2
				3
7,887,635				4
10,255,182				5
72,791				6
197,817				7
				8
				9
26,274,792				10
5,007,444				11
31,282,236				12
				13
31,282,236				14

Line 12, column (b) includes $ 0 of unbilled revenues.

Line 12, column (d) includes 0 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 17 Column: b

(451) Miscellaneous service revenues include the following items that were $250,000 or greater for the six-month period ended June 30, 2011:

Account service charges - disconnects/reconnects/returned check charges	$ 2,002,348
Customer contract flat rate billings	1,059,724

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

(456) Other electric revenues include the following items that were $250,000 or greater for the six-month period ended June 30, 2011:

Renewable energy credit sales, net of deferrals and amortization	$ 47,560,643
Demand-side management revenue	40,007,939
Wind-based ancillary services	4,295,662
Energy exchange credits	3,984,985
Steam sales	2,877,508
Flyash/by-product sales	1,436,146
Blue Sky revenue	752,554
Power sale and exchange agreements	545,646
Revenue from generation interconnection and transmission service request studies	481,626
Maintenance charges for work on transmission facilities	291,060

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (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					
2					
3					
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41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

ELECTRIC PRODUCTION, OTHER POWER SUPPLY EXPENSES, TRANSMISSION AND DISTRIBUTION EXPENSES

Report Electric production, other power supply expenses, transmission, regional control and market operation, and distribution expenses through the reporting period.

Line No.	Account (a)	Year to Date Quarter (b)
1	1. POWER PRODUCTION AND OTHER SUPPLY EXPENSES	
2	Steam Power Generation - Operation (500-509)	380,107,764
3	Steam Power Generation - Maintenance (510-515)	107,006,697
4	Total Power Production Expenses - Steam Power	487,114,461
5	Nuclear Power Generation - Operation (517-525)	
6	Nuclear Power Generation – Maintenance (528-532)	
7	Total Power Production Expenses - Nuclear Power	
8	Hydraulic Power Generation - Operation (535-540.1)	14,535,524
9	Hydraulic Power Generation – Maintenance (541-545.1)	3,888,060
10	Total Power Production Expenses – Hydraulic Power	18,423,584
11	Other Power Generation - Operation (546-550.1)	178,275,699
12	Other Power Generation - Maintenance (551-554.1)	9,473,581
13	Total Power Production Expenses - Other Power	187,749,280
14	Other Power Supply Expenses	
15	Purchased Power (555)	187,552,352
16	System Control and Load Dispatching (556)	776,786
17	Other Expenses (557)	29,349,524
18	Total Other Power Supply Expenses (line 15-17)	217,678,662
19	Total Power Production Expenses (Total of lines 4, 7, 10, 13 and 18)	910,965,987
20	2. TRANSMISSION EXPENSES	
21	Transmission Operation Expenses	
22	(560) Operation Supervision and Engineering	3,026,600
23	(561) Load Dispatching	
24	(561.1) Load Dispatch-Reliability	
25	(561.2) Load Dispatch-Monitor and Operate Transmission System	3,961,917
26	(561.3) Load Dispatch-Transmission Service and Scheduling	
27	(561.4) Scheduling, System Control and Dispatch Services	
28	(561.5) Reliability, Planning and Standards Development	546,398
29	(561.6) Transmission Service Studies	102,155
30	(561.7) Generation Interconnection Studies	441,798
31	(561.8) Reliability, Planning and Standards Development Services	
32	(562) Station Expenses	1,450,601
33	(563) Overhead Line Expenses	68,669
34	(564) Underground Line Expenses	
35	(565) Transmission of Electricity by Others	68,479,098
36	(566) Miscellaneous Transmission Expenses	2,016,473
37	(567) Rents	905,171
38	(567.1) Operation Supplies and Expenses (Non-Major)	

ELECTRIC PRODUCTION, OTHER POWER SUPPLY EXPENSES, TRANSMISSION AND DISTRIBUTION EXPENSES

Report Electric production, other power supply expenses, transmission, regional control and market operation, and distribution expenses through the reporting period.

Line No.	Account (a)	Year to Date Quarter (b)
39	TOTAL Transmission Operation Expenses (Lines 22 - 38)	80,998,880
40	Transmission Maintenance Expenses	
41	(568) Maintenance Supervision and Engineering	978,173
42	(569) Maintenance of Structures	111
43	(569.1) Maintenance of Computer Hardware	54,692
44	(569.2) Maintenance of Computer Software	580,590
45	(569.3) Maintenance of Communication Equipment	1,785,028
46	(569.4) Maintenance of Miscellaneous Regional Transmission Plant	
47	(570) Maintenance of Station Equipment	5,811,614
48	(571) Maintenance Overhead Lines	9,213,653
49	(572) Maintenance of Underground Lines	120,851
50	(573) Maintenance of Miscellaneous Transmission Plant	143,716
51	(574) Maintenance of Transmission Plant	
52	TOTAL Transmission Maintenance Expenses (Lines 41 - 51)	18,688,428
53	Total Transmission Expenses (Lines 39 and 52)	99,687,308
54	3. REGIONAL MARKET EXPENSES	
55	Regional Market Operation Expenses	
56	(575.1) Operation Supervision	
57	(575.2) Day-Ahead and Real-Time Market Facilitation	
58	(575.3) Transmission Rights Market Facilitation	
59	(575.4) Capacity Market Facilitation	
60	(575.5) Ancillary Services Market Facilitation	
61	(575.6) Market Monitoring and Compliance	
62	(575.7) Market Facilitation, Monitoring and Compliance Services	
63	Regional Market Operation Expenses (Lines 55 - 62)	
64	Regional Market Maintenance Expenses	
65	(576.1) Maintenance of Structures and Improvements	
66	(576.2) Maintenance of Computer Hardware	
67	(576.3) Maintenance of Computer Software	
68	(576.4) Maintenance of Communication Equipment	
69	(576.5) Maintenance of Miscellaneous Market Operation Plant	
70	Regional Market Maintenance Expenses (Lines 65-69)	
71	TOTAL Regional Control and Market Operation Expenses (Lines 63,70)	
72	4. DISTRIBUTION EXPENSES	
73	Distribution Operation Expenses (580-589)	34,492,934
74	Distribution Maintenance Expenses (590-598)	73,109,242
75	Total Distribution Expenses (Lines 73 and 74)	107,602,176

Schedule Page: 324   Line No.: 2   Column: b

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

Schedule Page: 324   Line No.: 17   Column: b

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

ELECTRIC CUSTOMER ACCOUNTS, SERVICE, SALES, ADMINISTRATIVE AND GENERAL EXPENSES

Report the amount of expenses for customer accounts, service, sales, and administrative and general expenses year to date.

Line No.	Account (a)	Year to Date Quarter (b)
1	(901-905) Customer Accounts Expenses	47,501,776
2	(907-910) Customer Service and Information Expenses	48,141,185
3	(911-917) Sales Expenses	
4	8. ADMINISTRATIVE AND GENERAL EXPENSES	
5	Operations	
6	920 Administrative and General Salaries	35,318,971
7	921 Office Supplies and Expenses	4,542,066
8	(Less) 922 Administrative Expenses Transferred-Credit	17,609,014
9	923 Outside Services Employed	9,219,547
10	924 Property Insurance	16,220,040
11	925 Injuries and Damages	3,850,011
12	926 Employee Pensions and Benefits	
13	927 Franchise Requirements	
14	928 Regulatory Commission Expenses	9,641,202
15	(Less) 929 Duplicate Charges-Credit	3,015,812
16	930.1General Advertising Expenses	3,077
17	930.2Miscellaneous General Expenses	7,662,974
18	931 Rents	3,237,354
19	TOTAL Operation (Total of lines 6 thru 18)	69,070,416
20	Maintenance	
21	935 Maintenance of General Plant	12,523,832
22	TOTAL Administrative and General Expenses (Total of lines 19 and 21)	81,594,248

Schedule Page: 325 Line No.: 12 Column: b

Pensions and benefits expense is associated with labor and generally charged to operations and maintenance expense and construction work in progress. During the six-month period ended June 30, 2011, pensions and benefits expense was $77,137,701.

