PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

825 NE Multnomah Street
Portland, OR 97232

February 22, 2013

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: *PacifiCorp*, Docket No. ER11-3643-000, -001
Offer of Settlement

Dear Secretary Bose:

Pursuant to Rule 602 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or the "Commission"), 18 C.F.R. § 385.602 (2012), PacifiCorp, Bonneville Power Administration, Deseret Generation & Transmission Co-operative, Inc., Utah Associated Municipal Power Systems, and the Utah Municipal Power Agency (the "Signatory Parties" for purposes of this transmittal letter), hereby submit for filing a Settlement Agreement (including appendices) and Explanatory Statement in Support of Settlement Agreement in the above-captioned proceeding.

The Signatory Parties entered into the Settlement Agreement to resolve all issues between and among themselves and the other parties in this proceeding. The Settlement Agreement is supported or not opposed by all of the parties to this proceeding and Commission Trial Staff.

This filing includes the following documents:

- This transmittal letter
- Attachment A – the Explanatory Statement in Support of Settlement Agreement
- Attachment B – the Settlement Agreement, including the following appendices attached thereto:
  - Appendix 1: Attachment H-1 of PacifiCorp's Open Access Transmission Tariff ("OATT") (the Formula, in clean and redline versions)
  - Appendix 2: Attachment H-2 of PacifiCorp's OATT (the Formula Rate Implementation Protocols, in clean and redline versions)
  - Appendix 3: Schedule 1 of PacifiCorp's OATT (clean and redline versions)

- Appendix 4: Schedule 2 of PacifiCorp's OATT (clean and redline versions)
- Appendix 5: Schedule 3 of PacifiCorp's OATT (clean and redline versions)
- Appendix 6: Schedule 3A of PacifiCorp's OATT (clean and redline versions)
- Appendix 7: Schedule 5 of PacifiCorp's OATT (clean and redline versions)
- Appendix 8: Schedule 6 of PacifiCorp's OATT (clean and redline versions)
- Appendix 9: Schedule 7 of PacifiCorp's OATT (clean and redline versions)
- Appendix 10: Schedule 8 of PacifiCorp's OATT (clean and redline versions)
- Appendix 11: Schedule 10 of PacifiCorp's OATT (clean and redline versions)
- Appendix 12: Section 1 of PacifiCorp's OATT (clean and redline versions)
- Appendix 13: Documentation Supporting Schedule 5 and 6 Rate Calculations
- Appendix 14: Explanation of Schedule 5 and 6 Energy Charge Calculations
- Appendix 15: Cost Allocation Manual
- Appendix 16: Losses Calculation
- Appendix 17: Losses Methodology
- Appendix 18: Formula Attachment 8 Depreciation Rates, effective June 1, 2012; and
- Appendix 19: Populated Formula with actual 2010 data

- Attachment C – a draft Commission order approving the Offer of Settlement

PacifiCorp is not filing the revised *pro forma* OATT sheets in eTariff format, pending Commission acceptance of the Settlement Agreement. Within 30 calendar days of a Commission order accepting the Settlement Agreement, PacifiCorp proposes to make a compliance filing in eTariff format consistent with Order No. 714 and Section 3.9 of the Settlement Agreement.

Also being filed contemporaneously with the Settlement Agreement is an Unopposed Motion for Interim Relief and Request for Expedited Action.

PacifiCorp requests that the Commission grant any and all waivers to the extent necessary to effectuate all provisions of the Settlement Agreement and permit the changes to rates, terms, and conditions agreed upon by all of the parties to become effective as of the dates specified in the Settlement Agreement.

All parties to this proceeding and the Commission's Trial Staff have been given an opportunity to review and comment on the Settlement Agreement, and no party has objected thereto. In accordance with the 20-day comment period under Rule 602(f)(2), 18 C.F.R. § 385.602(f)(2), the date for filing initial comments on the Settlement Agreement is March 14, 2013, with reply comments due March 25, 2013. The final Settlement Agreement and Explanatory Statement will be served on all parties on the official service list in this proceeding, pursuant to Rule 602(d)(1)(i), 18 C.F.R. § 385.602(d)(1)(i).

PacifiCorp requests that this filing be transmitted to Presiding Settlement Judge John P. Dring, in accordance with Rule 602(b)(2)(i), 18 C.F.R. § 385.602(b)(2)(i). PacifiCorp respectfully requests that Judge Dring certify this Settlement Agreement to the Commission, as required by Rule 602(g)(1),18 C.F.R. § 385.602(g)(1), at the earliest possible date following the comment period.

Further, PacifiCorp respectfully requests that the Commission approve the Settlement Agreement, without modification or condition, on the basis that the agreement is fair, reasonable, in the public interest, and fully resolves all issues set for hearing by the Commission in this proceeding. PacifiCorp respectfully requests an expedited decision by the Commission approving the Offer of Settlement by May 1, 2013.

If you have any questions regarding this filing, or if I can be of further assistance, please do not hesitate to contact me.

Respectfully Submitted,

/s/ Mark M. Rabuano

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On Behalf of Signatory Parties

Enclosures

cc: Chief ALJ Curtis L. Wagner, Jr.
Settlement Judge John P. Dring

CERTIFICATE OF SERVICE

I hereby certify that I have on this day caused a copy of the foregoing document to be served via first-class mail or electronic mail upon each of the parties listed in the Secretary's official service list for this proceeding.

Dated at Washington, D.C., this 22nd day of February, 2013.

_____*/s/*_______

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ATTACHMENT A

Explanatory Statement in Support of Settlement Agreement

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp	**Docket No.**	**ER11-3643-000**
		ER11-3643-001

EXPLANATORY STATEMENT IN SUPPORT OF SETTLEMENT AGREEMENT

Pursuant to Rule 602 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure ("Rules"), 18 C.F.R. § 385.602 (2012) ("Rule 602"), PacifiCorp hereby submits this Explanatory Statement in support of the concurrently filed Settlement Agreement offered by PacifiCorp, Bonneville Power Administration, Deseret Generation & Transmission Co-operative, Inc., Utah Associated Municipal Power Systems, and Utah Municipal Power Agency.[1] The Settlement Agreement, including Appendices 1 through 19 attached thereto, is supported or not opposed by all of the Parties to this proceeding and Commission Trial Staff ("Staff"), and it resolves all issues in the above-referenced proceeding.

This Explanatory Statement is provided to comply with Rule 602(c)(1)(ii) of the Commission Rules, 18 C.F.R. § 385.602(c)(1)(ii). Except as otherwise defined herein, the capitalized terms used in this Explanatory Statement have the meaning set forth in the Settlement Agreement. This Explanatory Statement is not intended to, and does not serve to, alter any of the provisions of the Settlement Agreement. In the event of an inconsistency between the Explanatory Statement and the Settlement Agreement, the Settlement Agreement shall control.

[1] NextEra Energy Resources, LLC, Western Area Power Administration, Utah Division of Public Utilities, Idaho Power Company, Pacific Gas and Electric Company, Tri-State Generation and Transmission Association, Inc., Industrial Customers of Northwest Utilities, Modesto Irrigation District, Cities of Santa Clara, California and Redding, California, M-S-R Public Power Agency, Utah Industrial Energy Consumers, Iberdrola Renewables, Inc., Powerex Corp, Los Angeles Department of Water and Power, Transmission Agency of Northern California and Puget Sound Energy, Inc. have expressly stated that they do not oppose the Settlement Agreement. PacifiCorp and each intervenor are each referred to as a "Party" and collectively referred to as the "Parties."

I. PROVISIONS OF THE SETTLEMENT

A. Article I: Background

Article I of the Settlement Agreement describes the procedural background, which is in part described below.

On May 26, 2011, PacifiCorp filed revised tariff sheets with the Commission pursuant to Section 205 of the Federal Power Act ("FPA")[2] to adopt and implement a cost-of-service formula rate for Network Integration Transmission Service ("NIT Service"), Point-To-Point Transmission Service ("PTP Service"), and Ancillary Service Schedule 1 (Scheduling, System Control and Dispatch Service) under its Open Access Transmission Tariff ("OATT" or "Tariff"). PacifiCorp's filing also proposed to amend its OATT to: (1) revise the rates for Ancillary Service Schedules 2, 3, 5 and 6; (2) add a new Schedule 3A to provide for Generator Regulation and Frequency Response Service; (3) revise the transmission service real power loss factors in Schedule 10; and (4) modify and add certain definitions in Section 1. A limited amendment to Ancillary Service Schedules 3, 3A, 5, and 6 was filed on June 9, 2011.

In an order issued August 8, 2011, the Commission accepted for filing and suspended the proposed tariff sheets for a five-month period to become effective December 25, 2011, subject to refund and the outcome of hearing and settlement judge procedures.[3]

Pursuant to the Commission's Hearing Order, Administrative Law Judge John P. Dring was appointed as the Settlement Judge. PacifiCorp provided responses to numerous informal discovery requests, sponsored several technical conferences, and engaged in extensive settlement discussions with the parties and Staff before a settlement was reached. The Settlement

[2] 16 U.S.C. § 824d (2006).
[3] *PacifiCorp*, 136 FERC ¶ 61,092 (2011) ("Hearing Order"), *reh'g denied* 137 FERC ¶ 61,147 (2011).

Agreement, which encapsulates the agreement of the Parties, resolves all issues set for hearing in this proceeding.

B. Article II: Scope of Settlement

Article II of the Settlement Agreement addresses the scope of the settlement, stating that the Settlement Agreement, upon approval by FERC, resolves all issues between the Parties involving the matters set for hearing in the Hearing Order, on the terms set forth in Article III of the Settlement Agreement and Appendices 1 through 19 thereto.

C. Article III: Terms of Settlement

Section 3.0 of the Settlement Agreement provides that the "Settlement Rates" for purposes of the agreement shall constitute the following: the revised Formula Rate template ("Formula") under Attachment H-1 of PacifiCorp's OATT, and the revised Formula Rate Implementation Protocols ("Protocols") under Attachment H-2 of PacifiCorp's OATT (the Formula and the Protocols collectively, the "Formula Rate"); and revised Schedules 1, 2, 3, 3A, 5, 6, 7, 8 and 10 under PacifiCorp's OATT. The Parties agree that the Settlement Rates shall be made effective as of December 25, 2011.

Section 3.0 also describes the various appendices to the Settlement Agreement constituting the Settlement Rates: Appendix 1 reflects the agreed-upon changes to Attachment H-1 of PacifiCorp's OATT; Appendix 2 reflects the agreed-upon changes to Attachment H-2 of PacifiCorp's OATT; Appendices 3 through 11 reflect the agreed-upon changes to the individual Ancillary Service Schedules; and Appendix 12 reflects the agreed-upon changes to Section 1 of PacifiCorp's OATT. All of the revised tariff sections are offered as appendices to the Settlement Agreement, in clean and redlined formats. The revised tariff sheets containing the agreed-upon additions and modifications shall supersede the current versions of those tariff sheets, effective

December 25, 2011.[4] Appendices 13 through 19 contain explanatory, methodological, and/or backup information.

Section 3.1 of the Settlement Agreement provides that PacifiCorp shall use a stated base Return on Equity ("ROE") of 9.8% and a stated incentive ROE adder of 50 basis points ("Incentive ROE") for those portions of PacifiCorp's Energy Gateway Project approved for an Incentive ROE. Section 3.1 also provides that the Incentive ROE shall be applied for purposes of settlement and this proceeding only, without prejudice to any proposed change in the base ROE or the Incentive ROE after the moratorium expires as set forth in Section 3.2. The Settlement agreement shall not limit: (i) PacifiCorp from seeking up to the full 200 basis point adder authorized by the Commission pursuant to the Commission's declaratory order[5] on incentive rates for the Energy Gateway Project, after the moratorium expires as set forth in Section 3.2; (ii) any person from intervening and protesting in any proceeding resulting from such filing contemplated in (i) above by PacifiCorp; and (iii) any person seeking to reduce or eliminate any incentive rates for the Energy Gateway Project under Section 206 of the FPA after the moratorium expires as set forth in Section 3.2.

Section 3.2 of the Settlement Agreement provides that the ROE (including the ROE used to calculate Schedule 3 and 3A charges), any incentives for PacifiCorp's Energy Gateway Project (including the Incentive ROE agreed to in the Settlement Agreement), and the rates, terms, and conditions in Schedules 2, 5, and 6 (collectively, the "Moratorium Provisions") shall not be subject to change prior to June 1, 2015. No Party shall seek an effective date earlier than June 1, 2015, in any filing made under Section 205 or 206 of the FPA proposing any changes or

[4] To the extent certain Tariff sheets were subsequently amended and approved by the Commission, revisions have been made to the currently effective versions. All subsequent amendments to the Tariff that have been accepted by the Commission are treated as effective language for purposes of the redlined versions of the Tariff sheets appended to the Settlement Agreement.
[5] *PacifiCorp*, 125 FERC ¶ 61,076 (2008).

additions to, or challenging the justness and reasonableness of, any Moratorium Provision. This moratorium applies to any proposed change or adder to or detraction from any Moratorium Provision. For example, no filing proposing to authorize the collection of Construction Work in Progress (or "CWIP") may be made to the extent such filing seeks an effective date earlier than June 1, 2015. Section 3.2 further provides that the Parties have agreed that "single issue" rate filings that affect or relate to the Formula Rate are not permissible (with the two exceptions only of the filing by PacifiCorp of (i) a lead-lag study pursuant to Section 3.4.2.15 of the Settlement Agreement and (ii) updated depreciation and amortization rates pursuant to Section 3.8 of the Settlement Agreement). Any future filings to the Commission proposing a change to any Moratorium Provision that affect or relate to the Formula Rate after the expiration of the moratorium will constitute a comprehensive re-opener of the Formula Rate.

Section 3.3 of the Settlement Agreement provides that the Annual Transmission Revenue Requirement ("ATRR") used to determine NIT Service and PTP Service charges under Attachment H of PacifiCorp's OATT shall be calculated annually using the Formula in Attachment H-1 of PacifiCorp's OATT, and shall be effective as of December 25, 2011.

Section 3.4 of the Settlement Agreement and its sub-sections contain numerous provisions addressing the Formula under Attachment H-1 of PacifiCorp's OATT, which shall be updated annually consistent with the Protocols. The initial calculation shall be effective as of December 25, 2011. Appendix 1 of the Settlement Agreement is the Formula set forth in Attachment H-1 of PacifiCorp's OATT and Appendix 19 is the populated version of the Formula using actual 2010 data. Section 3.4.1 addresses the treatment of PacifiCorp's annual projection of ATRR and charges under the Formula Rate for the next Rate Year (except for charges under Schedule 1, the "Projection") and the calculation of the true-up to actual ATRR and transmission charges from the Projection of ATRR and transmission charges for a calendar year (the "True-Up").

PacifiCorp shall use end-of-year inputs for the preceding calendar year for the Projection, except for the following: (a) plant additions shall be projected on a 13-month weighted average; (b) load shall be projected as provided in the Settlement Agreement; and (c) unfunded reserves shall be treated in the manner described in the Settlement Agreement. Section 3.4.1.1 also describes the manner in which load forecasting for long-term firm loads identified in Attachment 9a to the Formula shall be projected. Section 3.4.1.3 provides that the True-Up shall be calculated using either a 13-month average or the average of beginning-of-year and end-of-year balances, as provided for specific rate base inputs described in the Settlement Agreement.

Section 3.4.2 of the Settlement Agreement sets forth that the Parties agreed upon the treatment for the listed Formula inputs in Attachment H-1 of PacifiCorp's OATT. As a result, Sections 3.4.2.1 through 3.4.2.15 address the treatment of specific Formula inputs.

Section 3.5 of the Settlement Agreement provides that the agreed-upon revisions to the Protocols included in Attachment H-2 of PacifiCorp's OATT (Appendix 2 to the Settlement Agreement) shall be effective as of December 25, 2011.

Section 3.6 of the Settlement Agreement contains provisions concerning specific Ancillary Service Schedules to PacifiCorp's OATT. Section 3.6.1 provides that the formula rate for Scheduling, System Control and Dispatch Service shall be the same as the currently-effective version of Schedule 1 of PacifiCorp's OATT, effective December 25, 2011. However, the formula rate section of Schedule 1 has been moved as part of the Settlement Agreement to Attachment H-1, Appendix B, of PacifiCorp's OATT. The Schedule 1 formula rate shall be updated and calculated pursuant to this section of the Tariff. Agreed-upon changes to Schedule 1 of PacifiCorp's OATT are reflected in Appendix 3 to the Settlement Agreement.

Section 3.6.2 provides that the charge for Reactive Supply and Voltage Control from Generation or Other Sources Service ("Reactive Service") under Schedule 2 of PacifiCorp's OATT shall be $0.55/kW-year, effective as of December 25, 2011, as reflected in the agreed-upon changes to Schedule 2 of PacifiCorp's OATT (Appendix 4 to the Settlement Agreement). Schedule 2 is one of the Moratorium Provisions subject to the provisions of Section 3.2 of the Settlement Agreement.

Section 3.6.2 also addresses a mechanism by which credits not to exceed a transmission customer's maximum monthly Reactive Service obligation shall be provided to individual transmission customers who have demonstrated that they own and operate qualifying generators that will meet PacifiCorp's minimum eligibility criteria to serve such customer's load and supply Reactive Service, as established in a posted PacifiCorp business practice with an effective date of May 1, 2013. Section 3.6.2 also provides the specific qualifying generator requirements to be set forth in PacifiCorp's business practice. Details for the specific qualifying generator(s) and associated credits will be reflected in individual transmission customers' service agreements, consistent with the business practice; such revised agreements of eligible parties will have a proposed effective date of May 1, 2013. The qualifying generator requirements set forth in PacifiCorp's business practice shall not be changed prior to June 1, 2015. The requirements shall also be added to the service agreements of transmission customers with qualifying generators, and such requirements shall not be changed by PacifiCorp without an appropriate filing pursuant to Section 205 of the FPA.

Section 3.6.3 provides that the charge for Regulation and Frequency Response Service under Schedule 3 of PacifiCorp's OATT shall be $2.90/kW-year, effective as of December 25, 2011, as reflected in the agreed-upon changes to Schedule 3 of PacifiCorp's OATT (Appendix 5 to the Settlement Agreement). Section 3.6.4 provides that the charge for Generator Regulation and Frequency Response Service under Schedule 3A of PacifiCorp's OATT shall also be $2.90/kW-year, effective as of December 25, 2011, as reflected in the agreed-upon changes to Schedule 3A of PacifiCorp's OATT (Appendix 6 to the Settlement Agreement).

Section 3.6.4 also obligates PacifiCorp to make a filing with the Commission to propose adjusted Schedule 3 and 3A rates no later than April 1, 2013, with a proposed effective date of June 1, 2013. Such proposal shall be based on a study containing at least one year's worth of data to determine both the amount of reserves required by PacifiCorp's balancing authority areas and the different amounts of reserves needed for loads and resources. The ROE used to calculate Schedules 3 and 3A is one of the Moratorium Provisions subject to Section 3.2 of the Settlement Agreement. Any affected person may intervene in PacifiCorp's Schedule 3 and 3A filing, and seek any relief as may be appropriate under Section 205 of the FPA. No Party shall submit comments or protests challenging use of a 9.8% ROE in this Schedule 3 and 3A filing.

Section 3.6.5 provides that the charges for Operating Reserve – Spinning Reserve Service under Schedule 5 of PacifiCorp's OATT shall be an Hourly energy charge of: (i) $0.32 MWh, effective from December 25, 2011 through May 31, 2013, and (ii) $0.39 MWh, effective as of June 1, 2013, as reflected in the agreed-upon changes to Schedule 5 of PacifiCorp's OATT (Appendix 7 to the Settlement Agreement). Schedule 3.6.6 provides that the charges for Operating Reserve - Supplemental Reserve Service under Schedule 6 of PacifiCorp's OATT shall be an Hourly energy charge of: (i) $0.29 MWh, effective from December 25, 2011 through

May 31, 2013, and (ii) $0.34 MWh, effective as of June 1, 2013, as reflected in the agreed-upon changes to Schedule 6 of PacifiCorp's OATT (Appendix 8 to the Settlement Agreement). Sections 3.6.5 and 3.6.6 provide that Schedules 5 and 6, respectively, are Moratorium Provisions subject to the provisions of Section 3.2. Appendices 13 and 14 of the Settlement Agreement provide supporting documentation for the Schedule 5 and 6 rate calculations and an explanation of the Schedule 5 and 6 energy charge calculations, respectively.

Sections 3.6.7 and 3.6.8 provide that the changes under Schedule 7 (Long-term Firm and Short-term Firm PTP Service) and Schedule 8 (Non-firm PTP Service) of PacifiCorp's OATT, respectively, shall be calculated annually using the populated Formula Rate in Attachment H-1 of PacifiCorp's OATT, effective as of December 25, 2011, as reflected in the agreed-upon changes to Schedules 7 and 8 (Appendices 9 and 10, respectively).

Section 3.6.9 addresses revised Schedule 10 of PacifiCorp's OATT and Real Power Losses (Appendix 11 to the Settlement Agreement). Section 3.6.9 also provides that language currently in PacifiCorp's OATT describing system input gross up for losses has been agreed to by the Parties to be set forth in the affected Ancillary Service Schedules rather than Section 1.45 of PacifiCorp's OATT (definition of Reserved Capacity); removal of this language is reflected in revised Section 1 of PacifiCorp's OATT (Appendix 12 to the Settlement Agreement). Section 3.6.9 also includes a mechanism by which PacifiCorp shall file an adjusted Transmission System factor for Real Power Losses under Schedule 10, consistent with a losses calculation and methodology (Appendices 16 and 17 to the Settlement Agreement), following completion of every two Energy Gateway Project segments (or substantially similar transmission segments or combination thereof) which have been placed into commercial operation for at least one full calendar year.

Section 3.7 of the Settlement Agreement contains provisions describing the standard of review to be applied to the Moratorium Provisions or other provisions of the Settlement Agreement. Section 3.7.1 provides that to the extent that the Commission considers changes to Section 3.2 of the Settlement Agreement or any of the Moratorium Provisions listed therein pursuant to a filing by a Party, and the proposed changes would take effect prior to June 1, 2015, the standard of review for such proposed changes shall be subject to the "public interest" application of the just and reasonable standard set forth in the *Mobile-Sierra* Commission precedent. The ordinary just and reasonable standard of review (rather than the "public interest" standard of review), as clarified in FERC precedent, applies to future changes to the Moratorium Provisions sought by the Commission acting *sua sponte* or at the request of a non-Party to this proceeding. Section 3.7.2 provides that changes to Section 3.2 of the Settlement Agreement or any of the Moratorium Provisions listed therein that would take effect on or after June 1, 2015, or to any changes to other provisions of the Settlement Agreement, shall be subject to the ordinary just and reasonable standard of review, including without limitation, written amendments or modifications to the Settlement Agreement agreed to by all Parties.

Section 3.8 of the Settlement Agreement provides that the Parties jointly acknowledge that PacifiCorp's depreciation and amortization rates shall be the same as the version of Attachment 8 to the Formula, effective December 25, 2011 (as shown in Appendix 19 to the Settlement Agreement) and the version of Attachment 8 to the Formula, effective June 1, 2012 (as shown separately in Appendix 18 to the Settlement Agreement). For all subsequent annual updates to the Formula, PacifiCorp shall make a single issue filing pursuant to Section 205 of the FPA to update depreciation rates if and when one or more of PacifiCorp's retail jurisdictions change(s) the corresponding rates, using the methodology set forth in Attachment 8 to the

Formula. Section 3.8 further provides that the effective dates of any updated depreciation rates shall be the same as the effective dates in the respective retail jurisdiction(s).

Section 3.9 of the Settlement Agreement provides that within thirty (30) calendar days of the Commission's acceptance or approval of the Settlement Agreement, PacifiCorp shall make a compliance filing via eTariff to incorporate the revisions to Section 1, Attachments H-1 and H-2, and Schedules 1, 2, 3, 3A, 5, 6, 7, 8, and 10 of the Tariff, as reflected in the Settlement Agreement and relevant appendices thereto.

Section 3.9A of the Settlement Agreement addresses interim rates and provides that, contemporaneous with the filing of the Settlement Agreement with the Commission, PacifiCorp shall file an expedited motion for leave to charge rates on an interim basis. Interim rates for Schedules 2, 3, 3A, 5, 6, and 10 shall be as set forth in the revised Tariff sheets appended to the Settlement Agreement, pending Commission action on the Settlement Agreement, as follows:

(a) the effective date for interim rates for Schedules 3, 3A, 5, 6, and 10 shall be March 1, 2013 (provided the motion is approved prior to March 1, 2013);

(b) the effective date for interim rates for Schedule 2 shall be May 1, 2013 (provided the motion is approved prior to May 1, 2013); and

(c) the effective date for implementation of the Formula Rate on an interim basis for rates for Schedules 7 and 8 and for NIT Service shall be June 1, 2013, consistent with the effective date and procedures for the Formula Rate's Projection and True-Up processes described in the Protocols.

In the event that the motion for interim rates is not approved prior to March 1, 2013, the effective date for interim rates for Schedules 3, 3A, 5, 6, and 10 shall be April 1, 2013. In the event that the motion is not approved prior to May 1, 2013, the effective date for interim rates for Schedule 2 shall be June 1, 2013.

Section 3.10 of the Settlement Agreement provides that the Parties agree that any refunds required pursuant to the Settlement Agreement or by Commission order will be calculated from January 1, 2012. Section 3.10 also provides the precise manner in which refunds shall be provided, with interest, for rates charged under Schedules 2, 3, 3A, 5, 6, and 10, in order to reflect the difference between the rates charged for the applicable periods identified therein and the interim rates agreed to as part of the Settlement Agreement. In particular, the net refund for the period January 1, 2012 through April 30, 2013 has been calculated for Schedule 2 Reactive Service, for the following Parties: Bonneville Power Administration; Deseret Generation & Transmission Co-operative, Inc.; Utah Associated Municipal Power Systems; and Utah Municipal Power Agency. Section 3.10 also sets forth the specific amounts calculated to each of these Parties for Schedule 2 service, together with interest, which shall be calculated at the time the refund is sent. The refund associated with rates produced by the Formula Rate shall be performed concurrent with and pursuant to the True-Up process described in the Protocols.

Section 3.11 of the Settlement Agreement provides that in the event that the Formula included in Attachment H-1 to PacifiCorp's OATT requires a modification or adjustment to accommodate a future FERC Order No. 1000 compliance filing, PacifiCorp shall make an appropriate filing to reflect the necessary revisions with as limited an impact on the Formula as practicable consistent with the applicable compliance requirements; provided, however, that no such filing shall change any of the Moratorium Provisions prior to the expiration of the moratorium period established in Section 3.2 of the Settlement Agreement. Section 3.11 also provides language describing how the Formula Rate would accommodate a situation in which the Commission were to determine as a result of Order No. 1000 that the rate base of, or revenue responsibility for, some part of the Energy Gateway Project belongs to a third party and should be accommodated through PacifiCorp's rates.

D. Article IV: General Provisions

Article IV of the Settlement Agreement contains general provisions agreed upon by the Parties.

Section 4.0 provides in part that the Settlement Agreement, including its appendices, constitutes the entire agreement among the Parties with respect to the subject matter addressed therein.

Section 4.1 provides that the various provisions of the Settlement Agreement are not severable and shall not become operative unless and until the Commission issues an order accepting or approving the Settlement Agreement without modification or condition or with only modification(s) or condition(s) acceptable to the Parties. Section 4.1 also provides a duty for the Parties to initiate discussions within 10 business days of the issuance of a Commission order rejecting the Settlement Agreement or approving it with modification(s) or conditions(s), to address the Commission's conclusions and determine whether to agree to the Settlement Agreement with the inclusion of any modification(s) or condition(s) or to amend the Settlement Agreement to restore the balance of benefits and burdens in the Settlement Agreement while accommodating the required modification(s) or condition(s).

Section 4.2 provides that the Settlement Agreement and the provisions thereof shall become effective as of the date the Commission issues an order accepting or approving the Settlement Agreement without modification or condition.

Section 4.3 provides that nothing in the Settlement Agreement is intended to affect the rights that any Party has under the FPA in the event the Settlement Agreement does not become effective in accordance with Section 4.2 of the Settlement Agreement.

Section 4.4 provides in part that the Settlement Agreement is inadmissible as evidence in any proceeding, and of no effect unless it is accepted or approved and made effective as to all of its terms and conditions without modification (or with only modification(s) acceptable to the Parties). Further, the Settlement Agreement shall not constitute an admission by any Party, or a determination by the Commission, that any allegation or contention in these proceedings is true and valid. Section 4.4 further provides that no element of the Settlement Agreement shall constitute precedent.

Section 4.5 provides in part that the discussions between and among the Parties that produced the Settlement Agreement shall be privileged and confidential.

Section 4.6 provides in part that each Party shall cooperate with and support, and shall not take any action inconsistent with, the filing of the Settlement Agreement with the Commission and efforts to obtain Commission acceptance or approval of the Settlement Agreement.

Section 4.7 provides that no provisions of the Settlement Agreement may be waived except through a writing signed by an authorized representative of the waiving Party.

Sections 4.8 through 4.13 are general provisions related to the following: successors and assigns; titles and headings; ambiguities; authorization; notices; and counterparts.

II. RESPONSES TO REQUIRED SETTLEMENT QUESTIONS

By order dated October 23, 2003, the Chief Administrative Law Judge requires all parties submitting a Rule 602 settlement to address five questions in an explanatory statement.

Accordingly, the Parties provide the following responses to the five required questions in this Explanatory Statement:

A. What are the issues underlying the settlement and what are the major implications?

The Settlement Agreement comprehensively resolves all issues set for hearing in the Hearing Order on the terms set forth in the Settlement Agreement and Appendices 1 through 19 of the Settlement Agreement. The issues raised in this proceeding that underlie the Settlement Agreement relate to the appropriate rates to be charged by PacifiCorp for transmission services it provides under its OATT. There are no major implications arising from these underlying issues.

B. Do any of the issues underlying the settlement raise policy implications?

The Settlement Agreement and resolution of the underlying issues set for hearing in the Hearing Order do not raise any policy implications because they relate solely to charges for transmission services provided by PacifiCorp pursuant to its OATT, and the Settlement Agreement has been tailored to address the Parties' resolution of the issues set for hearing in the above-captioned proceeding. Further, the Settlement Agreement expressly provides that it does not constitute any precedent.

C. Are there other pending cases that may be affected by the settlement?

The Settlement Agreement addresses the specific transmission service rates at issue and resolves all issues set for hearing in the above-captioned proceeding. There are no pending proceedings affected by the Settlement Agreement.

D. Whether the settlement involves issues of first impression, or are there any previous reversals on the issues involved?

The Settlement Agreement does not involve any issues of first impression, and the Parties are not aware of any prior reversals of the issues involved herein with respect to the transmission service rates in this proceeding.

E. Is the proceeding subject to the just and reasonable standard or is there *Mobile-Sierra* language making it the standard (*i.e.*, the applicable standard of review)?

Section 3.7.1 of the Settlement Agreement provides that to the extent that the Commission considers changes to Section 3.2 of the Settlement Agreement or any of the Moratorium Provisions listed therein, pursuant to a filing by a Party, and the proposed changes would take effect prior to June 1, 2015, the standard of review for such proposed changes shall be the "public interest" application of the *Mobile-Sierra* just and reasonable standard.[6] However, the ordinary just and reasonable standard of review (rather than the "public interest" standard), clarified in *Morgan Stanley*,[7] applies to future changes to the Moratorium Provisions sought by the Commission acting *sua sponte* or at the request of a non-Party to this proceeding. Section 3.7.1 has been drafted to be consistent with Commission precedent discouraging settlement language that seeks to bind the Commission and non-settling third parties to the *Mobile-Sierra* "public interest" standard of review for terms of service under an OATT.[8]

With respect to changes to Section 3.2 or any of the Moratorium Provisions listed therein that would take effect on or after June 1, 2015, or to any changes to other provisions of the

[6] *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956), as clarified in *Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1 of Snohomish County, Wa.*, 128 S. Ct. 2733, 171 L. Ed. 2d 607 (2008) and refined in *NRG Power Mktg. v. Maine Pub. Utils. Comm'n*, 130 S. Ct. 693, 700 (2010).
[7] *Morgan Stanley Capital Group Inc. v. Public Util. Dist. No. 1 of Snohomish County, Wa.*, 128 S. Ct. 2733, 171 L. Ed. 2d 607 (2008) ("*Morgan Stanley*").
[8] *See Puget Sound Energy, Inc.*, 142 FERC ¶ 61,018, at P 5 (2013); *see also Bear Creek Storage Co L.L.C.*, 140 FERC ¶ 61,129, at P 12 (2012) (approving settlement where proposed changes to any "settled matter" sought by non-settling third parties or the Commission acting *sua sponte* shall be the just and reasonable standard).

Settlement Agreement, the standard of review shall be the ordinary just and reasonable standard, including without limitation, written amendments or modifications to the Settlement Agreement agreed to by all Parties.

III. CONCLUSION

The Settlement Agreement promotes certainty for the Parties and promotes administrative efficiency for the Commission. The Settlement Agreement sets forth the promises and mutual covenants and agreements agreed to by the Parties, is in the public interest, and should be approved. PacifiCorp is authorized by the other signatories to the Settlement Agreement to make this filing and to represent that all Parties urge the Commission to expeditiously approve the Settlement Agreement without condition or modification.

Respectfully submitted,

/s/ Mark M. Rabuano

Mark M. Rabuano
Attorney for PacifiCorp

Dated: February 22, 2013

ATTACHMENT B

Settlement Agreement

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp **Docket No. ER11-3643-000**
ER11-3643-001

SETTLEMENT AGREEMENT

This Settlement Agreement is made as an offer of settlement pursuant to Rule 602 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure ("Rules"), 18 C.F.R. § 385.602 (2012) ("Rule 602"), by PacifiCorp, Bonneville Power Administration, Deseret Generation & Transmission Co-operative, Inc., Utah Associated Municipal Power Systems, and the Utah Municipal Power Agency. This Settlement Agreement, including Appendices 1 through 19 attached hereto, upon approval by the Commission, resolves all issues in the above-referenced proceeding. This Settlement Agreement is supported or not opposed by all of the parties to this proceeding[1] and Commission Trial Staff ("Staff").

ARTICLE I
Background

1.0 On May 26, 2011, PacifiCorp filed revised tariff sheets with the Commission pursuant to Section 205 of the Federal Power Act (the "FPA")[2] to adopt and implement a cost-of-service formula rate for Network Integration Transmission Service ("NIT Service"), Point-To-Point Transmission Service ("PTP Service"), and Ancillary Service Schedule 1 (Scheduling,

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[1] NextEra Energy Resources, LLC, Western Area Power Administration, Utah Division of Public Utilities, Idaho Power Company, Pacific Gas and Electric Company, Tri-State Generation and Transmission Association, Inc., Industrial Customers of Northwest Utilities, Modesto Irrigation District, Cities of Santa Clara, California and Redding, California, M-S-R Public Power Agency, Utah Industrial Energy Consumers, Iberdrola Renewables, Inc., Powerex Corp, Los Angeles Department of Water and Power, Transmission Agency of Northern California and Puget Sound Energy, Inc. have expressly stated that they do not oppose the Settlement Agreement.

[2] 16 U.S.C. § 824d (2006).

System Control and Dispatch Service) under its Open Access Transmission Tariff ("OATT" or "Tariff"). PacifiCorp's filing also proposed to amend its OATT to: (1) revise the rates for Ancillary Services Schedules 2, 3, 5 and 6; (2) add a new Schedule 3A to provide for Generator Regulation and Frequency Response Service; (3) revise the transmission service real power loss factors in Schedule 10; and (4) modify and add certain definitions in Section 1. On May 26, 2011, the Commission issued a Notice of Filing, and established a comment date of June 16, 2011. That comment date was subsequently changed to June 30, 2011, due to amendments to Ancillary Service Schedules 3, 3A, 5, and 6 that PacifiCorp filed on June 9, 2011.

1.1 A number of entities filed timely motions to intervene in the proceeding including: Idaho Public Utilities Commission, NextEra Energy Resources, LLC, Deseret Generation & Transmission Co-operative, Inc., Utah Municipal Power Agency, Utah Associated Municipal Power Systems, Navajo Tribal Utility Authority, Cities of Santa Clara, California and Redding, California, and the M-S-R Public Power Agency, Transmission Agency of Northern California, Western Area Power Administration, Modesto Irrigation District, Utah Division of Public Utilities, Idaho Power Company, Seattle City Light, Pacific Gas and Electric Company, Tri-State Generation and Transmission Association, Inc., Bonneville Power Administration, Noble Americas Energy Solutions LLC, American Wind Energy Association, Renewable Northwest Project, the Industrial Customers of Northwest Utilities, Utah Industrial Energy Consumers, Iberdrola Renewables, Inc. and Powerex Corp. Several entities filed motions to intervene out-of-time which were granted, including: Los Angeles Department of Water and Power, Puget Sound Energy, Inc. and Sacramento Municipal Utility District. Several of the intervening entities also commented on and/or protested PacifiCorp's rate filing.[3] On July 1, 2011 and July 15, 2011, PacifiCorp filed answers to these comments and protests. PacifiCorp and each intervenor hereinafter are each referred to as a "Party" and collectively referred to as the "Parties."

1.2 In an order issued August 8, 2011, the Commission accepted the proposed tariff sheets for filing and suspended them for a five-month period to become effective December 25, 2011, subject to refund and the outcome of hearing and settlement judge procedures.[4]

1.3 Pursuant to the Commission's Hearing Order, the Parties selected, and the Chief Administrative Law Judge appointed, Administrative Law Judge John P. Dring as the Settlement Judge. PacifiCorp provided responses to numerous informal discovery requests, sponsored several technical conferences, and the Parties and Staff engaged in extensive settlement discussions before settlement was reached. This Settlement Agreement resolves all issues set for hearing in this proceeding.

ARTICLE II
Scope of Settlement

2.0 This Agreement, upon approval by the Commission, resolves all issues and matters set for hearing in the Hearing Order on the terms set forth in this Settlement Agreement, including Appendices 1 through 19 hereto.

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[3] The following parties filed comments and/or protests: Bonneville Power Administration, Noble Americas Energy Solutions LLC, American Wind Energy Association, Renewable Northwest Project, Deseret Generation & Transmission Co-operative, Inc., Iberdrola Renewables, Inc., Powerex Corp., Utah Municipal Power Agency, NextEra Energy Resources LLC, Utah Associated Municipal Power Systems and Industrial Customers of Northwest Utilities.

[4] *PacifiCorp*, 136 FERC ¶ 61,092 (2011) ("Hearing Order"), *reh'g denied* 137 FERC ¶ 61,147 (2011).

ARTICLE III
Terms of Settlement

3.0 *Settlement Rates and Modified Tariff Sheets*. The following shall be deemed to constitute the "Settlement Rates" for purposes of this Settlement Agreement: the revised Formula Rate template ("Formula") under Attachment H-1 of PacifiCorp's OATT and the revised Formula Rate Implementation Protocols ("Protocols") under Attachment H-2 of PacifiCorp's OATT (collectively, the "Formula Rate"); and revised Schedules 1, 2, 3, 3A, 5, 6, 7, 8 and 10 under PacifiCorp's OATT, all as attached to and incorporated into this Settlement Agreement. PacifiCorp shall incorporate the revised Settlement Rates into PacifiCorp's OATT promptly following the Commission's approval of this Settlement Agreement via a compliance filing, consistent with Section 3.9 below, to be effective as of December 25, 2011.

Appendix 1 to this Settlement Agreement reflects the agreed-upon changes to Attachment H-1 of PacifiCorp's OATT, in redlined and clean formats. Appendix 2 to this Settlement Agreement reflects the agreed-upon changes to Attachment H-2 of PacifiCorp's OATT, in redlined and clean formats. Appendices 3 through 11 to this Settlement Agreement reflect the agreed-upon changes to individual Ancillary Service Schedules, as described below. These tariff sheets reflect additions and modifications to the versions of the tariff sheets that were filed on May 26, 2011 and, in some cases, amended on June 9, 2011, and allowed to go into effect on December 25, 2011, subject to refund, pursuant to the Hearing Order. The modified tariff sheets to this Settlement Agreement shall supersede the current versions of those tariff sheets, effective December 25, 2011[5]. Appendix 12 reflects the agreed-upon changes to Section 1 of PacifiCorp's

[5] To the extent certain Tariff sheets were subsequently amended and approved by the Commission, revisions have been made to the currently effective versions. All subsequent amendments to the Tariff that have been accepted by

OATT, in redlined and clean formats. Appendices 13 through 19 contain explanatory, methodological, and/or backup information as described below. Appendices 1 through 19 attached hereto are each incorporated in and made part of this Settlement Agreement.

3.1 *Return on Equity*. In calculating the Settlement Rates, PacifiCorp shall use a stated base Return on Equity ("ROE") of 9.8%. PacifiCorp shall also apply a stated incentive ROE adder of 50 basis points ("Incentive ROE") for those portions of PacifiCorp's Energy Gateway Project approved for an Incentive ROE. The Parties agree that the Incentive ROE shall be applied for purposes of settlement and this proceeding only, without prejudice to any proposed change in the base ROE or the Incentive ROE after expiration of the moratorium set forth in Section 3.2. Such agreement shall not limit: (i) PacifiCorp from seeking up to the full 200 basis point adder authorized by the Commission pursuant to the Commission's declaratory order[6] on incentive rates for the Energy Gateway Project, after expiration of the moratorium set forth in Section 3.2; (ii) any person from intervening and protesting in any proceeding resulting from such filing contemplated in (i) above by PacifiCorp; or (iii) any person seeking to reduce or eliminate any incentive rates for the Energy Gateway Project under Section 206 of the FPA after expiration of the moratorium set forth in Section 3.2. Appendix 1 to this Settlement Agreement, incorporating the agreed-upon changes to the Formula in Attachment H-1 of PacifiCorp's OATT, reflects the stated ROE and Incentive ROE.

3.2 *Moratorium*. The ROE, including the ROE used to calculate the Schedule 3 and 3A charges, any incentives for PacifiCorp's Energy Gateway Project (including the Incentive

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the Commission are treated as effective language for purposes of the redlined versions of the Tariff sheets appended to this Settlement Agreement.

[6] *PacifiCorp*, 125 FERC ¶ 61,076 (2008).