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 07/02/2012	Year/Period of Report End of 2011/Q2

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Arizona Public Service Company	Arizona Public Service Company		OS
2	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	FNO
3	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	SFP
4	Black Hills/Colorado Electric Utility Company			NF
5	Black Hills/Colorado Electric Utility Company			SFP
6	Black Hills, Inc.		Montana-Dakota Utilities	FNO
7	Black Hills, Inc.			NF
8	Black Hills, Inc.			NF
9	Black Hills, Inc.			SFP
10	Black Hills, Inc.		Black Hills, Inc.	LFP
11	Bonneville Power Administration			OS
12	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
13	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	LFP
14	Bonneville Power Administration	Bonneville Power Administration	Umpqua Indian Utility Cooperative	FNO
15	Bonneville Power Administration	Bonneville Power Administration	Benton REA	FNO
16	Bonneville Power Administration	Bonneville Power Administration		FNO
17	Bonneville Power Administration	U. S. Bureau of Reclamation	Bonneville Power Administration	LFP
18	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
19	Bonneville Power Administration	Bonneville Power Administration	Yakama Power	FNO
20	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
21	Bonneville Power Administration			NF
22	Bonneville Power Administration	Bonneville Power Administration	Clark Public Utilities	FNO
23	Cargill Power Markets, LLC			NF
24	Constellation Energy Commodities Group			NF
25	Cowlitz County PUD	Cowlitz County PUD	Bonneville Power Administration	OS
26	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	OS
27	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	AD
28	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	OS
29	Deseret Generation & Trans.	Deseret Generation & Trans.		SFP
30	Eugene Water & Electric Board			NF
31	Fall River Rural Electric Cooperative	Marysville Hydro Partners	Idaho Power Company	OS
32	Foote Creek III, LLC	Foote Creek III, LLC		OS
33	Iberdrola Renewables Inc.			NF
34	Iberdrola Renewables Inc.	Iberdrola Renewables Inc.		OS
	TOTAL			

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 07/02/2012	Year/Period of Report End of 2011/Q2

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)
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Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Iberdrola Renewables Inc.	Exxon Mobile Corporation	Nevada Power Company	LFP
2	Idaho Power Company	Idaho Power Company	Idaho Power Company	OS
3	Idaho Power Company			NF
4	Idaho Power Company			OS
5	Idaho Power Company			OS
6	JP Morgan Ventures Energy Corp.			NF
7	Los Angeles Dept of Water & Power			NF
8	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	OS
9	Morgan Stanley Capital Group, Inc.			NF
10	Morgan Stanley Capital Group, Inc.			SFP
11	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	Grant County PUD	LFP
12	NextEra Energy Resources, LLC			NF
13	Noble Americas Energy Solutions LLC	Bonneville Power Administration	Oregon Direct Access	FNO
14	Pacific Gas & Electric Company			OS
15	Portland General Electric Co.			SFP
16	Powerex Corporation	Bonneville Power Administration	CAISO	LFP
17	Powerex Corporation			NF
18	Powerex Corporation			AD
19	Powerex Corporation			SFP
20	Powder River Energy Corporation	Western Area Power Administration	Sheridan-Johnson Rural Elect.	OS
21	PPL Energy Plus, LLC			NF
22	PPL Energy Plus, LLC			SFP
23	Public Service Co. of CO			SFP
24	Rainbow Energy Marketing Corporation			NF
25	Rainbow Energy Marketing Corporation			SFP
26	Raser Power Systems, Inc.	Raser Power Systems, Inc.	Raser Power Systems, Inc.	LFP
27	Seattle City & Light	FPL Energy Vansycle, LLC	Grant County PUD	LFP
28	Shell Energy North America			NF
29	Sierra Pacific Power Company			OS
30	Sierra Pacific Power Company			NF
31	Southern California Edison			SFP
32	Southern California Edison			NF
33	State of South Dakota	Western Area Power Administration	Black Hills Power & Light Company	LFP
34	Tenaska Power Services Co			NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	TransAlta Energy Marketing Corporation			NF
2	Tri-State Generation & Trans.		Tri-State Generation & Trans.	OS
3	Tri-State Generation & Trans.			NF
4	Tri-State Generation & Trans.		Tri-State Generation & Trans.	FNO
5	United States Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	FNO
6	United States Bureau of Reclamation	Bonneville Power Administration	Crooked River Irrigation District	OS
7	United States Bureau of Reclamation	Western Area Power Administration	Weber Basin Water Conserv.	OS
8	Utah Associated Municipal Power	Utah Associated Municipal Power	Utah Associated Municipal Power	OS
9	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	OS
10	Warm Springs Power Enterprises		Portland General Electric Co.	OS
11	Western Area Power Administration	Western Area Power Administration		OS
12	Western Area Power Administration	Western Area Power Administration		OS
13	Western Area Power Administration	Western Area Power Administration		NF
14	Western Area Power Administration	Western Area Power Administration		SFP
15	Western Area Power Administration	Western Area Power Administration		OS
16	Western Area Power Administration	Western Area Power Administration	Western Area Power Administration	FNO
17	Accrual			
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
R.S. 436		Borah/Brady Sub				1
7V11-3	Yellowtail Sub	Sheridan Substation	2	1,412	1,412	2
7V11-7	Various	Various		720	720	3
7V11-8	Various	Various		276	276	4
7V11-7	Various	Various		1,293	1,293	5
7V11	Various	Sheridan Substation	43	3,301	3,301	6
7V11-8	Various	Various		12,034	12,034	7
7V11-11	Various	Various				8
7V11-7	Various	Various		26,578	26,578	9
7V11-7	Various	Wyodak Substation	50	56,560	56,560	10
R.S. 369	Midpoint Substation	Summer Lake Sub				11
R.S. 237	Various	Various	189	301,955	301,955	12
7V11-3,4	Lost Creek Hydro	Alvey Substation	56	87,295	87,295	13
7V11-3,4	Bonneville Power Adm	Gazley Substation	3	6,398	6,398	14
7V11-3	Bonneville Power Adm	Tieton Substation	2	1,928	1,928	15
7V11-3	McNary Sub	Hinkle Substation	1	161	161	16
7V11-7	USBR Green Springs	Bonneville Power Adm	18	24,484	24,484	17
R.S. 368	Malin Substation	Malin Substation		147,455	147,455	18
7V11-3,4	Bonneville Power Adm	White Swan/Toppenish	7	8,896	8,896	19
R.S. 299	Various	Various	160	337,260	337,260	20
7V11-8	Various	Various		246	246	21
7V11-3,4	Cardwell-Merwin		24	31,876	31,876	22
7V11-8	Various	Various		61,830	61,830	23
7V11-8,9,11	Various	Various		249	249	24
R.S. 234	Swift Unit No. 2	Woodland Substation				25
R.S. 280	Various	Various	105	102,763	102,763	26
R.S. 280	Various	Various				27
R.S. 590	Various	Various				28
7V11-7	Various	Various		960	960	29
7V11-8	Various	Various		3,721	3,721	30
R.S. 322	Targhee Substation	Goshen Substation				31
S.A. 130	Foote Creek Sub	Various				32
7V11-8	Various	Various		4,700	4,700	33
7V11-5,6,9,11						34
			1,732	**3,293,869**	**3,293,869**	

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 07/02/2012	Year/Period of Report End of 2011/Q2

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.
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8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
7V11-7	Trona Substation		30	16,483	16,483	1
R.S. 427	Goshen Substation	Goshen Substation				2
7V11-8	Various	Various				3
R.S. 257	Antelope Sub	Antelope Sub		52,360	52,360	4
R.S. 203	Jim Bridger Sub	Bridger Pump Station				5
7V11-8,9,11	Various	Various		25,978	25,978	6
7V11-8	Various	Various		28,313	28,313	7
R.S. 302	Duchesne	Duchesne	3	3,890	3,890	8
7V11-8	Various	Various		60,988	60,988	9
7V11-7	Various	Various		6,127	6,127	10
7V11-5,6,9,11	Wallula Substation	Wala-MIDC Path	80	100,291	100,291	11
7V11-8	Various	Various				12
7V11-3,4	Bonneville Power Adm	Various	15	23,059	23,059	13
R.S. 607						14
7V11-7	Various	Various		3,273	3,273	15
7V11-7	Bonneville Power Adm	CRAG View Sub	80	79,592	79,592	16
7V11-5,6,8	Various	Various		122,029	122,029	17
7V11-5,6	Various	Various				18
7V11-7	Various	Various		6,772	6,772	19
R.S. 123	Various	Buffalo Substation				20
7V11-8	Various	Various		1,753	1,753	21
7V11-7	Various	Various		628	628	22
7V11-7	Various	Various		200	200	23
7V11-8	Various	Various		5,081	5,081	24
7V11-7	Various	Various		2,672	2,672	25
7V11-5,6,7,9	South Milford Sub	Mona Substation	11	13,758	13,758	26
7V11-5,6,7,9	Wallula Sub	Wala-MIDC Path	25	18,092	18,092	27
7V11-8	Various	Various		4,010	4,010	28
R.S. 674	Sigurd Sub					29
7V11-8	Various	Various		2,816	2,816	30
7V11-5,6,7	Various	Various		80	80	31
7V11-8,9,11	Various	Various		98,323	98,323	32
7V11-7	Yellowtail Sub	Wyodak Sub	4	4,609	4,609	33
7V11-8	Various	Various		2,165	2,165	34
			1,732	**3,293,869**	**3,293,869**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

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.
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FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
7V11-8	Various	Various		8,095	8,095	1
R.S. 123	Various	Various	31	34,733	34,733	2
7V11-8	Various	Various		646	646	3
7V11-3,4	Dave Johnston Sub	Thermopolis Sub	18	30,356	30,356	4
7V11-3	Walla Walla Sub	Burbank Pumps	1	520	520	5
R.S. 67	Redmond Sub	Crooked River Pumps	4	628	628	6
R.S. 286	Various	Various		2,423	2,423	7
R.S. 297	Various	Various	338	673,087	673,087	8
R.S. 637	Various	Various	101	100,184	100,184	9
R.S. 591	Pelton Reregulating	Round Butte Sub		28,423	28,423	10
R.S. 262	Various	Various	330	471,141	471,141	11
R.S. 263	Various	Various		28,446	28,446	12
7V11-8	Various	Various		4,534	4,534	13
7V11-7	Various	Various		1,935	1,935	14
R.S. 664	Dave Johnston Sub	Various				15
7V11	WY Distribution	WY Distribution	1	1,025	1,025	16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			1,732	**3,293,869**	**3,293,869**	

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
2,266		5,547	7,813	2
	2,790		2,790	3
	1,612		1,612	4
	7,668		7,668	5
176,455			176,455	6
	81,597		81,597	7
		13,578	13,578	8
	155,056		155,056	9
303,750			303,750	10
				11
1,065,886		18,531	1,084,417	12
340,200			340,200	13
13,318		40,129	53,447	14
1,878		308	2,186	15
315		26	341	16
109,350			109,350	17
		67,348	67,348	18
24,157		23,006	47,163	19
262,308		279,429	541,737	20
	1,437		1,437	21
80,560		6,110	86,670	22
	517,815		517,815	23
	1,454	2,816	4,270	24
		29,223	29,223	25
401,164		31,619	432,783	26
		395,469	395,469	27
		475,737	475,737	28
	3,720		3,720	29
	21,857		21,857	30
		37,827	37,827	31
		9,046	9,046	32
	29,147		29,147	33
		95,275	95,275	34
6,735,176	**3,577,957**	**8,851,079**	**19,164,212**	

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.
182,250			182,250	1
				2
	6		6	3
		18,456	18,456	4
		4,071	4,071	5
	214,873	1,480	216,353	6
	185,047		185,047	7
		5,090	5,090	8
	375,721		375,721	9
	28,737		28,737	10
486,000		233,969	719,969	11
	70,074		70,074	12
27,449		3,693	31,142	13
		5,000,000	5,000,000	14
	13,950		13,950	15
486,000			486,000	16
	904,820	18,300	923,120	17
		-18,399	-18,399	18
	30,076		30,076	19
		61	61	20
	15,705		15,705	21
	3,668		3,668	22
	1,168		1,168	23
	25,428		25,428	24
	15,108		15,108	25
66,825		10,274	77,099	26
151,875		21,529	173,404	27
	27,833		27,833	28
		12,531	12,531	29
	18,034		18,034	30
	467	60	527	31
	601,535	73,605	675,140	32
24,300			24,300	33
	18,677		18,677	34
6,735,176	**3,577,957**	**8,851,079**	**19,164,212**	

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.
	71,005		71,005	1
29,345			29,345	2
	4,170		4,170	3
70,393		6,192	76,585	4
1,097		2,488	3,585	5
89			89	6
		2,423	2,423	7
1,525,344		177,271	1,702,615	8
375,980		26,835	402,815	9
		29,925	29,925	10
521,690		150,000	671,690	11
		18,709	18,709	12
	116,282		116,282	13
	11,420		11,420	14
				15
4,932		9,889	14,821	16
		1,511,603	1,511,603	17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
6,735,176	**3,577,957**	**8,851,079**	**19,164,212**	

Schedule Page: 328 Line No.: 1 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 1 Column: d

Legacy Contract executed between PacifiCorp and Arizona Public Service Company concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Agreement between PacifiCorp and Arizona Public Service Company ("Restated TSA"), Rate Schedule 436). The contract terminates October 31, 2020. See also FERC Account 565, Transmission of electricity by others, page 332 of this Form 3-Q.

Schedule Page: 328 Line No.: 1 Column: f

Glen Canyon/Four Corners Substation.

Schedule Page: 328 Line No.: 2 Column: d

Network Transmission Service under the Open Access Transmission Tariff (1st Revised Service Agreement 505) terminating no earlier than 12 months from notice by the customer.

Schedule Page: 328 Line No.: 2 Column: m

Distribution voltage service charge. Primary delivery service. Regulation & frequency response.

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.: 4 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, LP.

Schedule Page: 328 Line No.: 4 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 4 Column: c

Various signatories to the 7th Revised 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.: 5 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 5 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 5 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 6 Column: b

PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

Schedule Page: 328 Line No.: 6 Column: d

Network Transmission Service under the Open Access Transmission Tariff (1st Revised Service Agreement 347) terminating on December 31, 2017.

Schedule Page: 328 Line No.: 7 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 7 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 7 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 8 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 8 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 8 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 8 Column: m

Unauthorized use of transmission service.

Schedule Page: 328 Line No.: 9 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 9 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 9 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 10 Column: b

PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

Schedule Page: 328 Line No.: 10 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (1st Revised Service Agreement 67) terminating on December 31, 2033.

Schedule Page: 328 Line No.: 11 Column: b

Capacity exchanged and operated by each transmission provider with no receipt or delivery of energy.

Schedule Page: 328 Line No.: 11 Column: c

Capacity exchanged and operated by each transmission provider with no receipt or delivery of energy.

Schedule Page: 328 Line No.: 11 Column: d

Legacy Contract executed between PacifiCorp and Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities ("Midpoint-Meridian Transmission Agreement", Rate Schedule 369). This agreement runs concurrently with the AC Intertie Agreement (Rate Schedule 368), which terminates when the facilities subject to that agreement are taken out of service. See also FERC Account 565, Transmission of electricity by others, page 332 of this Form 3-Q.

Schedule Page: 328 Line No.: 12 Column: d

Legacy Contract (Rate Schedule 237) executed between PacifiCorp and Bonneville Power Administration ("BPA") for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Contract subject to termination upon the earlier of the termination of the "Exchange Agreement" between PacifiCorp and BPA or the time of the termination of all deliveries as defined in the agreement.

Schedule Page: 328 Line No.: 12 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use/direct assigned facilities charge.

Schedule Page: 328 Line No.: 13 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (Service Agreement 656) terminating on August 31, 2030.