ROE as agreed to in this Settlement Agreement), and the rates, terms and conditions set forth in Schedules 2, 5 and 6 (collectively, the "Moratorium Provisions") shall not be subject to change prior to June 1, 2015. No Party shall seek an effective date earlier than June 1, 2015, in any filing made under Section 205 or 206 of the FPA proposing any changes or additions to, or challenging the justness and reasonableness of, any Moratorium Provision. This moratorium applies to any proposed change or adder to or detraction from any Moratorium Provision. For example, PacifiCorp is not currently authorized to include Construction Work in Progress ("CWIP") with respect to incentives for the Energy Gateway Project when calculating its Annual Transmission Revenue Requirement ("ATRR") and charges under the Formula, and no filing proposing to authorize the collection of CWIP may be made to the extent that filing seeks an effective date earlier than June 1, 2015. "Single issue" rate filings that affect or relate to the Formula Rate are not permissible (with the two exceptions only of the filing by PacifiCorp of (i) a lead-lag study pursuant to Section 3.4.2.15 of this Settlement Agreement and (ii) updated depreciation and amortization rates pursuant to Section 3.8 of this Settlement Agreement). Without limitation of the foregoing, any future filings to the Commission proposing a change to any Moratorium Provisions that affect or relate to the Formula Rate after the expiration of the moratorium will constitute a comprehensive re-opener of the Formula Rate.

3.3 *ATRR.* The ATRR used to determine NIT Service and PTP Service charges under Attachment H of PacifiCorp's OATT shall be calculated annually using the Formula in Attachment H-1 of PacifiCorp's OATT, and shall be effective as of December 25, 2011.

3.4 *Formula.* The calculation of the ATRR and charges under the Formula set forth in Attachment H-1 of PacifiCorp's OATT, included in Appendix 1, shall be updated annually consistent with the Protocols. The initial calculation shall be effective as of December 25, 2011.

The populated version of the Formula using actual 2010 data and on which this Settlement Agreement is in part based is provided as Appendix 19.

3.4.1 *Projections and True-Up of ATRR*.

3.4.1.1 PacifiCorp shall use end-of-year inputs for the preceding calendar year for the annual projection of ATRR and charges under the Formula Rate for the next Rate Year (as defined in the Protocols) (except for charges under Schedule 1, the "Projection"), except for the following:

(a) plant additions shall be projected on a 13-month weighted average;

(b) load shall be projected, as provided herein; and

(c) unfunded reserves shall be treated in the manner described in Section 3.4.2.3 of this Settlement Agreement.

Load forecasting for long-term firm loads identified in Attachment 9a [columns e, f, g and j] to Attachment H-1 of PacifiCorp's OATT, which is included as Appendix 1 to this Settlement Agreement, shall be projected based on an aggregation of each transmission customer's most recent three-year average of actual billing demands (or, if less than three years is available for any customer, the average of the available billing demand data) multiplied by a factor of 1.01. In addition, adjustments for known and measurable future changes to customer demands shall be made to reflect long-term contract changes within the calendar year for the relevant time periods consistent with contract start dates or end dates (*e.g.*, including new contract subscriptions and excluding contracts for which notices of termination have been provided by the transmission customer).

3.4.1.2 PacifiCorp shall include the following as a footnote to its Formula in Attachment H-1, as reflected in Appendix 1 to this Settlement Agreement:

> "Projected capital additions will include only the capital costs associated with plant expected to be energized and placed in service (as defined by the Uniform System of Accounts) in that month. The True-Up Adjustment will reflect the actual date the plant was energized and placed in service."

3.4.1.3 *True-Up*. The calculation of the true-up to actual ATRR and transmission charges from the Projection of ATRR and transmission charges for a calendar year (the "True-Up") shall be calculated using either a 13-month average or the average of beginning-of-year and end-of-year balances, as provided below for specific rate base inputs.

3.4.1.4 *Reclassification of Account 216 Subsidiary Earnings.* The Projection of ATRR for the 2012 Rate Year (as defined in the Protocols) and True-Up performed for the 2011 Rate Year shall reflect the accumulation of any undistributed subsidiary earnings in Account 216.1, Unappropriated Undistributed Subsidiary Earnings, from Account 216, Unappropriated Retained Earnings, consistent with the Commission's letter order dated April 17, 2012, in Docket No. AC11-132-000.

3.4.2 *Treatment of Formula Inputs.* The following treatment for the listed Formula inputs in Attachment H-1 of PacifiCorp's OATT (all of which are reflected in Appendix 1 to this Settlement Agreement, as well as in the populated version of the Formula provided in Appendix 19 to this Settlement Agreement) shall apply:

3.4.2.1 *Accumulated Deferred Income Taxes ("ADIT").* ADIT rate base items shall be based upon the average of beginning-of-year and end-of-year balances for

True-Up and end-of-year balances for the Projection of ATRR and transmission charges. Specific ADIT items shall be directly assigned as reflected in Attachment 1a to the Formula. For the Injuries and Damages Accrual, PacifiCorp shall exclude amounts for injuries and damages associated with non-transmission facilities.

3.4.2.2 *Land Held for Future Use*. Land Held for Future Use rate base items shall be based upon the average of beginning-of-year and end-of-year balances for True-Up and end-of-year balances for the Projection of ATRR and transmission charges.

3.4.2.3 *Unfunded Reserves.* Unfunded Reserves shall be based on a 13-month average for True-Up and the average of beginning-of-year and end-of-year balances for Projection of ATRR and transmission charges as shown in the Formula in Attachment H-1, as reflected in Appendix 1. Inclusion of specific Unfunded Reserves shall not require prior authorization through a filing under Section 205 of the FPA but shall be subject to challenge pursuant to the Protocols.

3.4.2.4 *Allocations*. General Plant and Intangible Plant, including Account 397, and associated expenses shall be allocated using the Wages and Salary Allocator.

3.4.2.5 *Capital Structure.* PacifiCorp shall use a 13-month average of its actual capital structure, subject to a 53% equity cap. PacifiCorp shall include the following as a footnote to its Formula in Attachment H-1, as reflected in Appendix 1 to this Settlement Agreement:

> "The equity ratio is capped at 53%, and if the actual equity ratio exceeds 53%, then the debt ratio will be equal to 1 minus the preferred stock ratio minus 53%."

3.4.2.6 *Long-Term Debt Expense; Inclusion of Gains and Losses on Interest Rate Locks*. PacifiCorp shall include in the Formula only the gains and losses on interest rate locks for new debt issuances. Accordingly, Attachment 14 to the Formula shall include the unamortized balance and annual amortization for all gains and losses on hedges. The annual amortization of the gains and losses on other hedges shall be treated as adjustments to the cost of debt. Accordingly, Attachment 14 to Attachment H-1 of PacifiCorp's OATT shall exclude all gains and losses associated with other hedges from the interest expense. PacifiCorp shall include the following as a footnote to its Formula in Attachment H-1, as reflected in Appendix 1 to this Settlement Agreement:

> "PacifiCorp will include only the gains and losses on interest rate locks for new debt issuances. Attachment 14 – Cost of Capital Detail will list the unamortized balance and annual amortization for all gains and losses on hedges."

An additional footnote has been added to the Formula related to long-term debt cost that states the following in reference to such cost components:

> "These line items will include only the balances associated with long-term debt and shall exclude balances associated with short-term debt."

3.4.2.7 *Prepayments.* Prepayments shall be allocated using the following categories: labor-related, plant-related, transmission-related, or other-related allocators in accordance with the Formula in Attachment H-1 (Attachment 11), as reflected in Appendix 1 to this Settlement Agreement.

3.4.2.8 *Excluded Facilities.* The Formula shall exclude specified collector sub/radials for wind farms and sub-transmission (34.5 kV) facilities. With respect to load interconnections, on an ongoing basis, PacifiCorp shall allocate costs for new facilities consistent with FERC's policy on rolling-in or directly assigning such facilities on a non-discriminatory basis for all transmission customers.

3.4.2.9 *Exclusion of Administrative and General Expenses.* Administrative and General Expenses shall address membership dues and lobbying expenses consistent with Commission precedent. PacifiCorp shall include the following as a footnote to its Formula in Attachment H-1, as reflected in Appendix 1 to this Settlement Agreement:

"Annual membership dues (*e.g.*, for EPRI, NEETRAC, SEPA and NCTA) are excluded from the calculation of the ATRR and charges under the Formula Rate and are subtracted from Total A&G. Total A&G does not include lobbying expenses."

All regulatory asset amortizations shall be excluded from the calculation of the ATRR and charges under the Formula Rate, unless approved by the Commission.

Holding company management charges that represent services provided by the tax, information technology, human resources, regulation, legal, and other corporate support functions that are appropriately allocated to PacifiCorp Transmission may be included in the calculation of the ATRR and charges under the Formula Rate.

3.4.2.10 *Exclusion of Regulatory Commission Expenses.* Regulatory Commission Expenses shall not include expenses relating to hydroelectric license compliance or relicensing.

3.4.2.11 *Property Insurance; Property Taxes.* Property Insurance shall be allocated based upon gross plant. Property Taxes shall be allocated based upon net plant.

3.4.2.12 *Revenue Credits.* The Formula shall include revenue credits for the following: (a) joint-use, pole attachment revenue covering various transmission facilities; (b) third-party distribution under-build to transmission; (c) various rents on transmission facilities, including rent for parking fees, mono-poles on land, wireless attachments to poles and rent for agriculture; (d) miscellaneous general revenues to be allocated based on the Wages and Salary Allocation Factor; and (e) transmission maintenance revenue.

All transmission revenues for short-term and non-firm PTP Service shall be credited 100 percent in determining the ATRR to the extent the associated loads are not included in the load divisor.

In addition, the Formula shall include a fixed, annual revenue credit equal to $555,768; this dollar amount is the product of the current number of PacifiCorp underbuild attachments to transmission poles or towers (46,314) multiplied by $12.00 per pole. PacifiCorp shall not charge another electric public utility or transmission customers a distribution under-build rate higher than $12.00 per pole without concurrently adjusting the revenue credit by a corresponding amount in the next available Annual Update (as defined in the Protocols) of the ATRR; in such adjustment the number of such underbuild attachments shall remain the same (*i.e*., 46,314).

The Formula shall not include a revenue credit for differential loss factors for contracts that have a contractual loss factor greater than PacifiCorp's Transmission System loss factor in Schedule 10 of its OATT.

3.4.2.13 *Load Divisor.* PacifiCorp shall include in the load divisor an additional 163 MW of demand representing large industrial behind-the-meter generation in excess of 10 MW of nameplate capacity per generating unit that is not designated for network load service. This amount shall be adjusted each Rate Year (as defined in the Protocols). The amount of capacity for long-term firm point-to-point demand included in the load divisor shall be increased in an amount equal to the loss factor set forth in

Schedule 10 in order to account for reserve capacity associated with the delivery of energy losses, consistent with Attachment 9a and 9b of Attachment H-1 of PacifiCorp's OATT.

The Formula load divisor shall not include additional capacity for a contract between Arizona Public Service Company ("APS") and PacifiCorp's merchant function (i.e., PacifiCorp Rate Schedule No. 307) beyond PacifiCorp's reserved capacity used for deliveries under this contract, consistent with Attachment 9a and 9b of Attachment H-1 of PacifiCorp's OATT.[7]

3.4.2.14 *Inter-Company Allocations*. PacifiCorp shall adopt the inter-company allocation methodology set forth in Appendix 15 to this Settlement Agreement.

3.4.2.15 *Cash Working Capital.* The allowance for Cash Working Capital ("CWC") shall be set using the Commission's "one-eighth (1/8th) method" in rate base for the Formula subject to the following conditions and as described in a footnote to PacifiCorp's Formula in Attachment H-1, as reflected in Appendix 1 to this Settlement Agreement:

(a) PacifiCorp shall be required to file a lead-lag study justifying the appropriate CWC allowance to be effective, subject to refund, as of June 1, 2014; provided, however, that if PacifiCorp does not file a study in the time required, the amount of CWC allowance includable in the calculation of the ATRR under the Formula shall be zero dollars ($0.00) as of June 1, 2014, and shall remain at

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[7] The contract demand associated with APS, PacifiCorp Rate Schedule No. 307, specifically is included in the total 12-Coincident Peak monthly demand denominator in the Formula by inclusion of long-term firm transmission service rights held by PacifiCorp Commercial & Trading. These rights are utilized to facilitate the exchange of transmission capacity contemplated by the agreement.

zero until such time as the Commission, in response to PacifiCorp filing a lead-lag study, authorizes a CWC allowance;

(b) PacifiCorp shall provide a draft to the other Parties of any such lead-lag study at least sixty (60) days prior to making any filing described in subsection (a) with the Commission; and

(c) Filing of the lead-lag study required in subsection (a) above, but not any subsequent filing affecting or relating to PacifiCorp's CWC allowance as permitted in subsection (a) above, may be a single issue FPA Section 205 filing.

3.5 *Protocols*. The Protocols included in Appendix 2 to this Settlement Agreement, Attachment H-2 of PacifiCorp's OATT, shall be effective as of December 25, 2011.

3.6 *Ancillary Service Schedules to PacifiCorp's OATT*

3.6.1. *Schedule 1: Scheduling, System Control and Dispatch Service.* The formula rate for Scheduling, System Control and Dispatch Service ("Scheduling Service") shall be the same as the currently-effective version of Schedule 1, effective December 25, 2011. The formula rate section of Schedule 1 has been moved as part of this Settlement Agreement to Attachment H-1, Appendix B, of PacifiCorp's OATT. The Schedule 1 formula rate shall be updated as calculated in Attachment H-1, Appendix B, of PacifiCorp's OATT. Appendix 3 to this Settlement Agreement reflects Schedule 1 of PacifiCorp's OATT, in redlined and clean formats.

3.6.2 *Schedule 2: Reactive Supply and Voltage Control from Generation or Other Sources Service.* The charge for Reactive Supply and Voltage Control from Generation or Other Sources Service ("Reactive Service") under Schedule 2 of PacifiCorp's OATT shall be $0.55/kW-year, effective as of December 25, 2011. Appendix 4 to this Settlement Agreement reflects the Reactive Service provisions under Schedule 2 of PacifiCorp's OATT, including stated rates for yearly, monthly, weekly, daily, and hourly service, in redlined and clean formats. Schedule 2 is one of the Moratorium Provisions subject to the provisions of Section 3.2 hereof.

Credits not to exceed a transmission customer's maximum monthly Reactive Service obligation shall be provided to individual transmission customers who have demonstrated that they own and operate qualifying generators that will meet PacifiCorp's minimum eligibility criteria to serve such customer's load and supply Reactive Service, as established in a business practice and posted on PacifiCorp's Open Access Same-Time Information System with an effective date of May 1, 2013. The business practice shall establish the credit mechanism and the process for applying for credits and shall establish the following, and only the following, qualifying generator requirements:

1) The generator has an exciter.

2) The generator is capable of responding automatically to voltage and/or reactive control settings and to manual directives from a PacifiCorp Control Area operator when called upon to supply reactive support (generate and absorb reactive energy) to PacifiCorp's Transmission System. Automatic response must be immediate and manual response must occur within 5 minutes of notice. Generators which fail to respond as directed will be disqualified until such time as the Control Area operator can be assured the unit can be relied upon.

3) The generator is interconnected to PacifiCorp's Transmission System or connected to a PacifiCorp transmission customer-owned transmission system within PacifiCorp's Control Area.

Any generators jointly owned by PacifiCorp and a transmission customer subject to Schedule 2 charges and PacifiCorp's costs of which are included in the calculation of Reactive Service rates shall be deemed qualified under the business practice. Details for the specific qualifying generator(s) and associated credits will be reflected in individual transmission customers' service agreements, consistent with the business practice. The revised service agreements of eligible Parties will have a proposed effective date of May 1, 2013.

The qualifying generator requirements set forth in PacifiCorp's business practice shall not be changed prior to June 1, 2015. The requirements shall also be incorporated into the service agreements of customers with qualifying generators, and shall not be changed by PacifiCorp without an appropriate filing under Section 205 of the FPA.

3.6.3 *Schedule 3: Regulation and Frequency Response Service.* The charge for Regulation and Frequency Response Service ("Regulation Service") under Schedule 3 of PacifiCorp's OATT shall be \$2.90/kW-year, effective as of December 25, 2011. Appendix 5 to this Settlement Agreement reflects the Regulation Service provisions under Schedule 3 of PacifiCorp's OATT, including stated rates for yearly, monthly, weekly, daily and hourly service, in redlined and clean formats.

3.6.4 *Schedule 3A: Generator Regulation and Frequency Response Service.* The charge for Generator Regulation and Frequency Response Service ("Generator Regulation Service") under Schedule 3A of PacifiCorp's OATT shall be \$2.90/kW-year effective as of December 25, 2011. Appendix 6 to this Settlement Agreement reflects the Generator Regulation Service provisions under Schedule 3A of PacifiCorp's OATT, including stated rates for yearly, monthly, weekly, daily and hourly service, in redlined and clean formats.

PacifiCorp shall make a filing with the Commission to propose adjusted Schedule 3 and 3A rates no later than April 1, 2013, with a proposed effective date of June 1, 2013. Such proposal shall be based on a study containing at least one year's worth of data to determine both the amount of reserves required by PacifiCorp's balancing authority areas and the different amounts of reserves needed for loads and resources. The ROE used to calculate Schedule 3 and

3A, as shall be revised pursuant to this paragraph, is one of the Moratorium Provisions subject to the provisions of Section 3.2 hereof. Any affected person may intervene in PacifiCorp's Schedule 3 and 3A filing, and seek any relief as may be appropriate under Section 205 of the FPA. No Party shall submit comments or protests challenging use of a 9.8% ROE in this Schedule 3 and 3A filing.

3.6.5 *Schedule 5: Operating Reserve – Spinning Reserve Service.* The charge for Operating Reserve – Spinning Reserve Service ("Spinning Reserve Service") under Schedule 5 of PacifiCorp's OATT shall be an Hourly energy charge of: (i) $0.32/MWh, effective from December 25, 2011 through May 31, 2013, and (ii) $0.39/MWh, effective as of June 1, 2013. Appendix 7 to this Settlement Agreement reflects the Spinning Reserve Service provisions under Schedule 5 of PacifiCorp's OATT, in redlined and clean formats. Schedule 5 is one of the Moratorium Provisions subject to the provisions of Section 3.2 hereof.

Appendices 13 and 14 to this Settlement Agreement provide support for the Schedule 5 rate calculations and an explanation of the Schedule 5 energy charge calculations, respectively.

3.6.6 *Schedule 6: Operating Reserve – Supplemental Reserve Service.* The charge for Operating Reserve - Supplemental Reserve Service ("Supplemental Reserve Service") under Schedule 6 of PacifiCorp's OATT shall be an Hourly energy charge of: (i) $0.29/MWh, effective from December 25, 2011 through May 31, 2013, and (ii) $0.34/MWh, effective as of June 1, 2013. Appendix 8 to this Settlement Agreement reflects the Supplemental Reserve Service provisions under Schedule 6 of PacifiCorp's OATT, in redlined and clean formats. Schedule 6 is one of the Moratorium Provisions subject to the provisions of Section 3.2 hereof.

Appendices 13 and 14 to this Settlement Agreement provide support for the Schedule 6 rate calculations and an explanation of the Schedule 6 energy charge calculations, respectively.

3.6.7 *Schedule 7: Long-Term Firm and Short-Term Firm PTP Service.* The charges under Schedule 7 of PacifiCorp's OATT shall be calculated annually using the Formula Rate in Attachment H-1 of PacifiCorp's OATT, effective as of December 25, 2011. Appendix 9 to this Settlement Agreement reflects Schedule 7 of PacifiCorp's OATT, in redlined and clean formats.

3.6.8 *Schedule 8: Non-Firm PTP Service.* The charges under Schedule 8 of PacifiCorp's OATT shall be calculated annually using the Formula Rate in Attachment H-1 of PacifiCorp's OATT, effective as of December 25, 2011. Appendix 10 to this Settlement Agreement reflects Schedule 8 of PacifiCorp's OATT, in redlined and clean formats.

3.6.9 *Schedule 10: Real Power Losses.* Appendix 11 to this Settlement Agreement reflects Schedule 10 of PacifiCorp's OATT, in redlined and clean formats.

The language currently in PacifiCorp's OATT that describes system input gross up for losses should instead be set forth in the affected Service Schedules rather than in Section 1.45 of PacifiCorp's OATT (definition of Reserved Capacity). Removal of this language is reflected in the redlined and clean versions of Section 1 of the OATT in Appendix 12.

PacifiCorp shall file an adjusted Transmission System factor for Real Power Losses under Schedule 10 of PacifiCorp's OATT, consistent with the calculation as identified in Appendix 16 to this Settlement Agreement, following completion of every two Energy Gateway Project segments (or substantially similar transmission segments or combination thereof) which have been placed into commercial operation for at least one full calendar year. PacifiCorp's update to the Transmission System loss factor shall be filed on or before April 1 following the full calendar year of commercial operation for the second of every two Energy Gateway Project segments (or substantially similar transmission segments or combination thereof) with a request to the Commission that the updated Transmission System loss factor be made effective June 1 of the calendar year in which the filing is made. Such filing shall be based on the most recent FERC Form No. 1 data for the prior calendar year. Appendix 17 describes the losses methodology to be employed by PacifiCorp.