Schedule Page: 328 Line No.: 14 Column: d

Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (3rd Revised Service Agreement 229) terminating on September 23, 2011. The 4th Revised Service Agreement 229 is effective starting October 1, 2001, with a termination date of September 30, 2028.

Schedule Page: 328 Line No.: 14 Column: m

Distribution voltage service charge. Primary delivery service. Regulation & frequency response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328 Line No.: 15 Column: c

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “BENTON REA" ON PAGES 328 – 330:
Complete name is Benton Rural Electric Association.

Schedule Page: 328 Line No.: 15 Column: d

Network Transmission and Distribution Delivery Service under the Open Access Transmission Tariff (Service Agreement 539) terminating on November 30, 2013.

Schedule Page: 328 Line No.: 15 Column: m

Regulation & frequency response.

Schedule Page: 328 Line No.: 16 Column: c

Umatilla Electric Cooperative Association and Columbia Basin Electric Cooperative, Inc.

Schedule Page: 328 Line No.: 16 Column: d

Network Transmission Service under the Open Access Transmission Tariff (Service Agreement 538) terminating on December 31, 2013.

Schedule Page: 328 Line No.: 16 Column: m

Regulation & frequency response.

Schedule Page: 328 Line No.: 17 Column: b

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "U.S. BUREAU OF RECLAMATION" ON PAGES 328 – 330:
Complete name is United States Bureau of Reclamation.

Schedule Page: 328 Line No.: 17 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (1st Revised Service Agreement 179) terminating on September 30, 2025.

Schedule Page: 328 Line No.: 18 Column: d

Legacy Contract (Rate Schedule 368) executed between PacifiCorp and Bonneville Power Administration for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Subject to termination upon mutual agreement.

Schedule Page: 328 Line No.: 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 Line No.: 19 Column: d

Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (2nd Revised Service Agreement 328) terminating on July 31, 2012.

Schedule Page: 328 Line No.: 19 Column: m

Distribution voltage service charge. Primary delivery service. Regulation & frequency response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328 Line No.: 20 Column: d

Legacy Contract (Rate Schedule 299) executed between PacifiCorp and Bonneville Power Administration ("BPA") for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Contract terminates with 3-year notice by BPA or 5-year notice by PacifiCorp. PacifiCorp provided notice of termination in June 2011.

Schedule Page: 328 Line No.: 20 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use/direct assigned facilities charge. Charges for scheduling and operating reserves.

Schedule Page: 328 Line No.: 21 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 21 Column: c

Various signatories to the 7th Revised 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.: 22 Column: d

Network Transmission Service under the Open Access Transmission Tariff (Service Agreement 370) terminating on December 7, 2012 or with six months written notice.

Schedule Page: 328 Line No.: 22 Column: g

Chelatchie/View 115kV

Schedule Page: 328 Line No.: 22 Column: m

Regulation & frequency response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328 Line No.: 23 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 23 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 24 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "CONSTELLATION ENERGY COMMODITIES GROUP" ON PAGES 328 – 330:
Complete name is Constellation Energy Commodities Group, Inc.

Schedule Page: 328 Line No.: 24 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 24 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 24 Column: m

Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328 Line No.: 25 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “COWLITZ COUNTY PUD” ON PAGES 328 – 330:
Complete name is Public Utility District No. 1 of Cowlitz County.

Schedule Page: 328 Line No.: 25 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 Line No.: 25 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and or proportional use as defined in the contract.

Schedule Page: 328 Line No.: 26 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “DESERET GENERATION & TRANS." ON PAGES 328 – 330:
Complete name is Deseret Generation and Transmission Cooperative.

Schedule Page: 328 Line No.: 26 Column: d

Legacy Contract executed between PacifiCorp and Deseret Generation and Transmission Cooperative for transmission service over agreed-upon facilities (3rd Amended and Restated Transmission Service and Operating Agreement, Rate Schedule 280). Agreement subject to termination upon mutual agreement.

Schedule Page: 328 Line No.: 26 Column: m

Scheduling and load following charges. Distribution voltage service charge. Charges for spinning and/or supplemental reserves.

Schedule Page: 328 Line No.: 27 Column: d

Legacy Contract executed between PacifiCorp and Deseret Generation and Transmission Cooperative for transmission service over agreed-upon facilities (3rd Amended and Restated Transmission Service and Operating Agreement, Rate Schedule 280). Agreement subject to termination upon mutual agreement.

Schedule Page: 328 Line No.: 27 Column: m

Charges for spinning and/or supplemental reserves covering 2009 - 2010.

Schedule Page: 328 Line No.: 28 Column: d

Control Area Services Agreement (Rate Schedule 590) for charges associated with providing control area support and ancillary services. Agreement terminated and was replaced by the First Amended and Restated Control Area Services Agreement (Rate Schedule 590 Rev. 1), which incorporates provisions in the previous agreement. Agreement terminates on the earlier of the effective Third Amended and Restated Transmission Service and Operating Agreement, ("TSOA"), (Rate Schedule 280) is superceded and replaced by an amended and restated TSOA providing for control area/ancillary services as defined in this agreement and accepted by the Federal Energy Regulatory Commission, or May 1, 2012. Contract provisions may be suspended due to termination of Power Marketing and Resource Management Services Agreement ("PMA") between PacifiCorp and Deseret Generation and Transmission Cooperative ("Deseret") or upon Deseret self-supplying, and re-assumption with a modified or replacement to the PMA agreement.

Schedule Page: 328 Line No.: 28 Column: m

Charges for spinning and/or supplemental reserves. Regulation & frequency response. Meter interrogation charge. Control area services charge.

Schedule Page: 328 Line No.: 29 Column: c

Various signatories to the 7th Revised 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.: 30 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 30 Column: c

Various signatories to the 7th Revised 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.: 31 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 Line No.: 31 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and or proportional use as defined in the contract.

Schedule Page: 328 Line No.: 32 Column: c

PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

Schedule Page: 328 Line No.: 32 Column: d

Service Agreement 130 executed between PacifiCorp and Foote Creek (Seawest) for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating July 2014.

Schedule Page: 328 Line No.: 32 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328 Line No.: 33 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 33 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 34 Column: c

Iberdrola Renewables Inc. and Utah Associated Municipal Power Systems.

Schedule Page: 328 Line No.: 34 Column: d

Ancillary Services under the Open Access Transmission Tariff (Service Agreement 476) in effect until superseded.

Schedule Page: 328 Line No.: 34 Column: f

Long Hollow, WY Switching Station

Schedule Page: 328 Line No.: 34 Column: g

Long Hollow, WY Switching Station

Schedule Page: 328 Line No.: 34 Column: m

Charges for spinning and/or supplemental reserves. Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.1 Line No.: 1 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (5th Revised Service Agreement 279). Agreement terminating April 30, 2014.

Schedule Page: 328.1 Line No.: 1 Column: g

Red Butte/Mona Substation.

Schedule Page: 328.1 Line No.: 2 Column: d

Legacy Contract (Rate Schedule 427) executed between PacifiCorp and Idaho Power Company concerning the exchange of transmission services over agreed-upon facilities (Draft Transmission Services Agreement between PacifiCorp and Idaho Power Company, Draft 1 – 5/19/95 ("Goshen Agreement")). Termination of this agreement occurs at the end of the calendar month following the earlier of the effectiveness of a replacement contract, or upon three years written notice of termination as long as PacifiCorp has facilities in place to serve PacifiCorp's Big Grassy load. See also FERC Account 565, Transmission of electricity by others, page 332 of this Form 3-Q.

Schedule Page: 328.1 Line No.: 3 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 3 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 3 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 4 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 4 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 4 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/USDOE Supply Agreement.

Schedule Page: 328.1 Line No.: 4 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.1 Line No.: 5 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 5 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 5 Column: d

Legacy Contract (Rate Schedule 203) executed between PacifiCorp and Idaho Power Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge (Service Agreement 203) for the Jim Bridger Pump. Agreement terminates upon 12-months written notice.