3.7 *Standard of Review.*

3.7.1 To the extent that the Commission considers changes to Section 3.2 or any of the Moratorium Provisions listed therein pursuant to a filing by a Party, and the proposed changes would take effect prior to June 1, 2015, the standard of review for such proposed changes shall be the "public interest" application of the just and reasonable standard set forth in *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956), as clarified in *Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1 of Snohomish County, Washington*, 128 S. Ct. 2733, 171 L. Ed. 2d 607 (2008) and refined in *NRG Power Mktg. v. Maine Pub. Utils. Comm'n*, 130 S. Ct. 693, 700 (2010). The ordinary just and reasonable standard of review (rather than the "public interest" standard), as clarified in *Morgan Stanley Capital Group Inc. v. Public Util. Dist. No. 1 of Snohomish County, Washington*, 128 S. Ct. 2733, 171 L. Ed. 2d 607 (2008), applies to future changes to the Moratorium Provisions sought by the Commission acting *sua sponte* or at the request of a non-Party to this proceeding.

3.7.2 With respect to changes to Section 3.2 or any of the Moratorium Provisions listed therein that would take effect on or after June 1, 2015, or to changes to other provisions of this Settlement Agreement, the standard of review shall be the ordinary just and reasonable standard (not the "public interest" standard), including without limitation, written amendments or modifications to the Settlement Agreement agreed to by all Parties.

3.8 *Depreciation.* For purposes of this Settlement Agreement, the Parties jointly acknowledge that PacifiCorp's depreciation and amortization rates shall be the same as the version of Attachment 8 to the Formula, effective December 25, 2011 (as shown in Appendix 19 to this Settlement Agreement) and the version of Attachment 8 to the Formula, effective June 1, 2012 (as shown separately in Appendix 18 to this Settlement Agreement). For all subsequent annual updates to the Formula, PacifiCorp shall make a single issue filing pursuant to Section 205 of the FPA to update depreciation rates if and when one or more of PacifiCorp's retail jurisdictions change(s) the corresponding rates, using the methodology set forth in Attachment 8 to the Formula. The effective dates of any updated depreciation rates shall be the same as the effective dates in the respective retail jurisdiction(s).

3.9 *Compliance Filing.* Within thirty (30) calendar days of the Commission's acceptance or approval of this Settlement Agreement, PacifiCorp shall make a compliance filing via eTariff to incorporate the revisions to Section 1, Attachments H-1 and H-2, and Schedules 1, 2, 3, 3A, 5, 6, 7, 8, and 10 of the Tariff, as reflected in this Settlement Agreement and relevant appendices.

3.9A *Interim Rates.* Contemporaneous with filing this Settlement Agreement with the Commission, PacifiCorp shall file an expedited motion for leave to charge rates on an interim basis. Interim rates for Schedules 2, 3, 3A, 5, 6, 7, 8, and 10, shall be as set forth in the revised Tariff sheets appended to this Settlement Agreement, pending Commission action on the Settlement, as follows:

(a) The effective date for interim rates for Schedules 3, 3A, 5, 6, and 10 shall be March 1, 2013 (provided the motion is approved prior to March 1, 2013).

(b) The effective date for interim rates for Schedule 2 shall be May 1, 2013 (provided the motion is approved prior to May 1, 2013).

(c) The effective date for implementation of the Formula Rate on an interim basis for rates for Schedules 7 and 8 and NIT Service shall be June 1, 2013, consistent with the effective date and procedures for the Formula Rate's annual update and true-up processes.

In the event that the motion is not approved prior to March 1, 2013, the effective date for interim rates for Schedules 3, 3A, 5, 6, and 10 shall be April 1, 2013. In the event that the motion is not approved prior to May 1, 2013, the effective date for interim rates for Schedule 2 shall be June 1, 2013.

3.10 *Refunds*. The Parties agree that any refunds required pursuant to this Settlement Agreement or by Commission order will be calculated from January 1, 2012. Refunds shall be provided as follows:

(a) PacifiCorp shall refund, with interest pursuant to 18 C.F.R. § 35.19a, all rates charged under Schedules 3, 3A, 5, 6, and 10 from January 1, 2012 through February 28, 2013 (or such later date as interim rates are approved for billing), to reflect the difference between the rates charged for that period and the interim rates agreed to as part of this Settlement Agreement.

(b) PacifiCorp shall refund, with interest pursuant to 18 C.F.R. § 35.19a, all rates charged under Schedule 2 from January 1, 2012 through April 30, 2013 (or such later date as interim rates are approved for billing), to reflect the difference between the rates charged for that period and the interim rates agreed to as part of this Settlement Agreement.

The net refund for the period January 1, 2012 through April 30, 2013 has been calculated for the following parties for Schedule 2 Reactive Service and shall be as follows, together with interest pursuant to 18 C.F.R. § 35.19a, which shall be calculated at the time the refund is sent:

Bonneville Power Administration	$89,446.06
Deseret Generation & Transmission Co-operative, Inc.	$86,941.83

Utah Associated Municipal Power Systems	$134,710.61
Utah Municipal Power Agency	$57,748.78

In the event that the motion for leave to charge interim rates is not approved prior to May 1, 2013, the refund period for these parties for Schedule 2 Reactive Service shall be January 1, 2012 through May 31, 2013, and refund amounts shall be adjusted accordingly.

(c) The refund associated with rates produced by the Formula Rate pursuant to this Settlement Agreement shall be performed concurrent with and pursuant to the True-Up process described in the Protocols.

3.11 Order No. 1000. In the event that the Formula included in Attachment H-1 to PacifiCorp's OATT requires a modification or adjustment to accommodate a future FERC Order No. 1000 compliance filing, PacifiCorp shall make an appropriate filing to reflect the necessary revisions with as limited an impact on the Formula as practicable consistent with the applicable compliance requirements; provided, however, that no such filing shall change any of the Moratorium Provisions prior to the expiration of the moratorium period established in Section 3.2 hereof. To the extent the Commission were to determine as a result of Order No. 1000 that the rate base of, or revenue responsibility for, some part of the Energy Gateway Project belongs to a third party and should be accommodated through PacifiCorp's rates, the formula rate would accommodate such a situation as follows:

3.11.1 Attachment 7 of Attachment H-1 (the Formula) sets out the revenue requirement for all projects that receive incentives or for which all or a portion of the project will be allocated regionally. For each project, the ATRR for each year is shown. If the region, in compliance with Order No. 1000, assigns all or a portion of the revenue requirement of a project to third parties, the allocation percentage determined in the regional compliance filing will be applied to the ATRR of the project and the third parties will make payments to PacifiCorp. Those payments will be booked to Account 456 (see Attachment 3 to the Formula – Revenue Credit Worksheet), and credited to the revenue requirement on line 144 of Attachment H-1. This reduces the rate paid by all customers under PacifiCorp's OATT.

ARTICLE IV
General Provisions

4.0 *Entire Agreement.* This Settlement Agreement, including appendices hereto, constitutes the entire agreement among the Parties with respect to the subject matter addressed herein, and supersedes any and all prior or contemporaneous representations, agreements, instruments and understandings between them, whether written or oral. There are no oral understandings, terms or conditions, and none of the Parties has relied upon any representations, express or implied, not contained in this Settlement Agreement.

4.1 *Non-Severability; Effect of Non-Approval.* The Parties agree and understand that the various provisions of this Settlement Agreement are not severable and shall not become operative unless and until the Commission issues an order accepting or approving the Settlement Agreement without modification or condition or with only modification or condition acceptable to the Parties. If the Commission issues an order rejecting this Settlement Agreement or approving it with modification(s) or condition(s), the Parties shall have a duty to initiate discussions within 10 business days of the issuance of the Commission order to address the Commission's conclusions and directed modification(s) or condition(s) and determine whether to agree to the Settlement Agreement with the inclusion of such modification(s) or condition(s) or to amend the Settlement Agreement to restore the balance of benefits and burdens in this Settlement Agreement while accommodating the required modification(s) or condition(s).

4.2 *Effectiveness of Settlement Agreement.* This Settlement Agreement and the provisions hereof shall become effective as of the date that the Commission issues an order accepting or approving the Settlement Agreement without modification or condition.

4.3 *Reservations.* Nothing in this Settlement Agreement is intended to affect rights that any Party has under the FPA in the event that this Settlement Agreement does not become effective in accordance with Section 4.2.

4.4 *No Admissions or Precedent.* This Settlement Agreement is submitted pursuant to Rule 602, and is inadmissible as evidence in any proceeding, and of no effect unless it is accepted or approved and made effective as to all of its terms and conditions without modification or with only modification acceptable to the Parties. Further, the making of this Settlement Agreement and its acceptance or approval by the Commission shall not in any respect constitute an admission by any Party, or a determination by the Commission, that any allegation or contention in these proceedings, or concerning any of the foregoing matters, is true and valid. In consideration of all elements of this negotiated settlement, no element of this Settlement Agreement shall constitute precedent nor be deemed a "settled practice" as that term was interpreted and applied in *Public Service Commission of New York v. FERC*, 642 F.2d 1335 (D.C. Cir. 1980). It is further understood and agreed that this Settlement Agreement constitutes a negotiated agreement and, except as explicitly set forth herein, no Party shall be deemed to have approved, accepted, agreed on or consented to any principle or position in this proceeding, and with the exception above noted, none of the provisions of this Settlement Agreement shall be cited or referenced by any party in any federal or state proceeding as establishing any precedent or settled practice.

4.5 *Settlement Discussions.* The discussions between and among the Parties that have produced this Settlement Agreement have been conducted with the explicit understanding, pursuant to Rule 602, that all offers of settlement and discussions relating thereto shall be privileged and confidential, shall be without prejudice to the position of any Party or participant presenting any such offer or participating in any such discussion, and are not to be used in any manner in connection with this proceeding, any other proceeding, or otherwise, except to the extent necessary to enforce its terms.

4.6 *Further Assistance.* Each Party shall cooperate with and support, and shall not take any action inconsistent with: (i) the filing of this Settlement Agreement with the Commission, and (ii) efforts to obtain Commission acceptance or approval of this Settlement Agreement. No Party shall take any actions that are inconsistent with the provisions of this Settlement Agreement or seek additional terms and conditions for this Settlement Agreement beyond those contained herein.

4.7 *Waiver.* No provisions of this Settlement Agreement may be waived except through a writing signed by an authorized representative of the waiving Party. Waiver of any provisions of this Settlement Agreement shall not be deemed to waive any other provisions.

4.8 *Successors and Assigns.* This Settlement Agreement is binding upon and for the benefit of the Parties and their successors and assigns.

4.9 *Titles and Headings.* The titles and headings of this Settlement Agreement are for reference purposes only and are not a part of this Settlement Agreement and do not in any way limit or amplify the terms and provisions of this Settlement Agreement and shall have no effect on its interpretation.

4.10 *Ambiguities Neutrally Construed.* This Settlement Agreement is the result of negotiations and discussions among, and has been reviewed by, each Party and its respective counsel. Accordingly, this Settlement Agreement shall be deemed to be the product of each Party, and no ambiguity shall be construed in favor of or against any Party.

4.11 *Authorization.* Each person executing this Settlement Agreement on behalf of a Party represents and warrants that he or she is duly authorized and empowered to act on behalf of, and to authorize this Settlement Agreement to be executed on behalf of, the Party that he or she represents.

4.12 *Notices.* All notices, demands, and other communications under this Settlement Agreement shall be in writing and shall be delivered to each Party's "Corporate Official" as found on the Commission's website at http://www.ferc.gov/docs-filing/corp-off.asp or the representatives of each Party on the official service list in Docket No. ER11-3643.

4.13 *Counterparts.* This Settlement Agreement may be executed in one or more counterparts, each of which shall be deemed to be an original and all of which together shall be deemed to be one and the same instrument.

[THE NEXT PAGE IS THE SIGNATURE PAGE]

SETTLEMENT AGREEMENT
SIGNATURE PAGE

PACIFICORP

By: Natalie L Hocken

Name: Natalie L. Hocken

Title: SVP, Transmission + System Ops

BONNEVILLE POWER ADMINISTRATION

By: ______________________________

Name: ______________________________

Title: ______________________________

DESERET GENERATION &
TRANSMISSION CO-OPERATIVE

By: ______________________________

Name: ______________________________

Title: ______________________________

UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

By: ______________________________

Name: ______________________________

Title: ______________________________

UTAH MUNICIPAL POWER AGENCY

By: ______________________________

Name: ______________________________

Title: ______________________________

SETTLEMENT AGREEMENT
SIGNATURE PAGE

PACIFICORP

By: ______________________________

Name: ______________________________

Title: ______________________________

BONNEVILLE POWER ADMINISTRATION

By: ______________________________

Name: Mark Gendron

Title: Vice President, Northwest Requirements Marketing

DESERET GENERATION & TRANSMISSION CO-OPERATIVE

By: ______________________________

Name: ______________________________

Title: ______________________________

UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

By: ______________________________

Name: ______________________________

Title: ______________________________

UTAH MUNICIPAL POWER AGENCY

By: ______________________________

Name: ______________________________

Title: ______________________________

SETTLEMENT AGREEMENT
SIGNATURE PAGE

PACIFICORP

By: ______________________________

Name: ____________________________

Title: _____________________________

BONNEVILLE POWER ADMINISTRATION

By: ______________________________

Name: ____________________________

Title: _____________________________

DESERET GENERATION &
TRANSMISSION CO-OPERATIVE

By: Curtis K. Winterfeld

Name: CURTIS K. WINTERFELD

Title: Vice-President

UTAH ASSOCIATED MUNICIPAL POWER
SYSTEMS

By: ______________________________

Name: ____________________________

Title: _____________________________

UTAH MUNICIPAL POWER AGENCY

By: ______________________________

Name: ____________________________

Title: _____________________________

SETTLEMENT AGREEMENT
SIGNATURE PAGE

PACIFICORP

By: ______________________

Name: ______________________

Title: ______________________

BONNEVILLE POWER ADMINISTRATION

By: ______________________

Name: ______________________

Title: ______________________

DESERET GENERATION & TRANSMISSION CO-OPERATIVE

By: ______________________

Name: ______________________

Title: ______________________

UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

By: ______________________

Name: Marshall Empey

Title: Manager - Operations and Planning

UTAH MUNICIPAL POWER AGENCY

By: ______________________

Name: ______________________

Title: ______________________

SETTLEMENT AGREEMENT
SIGNATURE PAGE

PACIFICORP

By: ______________________________

Name: ______________________________

Title: ______________________________

BONNEVILLE POWER ADMINISTRATION

By: ______________________________

Name: ______________________________

Title: ______________________________

DESERET GENERATION & TRANSMISSION CO-OPERATIVE

By: ______________________________

Name: ______________________________

Title: ______________________________

UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

By: ______________________________

Name: ______________________________

Title: ______________________________

UTAH MUNICIPAL POWER AGENCY

By: W Leon Pexton

Name: W. Leon Pexton

Title: COO / General Manager

Appendix 1
(Clean Version)

Attachment H-1 of PacifiCorp’s OATT

(the Formula)

ATTACHMENT H-1
PacifiCorp
Appendix A - Formula Rate

Shaded cells are inputs		Notes	Reference (FERC Form 1 reference, attachment, or instruction)	
Allocators				
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		354.21b	0
2	Total Wages Expense		354.28b	0
3	Less A&G Wages Expense		354.27b	0
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	0
5	**Wages & Salary Allocator**		(Line 1 / Line 4)	**0.0000%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note M)	Attachment 5	0
7	Accumulated Depreciation (Total Electric Plant)	(Note M)	Attachment 5	0
8	Accumulated Amortization	(Note N)	Attachment 5	0
9	Total Accumulated Depreciation		(Line 7 + 8)	0
10	Net Plant		(Line 6 - Line 9)	0
11	Transmission Gross Plant (excluding Land Held for Future Use)		(Line 24 - Line 23)	0
12	**Gross Plant Allocator**		(Line 11 / Line 6)	**0.0000%**
13	Transmission Net Plant (excluding Land Held for Future Use)		(Line 32 - Line 23)	0
14	**Net Plant Allocator**		(Line 13 / Line 10)	**0.0000%**
Plant Calculations				
	Plant In Service			
15	Transmission Plant In Service	(Note M)	Attachment 5	0
16	New Transmission Plant Additions for Current Calendar Year (weighted by months in service)	(Notes A & P)	Attachment 6	0
17	**Total Transmission Plant**		(Line 15 + Line 16)	**0**
18	General Plant	(Note N)	Attachment 5	0
19	Intangible Plant	(Note N)	Attachment 5	0
20	Total General and Intangible Plant		(Line 18 + Line 19)	0
21	Wage & Salary Allocator		(Line 5)	0.0000%
22	General and Intangible Allocated to Transmission		(Line 20 * Line 21)	0
23	**Land Held for Future Use**	(Notes B & L)	Attachment 5	**0**
24	**Total Plant In Rate Base**		(Line 17 + Line 22 + Line 23)	**0**

ATTACHMENT H-1
PacifiCorp
Appendix A - Formula Rate

	Shaded cells are inputs	Notes	Reference (FERC Form 1 reference, attachment, or instruction)		
	Accumulated Depreciation and Amortization				
25	Transmission Accumulated Depreciation	(Note M)	Attachment 5		**0**
26	Accumulated General Depreciation	(Note N)	Attachment 5		0
27	Accumulated Amortization	(Note N)	(Line 8)		0
28	Accumulated General and Intangible Depreciation		(Line 26 + 27)		0
29	Wage & Salary Allocator		(Line 5)		0.0000%
30	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line 28 * Line 29)		0
31	**Total Accumulated Depreciation and Amortization**		Line 25 + Line 30)		**0**
32	**Total Net Property, Plant & Equipment**		(Line 24 - Line 31)		**0**
	Adjustments To Rate Base				
	Accumulated Deferred Income Taxes				
33	ADIT net of FASB 106 and 109		Attachment 1A		**0**
	CWIP for Incentive Transmission Projects				
34	CWIP Balances for Current Rate Year	(Note O)	Attachment 6		**0**
	ITC Adjustment				
35	IRC 46(f)1 adjustment		Attachment 5		**0**
	Unfunded Reserves				
36	Unfunded Reserves		Attachment 16		**0**
	Prepayments				
37	Prepayments	(Note K & N)	Attachment 11		**0**
	Abandoned Plant				
38	Unamortized Abandoned Plant	(Note O)			0
	Materials and Supplies				
39	Undistributed Stores Expense	(Note N)	Attachment 5		0
40	Wage & Salary Allocator		(Line 5)		0.0000%
41	Total Undistributed Stores Expense Allocated to Transmission		(Line 39 * Line 40)		0
42	Construction Materials & Supplies	(Note N)	Attachment 5		0
43	Wage & Salary Allocator		(Line 5)		0.0000%
44	Construction Materials & Supplies Allocated to Transmission		(Line 42 * Line 43)		0
45	Transmission Materials & Supplies	(Note N)	Attachment 5		0
46	**Total Materials & Supplies Allocated to Transmission**		(Line 41 + Line 44 + Line 45)		**0**
	Cash Working Capital				
47	Operation & Maintenance Expense		(Line 75)		0
48	1/8th Rule	(Note S)	1/8		0.0%
49	**Total Cash Working Capital Allocated to Transmission**		(Line 47 * Line 48)		**0**
	Network Upgrade Balance				
50	Network Upgrade Balance	(Note N)	Attachment 5		**0**
51	**Total Adjustment to Rate Base**		(Lines 33 + 34 + 35 + 36 + 37 + 38 + 46 + 49 + 50)		**0**
52	**Rate Base**		(Line 32 + Line 51)		**0**

ATTACHMENT H-1
PacifiCorp
Appendix A - Formula Rate

	Shaded cells are inputs	**Notes**	**Reference** (FERC Form 1 reference, attachment, or instruction)	
	Operations & Maintenance Expense			
	Transmission O&M			
53	Transmission O&M		Attachment 5	0
54	Less: Cost of Providing Ancillary Services Accounts 561.0-5		Attachment 5	0
55	Less: Account 565		Attachment 5	0
56	**Transmission O&M**		(Lines 53 - 55)	**0**
	Allocated Administrative & General Expenses			
57	Total A&G		323.197b	0
58	Less Actual PBOP Expense Adjustment		Attachment 5	0
59	Less Property Insurance Account 924		323.185b	0
60	Less Regulatory Asset Amortizations Account 930.2		Attachment 5	0
61	Less Regulatory Commission Exp Account 928	(Note D)	323.189b	0
62	Less General Advertising Exp Account 930.1		323.191b	0
63	Less Membership Dues	(Note C)	Attachment 5	0
64	Administrative & General Expenses		(Line 57 - Sum (Lines 58 to 63)	0
65	Wage & Salary Allocator		(Line 5)	0.0000%
66	**Administrative & General Expenses Allocated to Transmission**		(Line 64 * Line 65)	**0**
	Directly Assigned A&G			
67	Regulatory Commission Exp Account 928	(Note E)	Attachment 5	0
68	General Advertising Exp Account 930.1 - Safety-related Advertising		Attachment 5	0
69	**Subtotal - Accounts 928 and 930.1 - Transmission Related**		(Line 67 + Line 68)	**0**
70	Property Insurance Account 924	(Note F)	Attachment 5	0
71	General Advertising Exp Account 930.1 - Education and Outreach		Attachment 5	0
72	Total Accounts 924 and 930.1 - General		(Line 70 + Line 71)	0
73	Gross Plant Allocator		(Line 12)	0.0000%
74	**A&G Directly Assigned to Transmission**		(Line 72 * Line 73)	**0**
75	**Total Transmission O&M**		(Lines 56 + 66 + 69 + 74)	**0**
	Depreciation & Amortization Expense			
	Depreciation Expense			
76	Transmission Depreciation Expense Including Amortization of Limited Term Plant	(Note H)	Attachment 5	**0**
77	General Depreciation Expense Including Amortization of Limited Term Plant	(Note H)	Attachment 5	0
78	Intangible Amortization	(Note H)	Attachment 5	0
79	Total		(Line 77 + Line 78)	0
80	Wage & Salary Allocator		(Line 5)	0.0000%
81	**General Depreciation and Intangible Amortization Functionalized to Transmission**		(Line 79 * Line 80)	**0**
82	Abandoned Plant Amortization	(Note O)		0
83	**Total Transmission Depreciation & Amortization**		(Lines 76 + 81 + 82)	**0**
	Taxes Other Than Income			
84	**Taxes Other than Income Taxes**		Attachment 2	**0**
85	**Total Taxes Other than Income Taxes**		(Line 84)	**0**

ATTACHMENT H-1
PacifiCorp
Appendix A - Formula Rate

Shaded cells are inputs	**Notes**	**Reference** (FERC Form 1 reference, attachment, or instruction)		
Return \ Capitalization Calculations				
Long-Term Debt				
86 Account 221 Bonds		Attachment 14		0
87 Less Account 222 Reaquired Bonds		Attachment 14		0
88 Account 223 Long-term Advances from Associated Cos.		Attachment 14		0
89 Account 224 Other Long-term Debt		Attachment 14		0
90 **Gross Proceeds Outstanding Long-term Debt**		Sum Lines 86 through 89		**0**
91 Less Account 226 Unamortizedized Discount	(Note T)	Attachment 14		0
92 Less Account 181 Unamortizedized Debt Expense	(Note T)	Attachment 14		0
93 Less Account 189 Unamortizedized Loss on Reaquired Debt	(Note T)	Attachment 14		0
94 Plus Account 225 Unamortizedized Premium	(Note T)	Attachment 14		0
95 Plus Account 257 Unamortizedized Gain on Reaquired Debt	(Note T)	Attachment 14		0
96 **Net Proceeds Long Term Debt**		Sum Lines 90 through 95		**0**
Long Term Debt Cost				
97 Accounts 427 and 430 Long Term Interest Expense	(Notes R & T)	Attachment 14		0
98 Less Hedging Expense	(Note R)	Attachment 14		0
99 Account 428 Amortized Debt Discount and Expense	(Note T)	Attachment 14		0
100 Account 428.1 Amortized Loss on Reaquired Debt	(Note T)	Attachment 14		0
101 Less Account 429 Amortized Premium	(Note T)	Attachment 14		0
102 Less Account 429.1 Amortized Gain on Reaquired Debt	(Note T)	Attachment 14		0
103 **Total Long Term Debt Cost**		Sum Lines 97 through 102		**0**
Preferred Stock and Dividend				
104 Account 204 Preferred Stock Issued		Attachment 14		0
105 Less Account 217 Reaquired Capital Stock (preferred)		Attachment 14		0
106 Account 207 Premium on Preferred Stock		Attachment 14		0
107 Account 207-208 Other Paid-In Capital (preferred)		Attachment 14		0
108 Less Account 213 Discount on Capital Stock (preferred)		Attachment 14		0
109 Less Account 214 Capital Stock Expense (preferred)		Attachment 14		0
110 **Total Preferred Stock**		Sum Lines 104 through 109		**0**
111 **Preferred Dividend**		Attachment 14	(Enter positive)	**0**
Common Stock				
112 Proprietary Capital		Attachment 14		0
113 Less: Total Preferred Stock		(Line 110)		0
114 Less: Account 216.1 Unappropriated Undistributed Subsidiary Earnings		Attachment 14		0
115 Less: Account 219		Attachment 14		0
116 **Total Common Stock**		Sum Lines 112 through 115		**0**

ATTACHMENT H-1
PacifiCorp
Appendix A - Formula Rate

Shaded cells are inputs		Notes	**Reference** (FERC Form 1 reference, attachment, or instruction)	

117	Debt percent	Total Long Term Debt	(Notes Q & R)	(Line 90 / (Lines 90 + 110 +116))	0.00%
118	Preferred percent	Preferred Stock		(Line 110 / (Lines 90 + 110 +116))	0.00%
119	Common percent	Common Stock	(Notes Q & R)	(Line 116 / (Lines 90 + 110 +116))	0.00%
120	Debt Cost	Long Term Debt Cost = Long Term Debt Cost / Net Proceeds Long Term Debt		(Line 103 / Line 96)	0.00%
121	Preferred Cost	Preferred Stock cost = Preferred Dividends / Total Preferred Stock		(Line 111 / Line 110)	0.00%
122	Common Cost	Common Stock	(Note H)	Fixed	0.00%
123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 117 * Line 120)	0.00%
124	Weighted Cost of Preferred	Preferred Stock		(Line 118 * Line 121)	0.00%
125	Weighted Cost of Common	Common Stock		(Line 119 * Line 122)	0.00%
126	**Rate of Return on Rate Base (ROR)**			(Sum Lines 123 to 125)	**0.00%**
127	**Investment Return = Rate Base * Rate of Return**			(Line 52 * Line 126)	**0**

Composite Income Taxes

	Income Tax Rates				
128	FIT = Federal Income Tax Rate		(Note G)		0.00%
129	SIT = State Income Tax Rate or Composite		(Note G)	Attachment 5	0.00%
130	p	(percent of federal income tax deductible for state purposes)		Per state tax code	0.00%
131	T	T = 1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			0.000%
132	T / (1-T)				0.000%
	ITC Adjustment				
133	Amortized Investment Tax Credit - Transmission Related			Attachment 5	0
134	**ITC Adjust. Allocated to Trans. - Grossed Up**	ITC Adjustment x 1 / (1-T)		Line 133 * (1 / (1 - Line 131))	**0**
135	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =		[Line 132 * Line 127 * (1- (Line 123 / Line 126))]	**0**
136	**Total Income Taxes**			(Line 134 + Line 135)	**0**

ATTACHMENT H-1
PacifiCorp
Appendix A - Formula Rate

Shaded cells are inputs		Notes	Reference (FERC Form 1 reference, attachment, or instruction)	
Revenue Requirement				
	Summary			
137	Net Property, Plant & Equipment		(Line 32)	0
138	Total Adjustment to Rate Base		(Line 51)	0
139	Rate Base		(Line 52)	0
140	Total Transmission O&M		(Line 75)	0
141	Total Transmission Depreciation & Amortization		(Line 83)	0
142	Taxes Other than Income		(Line 85)	0
143	Investment Return		(Line 127)	0
144	Income Taxes		(Line 136)	0
145	**Gross Revenue Requirement**		(Sum Lines 140 to 144)	**0**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
146	Transmission Plant In Service		(Line 15)	0
147	Excluded Transmission Facilities	(Note J)	Attachment 15	0
148	Included Transmission Facilities		(Line 146 - Line 147)	0
149	Inclusion Ratio		(Line 148 / Line 146)	0.00%
150	Gross Revenue Requirement		(Line 145)	0
151	**Adjusted Gross Revenue Requirement**		(Line 149 * Line 150)	**0**
	Revenue Credits			
152	**Revenue Credits**		Attachment 3	**0**
153	**Net Revenue Requirement**		(Line 151 - Line 152)	**0**
	Net Plant Carrying Charge			
154	Gross Revenue Requirement		(Line 150)	0
155	Net Transmission Plant		(Line 17 - Line 25 + Line 34)	0
156	Net Plant Carrying Charge		(Line 154 / Line 155)	0.0000%
157	Net Plant Carrying Charge without Depreciation		(Line 154 - Line 76) / Line 155	0.0000%
158	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 154 - Line 76 - Line 127 - Line 136) / Line 155	0.0000%
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE			
159	Gross Revenue Requirement Less Return and Taxes		(Line 150 - Line 143 - Line 144)	0
160	Increased Return and Taxes		Attachment 4	0
161	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 159 + Line 160)	0
162	Net Transmission Plant		(Line 17 - Line 25 + Line 34)	0
163	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 161 / Line 162)	0.0000%
164	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation		(Line 161 - Line 76) / Line 162	0.0000%
165	**Net Revenue Requirement**		(Line 153)	0
166	Facility Credits under Section 30.9 of the OATT		Attachment 5	0
167	Transmission Incentive Credit		Attachment 7	0
168	Interest on Network Upgrade Facilities		Attachment 5	0
169	**Net Zonal Revenue Requirement**		(Line 165 + 166 + 167 + 168)	0
	Network Service Rate			
170	12 CP Monthly Peak (MW)	(Note I)	Attachment 9a/9b	**0**
171	Rate ($/MW-year)		(Line 169 / 170)	**0**
172	**Network Service Rate** ($/MW-year)		(Line 171)	**0**

ATTACHMENT H-1
PacifiCorp
Appendix A - Formula Rate

Shaded cells are inputs	**Notes**	**Reference** (FERC Form 1 reference, attachment, or instruction)	

Notes

A Line 16 includes New Transmission Plant to be placed in service in the current calendar year. Projected capital additions will include only the capital costs associated with plant expected to be energized and placed in service (as defined by the Uniform System of Accounts) in that month. The True-Up Adjustment will reflect the actual date the plant was energized and placed in service.

B Includes Transmission portion only.

C Annual membership dues (e.g., for EPRI, NEETRAC, SEPA and NCTA) are excluded from the calculation of the ATRR and charges under the Formula Rate and are subtracted from Total A&G. Total A&G does not include lobbying expenses.

D Includes all Regulatory Commission Expenses.

E Includes Regulatory Commission Expenses directly related to transmission service.

F Property Insurance excludes prior period adjustment in the first year of the formula's operation and reconciliation for the first year.

G The calculation of the Reconciliation revenue requirement according to Step 7 of Attachment 6 ("Estimate and Reconciliation Worksheet") shall reflect the actual tax rates in effect for the Rate Year, as defined in Attachment H-2, being reconciled ("Test Year"). When statutory marginal tax rates change during such Test Year, the effective tax rates used in the formula shall be weighted by the number of days each such rate was in effect. For example, a 35% rate in effect for 120 days superseded by a 40% rate in effect for the remainder of the year will be calculated as: ((.3500 x 120) + (.4000 x 245))/365 = .3836.

H No change in ROE will be made absent a filing at FERC.
PBOP expense is fixed until changed as the result of a filing at FERC.
Depreciation rates shown in Attachment 8 are fixed until changed as the result of a filing at FERC.

I The 12 CP monthly peak is the average of the 12 monthly system peaks calculated as the Network customers Monthly Network Load (Section 34.2 of the OATT) plus the reserve capacity of all long term firm point-to-point customers.

J Amount of transmission plant excluded from rates per Attachment 5.

K Adjustment reflects exclusion of tax receivables due to 2008 NOLs, which resulted in MidAmerican Energy Holdings Company delivering refund to PacifiCorp.

L Any gain from the sale of land included in Land Held for Future Use in the Formula Rate received during the Rate Year, as defined in Attachment H-2, shall be used to reduce the ATRR in the Rate Year. The Formula Rate shall not include any losses on sales of such land.

M The Update uses end of year balances and the True-up uses 13 monthly averages shown on Attachment 5.

N The Update uses end of year balances and the True-up uses the average of beginning of year and end of year balances shown on Attachments.

O Placeholder that is zero until PacifiCorp receives authorization by FERC to include amounts.

P Projected capital additions will include only the capital costs associated with plant expected to be energized and placed in service (as defined by the Uniform System of Accounts) in that month. The True-Up Adjustment will reflect the actual date the plant was energized and placed in service.

Q The equity ratio is capped at 53%, and if the actual equity ratio exceeds 53%, then the debt ratio will be equal to 1 minus the preferred stock ratio minus 53%.

R PacifiCorp will include only the gains and losses on interest rate locks for new debt issuances. Attachment 14 – Cost of Capital Detail will list the unamortized balance and annual amortization for all gains and losses on hedges.

S PacifiCorp shall use FERC’s 1/8th method for cash working capital subject to the following limitations:
(a) PacifiCorp shall be required to file a lead-lag study justifying the appropriate cash working capital allowance to be effective, subject to refund, as of June 1, 2014; provided, however, that if PacifiCorp does not file a study in the time required, the amount of cash working capital allowance includable in the calculation of the ATRR under the Formula shall be zero dollars ($0.00) as of June 1, 2014, and shall remain at zero until such time as the Commission, in response to a PacifiCorp filing of a lead-lag study, authorizes a cash working capital allowance;
(b) PacifiCorp shall provide a draft to the other Parties of any such lead-lag study at least sixty (60) days prior to making any filing described in (a) with the Commission; and
(c) Filing of the lead-lag study in (a) above, but not any subsequent filing affecting or relating to PacifiCorp’s cash working capital allowance as permitted in subsection (a) above, may be a single issue FPA Section 205 filing.

T These line items will include only the balances associated with long-term debt and shall exclude balances associated with short-term debt.

PacifiCorp

Appendix B - Schedule 1: Scheduling, System Control and Dispatch Service

Calculated from historical data--no true-up

Line	Description	FERC Form 1 page # / Reference	Amount
1	(561.1) Load Dispatch-Reliability	pg. 321.85b	
2	(561.2) Load Dispatch-Monitor and Operate Transmission System	pg. 321.86b	
3	(561.3) Load Dispatch-Transmission Service and Scheduling	pg. 321.87b	
4	(561.4) Scheduling, System Control and Dispatch Services	pg. 321.88b	
5	(561.5) Reliability, Planning and Standards Development	pg. 321.89b	
6	Total 561 Costs for Schedule 1 Annual Revenue Requirement	(Sum Lines 1 through 5)	0
7	Schedule 1 Annual Revenue Requirement	(Line 6)	0
	Schedule 1 - Rate Calculations		
8	Average 12-Month Demand - Current Year (kW)	Divisor	
9	Rate in $/kW - Yearly	(Line 7 / Line 8)	0.000
10	Rate in $/kW - Monthly	((Line 7 / Line 8) / 12)	0.000
11	Rate in $/kW - Weekly	((Line 7 / Line 8) / 52)	0.000
12	Rate in $/kW - Daily On-Peak	(Line 11 / 5)	0.000
13	Rate in $/kW - Daily Off-Peak	(Line 11 / 7)	0.000
14	Rate in $/MW - Hourly On-Peak	((Line 12 / 16) * 1000)	0.000
15	Rate in $/MW - Hourly Off-Peak	((Line 13 / 24) * 1000)	0.000

PacifiCorp
OATT Transmission Rate Formula Template Using Form 1 Data
Summary of Rates

Line	Description	Reference	Amount
1	Adjusted Gross Revenue Requirement	Appendix A, Line 151	$0
	Revenue Credits:		
2	Acct 454 - Allocable to Transmission	Attachment 3, Line 6	$0
3	Acct 456 - Allocable to Transmission	Attachment 3, Line 12	$0
4	Total Revenue Credits	Line 2 + Line 3	$0
5	Interest on Network Upgrades	Attachment 5	$0
6	Transmission Incentive Credit	Attachment 7	$0
7	Annual Transmission Revenue Requirement	Line 1 - Line 4 + Line 5 + Line 6	$0
8	Divisor - 12 Month Average Transmission Peak (MW)	Appendix A, Line 170	0
	Rates:		
9	Transmission Rate ($/kW-year)	Line 7 / Line 8 / 1000	$0.000000
10	Transmission Rate ($/kW-month)	Line 9 / 12 months	$0.000000
11	Weekly Firm/Non-Firm Rate ($/kW-week)	Line 9 / 52 weeks	$0.000000
	Daily Firm/Non-Firm Rates:		
12	On-Peak Days ($/kW)	Line 11 / 5 days	$0.000000
13	Off-Peak Days ($/kW)	Line 11 / 7 days	$0.000000
	Non-Firm Hourly Rates:		
14	On-Peak Hours ($/MWh)	Line 12 / 16 hours * 1000	$0.000000
15	Off-Peak Hours ($/MWh)	Line 13 / 24 hours * 1000	$0.000000

PacifiCorp
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet
Beginning of Current Year

Line	Description	Reference	Transmission related	Plant related	Labor related	Total Transmission ADIT	
	(A)	(B)	(C)	(D)	(E)	(F)	
1	ADIT- 282	Sch. 282 Below	0	0	0		
2	ADIT-281	Sch. 281 Below	0	0	0		
3	ADIT-283	Sch. 283 Below	0	0	0		
4	ADIT-190	Sch. 190 Below	0	0	0		
5	**Subtotal ADIT**	Sum (Lines 1 to 4)	0	0	0		
6	Allocator (100% Transmission; Net Plant; Wages & Salary)	Appendix A	100.0000%	0.0000%	0.0000%		
7	**Sub-total Transmission Related ADIT**	Line 5 * Allocator	0	0	0		
8	**Total Transmission ADIT**	Sum Cols. (C), (D), (E)				0	Attachment 1a input

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-F and each separate ADIT item will be listed, dissimilar items with amounts exceeding $100,000 will be listed separately.

A		B	C	D	E	F	G
Schedule ADIT-190		**Total**	**Gas, Prod, Dist Or Other Related**	**Transmission Related**	**Plant Related**	**Labor Related**	**Justification**
Account 190							
Subtotal - p234		0	0	0	0	0	
Less FASB 109 Above if not separately removed							
Less FASB 106 Above if not separately removed							
Total		0	0	0	0	0	

Instructions for Account 190:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

PacifiCorp

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A		B	C	D	E	F	G
Schedule ADIT-281		**Total**	**Gas, Prod, Dist Or Other Related**	**Transmission Related**	**Plant Related**	**Labor Related**	**Justification**
Account 281							
Subtotal - p275		0	0	0	0	0	
Less FASB 109 Above if not separately removed							
Less FASB 106 Above if not separately removed							
Total		0	0	0	0	0	

Instructions for Account 282:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

PacifiCorp

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

Schedule ADIT-282	B Total	C Gas, Prod, Dist Or Other Related	D Transmission Related	E Plant Related	F Labor Related	G Justification
Account 282						
Subtotal - p275	0	0	0	0	0	
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed						
Total	0	0	0	0	0	

Instructions for Account 282:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

A

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

Schedule ADIT-283	B Total	C Gas, Prod, Dist Or Other Related	D Transmission Related	E Plant Related	F Labor Related	G Justification
Account 283						
Subtotal - p277	0	0	0	0	0	
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed						
Total	0	0	0	0	0	

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

PacifiCorp
Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet
End of Current Year for Projection and Average of Beginning and End of Current Year for True-up

Line	Description	Reference	Total Company	Gas, Prod., Dist., or Other	Transmission Related	Plant Related	Labor Related	Total Transmission ADIT
	(A)	(B)			(C)	(D)	(E)	(F)
1	ADIT-282	Sch. 282 Below	0	0	0	0	0	
2	ADIT-281	Sch. 281 Below	0	0	0	0	0	
3	ADIT-283	Sch. 283 Below	0	0	0	0	0	
4	ADIT-190	Sch. 190 Below	0	0	0	0	0	
5	Subtotal ADIT	Sum (Lines 1 to 4)	0	0	0	0	0	
6	Allocator (100% Transmission; Net Plant; Wages & Salary)	Appendix A			100.0000%	0.0000%	0.0000%	
7	Sub-total Transmission Related ADIT	Line 5 * Allocator			0	0	0	
8	Total End of Year Transmission ADIT	Sum Cols. (C), (D), (E)						0
9	Beginning of Year Total (Attachment 1)				0	0	0	0
10	**Appendix A, line 33 input**	Line 8 for Projection and average of Lines 8 & 9 for True-Up						**0**

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-F and each separate ADIT item will be listed, dissimilar items with amounts exceeding $100,000 will be listed separately.

Schedule ADIT-190

	A	B	C	D	E	F	G
Description	**Form 1 Reference**	**Total Company**	**Gas, Prod, Dist Or Other Related**	**Transmission Related**	**Plant Related**	**Labor Related**	**Justification**
Account 190							
Rounding							
Subtotal - p234		0	0	0	0	0	
Less FASB 109 Above if not separately removed							
Less FASB 106 Above if not separately removed							
Total		0	0	0	0	0	

Instructions for Account 190:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the

PacifiCorp

Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet
Schedule ADIT-281

A	B	C	D	E	F	G
	Total	**Gas, Prod, Dist Or Other Related**	**Transmission Related**	**Plant Related**	**Labor Related**	**Justification**
Account 281						
Rounding						
Subtotal - p275	0	0	0	0	0	
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed						
Total	0	0	0	0	0	

Instructions for Account 281:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the

Description	A Form 1 Reference	B Total Company	C Gas, Prod, Dist Or Other Related	D Transmission Related	E Plant Related	F Labor Related	G Justification

PacifiCorp

Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet

Schedule ADIT-282

A	B Total	C Gas, Prod, Dist Or Other Related	D Transmission Related	E Plant Related	F Labor Related	G Justification
Account 282						
Rounding						
Subtotal - p275	0	0	0	0	0	
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed						
Total	0	0	0	0	0	

Instructions for Account 282:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the

PacifiCorp

Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet

Schedule ADIT-283

A	B Total	C Gas, Prod, Dist Or Other Related	D Transmission Related	E Plant Related	F Labor Related	G Justification
Account 283						
Rounding						
Subtotal - p277	0	0	0	0	0	
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed						
Total	0	0	0	0	0	

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the

PacifiCorp
Attachment 2 - Taxes Other Than Income Worksheet

	Other Taxes	Page 263, Col (i)	Allocator	Allocated Amount
	Plant Related		Net Plant Allocator	
1	**Total Plant Related**	0	0.0000%	0
	Labor Related		Wages & Salary Allocator	
2	**Total Labor Related**	0	0.0000%	0
	Other Included		Net Plant Allocator	
3	**Total Other Included**	0	0.0000%	0
4	**Appendix A input: Total Included Taxes (Lines 1 + 2 + 3)**	0		**0**
	Currently Excluded			
5	**Subtotal Excluded Taxes**	0		
6	**Total Other Taxes Included and Excluded (Line 4 + Line 5)**	0		
	Total Other Taxes			
7	114.14c			
8	Difference (Line 6 - Line 7)	0		

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant, including transmission plant, will be allocated based on the Net Plant Allocator. If the taxes are 100% recovered at retail, they shall not be included.