Schedule Page: 328.1 Line No.: 5 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.1 Line No.: 6 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “JP MORGAN VENTURES ENERGY CORP" ON PAGES 328 – 330:
Complete name is JP Morgan Ventures Energy Corporation.

Schedule Page: 328.1 Line No.: 6 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 6 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 6 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 6 Column: m

Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.1 Line No.: 7 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “LOS ANGELES DEPT OF WATER & POWER" ON PAGES 328 – 330:
Complete name is Los Angeles Department of Water and Power.

Schedule Page: 328.1 Line No.: 7 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 7 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 7 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 8 Column: d

Legacy Contract (2nd Revised Rate Schedule 302) executed between PacifiCorp and Moon Lake Electric Association for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Either party may terminate the agreement at any time after October 14, 2011, by providing two years written notice.

Schedule Page: 328.1 Line No.: 8 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.: 9 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 9 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 9 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 10 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 10 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 10 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 11 Column: c

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “GRANT COUNTY PUD" ON PAGES 328 – 330:
Complete name is Grant County Public Utility District.

Schedule Page: 328.1 Line No.: 11 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (Service Agreement 626), assignment from Seattle City & Light, terminating December 31, 2011.

Schedule Page: 328.1 Line No.: 11 Column: m

Charges for spinning and/or supplemental reserves. Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.1 Line No.: 12 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 12 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 12 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 13 Column: d

Transmission Service under the Open Access Transmission Tariff (Service Agreement 299). Service provided pursuant to rules and regulations of Oregon Direct Access. Agreement termination upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 328.1 Line No.: 13 Column: m

Regulation & frequency response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.1 Line No.: 14 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 14 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 14 Column: d

Legacy Contract (Rate Schedule 607) executed between PacifiCorp and Pacific Gas & Electric Company for transmission service over agreed-upon facilities (Malin to Round Mountain) and/or subject to a sole-use or facilities charge. Terminating December 31, 2017. See, PacifiCorp, Docket No. ER07-882, et al, Settlement Agreement, Appendix 2 (filed November 20, 2007).

Schedule Page: 328.1 Line No.: 14 Column: f

Malin to Indian Springs line segment.

Schedule Page: 328.1 Line No.: 14 Column: g

Malin to Indian Springs line segment.

Schedule Page: 328.1 Line No.: 14 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.1 Line No.: 15 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “PORTLAND GENERAL ELECTRIC CO." ON PAGES 328 – 330:
Complete name is Portland General Electric Company.

Schedule Page: 328.1 Line No.: 15 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 15 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 15 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 16 Column: c

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “CAISO" ON PAGES 328 – 330:
Complete name is California Independent System Operator Corporation.

Schedule Page: 328.1 Line No.: 16 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (5th Revised Service Agreement 169) terminating on October 31, 2020.

Schedule Page: 328.1 Line No.: 17 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 17 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 17 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 17 Column: m

Charges for spinning and/or supplemental reserves. Penalty revenues covering imbalance charges per Schedules 4 and 9. Unauthorized use of transmission service.

Schedule Page: 328.1 Line No.: 18 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 18 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 18 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 18 Column: m

Refunds of spinning and/or supplemental reserves for 2009 and 2010.

Schedule Page: 328.1 Line No.: 19 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 19 Column: c

Various signatories to the 7th Revised 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.: 20 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: 328.1 Line No.: 20 Column: d

Legacy Contract (Rate Schedule 123) providing for transmission service from Western Area Power Administration's Casper Substation in Wyoming and Yellowtail Substation in Montana to Sheridan-Johnson Rural Electric Association's load at PacifiCorp's Buffalo Substation in Wyoming.

Schedule Page: 328.1 Line No.: 20 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.1 Line No.: 21 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 21 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 21 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 22 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 22 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 22 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 23 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “PUBLIC SERVICE CO. OF CO" ON PAGES 328 – 330: Complete name is Public Service Company of Colorado.

Schedule Page: 328.1 Line No.: 23 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 23 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 23 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 24 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 24 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 24 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 25 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 25 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 25 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 26 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (1st Revised Service Agreement 568) terminating April 30, 2029.

Schedule Page: 328.1 Line No.: 26 Column: m

Charges for spinning and/or supplemental reserves. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.1 Line No.: 27 Column: d

Roint-to-Point Transmission Service under the Open Access Transmission Tariff (7th Revised Service Agreement 289), terminating October 31, 2014.

Schedule Page: 328.1 Line No.: 27 Column: m

Charges for spinning and/or supplemental reserves. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.1 Line No.: 28 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 28 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 28 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 29 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 29 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.1 Line No.: 29 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 45 years from the date the second interconnection is placed in service and shall continue in effect beyond such time unless terminated by either party through written notice given to the other party not later than four years in advance of the desired termination date.

Schedule Page: 328.1 Line No.: 29 Column: g

Utah-Nevada Border.

Schedule Page: 328.1 Line No.: 29 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.1 Line No.: 30 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 30 Column: c

Various signatories to the 7th Revised 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.: 31 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 31 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 31 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 31 Column: m

Charges for spinning and/or supplemental reserves.

Schedule Page: 328.1 Line No.: 32 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 32 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 32 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 32 Column: m

Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.1 Line No.: 33 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (Service Agreement 170) terminating on May 31, 2014.

Schedule Page: 328.1 Line No.: 34 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 34 Column: c

Various signatories to the 7th Revised 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: 328.2 Line No.: 1 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 1 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 1 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 2 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: 328.2 Line No.: 2 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 2 Column: d

Legacy Contract (Rate Schedule 123) executed between PacifiCorp and Tri-State Generation and Transmission Association, Inc. for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating October 1, 2014.

Schedule Page: 328.2 Line No.: 3 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 3 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 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: 328.2 Line No.: 4 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 4 Column: d

Network Transmission Service under the Open Access Transmission Tariff (3rd Revised Service Agreement 628) terminating on June 30, 2021.

Schedule Page: 328.2 Line No.: 4 Column: m

Regulation & frequency response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.2 Line No.: 5 Column: d

Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (Service Agreement 506) terminating upon written notification.

Schedule Page: 328.2 Line No.: 5 Column: m

Distribution voltage service charge. Primary delivery service. Regulation & frequency response.

Schedule Page: 328.2 Line No.: 6 Column: d

Legacy Contract (Rate Schedule 67) executed between PacifiCorp and United States Bureau of Reclamation Crooked River Irrigation District for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Agreement termination with one year written notice.

Schedule Page: 328.2 Line No.: 7 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: 328.2 Line No.: 7 Column: d

Legacy Contract (Rate Schedule 286) executed between PacifiCorp and United States Bureau of Reclamation Weber Basin Water Conservancy District for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge for energy deliveries at and below 138kV. Agreement termination any time after April 1, 2040 with four years written notification.

Schedule Page: 328.2 Line No.: 7 Column: m

Energy consumption charge for deliveries at and below 138kV.

Schedule Page: 328.2 Line No.: 8 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “UTAH ASSOCIATED MUNICIPAL POWER" ON PAGES 328 – 330:
Complete name is Utah Associated Municipal Power Systems.

Schedule Page: 328.2 Line No.: 8 Column: d

Legacy Contract executed between PacifiCorp and Utah Associated Municipal Power Systems for transmission service over agreed-upon facilities (Amended and Restated Transmission Service and Operating Agreement, Rate Schedule 297). Agreement subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.2 Line No.: 8 Column: m

Charges for scheduling and load following. Charges for spinning and/or supplemental reserves. Distribution voltage service charge.

Schedule Page: 328.2 Line No.: 9 Column: d

Legacy Contract (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: 328.2 Line No.: 9 Column: m

Charges for scheduling and load following.

Schedule Page: 328.2 Line No.: 10 Column: b

Warm Springs Power Enterprises.

Schedule Page: 328.2 Line No.: 10 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 of or facilities charge. Agreement terminating January 31, 2032.

Schedule Page: 328.2 Line No.: 10 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.: 11 Column: c

Various Western Area Power Administration customers in Pacificorp's Control Area.