B Other taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. If the taxes are 100% recovered at retail, they shall not be included.

C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator.

D Other taxes, except as provided for in A, B and C above, which are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service, will be allocated based on the Net Plant Allocator; provided, however, that overheads shall be treated, as described in footnote B above.

E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year.

PacifiCorp
Attachment 3 - Revenue Credit Worksheet

Line	Description	Notes	Reference	Value
	Account 454 - Rent from Electric Property			
1	Rent from Electric Property - Transmission Related			0
2	Pole Attachments - Transmission Related			
3	Distribution Underbuild - Transmission Related		*detail below*	
4	Various Rents - Transmission Related			
5	Miscellaneous General Revenues		*detail below*	
6	**Account 454 subtotal**		(Sum Lines 1-5)	**0**
	Account 456 - Other Electric Revenues (Note 1)			
7	Transmission for Others	Note 3	Attachment 13	0
8	Net revenues associated with Network Integration Transmission Service (NITS) for which the load is not included in the divisor	Note 3		
9	Short-term firm and non-firm service revenues for which the load is not included in the divisor received by Transmission Owner		Attachment 13	0
10	Facilities Charges including Interconnection Agreements	Note 2		
11	Transmission maintenance revenue		Account 456.2	
12	**Account 456 subtotal**		(Sum Lines 7-11)	**0**
13	Appendix A input: **Gross Revenue Credits**		(Sum Lines 6 &12)	**0**

Detail for selected items above

Miscellaneous General Revenues		
Total Miscellaneous General Revenue		0
Wages & Salary Allocator		0.00%
Total Allocated Miscellaneous General Revenue		**0**
Distribution Underbuild		
Common pole location fixed annual revenue credit	fixed	0
Distribution Underbuild - Transmission related		**0**

Notes

Note 1 All revenues related to transmission that are received as a transmission owner (i.e., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this Attachment or elsewhere in the formula, will be included as a revenue credit or included in the peak on line 170 of Appendix A.

Note 2 If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.

Note 3 If the facilities associated with the revenues are not included in the formula, the revenue is shown here, but not included in the total above and explained in the Cost Support, (e.g., revenues associated with distribution facilities).

PacifiCorp
Attachment 4 - Calculation of 100 Basis Point Increase in ROE

	Return and Taxes with 100 Basis Point increase in ROE				
A	100 Basis Point increase in ROE and Income Taxes			Appendix A input: Line 127 + Line 137 from below	0
B	100 Basis Point increase in ROE				1.00%
Return Calculation					
			Notes	**Reference** (Appendix A Line or Source)	
117	Debt percent	Total Long Term Debt	(Notes Q & R)	(Line 90 / (Lines 90 + 110 +116))	0.00%
118	Preferred percent	Preferred Stock		(Line 110 / (Lines 90 + 110 +116))	0.00%
119	Common percent	Common Stock	(Notes Q & R)	(Line 116 / (Lines 90 + 110 +116))	0.00%
120	Debt Cost	Long Term Debt Cost = Long Term Debt Cost / Net Proceeds Long Term Debt		(Line 103 / Line 96)	0.00%
121	Preferred Cost	Preferred Stock cost = Preferred Dividends / Total Preferred Stock		(Line 111 / Line 110)	0.00%
122	Common Cost	Common Stock	(Note H)	Fixed plus 100 basis points	1.00%
123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 117 * Line 120)	0.00%
124	Weighted Cost of Preferred	Preferred Stock		(Line 118 * Line 121)	0.00%
125	Weighted Cost of Common	Common Stock		(Line 119 * Line 122)	0.00%
126	**Rate of Return on Rate Base (ROR)**			(Sum Lines 123 to 125)	**0.00%**
127	**Investment Return = Rate Base * Rate of Return**			**(Line 52 * Line 126)**	**0**
Composite Income Taxes					
	Income Tax Rates				
128	FIT = Federal Income Tax Rate				0.00%
129	SIT = State Income Tax Rate or Composite				0.00%
130	p = percent of federal income tax deductible for state purposes			Per state tax code	0.00%
131	T	T = 1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			0.00%
132	CIT = T / (1-T)				0.00%
133	1 / (1-T)				100.00%
	ITC Adjustment				
134	Amortized Investment Tax Credit			Attachment 5	0
135	**ITC Adjust. Allocated to Trans. - Grossed Up**			(Line 134 * (1 / (1 - Line 131)	**0**
136	**Income Tax Component =**	CIT = (T/1-T) * Investment Return * (1-(WCLTD/R)) =			0
137	**Total Income Taxes**				**0**

PacifiCorp

Attachment 5 - Cost Support

Plant in Service Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions							Detail/notes
		Calculation of Transmission Plant In Service	Source	Footnotes	Year	Balance	
	1	December	p206.58.b		2009		
	2	January	Monthly Balances		2010		
	3	February	Monthly Balances		2010		
	4	March	Monthly Balances		2010		
	5	April	Monthly Balances		2010		
	6	May	Monthly Balances		2010		
	7	June	Monthly Balances		2010		
	8	July	Monthly Balances		2010		
	9	August	Monthly Balances		2010		
	10	September	Monthly Balances		2010		
	11	October	Monthly Balances		2010		
	12	November	Monthly Balances		2010		
	13	December	p207.58.g		2010		
15	14	**Transmission Plant In Service**	(line 13)	(Note M)	Projection	**0**	Appendix A input
		Calculation of Distribution Plant In Service	Source		Year	Balance	
	15	December	p206.75.b		2009		
	16	January	Monthly Balances		2010		
	17	February	Monthly Balances		2010		
	18	March	Monthly Balances		2010		
	19	April	Monthly Balances		2010		
	20	May	Monthly Balances		2010		
	21	June	Monthly Balances		2010		
	22	July	Monthly Balances		2010		
	23	August	Monthly Balances		2010		
	24	September	Monthly Balances		2010		
	25	October	Monthly Balances		2010		
	26	November	Monthly Balances		2010		
	27	December	p207.75.g		2010		
	28	**Distribution Plant In Service**	(line 27)		Projection	**0**	
		Calculation of Intangible Plant In Service	Source		Year	Balance	
	29	December	p204.5.b		2009		
	30	December	p205.5.g		2010		
19	31	**Intangible Plant In Service**	(line 30)	(Note N)	Projection	**0**	Appendix A input
		Calculation of General Plant In Service	Source		Year	Balance	
	32	December	p206.99.b		2009		
	33	December	p207.99.g		2010		
18	34	**General Plant In Service**	(line 33)	(Note N)	Projection	**0**	Appendix A input
		Calculation of Production Plant In Service	Source		Year	Balance	
	35	December	p204.46b		2009		
	36	January	Monthly Balances		2010		
	37	February	Monthly Balances		2010		
	38	March	Monthly Balances		2010		
	39	April	Monthly Balances		2010		
	40	May	Monthly Balances		2010		
	41	March	Monthly Balances		2010		
	42	April	Monthly Balances		2010		
	43	August	Monthly Balances		2010		
	44	September	Monthly Balances		2010		
	45	October	Monthly Balances		2010		
	46	November	Monthly Balances		2010		
	47	December	p205.46.g		2010		
	48	**Production Plant In Service**	(line 47)		Projection	0	
	49	Electric Plant Sold	p207.102.g			0	
6	50	**Total Plant In Service**	(sum lines 14, 28, 31, 34, 48, & 49)	(Note M)	Projection	**0**	Appendix A input

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Attachment 5 - Cost Support

Accumulated Depreciation Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions							Notes
		Calculation of Transmission Accumulated Depreciation	Source		Year	Balance	
	51	December	Prior year p219.25		2009		
	52	January	Monthly Balances		2010		
	53	February	Monthly Balances		2010		
	54	March	Monthly Balances		2010		
	55	April	Monthly Balances		2010		
	56	May	Monthly Balances		2010		
	57	June	Monthly Balances		2010		
	58	July	Monthly Balances		2010		
	59	August	Monthly Balances		2010		
	60	September	Monthly Balances		2010		
	61	October	Monthly Balances		2010		
	62	November	Monthly Balances		2010		
	63	December	p219.25		2010		
25	64	**Transmission Accumulated Depreciation**	(line 63)	(Note M)	Projection	**0**	Appendix A input
		Calculation of Distribution Accumulated Depreciation	Source		Year	Balance	
	65	December	Prior year p219.26		2009		
	66	January	Monthly Balances		2010		
	67	February	Monthly Balances		2010		
	68	March	Monthly Balances		2010		
	69	April	Monthly Balances		2010		
	70	May	Monthly Balances		2010		
	71	June	Monthly Balances		2010		
	72	July	Monthly Balances		2010		
	73	August	Monthly Balances		2010		
	74	September	Monthly Balances		2010		
	75	October	Monthly Balances		2010		
	76	November	Monthly Balances		2010		
	77	December	p219.26		2010		
	78	**Distribution Accumulated Depreciation**	(line 77)		Projection	0	
		Calculation of Intangible Accumulated Depreciation	Source		Year	Balance	
	79	December	Prior year p200.21.c		2009		
	80	December	p200.21c		2010	0	
8	81	**Accumulated Intangible Depreciation**	(line 80)	(Note N)	Projection	**0**	Appendix A input
		Calculation of General Accumulated Depreciation	Source		Year	Balance	
	82	December	Prior year p219.28		2009		
	83	December	p219.28		2010		
26	84	**Accumulated General Depreciation**	(line 83)	(Note N)	Projection	**0**	Appendix A input
		Calculation of Production Accumulated Depreciation	Source		Year	Balance	
	85	December	Prior year p219		2009		
	86	January	Monthly Balances		2010		
	87	February	Monthly Balances		2010		
	88	March	Monthly Balances		2010		
	89	April	Monthly Balances		2010		
	90	May	Monthly Balances		2010		
	91	June	Monthly Balances		2010		
	92	July	Monthly Balances		2010		
	93	August	Monthly Balances		2010		
	94	September	Monthly Balances		2010		
	95	October	Monthly Balances		2010		
	96	November	Monthly Balances		2010		
	97	December	p219.20 through 219.24		2010		
	98	**Production Accumulated Depreciation**	(line 97)		Projection	0	
7	99	**Accumulated Depreciation (Total Electric Plant)**	(sum lines 64, 78, 84, & 98)	(Note M)	Projection	**0**	Appendix A input
	100	**Total Accumulated Depreciation**	(sum lines 64, 78, 81, 84, & 98)		Projection	0	

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Attachment 5 - Cost Support

Materials & Supplies

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions					Form No. 1 Amount	
	Undistributed Stores Expense		Prior Year	227.16c	0	
			Current Year	227.16c	0	
39		(Note N)	**Appendix A input**	Projection	**0**	current end-of-year balance
	Construction Materials & Supplies		Prior Year	227.5c	0	
			Current Year	227.5c	0	
42		(Note N)	**Appendix A input**	Projection	**0**	current end-of-year balance
	Transmission Materials & Supplies		Prior Year	227.8c	0	
			Current Year	227.8c	0	
45		(Note N)	**Appendix A input**	Projection	**0**	current end-of-year balance

ITC Adjustment

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				Form No. 1 Amount	Transmission related portion	**Appendix A input**	Details
	Amortized Investment Tax Credit				Net Plant Allocator		
133	Utility Investment Tax Credit Adj. - Net (411.4)		114.19c	0	0.00%	**0**	
	Rate Base Adjustment						
	Internal Revenue Code (IRC) 46(f)(1) adjustment to rate base						
		Current beg of year balance	266.6b	0			
		Current end of year balance	266.6h	0			
35	Internal Revenue Code (IRC) 46(f)(1) adjustment to rate base		Average	0	0.00%	**0**	(enter negative in Appendix A)

Transmission / Non-transmission Cost Support

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions					Form No. 1 Amount	Transmission Related	Non-transmission Related	Details
	Land Held for Future Use							
			Prior Year	214.47d	0	**0**	0	Detail for transmission-related value on Attachment 12
			Current Year	214.47d	0	**0**	0	Detail for transmission-related value on Attachment 12
23		(Notes B & L)	**Appendix A input**	Projection		**0**		current end-of-year balance

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Attachment 5 - Cost Support

Adjustments to A & G Expense

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				Adjusted Total	Details
	Excluded Membership Dues Expense				
				0	
				0	
				0	
				0	
63	Total	(Note C)	**Appendix A Input**	**0**	
	PBOP				
	Fixed PBOP expense		FERC Authorized	0	
	Actual PBOP expense		Attachment 17	0	
58	Adjusted total (Current year actual)		**Appendix A Input**	**0**	Authorized minus Att 17 = Current year actual PBOP expense
	Property Insurance				
	Property Insurance Account 924		323.185b	0	
70		(Note F)	**Appendix A Input**	**0**	

Regulatory Expense Related to Transmission Cost Support

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount	Transmission Related **Appendix A input**	Non-transmission Related	Details
	Directly Assigned A&G					
	Specific Transmission related Regulatory Expenses					
	Federal Energy Regulatory Commission:					
	Annual Fee	350.30d	0			
	Annual Land Use Fee (hydro)	350.31d	0			
	Transmission Rate Case	350.32d	0			
67	**Total**	sum	0	**0**	0	

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Attachment 5 - Cost Support

Safety Related Advertising Cost Support

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount	Safety Related **Appendix A Input**	Non-safety Related	Details
	Directly Assigned A&G					
68	General Advertising Exp Account 930.1 - Safety-related Advertising	323.191b	0	**0**	0	Based on FERC 930.1 download

Education and Out Reach Cost Support

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount	Education & Outreach **Appendix A Input**	Other	Details
	Directly Assigned A&G					
71	General Advertising Exp Account 930.1 - Education and Outreach	323.191b	0	**0**	0	Based on FERC 930.1 download

Multistate worksheet

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				Details
	Income Tax Rates			
129	SIT = State Income Tax Rate or Composite	(Note G)	0.00%	Enter Average State Income Tax Rate

Adjustments to Transmission O&M

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Total	Plus adjustments	Transmission Related **Appendix A input**	Details
53	**Transmission O&M**	321.112b	0	0	**0**	
	Adjustment for Ancillary Services Accounts 561-561.5					
	(561) Load Dispatching	321.84b	0			
	(561.1) Load Dispatch-Reliability	321.85b	0			
	(561.2) Load Dispatch-Monitor and Operate Transmission System	321.86b	0			
	(561.3) Load Dispatch-Transmission Service and Scheduling	321.87b	0			
	(561.4) Scheduling, System Control and Dispatch Services	321.88b	0			
	(561.5) Reliability, Planning and Standards Development	321.89b	0			
54	**Less: Cost of Providing Ancillary Services Accounts 561.0-5**	sum	0	0	**0**	Adjustment for Ancillary Services Accounts 561-561.5
55	**Less: Account 565**		0	0	**0**	

Facility Credits under Section 30.9 of the OATT

Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Amount	Description & Documentation
	Net Revenue Requirement		
166	Facility Credits under Section 30.9 of the OATT	**0**	Appendix A Input
168	Interest on Network Upgrade Facilities	**0**	Appendix A Input

Other adjustments to rate base

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions					Amount	
	Network Upgrade Balance					
			Prior Year	Enter negative	0	
			Current Year	Enter negative	0	
50	Network Upgrade Balance	(Note N)	Appendix A input	Projection	**0**	current end-of-year balance

Depreciation Expense

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				Total	
	Transmission Plant				
	Depreciation expense (403)	(Note H)	336.7b	0	
	Amortization of limited term electric plant (404)	(Note H)	336.7d	0	
76	**Transmission Depreciation Expense Including Amortization of Limited Term Plant**	(Note H)	sum	**0**	Appendix A Input
	General Plant				
	Depreciation expense (403)	(Note H)	336.10b	0	
	Amortization of limited term electric plant (404)	(Note H)	336.10d	0	
77	**General Depreciation Expense Including Amortization of Limited Term Plant**	(Note H)	sum	**0**	Appendix A Input
	Intangible plant				
	Amortization of limited term electric plant (404)	(Note H)	336.1d	0	
	Amortization of other electric plant (405)	(Note H)	336.1e	0	
78	**Total Intangible Amortization**	(Note H)	sum	**0**	Appendix A Input

Less Regulatory Asset Amortizations Account 930.2

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Amount	
			0	
			0	
			0	
			0	
61	Total	sum	**0**	Appendix A Input

PacifiCorp
Attachment 6 - Estimate and Reconciliation Worksheet

Instruction Summary

Step	Month	Year	Action
1	April	Year 2	TO populates the formula with Year 1 data from FERC Form No. 1 data for Year 1 (e.g., 2010)
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2011)
3	April	Year 2	TO adds weighted Cap Adds to plant in service in Formula
4	May	Year 2	Post results of Step 3
5	June	Year 2	Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2011 - May 31, 2012)
6	April	Year 3	TO populates the formula with Year 2 data from FERC Form No. 1 for Year 2 (e.g., 2011)
7	April	Year 3	Reconciliation - actual data
8	April	Year 3	TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2012)

Worksheet

Step	Month	Year	Action
1	April	Year 2	TO populates the formula with Year 1 data from FERC Form No. 1 data for Year 1 (e.g., 2010)

$ - Rev Req based on Year 1 data — Must run Appendix A to get this number (without inputs in lines 16 or 34 of Appendix A)

Step	Month	Year	Action
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2011) in projection and populates for actuals as inputs to Attachment 7 (but not Appendix A) for true up.

	Plant In Service (A) Monthly Additions Other Transmission PIS (EXCLUDING GATEWAY)	(B) Monthly Additions Energy Gateway	(C) Monthly Additions Energy Gateway Segment B	(D) Monthly Additions Energy Gateway Segment C	(E) Monthly Additions Energy Gateway Segment D	(F) Monthly Additions Energy Gateway Segment E	(G) Monthly Additions Energy Gateway Segment F	(H) Monthly Additions Energy Gateway Segment G	(I) Monthly Additions Energy Gateway Segment H	(J) Monthly Additions Energy Gateway Total (Segments A-H)	CWIP (K) Monthly Additions Transmission CWIP (Gateway only)
CWIP Balance Dec (prior year)	-	-	-	-	-	-	-	-	-	-	-
Jan	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	-	-	-	-	-	-	-
Apr	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	-	-	-	-	-	-
Jul	-	-	-	-	-	-	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	-	-	-
Sep	-	-	-	-	-	-	-	-	-	-	-
Oct	-	-	-	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-

	(L) Weighting	Plant In Service (M) Other Transmission PIS Amount (A x L)	(N) Energy Gateway Amount (J x L)	(O) Other Transmission PIS (M / 13)	(P) Energy Gateway (N / 13)	CWIP (Q) Transmission CWIP Amount (K x L)	(R) Transmission CWIP (O / 13)	(S) Input/Total
CWIP Balance Dec (prior year)	13	-	-	-	-	-	-	
Jan	12	-	-	-	-	-	-	
Feb	11	-	-	-	-	-	-	
Mar	10	-	-	-	-	-	-	
Apr	9	-	-	-	-	-	-	
May	8	-	-	-	-	-	-	
Jun	7	-	-	-	-	-	-	
Jul	6	-	-	-	-	-	-	
Aug	5	-	-	-	-	-	-	
Sep	4	-	-	-	-	-	-	
Oct	3	-	-	-	-	-	-	
Nov	2	-	-	-	-	-	-	
Dec	1	-	-	-	-	-	-	
Total		-	-	-	-	-	-	

New Transmission Plant Additions and CWIP (weighted by months in service)

Input to Line 16 of Appendix A	-
Input to Line 34 of Appendix A	-

Step	Month	Year	Action
3	April	Year 2	TO adds weighted Cap Adds to plant in service in Formula

$ - — Must run Appendix A to get this number (with inputs in lines 16 and 34 of Appendix A)

Step	Month	Year	Action
4	May	Year 2	Post results of Step 3

$ - — Must run Appendix A to get this number (with inputs in lines 16 and 34 of Appendix A)

Step	Month	Year	Action
5	June	Year 2	Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2011 - May 31, 2012)

$ -

Step	Month	Year	Action
6	April	Year 3	TO populates the formula with Year 2 data from FERC Form No. 1 for Year 2 (e.g., 2011)

$ - Rev Req based on Prior Year data — Must run Appendix A to get this number (without inputs in lines 16 or 34 of Appendix A)

Step	Month	Year	Action
7	April	Year 3	Reconciliation - actual data

$ - Result of Formula for Reconciliation — Must run Appendix A to get this number (with inputs in lines 16 and 34 of Appendix A)

$ - Schedule 1 Reconciliation

Estimated Life		
Estimated Depreciation for Attachment 7		
Jan	11.5	-
Feb	10.5	-
Mar	9.5	-
Apr	8.5	-
May	7.5	-
Jun	6.5	-
Jul	5.5	-
Aug	4.5	-
Sep	3.5	-
Oct	2.5	-
Nov	1.5	-
Dec	0.5	-
Total Estimated Depreciation for Attachment 7		-