Schedule Page: 328.2 Line No.: 11 Column: d

Legacy Contract (Rate Schedule 262) executed between PacifiCorp and Western Area Power Administration for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge for load service to preferential customers for deliveries of Colorado River Storage Project power and energy. Agreement termination upon three years after written notice and mutual consent.

Schedule Page: 328.2 Line No.: 11 Column: m

Fixed termination fee associated with a contract cancellation applied for the duration of this agreement.

Schedule Page: 328.2 Line No.: 12 Column: c

Various Western Area Power Administration customers in Pacificorp's Control Area.

Schedule Page: 328.2 Line No.: 12 Column: d

Legacy Contract (Rate Schedule 263) executed between PacifiCorp and Western Area Power Administration for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge for load service to low voltage customers for deliveries of power and energy from Salt Lake City Area Integrated Projects, including the Colorado River Storage Projects, to certain municipalities at service below 138kV. Agreement termination upon three years after written notice and mutual consent.

Schedule Page: 328.2 Line No.: 12 Column: m

Charges for low-voltage transmission of power and energy.

Schedule Page: 328.2 Line No.: 13 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 13 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 14 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 14 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 15 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 15 Column: d

Legacy Contract (Rate Schedule 664) executed between PacifiCorp and Western Area Power Administration concerning the exchange of transmission services over agreed-upon facilities. The contract terminates fifty years from execution. See also FERC Account 565, Transmission of electricity by others, page 332 of this Form 3-Q.

Schedule Page: 328.2 Line No.: 16 Column: d

Evergreen Network Transmission Service under the Open Access Transmission Tariff (Service Agreement 175).

Schedule Page: 328.2 Line No.: 16 Column: m

Distribution voltage service charge. Primary delivery service.

Schedule Page: 328.2 Line No.: 17 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 during the period to FERC Account 456.1, Revenues from transmission of electricity for others.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) 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.
4. In column (c) 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 (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
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	TOTAL				

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 07/02/2012	Year/Period of Report End of 2011/Q2

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Arizona Public Service	LFP	52,907	52,907	275,713			275,713
2	Arizona Public Service	NF	1,364	1,364	4,701			4,701
3	Arizona Public Service	OS					1,753	1,753
4	Arizona Public Service	OS						
5	Arizona Public Service	SFP	37,266	37,266	99,687			99,687
6	Ashland, City of	FNS	375	375		2,578		2,578
7	Avista Corporation	AD	120	120	692			692
8	Avista Corporation	FNS	11,278	11,604	58,497			58,497
9	Big Horn Rural Electric	OS					43,425	43,425
10	Bonneville Power Admin	AD	1	1	-2,782	510	-991	-3,263
11	Bonneville Power Admin	FNS			1,270,006			1,270,006
12	Bonneville Power Admin	LFP	1,144,531	1,144,531	13,377,792			13,377,792
13	Bonneville Power Admin	NF	197,046	197,046		853,209		853,209
14	Bonneville Power Admin	OLF	419,414	419,598	7,667,342		27,117	7,694,459
15	Bonneville Power Admin	OS	3,990	3,990		4,779	1,052,685	1,057,464
16	Bonneville Power Admin	SFP	12,880	12,880		21,497		21,497
	TOTAL		3,399,354	3,446,933	27,852,058	1,812,872	4,464,926	34,129,856

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Bonneville Power Admin	OS						
2	CA Ind. Sys. Operator	AD				-26,838	25,479	-1,359
3	CA Ind. Sys. Operator	OS					390,749	390,749
4	CA Ind. Sys. Operator	SFP	145,485	145,485		957,137		957,137
5	Deseret Gen & Trans	LFP	34,849	34,849	1,073,054			1,073,054
6	Deseret Gen & Trans	NF	60,845	60,845	352,335			352,335
7	Flathead Elec. Coop.	OS					13,037	13,037
8	Idaho Power Company	AD			-2,318			-2,318
9	Idaho Power Company	FNS			2,228			2,228
10	Idaho Power Company	LFP	646,454	663,936	1,489,570			1,489,570
11	Idaho Power Company	NF	36,743	65,772	199,245			199,245
12	Idaho Power Company	OS			-12,633		2,961,796	2,949,163
13	Idaho Power Company	OS						
14	Idaho Power Company	SFP	720	720	2,395			2,395
15	Moon Lake Elec. Assoc.	OLF					64,541	64,541
16	Nevada Power Company	NF	1,281	1,281	4,127			4,127
	TOTAL		3,399,354	3,446,933	27,852,058	1,812,872	4,464,926	34,129,856

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 07/02/2012	Year/Period of Report End of 2011/Q2

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Nevada Power Company	OS					55,702	55,702
2	NorthWestern Corp.	NF	2,798	2,798	12,113			12,113
3	NorthWestern Corp.	OS					842	842
4	NorthWestern Corp.	SFP	1,200	1,200	5,195			5,195
5	Platte River Power	LFP	21,878	21,878	241,500			241,500
6	Platte River Power	OS					2,566	2,566
7	Portland General Elec.	OS					219	219
8	Powerex Corporation	SFP			-501,162			-501,162
9	Public Svc. Co. of CO	LFP	5,697	5,975	229,975			229,975
10	Public Svc. Co. of NM	LFP	28,821	28,821	161,178			161,178
11	Public Svc. Co. of NM	OS					5,280	5,280
12	Shell Energy N. America	SFP			-149,400			-149,400
13	Sierra Pacific Pwr. Co.	NF	34,352	34,352	168,837			168,837
14	Sierra Pacific Pwr. Co.	OS					32,750	32,750
15	Surprise Valley Elec.	OLF					2,445	2,445
16	TransAlta Energy Mktg	SFP			-54,000			-54,000
	TOTAL		3,399,354	3,446,933	27,852,058	1,812,872	4,464,926	34,129,856

Name of Respondent PacifiCorp	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 07/02/2012	Year/Period of Report End of 2011/Q2

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. & Trans.	AD	3	3	1			1
2	Tri-State Gen. & Trans.	LFP	10,084	10,364	229,975			229,975
3	Tri-State Gen. & Trans.	NF	93,449	93,449	198,582			198,582
4	Tri-State Gen. & Trans.	OS					51,931	51,931
5	Tucson Electric Pwr.	NF	28	28	87			87
6	Tucson Electric Pwr.	OS					466	466
7	Tucson Electric Pwr.	SFP	1,200	1,200	5,200			5,200
8	Westport Field Svc. LLC	LFP			-802,860			-802,860
9	Western Area Pwr. Admin	AD	4,951	4,951	-10,460		-1,302	-11,762
10	Western Area Pwr. Admin	FNS			1,207,793			1,207,793
11	Western Area Pwr. Admin	LFP	79,816	79,816	370,000			370,000
12	Western Area Pwr. Admin	NF	215,571	215,571	527,434			527,434
13	Western Area Pwr. Admin	OS					138,877	138,877
14	Western Area Pwr. Admin	OS						
15	Western Area Pwr. Admin	SFP	91,957	91,957	152,419			152,419
16	Accrual						-404,441	-404,441
	TOTAL		3,399,354	3,446,933	27,852,058	1,812,872	4,464,926	34,129,856

Schedule Page: 332 Line No.: 1 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "ARIZONA PUBLIC SERVICE" ON PAGES 332-332.3:
Complete name is Arizona Public Service Company.

Schedule Page: 332 Line No.: 1 Column: b

Arizona Public Service Company - Contract Termination Dates: May 1, 2013, August 31, 2013, January 11, 2041 and May 31, 2047.

Schedule Page: 332 Line No.: 3 Column: g

Ancillary Services.

Schedule Page: 332 Line No.: 4 Column: b

Legacy Contract executed between PacifiCorp and Arizona Public Service Company concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Agreement between PacifiCorp and Arizona Public Service Company ("Restated TSA"), Rate Schedule 436). The contract terminates October 31, 2020. See also FERC Account 456.1, Transmission of electricity for others, page 328 of this Form 3-Q.

Schedule Page: 332 Line No.: 7 Column: b

Settlement Adjustment.

Schedule Page: 332 Line No.: 9 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "BIG HORN RURAL ELECTRIC" ON PAGES 332-332.3:
Complete name is Big Horn Rural Electric Cooperative.