PacifiCorp
Attachment 7 - Transmission Enhancement Charge Worksheet

Line					
1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if not Contributions in Aid of Construction (CIAC)**				
		Formula Line			
3	A	157	Net Plant Carrying Charge without Depreciation	0.0000%	
4	B	164	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	0.0000%	
5	C		Line B less Line A	0.0000%	
6	**FCR if CIAC**				
7	D	158	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	0.0000%	

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years
In the True-up, the actual depreciation expense will be used.
Columns and rows may be added to accommodate more projects

Line				Transmission CWIP (Energy Gateway only)	Transmission PIS Projection (Energy Gateway Segment B-H)	Transmission PIS Actuals (Energy Gateway Segment B-H)	
8	Useful life of the project	Life			58.00	58.00	
9	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	
10	Input the allowed increase in ROE	Increased ROE (basis points)		0	0	0	
11	From line 3 above if "No" on line 13 and from line 7 above if "Yes" on line 13	0% ROE		0.0000%	0.0000%	0.0000%	0.0000%
12	Line 14 plus (line 5 times line 13)/100	FCR for This Project		0.0000%	0.0000%	0.0000%	0.0000%
13	13 Month Net Plant or CWIP Balance	Investment		-	-	-	-
14	Actual or estimated depreciation expense	Annual Depreciation Expense		-	-	-	-

Line		Invest Yr	13 Month Net Plant or CWIP Balance	Depreciation	Revenue	13 Month Net Plant or CWIP Balance	Depreciation	Revenue	13 Month Net Plant or CWIP Balance	Depreciation	Revenue	13 Month Net Plant or CWIP Balance	Depreciation	Revenue	Total	Incentive Charged	Without Incentive	Transmission Incentive Credit (incentive minus without)
15	W 0 % ROE	2010	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -	
16	W Increased ROE	2010	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
17	W 0 % ROE	2011	-	-	-	-	-	-		-	-	-	-	-	$ -		$ -	
18	W Increased ROE	2011	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
19	W 0 % ROE	2012	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -	
20	W Increased ROE	2012	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
21	W 0 % ROE	2013	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -	
22	W Increased ROE	2013	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
23	W 0 % ROE	2014	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -	
24	W Increased ROE	2014	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
25	W 0 % ROE	2015	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -	
26	W Increased ROE	2015	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
27	W 0 % ROE	2016	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -	
28	W Increased ROE	2016	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
29	W 0 % ROE	2017	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -	
30	W Increased ROE	2017	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
31	W 0 % ROE	2018	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -	
32	W Increased ROE	2018	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
33	W 0 % ROE	2019	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -	
34	W Increased ROE	2019	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
35	W 0 % ROE	2020	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -	
36	W Increased ROE	2020	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
37	W 0 % ROE	2021	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -	
38	W Increased ROE	2021	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
39	W 0 % ROE	2022	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -	
40	W Increased ROE	2022	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
41	W 0 % ROE	2023	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -	
42	W Increased ROE	2023	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
43	W 0 % ROE	2024	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -	
44	W Increased ROE	2024	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
45	W 0 % ROE	2025	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -	
46	W Increased ROE	2025	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
47	W 0 % ROE	2026	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -	
48	W Increased ROE	2026	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
49	W 0 % ROE	2027	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -	
50	W Increased ROE	2027	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
51	W 0 % ROE	2028	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -	
52	W Increased ROE	2028	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
53	W 0 % ROE	2029	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -	
54	W Increased ROE	2029	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -		$ -
55		....				-	-		-	-	....	-	-				$ -	
56		....				-	.....		-	....	....	-	.....			$ -		$ -

PacifiCorp
Attachment 8 - Depreciation Rates

Applied Depreciation Rates by State

			Oregon		Washington		California		Utah		Wyoming		AZ, CO, MT, NM		Idaho		Company
Row	A/C	Description	Balance	Rate	Balance	Rate	Balance	Rate	Balance	Rate	Balance	Rate	Balance	Rate	Balance	Rate	Rate
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	350.2	Land Rights															1.35%
2	352	Structures and Improvements															1.31%
3	353	Station Equipment															1.75%
4	353.7	Supervisory Equipment															3.78%
5	354	Towers and Fixtures															1.56%
6	355	Poles and Fixtures															2.63%
7	356	Overhead Conductors and Devices															2.25%
8	356.2	Clearing & Grading															1.40%
9	357	Underground Conduit															1.65%
10	358	Underground Conductors and Devices															1.64%
11	359	Roads & Trails															1.39%
12		Unclassified Transmission															2.03%
13	389.2	Land Rights		0.00%		0.00%		0.00%		2.32%		2.01%		0.00%		2.01%	
14	390	Structures and Improvements		2.21%		3.80%		2.38%		2.18%		3.03%		2.06%		2.12%	
15	390.3	Structures and Improvements - Office Panels															6.67%
16	391	Office Furniture and Equipment															5.00%
17	391.2	Office Furniture and Equipment - Personal Computers															20.00%
18	393	Store Equipment															4.00%
19	394	Tools, Shop and Garage Equipment															4.17%
20	395	Laboratory Equipment															5.00%
21	397	Communication Equipment		4.06%		5.24%		4.15%		4.09%		5.40%		3.18%		3.79%	
22	397.2	Communication Equipment - Mobile Radio Equipment															9.09%
23	398	Miscellaneous Equipment															5.00%
24		Unclassified General		4.37%		5.49%		5.15%		4.30%		5.46%		3.17%		3.81%	
25	302	Franchises and Consents															2.73%
26	303	Miscellaneous Intangible Plant															4.85%
27	390.1	Leasehold Improvements - Gen															7.13%

Notes:

1 Depreciation Rates shown in rows 1 through 24 were approved by each of the Company's respective state jurisdictions during the last depreciation study.

2 The columns labeled "Balance" are the amount of investment physically located in each state.

3 The plant balance is updated each month as new plant is added.

4 The balances to be reported in the columns labeled "Balances" in any update are the weighted 13-month average balances for the rate year.

5 "Company Rate" shows the depreciation rate approved by all of the jurisdictions on a total company basis.

6 Unclassified Transmission represents the transmission additions placed in service but not yet classified to a FERC level account. Monthly depreciation is calculated by multiplying the month's beginning unclassified balance by the monthly transmission composite depreciation rate.

7 Unclassified General represents the general plant additions placed in service but not yet classified to a FERC level account. Monthly depreciation is calculated by multiplying the month's beginning unclassified balance by the monthly state general plant composite depreciation rate.

8 Transfers into the General amortized accounts (rows 15 through 20, 22, and 23) are depreciated over the remaining life based on the account life.

9 Depreciation expense for General plant is decreased by the amount that is billed to joint owners for computer hardware.

10 Intangible and Leasehold Improvements (rows 25 through 27) are composite rates based on the 13 month average balance divided into the 2010 amortization expense for each account.

11 Amortization expense for Intangible is decreased by the amount that is billed to joint owners for computer software.

12 If the depreciation rates shown differ from the depreciation rates used to calculate the depreciation expense reported in FERC Form 1, then PacifiCorp is required to file under Section 205 for a modification of this Attachment or the calculation of depreciation expense and accumulated depreciation under this formula

PacifiCorp
Attachment 9a - Load Divisor for Projection
Average of current year and prior two years

	OATT (Part III - Network Service)													
Column	e	f1	f2	f3	f4	f5	f6	f7	f8	f9	f10	f11	f12	f
Customer Class RS / SA														Total NFO
Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sept	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ave 12CP	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Other Service					
j1	j2	j3	j4	j5	j
					Total OS
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-

	OATT Part II Long-Term Firm Point-to-Point Transmission Service 2011													
Column	g1	g2	g3	g4	g5	g6	g7	g8	g9	g10	g12	g13	g13	g
Customer Class RS / SA														Total LTP
Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sept	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ave 12CP	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Total Network & OS	1% Growth	Behind-the Meter	Total Network Load
-	-	-	-
-	-	-	-
-	-	-	-
-	-	-	-
-	-	-	-
-	-	-	-
-	-	-	-
-	-	-	-
-	-	-	-
-	-	-	-
-	-	-	-
-	-	-	-
-	-	-	-
-	-	-	-

Divisor
Network + OS + LTP
-
-
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-
-
-
-
-

PacifiCorp
Attachment 9a1 - Load (Current Year)
YYYY

Column			OATT (Part III - Network Service)													
Column			e	f1	f2	f3	f4	f5	f6	f7	f8	f9	f10	f11	f12	f
Customer Class RS / SA	Day	Time														Total NFO
Jan			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb			-	-	-	-	-	-	-	-	-	-	-	-	-	-
March			-	-	-	-	-	-	-	-	-	-	-	-	-	-
April			-	-	-	-	-	-	-	-	-	-	-	-	-	-
May			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sept			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oct			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total			-	-	-	-	-	-	-	-	-	-	-	-	-	-

Column			Other Service					
Column			j1	j2	j3	j4	j5	j
Customer Class RS / SA	Day	Time						Total OS
Jan			-	-	-	-	-	-
Feb			-	-	-	-	-	-
March			-	-	-	-	-	-
April			-	-	-	-	-	-
May			-	-	-	-	-	-
Jun			-	-	-	-	-	-
Jul			-	-	-	-	-	-
Aug			-	-	-	-	-	-
Sept			-	-	-	-	-	-
Oct			-	-	-	-	-	-
Nov			-	-	-	-	-	-
Dec			-	-	-	-	-	-
Total			-	-	-	-	-	-

PacifiCorp
Attachment 9a1 - Load (One Year Prior)
YYYY

			OATT (Part III - Network Service)													
Column			e	f1	f2	f3	f4	f5	f6	f7	f8	f9	f10	f11	f12	f
Customer Class RS / SA	Day	Time														Total NFO
Jan			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb			-	-	-	-	-	-	-	-	-	-	-	-	-	-
March			-	-	-	-	-	-	-	-	-	-	-	-	-	-
April			-	-	-	-	-	-	-	-	-	-	-	-	-	-
May			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sept			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oct			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total			-	-	-	-	-	-	-	-	-	-	-	-	-	-

			Other Service					
Column			j1	j2	j3	j4	j5	j
Customer Class RS / SA	Day	Time						Total OS
Jan			-	-	-	-	-	-
Feb			-	-	-	-	-	-
March			-	-	-	-	-	-
April			-	-	-	-	-	-
May			-	-	-	-	-	-
Jun			-	-	-	-	-	-
Jul			-	-	-	-	-	-
Aug			-	-	-	-	-	-
Sept			-	-	-	-	-	-
Oct			-	-	-	-	-	-
Nov			-	-	-	-	-	-
Dec			-	-	-	-	-	-
Total			-	-	-	-	-	-

PacifiCorp

Attachment 9a1 - Load (Two Years Prior)

YYYY

			OATT (Part III - Network Service)													
Column			e	f1	f2	f3	f4	f5	f6	f7	f8	f9	f10	f11	f12	f
Customer Class RS / SA	Day	Time														Total NFO
Jan			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb			-	-	-	-	-	-	-	-	-	-	-	-	-	-
March			-	-	-	-	-	-	-	-	-	-	-	-	-	-
April			-	-	-	-	-	-	-	-	-	-	-	-	-	-
May			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sept			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oct			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total			-	-	-	-	-	-	-	-	-	-	-	-	-	-

			Other Service					
Column			j1	j2	j3	j4	j5	j
Customer Class RS / SA	Day	Time						Total OS
Jan			-	-	-	-	-	-
Feb			-	-	-	-	-	-
March			-	-	-	-	-	-
April			-	-	-	-	-	-
May			-	-	-	-	-	-
Jun			-	-	-	-	-	-
Jul			-	-	-	-	-	-
Aug			-	-	-	-	-	-
Sept			-	-	-	-	-	-
Oct			-	-	-	-	-	-
Nov			-	-	-	-	-	-
Dec			-	-	-	-	-	-
Total			-	-	-	-	-	-

PacifiCorp

Attachment 9b - Load Divisor for True up

	OATT (Part III - Network Service)													
Column	e	f1	f2	f3	f4	f5	f6	f7	f8	f9	f10	f11	f12	f
Customer Class RS / SA														Total NFO
Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sept	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ave 12CP	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Other Service					
j1	j2	j3	j4	j5	j
					Total OS
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-

	OATT Part II Long-Term Firm Point-to-Point Transmission Service														
Column	g1	g2	g3	g4	g5	g6	g7	g8	g19	g10	g11	g12	g13	g14	g15	g
Customer Class RS / SA																Total LTP
Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sept	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ave 12CP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Total Network & OS	Behind-the Meter	Total Network Load
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-

Divisor
Network + OS + LTP
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-
-
-
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-
-
-
-
-
-

PacifiCorp
Attachment 10 - Accumulated Amortization of Plant in Service

Plant in Service - Accumulated Amortization Detail

FERC Account	Account Number	Description	Balance
		Attachment 5 input: **Total Accumulated Amortization**	**0**

PacifiCorp
Attachment 11 - Prepayments

Prepayments Detail

FERC Account	Account Number	Account Description	Category	Prior Year-end Balance	Current Year-end Balance	BoY-EoY Average	Other	100% Transmission	Plant-related	Labor-related
		Total Prepayments		$ -	$ -	$ -	$ -	$ -	$ -	$ -
					Allocator		0.000%	100.000%	0.000%	0.000%
					Total Allocated to Transmission by Category		$ -	$ -	$ -	$ -
					Appendix A input: **Total Allocated to Transmission**	**$ -**				

PacifiCorp
Attachment 12 - Plant Held for Future Use

Plant/Land Held For Future Use - Assets associated with Transmission at December 31

		Prior year	Current year
Attachment 5 input: **Total - Transmission**		**0**	**0**

		Prior year	Current year
Total - PacifiCorp	214.47d		

PacifiCorp
Attachment 13 - Revenue Credit Detail

Revenue Credit Detail

Other Service (OS) contracts

Description	Revenue	MW	**As Filed** 1=Revenue credit 0=Denominator Treatment
Att 3 input: **Total OS contract revenue credits**	**0**	0.0	

Short-term revenue

Short-term firm	
PacifiCorp Commercial and Trading (C&T)	
Third parties	
Total short-term firm	0
Short-term non-firm	
PacifiCorp Commercial and Trading (C&T)	
Third parties	
Total short-term non-firm	0

Short term firm and non-firm

PacifiCorp Commercial and Trading (C&T)	0
Third parties	0
Att. 3 input: **Total short term-firm and non-firm revenue**	**0**

PacifiCorp
Attachment 14 - Cost of Capital Detail

					Prior Year (month end)	**Current Year** (month end)											
Appendix A Line	**Operation** to apply to monthly input columns at right	**Appendix A input value** (result of operation specified in column to left on monthly data)	**Description** (Account)	**Reference**	**December**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
86	13-month average	0	Bonds (221)	Form 1, pg 112, ln 18 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
87	13-month average	0	Reacquired Bonds (222)	Form 1, pg 112, ln 19 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
88	13-month average	0	Advances from Associated Companies (223)	Form 1, pg 256, various ln, col a,b	0	0	0	0	0	0	0	0	0	0	0	0	0
89	13-month average	0	Other Long-Term Debt (224)	Form 1, pg 112, ln 21 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
91	13-month average	0	Unamortized Discount (226)	Form 1, pg 112, ln 23 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
92	13-month average	0	Unamortized Debt Expense (181)	Form 1, pg 111, ln 69 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
93	13-month average	0	Unamortized Loss On Reacquired Debt (189)	Form 1, pg 111, ln 81 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
94	13-month average	0	Unamortized Premium (225)	Form 1, pg 112, ln 22 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
95	13-month average	0	Unamortized Gain On Reacquired Debt (257)	Form 1, pg 113, ln 61 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
97	12-month sum	0	Interest on Long Term (427) and Associated Companies (430) **LONG TERM ONLY**	Form 1, pg 257, ln 33 i	0	0	0	0	0	0	0	0	0	0	0	0	0
98	12-month sum	0	Hedging Expense (as noted in Appendix A, Note R)	Company records	0	0	0	0	0	0	0	0	0	0	0	0	0
99	12-month sum	0	Amort Debt Discount and Expense (428)	Form 1, pg 117, ln 63 c (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
100	12-month sum	0	Amort Loss on Reacquired Debt (428.1)	Form 1, pg 117, ln 64 c (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
101	12-month sum	0	Amort Premium (429)	Form 1, pg 117, ln 65 c (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
102	12-month sum	0	Amort Gain on Reacquired Debt (429.1)	Form 1, pg 117, ln 66 c (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
104	13-month average	0	Preferred Stock Issued (204)	Form 1, pg 112, ln 3 c, d	0	0	0	0	0	0	0	0	0	0	0	0	0
105	13-month average	0	Reacquired Capital Stock (217) **PREFERRED ONLY**	Form 1, pg 112, ln 13 c, d (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
106	13-month average	0	Premium on Preferred Stock (207)	Form 1, pg 112, ln 6 c, d (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
107	13-month average	0	Other Paid-In Capital (207-208) **PREFERRED ONLY**	Form 1, pg 112, ln 7 c, d (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
108	13-month average	0	Discount on Capital Stock (213) **PREFERRED ONLY**	Form 1, pg 112, ln 9 c, d (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
109	13-month average	0	Capital Stock Expense (214) **PREFERRED ONLY**	Form 1, pg 112, ln 10 c, d (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
111	12-month sum (enter positive)	0	Preferred Dividend	Form 1, pg 118, ln 29 c	0	0	0	0	0	0	0	0	0	0	0	0	0
112	13-month average	0	Total proprietary Capital	Form 1, pg 112, ln 16 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
114	13-month average	0	Unappropriated Undistributed Subsidiary Earnings (216.1)	Form 1, pg 112, ln 12 c, d	0	0	0	0	0	0	0	0	0	0	0	0	0
115	13-month average (enter negative)	0	Accumulated Other Comprehensive Income (219)	Form 1, pg 112, ln 15 c, d	0	0	0	0	0	0	0	0	0	0	0	0	0
n/a	-	-	Common Stock Issued (201)	Company records	0	0	0	0	0	0	0	0	0	0	0	0	0
n/a	-	-	Other Paid-In Capital (211)	Company records	0	0	0	0	0	0	0	0	0	0	0	0	0

Description		**Total**	**Interest Locks**	**Other**
Unamortized balance for gains and losses on hedges.	(Note R)	0	0	0
Annual amortization for gains and losses on hedges.	(Note R)	0	0	0

PacifiCorp
Attachment 15 - GSU and Associated Equipment

Asset Class 353.40 - GSU (generator step-up) and Associated Equipment &
Asset Class 345 - Accessory Electrical Equipment
(At December 31)

353.4 Class Assets	**Acquisition value**
Total 353.4 Class Assets	**0**
Wind Generation Facilities	**0**
34.5 kV Facilities	**0**
Appendix A input: **Total Assets to Exclude**	**0**

PacifiCorp
Attachment 16 - Unfunded Reserves

Accounts with Unfunded Reserve Balances contributed by customers
(Dollar values in millions)

Description	Account Calculation	Reserve type	Accrued Liability: SAP Account	Accrued Liability: FERC Account	Charged to: SAP Account	Charged to: FERC Account	Prior year December month end	Current Year December month end	Projection Beg-/End-of-Year Average	Category	By Category 100% Transmission	Plant	Labor	Other	Total Transmission-related Unfunded Reserves
Totals							0.0	0.0	0.0		0.000	0.000	0.000	0.000	
										Allocators	100.000%	0.000%	0.000%	0.000%	
										Total ($ millions)	0.000	0.000	0.000	0.000	0.000
										Appendix A input					**0**

PacifiCorp

Attachment 17 - Post-Retirement Benefits Other Than Pensions (PBOP)

FERC Acct	Description	Expense
	Attachment 5 input: **Total PBOP**	**0**

Notes:

Appendix 1
(Redline Version)

Attachment H-1 of PacifiCorp's OATT

(the Formula)

Report	**Litéra® Change-Pro for Excel 7.0.0.130**
	Comparison done on 2/21/2013 8:54:23 AM
	plus worksheet additions (manually added)
Modified:	1894
Row Add:	165
~~Row Del:~~	~~193~~
Col Add:	16
~~Col Del:~~	~~38~~
Formula And Value Change:	1894
Formula Change Only:	81
Formula Auto Adjusted:	0
Format Modified:	8904
Named range Add:	17
Named range Del:	62
Named range Modified:	77
Worksheet Add:	14
Worksheet Del:	0