Schedule Page: 332 Line No.: 9 Column: g

Use of Facilities.

Schedule Page: 332 Line No.: 10 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "BONNEVILLE POWER ADMIN" ON PAGES 332-332.3:
Complete name is Bonneville Power Administration.

Schedule Page: 332 Line No.: 10 Column: b

Settlement Adjustment.

Schedule Page: 332 Line No.: 10 Column: g

Ancillary Services.

Schedule Page: 332 Line No.: 12 Column: b

Bonneville Power Administration - Contract Termination Dates: December 1, 2011, April 1, 2012, July 1, 2012, November 1, 2012, September 1, 2013, October 1, 2013, December 1, 2013, January 1, 2014, November 1, 2014, November 1, 2015, July 1, 2016, December 1, 2016, October 1, 2027, November 1, 2033 and evergreen.

Schedule Page: 332 Line No.: 14 Column: b

Bonneville Power Administration - Contract Termination Dates: October 3, 2014, December 31, 2018, September 30, 2027 and evergreen.

Schedule Page: 332 Line No.: 14 Column: g

Use of Facilities.

Schedule Page: 332 Line No.: 15 Column: g

Ancillary Services. Use of Facilities.

Schedule Page: 332.1 Line No.: 1 Column: b

Legacy Contract executed between PacifiCorp and Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities ("Midpoint-Meridian Transmission Agreement", Rate Schedule 369). This agreement runs concurrently with the AC Intertie Agreement (Rate Schedule 368), which terminates when the facilities subject to that agreement are taken out of service. See also FERC Account 456.1, Transmission of electricity for others, page 328 of this Form 3-Q.

Schedule Page: 332.1 Line No.: 2 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "CA IND. SYS. OPERATOR" ON PAGES 332-332.3:
Complete name is California Independent System Operator Corporation.

Schedule Page: 332.1 Line No.: 2 Column: b

Settlement Adjustment.

Schedule Page: 332.1 Line No.: 2 Column: g

Ancillary Services.

Schedule Page: 332.1 Line No.: 3 Column: g

Ancillary Services.

Schedule Page: 332.1 Line No.: 5 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "DESERET GEN & TRANS" ON PAGES 332-332.3: Complete name is Deseret Generation and Transmission Cooperative.

Schedule Page: 332.1 Line No.: 5 Column: b

Deseret Generation and Transmission Cooperative - Contract Termination Dates: October 31, 2012 and September 1, 2018.

Schedule Page: 332.1 Line No.: 7 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "FLATHEAD ELEC. COOP." ON PAGE 332-332.3: Complete name is Flathead Electric Cooperative, Inc.

Schedule Page: 332.1 Line No.: 7 Column: g

Use of Facilities.

Schedule Page: 332.1 Line No.: 8 Column: b

Settlement Agreement.

Schedule Page: 332.1 Line No.: 10 Column: b

Idaho Power Company - Contract Termination Date: April 1, 2025 and July 1, 2025.

Schedule Page: 332.1 Line No.: 12 Column: e

Credit for unreserved use.

Schedule Page: 332.1 Line No.: 12 Column: g

Ancillary Services. Use of Facilities. Respondent's portion of specified costs of certain facilities.

Schedule Page: 332.1 Line No.: 13 Column: b

Legacy Contract (Rate Schedule 427) executed between PacifiCorp and Idaho Power Company concerning the exchange of transmission services over agreed-upon facilities (Draft Transmission Services Agreement between PacifiCorp and Idaho Power Company, Draft 1 – 5/19/95 (“Goshen Agreement”)). Termination of this agreement occurs at the end of the calendar month following the earlier of the effectiveness of a replacement contract, or upon three years written notice of termination as long as PacifiCorp has facilities in place to serve PacifiCorp's Big Grassy load. See also FERC Account 456.1, Transmission of electricity for others, page 328 of this Form 3-Q.

Schedule Page: 332.1 Line No.: 15 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "MOON LAKE ELEC. ASSOC." ON PAGES 332-332.3: Complete name is Moon Lake Electric Association.

Schedule Page: 332.1 Line No.: 15 Column: g

Use of Facilities.

Schedule Page: 332.2 Line No.: 1 Column: g

Ancillary Services.

Schedule Page: 332.2 Line No.: 2 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "NORTHWESTERN CORP." ON PAGES 332-332.3: Complete name is NorthWestern Corporation.

Schedule Page: 332.2 Line No.: 3 Column: g

Ancillary Services.

Schedule Page: 332.2 Line No.: 5 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "PLATTE RIVER POWER" ON PAGES 332-332.3: Complete name is Platte River Power Authority.

Schedule Page: 332.2 Line No.: 5 Column: b

Platte River Power Authority - Contract Termination Date: October 31, 2012.

Schedule Page: 332.2 Line No.: 6 Column: g

Ancillary Services.

Schedule Page: 332.2 Line No.: 7 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "PORTLAND GENERAL ELEC." ON PAGES 332-332.3: Complete name is Portland General Electric Company.

Schedule Page: 332.2 Line No.: 7 Column: g

Use of Facilities.

Schedule Page: 332.2 Line No.: 8 Column: e

Reassignment of Bonneville Power Administration Transmission.

Schedule Page: 332.2 Line No.: 9 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "PUBLIC SVC. CO. OF CO" ON PAGES 332-332.3:
Complete name is Public Service Company of Colorado.

Schedule Page: 332.2 Line No.: 9 Column: b

Public Service Company of Colorado - Contract Termination Date: The date that all generating plants comprising PacifiCorp resources have been retired from service or interests transferred.

Schedule Page: 332.2 Line No.: 10 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "PUBLIC SVC. CO. OF NM" ON PAGES 332-332.3:
Complete name is Public Service Company of New Mexico.

Schedule Page: 332.2 Line No.: 10 Column: b

Public Service Company of New Mexico - Contract Termination Date: December 1, 2012.

Schedule Page: 332.2 Line No.: 11 Column: g

Ancillary Services.

Schedule Page: 332.2 Line No.: 12 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “SHELL ENERGY N. AMERICA” ON PAGES 332-332.3:
Complete name is Shell Energy North America (US), L.P.

Schedule Page: 332.2 Line No.: 12 Column: e

Reassignment of Bonneville Power Administration Transmission.

Schedule Page: 332.2 Line No.: 13 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "SIERRA PACIFIC PWR. CO." ON PAGES 332-332.3:
Complete name is Sierra Pacific Power Company.

Schedule Page: 332.2 Line No.: 14 Column: g

Ancillary Services.

Schedule Page: 332.2 Line No.: 15 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "SURPRISE VALLEY ELEC." ON PAGES 332-332.3:
Complete name is Surprise Valley Electrification Corp.

Schedule Page: 332.2 Line No.: 15 Column: b

Surprise Valley Electrification Corp. - Contract Termination Date: Evergreen.

Schedule Page: 332.2 Line No.: 15 Column: g

Use of Facilities.

Schedule Page: 332.2 Line No.: 16 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “TRANSALTA ENERGY MKTG” ON PAGE 332-332.3:
Complete name is TransAlta Energy Marketing, Inc.

Schedule Page: 332.2 Line No.: 16 Column: e

Reassignment of Bonneville Power Administration Transmission.

Schedule Page: 332.3 Line No.: 1 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "TRI-STATE GEN. & TRANS." ON PAGES 332-332.3:
Complete name is Tri-State Generation and Transmission Association, Inc.

Schedule Page: 332.3 Line No.: 1 Column: b

Settlement Agreement.

Schedule Page: 332.3 Line No.: 2 Column: b

Tri-State Generation and Transmission Association, Inc. - Contract Termination Date: The date that all generating plants comprising PacifiCorp resources have been retired from service or interests transferred.

Schedule Page: 332.3 Line No.: 4 Column: g

Ancillary Services.

Schedule Page: 332.3 Line No.: 5 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "TUCSON ELECTRIC PWR." ON PAGES 332-332.3:
Complete name is Tucson Electric Power Company.

Schedule Page: 332.3 Line No.: 6 Column: g

Ancillary Services.

Schedule Page: 332.3 Line No.: 8 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "WESTPORT FIELD SVC. LLC" ON PAGES 332-332.3:
Complete name is Westport Field Services, LLC.

Schedule Page: 332.3 Line No.: 8 Column: b

Westport Field Services, LLC - Contract Termination Date: Evergreen.

Schedule Page: 332.3 Line No.: 8 Column: e

Reimbursement for providing third party service.

Schedule Page: 332.3 Line No.: 9 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "WESTERN AREA PWR. ADMIN" ON PAGES 332-332.3: Complete name is Western Area Power Administration.

Schedule Page: 332.3 Line No.: 9 Column: b

Settlement Adjustment.

Schedule Page: 332.3 Line No.: 9 Column: g

Ancillary Services.

Schedule Page: 332.3 Line No.: 11 Column: b

Western Area Power Administration - Contract Termination Date: May 31, 2022. Transmission service provided year round, financially settled November - April.

Schedule Page: 332.3 Line No.: 13 Column: g

Ancillary Services. Use of Facilities.

Schedule Page: 332.3 Line No.: 14 Column: b

Legacy Contract (Rate Schedule 664) executed between PacifiCorp and Western Area Power Administration concerning the exchange of transmission services over agreed-upon facilities. The contract terminates fifty years from execution. See also FERC Account 456.1, Transmission of electricity for others, page 328 of this Form 3-Q.

Schedule Page: 332.3 Line No.: 16 Column: g

Represents the difference between actual wheeling expenses for the period as reflected on the individual line items within this schedule, and the accruals charged to FERC Account 565, Transmission of electricity by others, during the period.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

Depreciation, Depletion and Amortization of Electric Plant (Accts 403, 403.1, 404, and 405) (Except Amortization of Acquisition Adjustments)

1. Report the year to date amounts of depreciation expense, asset retirement cost depreciation, depletion and amortization, except amortization of acquisition adjustments for the accounts indicated and classified according to the plant functional groups described.

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Other Limited-Term Electric Plant (Account 404) (e)	Amortization of Other Electric Plant (Account 405) (e)	Total (f)
1	Intangible Plant			20,905,277		20,905,277
2	Steam Production Plant	67,923,050				67,923,050
3	Nuclear Production Plant					
4	Hydraulic Production Plant Conv	10,305,984		128,361		10,434,345
5	Hydraulic Production Plant - Pumped Storage					
6	Other Production Plant	57,727,804				57,727,804
7	Transmission Plant	41,877,984				41,877,984
8	Distribution Plant	74,604,281				74,604,281
9	General Plant	17,983,870		1,687,928		19,671,798
10	Common Plant					
11	TOTAL ELECTRIC (lines 2 through 10)	270,422,973		22,721,566		293,144,539

Schedule Page: 338   Line No.: 11   Column: b

Depreciation expense associated with transportation equipment is generally charged to operations and maintenance expense and construction work in progress. During the six-month period ended June 30, 2011, depreciation expense associated with transportation equipment was $6,984,916.

Schedule Page: 338   Line No.: 11   Column: c

Generally, PacifiCorp records depreciation 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) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
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40					
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42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

MONTHLY PEAKS AND OUTPUT

(1) (1) Report the monthly peak load and energy output. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non- integrated system. In quarter 1 report January, February, and March only. In quarter 2 report April, May, and June only. In quarter 3 report July, August, and September only.
(2) Report on column (b) by month the system's output in Megawatt hours for each month.
(3) Report on column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on columns (e) and (f) the specified information for each monthly peak load reported on column (d).
(6) Report Monthly Peak Hours in military time; 0100 for 1:00 AM, 1200 for 12 AM, and 1830 for 6:30 PM, etc.

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (MWH) (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
1	January				0	0
2	February				0	0
3	March				0	0
4	Total					
5	April	5,448,456	912,780	7,518	8	900
6	May	5,364,240	858,111	7,087	17	1000
7	June	5,506,650	834,335	8,623	28	1700
8	Total	16,319,346	2,605,226	23,228		
9	July				0	0
10	August				0	0
11	September				0	0
12	Total					

Schedule Page: 399 Line No.: 7 Column: d

Peak load data is acquired from the system operational log which, in some cases, uses schedules to estimate actual values of borderline loads.

Schedule Page: 399 Line No.: 7 Column: e

Peak load data is acquired from the system operational log which, in some cases, uses schedules to estimate actual values of borderline loads.

Schedule Page: 399 Line No.: 7 Column: f

Peak load data is acquired from the system operational log which, in some cases, uses schedules to estimate actual values of borderline loads. Monthly peak hours for April, May and June are Pacific Daylight Time.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	16,312	11	1800	8,682	118	4,999		840	1,673
2	February	17,334	2	800	8,602	119	4,999		1,947	1,667
3	March	15,438	7	1900	7,696	104	4,999		1,186	1,453
4	Total for Quarter 1	49,084			24,980	341	14,997		3,973	4,793
5	April	15,768	8	900	7,518	96	4,999		1,731	1,424
6	May	15,100	17	1000	7,087	83	5,159		1,432	1,339
7	June	17,796	28	1700	8,623	95	5,500		1,829	1,749
8	Total for Quarter 2	48,664			23,228	274	15,658		4,992	4,512
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year	97,748			48,208	615	30,655		8,965	9,305

Schedule Page: 400 Line No.: 1 Column: c

1st Quarter 2011 Net System Load information was estimated using metering and/or scheduling data.

Schedule Page: 400 Line No.: 1 Column: d

PST. 1st Quarter 2011 Net System Load information was estimated using metering and/or scheduling data.

Schedule Page: 400 Line No.: 2 Column: c

Refer to footnote for line 1 column (c).

Schedule Page: 400 Line No.: 2 Column: d

Refer to footnote for line 1 column (d).

Schedule Page: 400 Line No.: 3 Column: c

Refer to footnote for line 1 column (c).

Schedule Page: 400 Line No.: 3 Column: d

Refer to footnote for line 1 column (d).

Schedule Page: 400 Line No.: 4 Column: e

1st Quarter 2011 Net System Load information was estimated using metering and/or scheduling data. Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 4 Column: f

1st Quarter 2011 Net System Load information was estimated using metering and/or scheduling data. Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 4 Column: g

1st Quarter 2011 Net System Load information was estimated using metering and/or scheduling data. Reflects reservations in OASIS at time of Transmission System Peak.

Schedule Page: 400 Line No.: 4 Column: i

1st Quarter 2011 Net System Load information was estimated using metering and/or scheduling data. Reflects reservations in OASIS at time of Transmission System Peak.

Schedule Page: 400 Line No.: 5 Column: c

2nd Quarter 2011 Net System Load information was estimated using metering and/or scheduling data.

Schedule Page: 400 Line No.: 5 Column: d

PDT. 2nd Quarter 2011 Net System Load information was estimated using metering and/or scheduling data.

Schedule Page: 400 Line No.: 6 Column: c

Refer to footnote for line 5 column (c).

Schedule Page: 400 Line No.: 6 Column: d

Refer to footnote for line 5 column (d).

Schedule Page: 400 Line No.: 7 Column: c

Refer to footnote for line 5 column (c).

Schedule Page: 400 Line No.: 7 Column: d

Refer to footnote for line 5 column (d).

Schedule Page: 400 Line No.: 8 Column: e

2nd Quarter 2011 Net System Load information was estimated using metering and/or scheduling data. Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 8 Column: f

2nd Quarter 2011 Net System Load information was estimated using metering and/or scheduling data. Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 8 Column: g

2nd Quarter 2011 Net System Load information was estimated using metering and/or scheduling data. Reflects reservations in OASIS at time of Transmission System Peak.

Schedule Page: 400 Line No.: 8 Column: i

2nd Quarter 2011 Net System Load information was estimated using metering and/or scheduling data. Reflects reservations in OASIS at time of Transmission System Peak.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	07/02/2012	End of 2011/Q2

MONTHLY ISO/RTO 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 Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Schedule | Page No.

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