ATTACHMENT H-1

PacifiCorp

Appendix A - Formula Rate

~~Formula Rate -- Appendix A~~ Shaded cells are inputs

~~Shaded cells are input cells~~

Line	Description	Notes	Reference (FERC Form 1 ~~Page #~~ reference, attachm	Projection 2010
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		354.21b	0
2	Total Wages Expense		354.28b	0
3	Less A&G Wages Expense		354.27b	0
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	0
5	Wages & Salary Allocator		(Line 1 / Line 4)	0
	Plant Allocation Factors			
6	Electric Plant in Service	(Note M)	Attachment 5	0
7	Accumulated Depreciation (Total Electric Plant)	(Note M)	Attachment 5	0
8	Accumulated Amortization	(Note N)	Attachment 5	0
9	Total Accumulated Depreciation		(Line 7 + 8)	0
10	Net Plant		(Line 6 - Line 9)	0
11	Transmission Gross Plant (excluding Land Held for Future Use)		(Line ~~29~~ 24 - Line ~~28~~ 23)	0
12	Gross Plant Allocator		(Line 11 / Line 6)	0
13	Transmission Net Plant (excluding Land Held for Future Use)		(Line ~~40~~ 32 - Line ~~28~~ 23)	0
14	Net Plant Allocator		(Line 13 / Line 10)	0
	Plant Calculations			
	Plant In Service			
15	Transmission Plant In Service	(Note M)	~~207.58g~~ Attachment 5	0
~~16~~	~~For Reconciliation only - remove New Transmission Plant Additions for Current Calendar Year~~	~~(Note A)~~	~~Attachment 6~~	
~~17~~ 16	New Transmission Plant Additions for Current Calendar Year (weighted by months in service)	(~~Note~~ Notes A & P)	Attachment 6	0
~~18~~ 17	Total Transmission Plant		(Line 15 ~~- Line 16~~ + Line ~~17~~ 16)	0
~~19~~ 18	General Plant	(Note N)	~~207.99g~~ Attachment 5	0
~~20~~ 19	Intangible Plant	(Note N)	~~205.5g~~ Attachment 5	0
~~21~~ 20	Total General and Intangible Plant		(Line ~~19~~ 18 + Line ~~20~~ 19)	0
~~22~~	~~Less: General Plant Account 397 - Communications~~	~~(Note N)~~	~~207.94g~~	
~~23~~	~~General and Intangible Excluding Account 397~~		~~(Line 21 - Line 22)~~	
~~24~~ 21	Wage & Salary Allocator		(Line 5)	0
~~25~~ 22	General and Intangible Allocated to Transmission		(Line ~~23~~ 20 * Line ~~24~~ 21)	0
~~26~~	~~General Plant Account 397 Directly Assigned to Transmission~~		~~Attachment 5~~	
~~27~~	~~Total General and Intangible Functionalized to Transmission~~		~~(Line 25 + Line 26)~~	
~~28~~ 23	Land Held for Future Use	(~~Note~~ Notes B ~~) (Note~~ & L)	Attachment 5	0
~~29~~ 24	Total Plant In Rate Base		**(Line ~~18~~ 17 + Line ~~27~~ 22 + Line ~~28~~ 23)**	0
	Accumulated Depreciation and Amortization			
~~30~~ 25	Transmission Accumulated Depreciation	(Note M)	~~219.25c~~ Attachment 5	0
~~31~~	~~Accumulated General Depreciation~~	~~(Note N)~~	~~219.28c~~	
~~32~~ 26	~~Less:~~ Accumulated General Depreciation ~~Associated with Account 397~~	(Note N)	Attachment 5	0
~~33~~	~~Balance of Accumulated General Depreciation~~		~~(Line 31 - Line 32)~~	
~~34~~ 27	Accumulated Amortization	(Note N)	(Line 8)	0
~~35~~ 28	Accumulated General and Intangible Depreciation ~~Excluding Account 397~~		(Line ~~33~~ 26 + ~~34~~ 27)	0
~~36~~ 29	Wage & Salary Allocator		(Line 5)	0
~~37~~ 30	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line ~~35~~ 28 * Line ~~36~~ 29)	0
~~38~~	~~Amount of Gen. Depr. Associated with Account 397 Directly Assigned to Transmission~~	~~(Note N)~~	~~Attachment 5~~	
~~39~~ 31	**Total Accumulated Depreciation** and Amortization		**Line ~~30~~ 25 + Line ~~37 + Line 38~~ 30)**	0

~~40~~32	Total Net Property, Plant & Equipment			(Line ~~29~~ 24 - Line ~~39~~ 31)	0
~~Adjustment~~Adjustments To Rate Base					
	Accumulated Deferred Income Taxes				
~~41~~33	ADIT net of FASB 106 and 109			Attachment 1A	0
	CWIP for Incentive Transmission Projects				
~~42~~34	CWIP Balances for Current Rate Year		(Note O)	Attachment 6	0
	ITC Adjustment				
35	IRC 46(f)1 adjustment			Attachment 5	0
	Unfunded Reserves				
36	Unfunded Reserves			Attachment 16	0
	Prepayments				
~~43~~37	Prepayments		(Note K & N)	Attachment ~~5~~ 11	0
	Abandoned Plant				
~~44~~38	Unamortized Abandoned Plant		(Note O)	~~Attachment 5~~	0
	Materials and Supplies				
~~45~~39	Undistributed Stores Expense		(Note N)	~~227.16c~~Attachment 5	0
~~46~~40	Wage & Salary Allocator			(Line 5)	0
~~47~~41	Total Undistributed Stores Expense Allocated to Transmission			(Line ~~45~~ 39 * Line ~~46~~ 40)	0
~~48~~42	Construction Materials & Supplies		(Note N)	~~227.5c~~Attachment 5	0
~~49~~43	Wage & Salary Allocator			(Line 5)	0
~~50~~44	Construction Materials & Supplies Allocated to Transmission			(Line ~~48~~ 42 * Line ~~49~~ 43)	0
~~51~~45	Transmission Materials & Supplies		(Note N)	~~227.8c~~Attachment 5	0
~~52~~46	Total Materials & Supplies Allocated to Transmission			(Line ~~47~~ 41 + Line ~~50~~ 44 + Line ~~51~~ 45)	0
	Cash Working Capital				
~~53~~47	Operation & Maintenance Expense			(Line ~~80~~ 75)	0
~~54~~48	1/8th Rule		(Note S)	1/8	0
~~55~~49	Total Cash Working Capital Allocated to Transmission			(Line ~~53~~ 47 * Line ~~54~~ 48)	0
	Network Upgrade Balance				
~~56~~50	Network Upgrade Balance		(Note N)	Attachment 5	0
~~57~~51	Total Adjustment to Rate Base			(Lines ~~41~~ 33 + ~~42~~ 34 + ~~43~~ 35 + ~~52~~ 36 + ~~55~~ 37 + ~~56~~ 38 + 46 + 49 + 50)	0
~~58~~52	Rate Base			(Line ~~40~~ 32 + Line ~~57~~ 51)	0
Operations & Maintenance Expense					
	Transmission O&M				
~~59~~53	Transmission O&M			Attachment 5	0
~~60~~54	Less: Cost of Providing Ancillary Services Accounts 561.0-5			Attachment 5	0
~~61~~55	Less: Account 565			Attachment 5	0
~~62~~56	Transmission O&M			(Lines ~~59~~ 53 - ~~61~~ 55)	0
	Allocated Administrative & General Expenses				
~~63~~57	Total A&G			323.197b	0
~~64~~58	Less~~:~~ Actual PBOP Expense Adjustment			Attachment 5	0
~~65~~59	Less Property Insurance Account 924			323.185b	0
60	Less Regulatory Asset Amortizations Account 930.2			Attachment 5	0
~~66~~61	Less Regulatory Commission Exp Account 928		(Note D)	323.189b	0
~~67~~62	Less General Advertising Exp Account 930.1			323.191b	0
~~68~~63	Less Membership Dues		(Note C)	~~353.2f, 353.5f, 353.7f~~Attachment 5	0
~~69~~64	Administrative & General Expenses			~~Sum~~ (~~Lines 63~~Line 57 - Sum (Lines ~~64~~ 58 to ~~68~~ 63)	0
~~70~~65	Wage & Salary Allocator			(Line 5)	0
~~71~~66	Administrative & General Expenses Allocated to Transmission			(Line ~~69~~ 64 * Line ~~70~~ 65)	0
	Directly Assigned A&G				
~~72~~67	Regulatory Commission Exp Account 928		(Note E)	Attachment 5	0
~~73~~68	General Advertising Exp Account 930.1 - Safety-related Advertising			Attachment 5	0
~~74~~69	Subtotal - Accounts 928 and 930.1 - Transmission Related			(Line ~~72~~ 67 + Line ~~73~~ 68)	0
~~75~~70	Property Insurance Account 924		(Note F)	Attachment 5	0
~~76~~71	General Advertising Exp Account 930.1 - Education and Outreach			Attachment 5	0
~~77~~72	Total Accounts 924 and 930.1 - General			(Line ~~75~~ 70 + Line ~~76~~ 71)	0
~~78~~73	~~Net~~Gross Plant Allocator			(Line ~~14~~ 12)	0

~~79~~74	A&G Directly Assigned to Transmission		(Line ~~77~~ 72 * Line ~~78~~ 73)		0
~~80~~75	Total Transmission O&M		**(Lines ~~62~~ 56 + ~~71~~ 66 + 69 + 74 ~~+ 79~~)**		0
	Depreciation & Amortization Expense				
	Depreciation Expense				
~~81~~76	Transmission Depreciation Expense Including Amortization of Limited Term Plant	(Note H)	Attachment 5		0
~~82~~77	General Depreciation Expense Including Amortization of Limited Term Plant	(Note H)	Attachment 5		0
~~83~~	~~Less: Amount of General Depreciation Expense Associated with Account 397~~		~~Attachment 5~~		
~~84~~	~~Balance of General Depreciation Expense~~		~~(Line 82 - Line 83)~~		
~~85~~78	Intangible Amortization	(Note H)	~~336.1d e~~Attachment 5		0
~~86~~79	Total		(Line ~~82~~ 77 + Line ~~85~~ 78)		0
~~87~~80	Wage & Salary Allocator		(Line 5)		0
~~88~~	~~General Depreciation & Intangible Amortization Allocated to Transmission~~		~~(Line 86 * Line 87)~~		
~~89~~	~~General Depreciation Expense for Account 397 Directly Assigned to Transmission~~		~~Attachment 5~~		
~~90~~81	General Depreciation and Intangible Amortization Functionalized to Transmission		(Line ~~88 +~~ 79 * Line ~~89~~ 80)		0
~~91~~82	Abandoned Plant Amortization	(Note O)	~~Future Use~~		0
~~92~~83	Total Transmission Depreciation & Amortization		**(Lines 76 + 81 + ~~90 + 91~~ 82)**		0
	Taxes Other Than Income				
~~93~~84	Taxes Other than Income Taxes		Attachment 2		0
~~94~~85	Total Taxes Other than Income Taxes		**(Line ~~93~~ 84)**		0
	Return \ Capitalization Calculations				
~~95~~	**Long- Term ~~Interest~~ Debt**		~~Attachment 5~~		
86	Account 221 Bonds		Attachment 14		0
~~96~~87	~~Pre~~ Less Account 222 Reaquired Bonds		Attachment ~~5~~ 14		0
88	Account 223 Long-term Advances from Associated Cos.		Attachment 14		0
89	~~Co~~ Account 224 Other Long-term Debt		Attachment 14		0
~~97~~90	~~Proprietary Capital~~Gross Proceeds Outstanding Long-term Debt		~~Attachment 5~~Sum Lines 86 through 89		0
~~98~~91	Less ~~Accumulated Other Comprehensive Income~~ Account ~~219~~ 226 Unamortizedized Discount	(Note T)	Attachment ~~5~~ 14		0
~~99~~92	Less ~~Preferred Stock~~ Account 181 Unamortizedized Debt Expense	(Note T)	~~(Line 106)~~Attachment 14		0
~~100~~93	Less Account ~~216.1~~ 189 Unamortizedized Loss on Reaquired Debt	(Note T)	Attachment ~~5~~ 14		0
94	Plus Account 225 Unamortizedized Premium	(Note T)	Attachment 14		0
~~101~~95	~~Total Common Stock~~Plus Account 257 Unamortizedized Gain on Reaquired Debt	(Note T)	~~(Line 97 - 98 - 99 - 100)~~Attachment 14		0
96	Net Proceeds Long Term Debt		Sum Lines 90 through 95		0
	~~Capitalization~~Long Term Debt Cost				
~~102~~97	Accounts 427 and 430Long Term ~~Debt~~ Interest Expense	(Notes R & T)	Attachment ~~5~~ 14		0
98	Less Hedging Expense	(Note R)	Attachment 14		0
99	Account 428 Amortized Debt Discount and Expense	(Note T)	Attachment 14		0
~~103~~100	~~Less~~Account 428.1 Amortized Loss on ~~Reacquired~~ Reaquired Debt	(Note T)	Attachment ~~5~~ 14		0
101	Less Account 429 Amortized Premium	(Note T)	Attachment 14		0
~~104~~102	~~Plus~~Less Account 429.1 Amortized Gain on ~~Reacquired~~ Reaquired Debt	(Note T)	Attachment ~~5~~ 14		0
~~105~~103	Total Long Term Debt Cost		~~(Line~~Sum Lines 97 through 102 ~~- 103 + 104)~~		0
	Preferred Stock and Dividend				
104	Account 204 Preferred Stock Issued		Attachment 14		0
105	Less Account 217 Reaquired Capital Stock (preferred)		Attachment 14		0
106	Account 207 Premium onPreferred Stock		Attachment ~~5~~ 14		0
107	Account 207-208 Other Paid-In Capital (preferred)		Attachment 14		0
108	Less Account 213 Discount on Capital Stock (preferred)		Attachment 14		0
109	Less Account 214 Capital Stock Expense (preferred)		Attachment 14		0
110	Total Preferred Stock		Sum Lines 104 through 109		0
111	Preferred Dividend		Attachment 14	(Enter positive)	0
	Common Stock				
112	Proprietary Capital		Attachment 14		0

Line	Description	Source	Notes	Formula	Amount
~~107~~113	~~Common~~Less: Total Preferred Stock			(Line ~~101~~ 110)	0
114	Less: Account 216.1 Unappropriated Undistributed Subsidiary Earnings			Attachment 14	0
115	Less: Account 219			Attachment 14	0
~~108~~116	**Total** ~~Capitalization~~ Common Stock			(Sum Lines ~~105 to 107)~~ 112 through 115	0
~~109~~117	Debt ~~%~~ percent	Total Long Term Debt	(Notes Q & R)	(Line ~~105~~ 90 / ~~Line 108~~ (Lines 90 + 110 +116))	0
~~110~~118	Preferred ~~%~~ percent	Preferred Stock		(Line ~~106~~ 110 / ~~Line 108~~ (Lines 90 + 110 +116))	0
~~111~~119	Common ~~%~~ percent	Common Stock	(Notes Q & R)	(Line ~~107~~ 116 / ~~Line 108~~ (Lines 90 + 110 +116))	0
~~112~~120	Debt Cost	~~Total~~ Long Term Debt Cost = Long Term Debt Cost / Net Proceeds		(Line ~~95~~ 103 / Line ~~105~~ 96)	0
~~113~~121	Preferred Cost	Preferred Stock cost = Preferred Dividends / Total Preferred Stock		(Line ~~96~~ 111 / Line ~~106~~ 110)	0
~~114~~122	Common Cost	Common Stock	(Note H)	Fixed	0
~~115~~123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line ~~109~~ 117 * Line ~~112~~ 120)	0
~~116~~124	Weighted Cost of Preferred	Preferred Stock		(Line ~~110~~ 118 * Line ~~113~~ 121)	0
~~117~~125	Weighted Cost of Common	Common Stock		(Line ~~111~~ 119 * Line ~~114~~ 122)	0
~~118~~126	~~Ra~~ Rate of Return on Rate Base (ROR)			(Sum Lines ~~115~~ 123 to ~~117~~ 125)	0
~~119~~127	Investment Return = Rate Base * Rate of Return			**(Line ~~58~~ 52 * Line ~~118~~ 126)**	0
	Composite Income Taxes				
	Income Tax Rates				
~~120~~128	FIT=Federal Income Tax Rate		(Note G)		0
~~121~~129	SIT=State Income Tax Rate or Composite		(Note G)	Attachment 5	0
~~122~~130	p	(percent of federal income tax deductible for state purposes)		Per ~~State Tax Code~~ state tax code	0
~~123~~131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			0
~~124~~132	T / (1-T)				0
	ITC Adjustment				
~~125~~133	Amortized Investment Tax Credit - Transmission Related			Attachment 5	0
~~126~~134	ITC Adjust. Allocated to Trans. - Grossed Up	ITC Adjustment x 1 / (1-T)		Line ~~125~~ 133 * (1 / (1 - Line ~~123~~ 131))	0
~~127~~135	Income Tax Component =	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =		[Line ~~124~~ 132 * Line ~~119~~ 127 * (1- (Line ~~115~~ 123 / Line ~~118~~ 126))]	0
~~128~~136	Total Income Taxes			**(Line ~~126~~ 134 + Line ~~127~~ 135)**	0
	Revenue Requirement				
	Summary				
~~129~~137	Net Property, Plant & Equipment			(Line ~~40~~ 32)	0
~~130~~138	Total Adjustment to Rate Base			(Line ~~57~~ 51)	0
~~131~~139	Rate Base			(Line ~~58~~ 52)	0
~~132~~140	Total Transmission O&M			(Line ~~80~~ 75)	0
~~133~~141	Total Transmission Depreciation & Amortization			(Line ~~92~~ 83)	0
~~134~~142	Taxes Other than Income			(Line ~~94~~ 85)	0
~~135~~143	Investment Return			(Line ~~119~~ 127)	0
~~136~~144	Income Taxes			(Line ~~128~~ 136)	0
~~137~~14	Gross Revenue Requirement			**(Sum Lines ~~132~~ 140 to ~~136~~ 144)**	0
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
~~138~~146	Transmission Plant In Service			(Line 15)	0
~~139~~147	Excluded Transmission Facilities		(Note J)	Attachment ~~5~~ 15	0
~~140~~148	Included Transmission Facilities			(Line ~~138~~ 146 - Line ~~139~~ 147)	0
~~141~~149	Inclusion Ratio			(Line ~~140~~ 148 / Line ~~138~~ 146)	0
~~142~~150	Gross Revenue Requirement			(Line ~~137~~ 145)	0
~~143~~151	Adjusted Gross Revenue Requirement			(Line ~~141~~ 149 * Line ~~142~~ 150)	0
	Revenue Credits				
~~144~~152	Revenue Credits			Attachment 3	0
~~145~~15	Net Revenue Requirement			**(Line ~~143~~ 151 - Line ~~144~~ 152)**	0
	Net Plant Carrying Charge				
~~146~~154	Gross Revenue Requirement			(Line ~~142~~ 150)	0
~~147~~155	Net Transmission Plant			(Line ~~18~~ 17 - Line ~~30~~ 25 + Line ~~42~~ 34)	0
~~148~~156	Net Plant Carrying Charge			(Line ~~146~~ 154 / Line ~~147~~ 155)	0
~~149~~157	Net Plant Carrying Charge without Depreciation			(Line ~~146~~ 154 - Line ~~81~~ 76) / Line ~~147~~ 155	0
~~150~~158	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes			(Line ~~146~~ 154 - Line ~~81~~ 76 - Line ~~119~~ 127 - Line ~~128~~ 136) / Line ~~147~~ 15	0

Line	Description	Note	Reference	Amount
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE			
~~151~~159	Gross Revenue Requirement Less Return and Taxes		(Line ~~142~~ 150 - Line ~~135~~ 143 - Line ~~136~~ 144)	0
~~152~~160	Increased Return and Taxes		Attachment 4	0
~~153~~161	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line ~~151~~ 159 + Line ~~152~~ 160)	0
~~154~~162	Net Transmission Plant		(Line ~~18~~ 17 - Line ~~30~~ 25 + Line ~~42~~ 34)	0
~~155~~163	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line ~~153~~ 161 / Line ~~154~~ 162)	0
~~156~~164	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation		(Line ~~153~~ 161 - Line ~~81~~ 76) / Line ~~154~~ 162	0
~~157~~165	Net Revenue Requirement		(Line ~~145~~ 153)	0
~~158~~	~~True-up amount~~		~~Attachment 6~~	
~~159~~166	Facility Credits under Section 30.9 of the OATT		Attachment 5	0
~~160~~167	Transmission Incentive Credit		Attachment 7	0
~~161~~168	Interest on Network Upgrade Facilities		Attachment 5	0
~~162~~169	Net Zonal Revenue Requirement		(Line ~~157~~ 165 + ~~158~~ 166 + ~~159~~ 167 + ~~160 + 161~~ 168)	0
	Network ~~Zonal~~ Service Rate			
~~163~~170	12 CP Monthly Peak (MW)	(Note I)	~~FERC Form 1 page 400~~ Attachment 9a/9b	0
~~164~~171	Rate ($/MW-year)		(Line ~~162~~ 169 / ~~163~~ 170)	0
~~165~~17	**Network Service Rate ($/MW/~~Year~~-year)**		**(Line ~~164~~ 171)**	0

Notes ~~Notes~~

A Line 16~~, for the Reconciliation,~~ includes New Transmission Plant ~~that actually was~~ to be placed in service ~~weighted by the number of months it actually was~~ in ~~service~~ the current calendar year. Projected capital additions will include only the capital cos

~~Line 17 includes New Transmission Plant~~ with plant expected to be energized and placed in service ~~in~~ (as defined by the ~~current calendar year~~ Uniform System of Accounts) in that month. The True-Up Adjustment will reflect the actual date the plant was energized and placed in service.

B Includes Transmission portion only.

C ~~Includes all annual~~ Annual membership dues (e.g., for EPRI, ~~National Electric Testing~~ NEETRAC, ~~Research & Applications Center,~~ SEPA and ~~Distribution Systems, Application & Research.~~ NCTA) are excluded from the calculation of the ATRR and char

Total A&G. Total A&G does not include lobbying expenses.

D Includes all Regulatory Commission Expenses.

E Includes Regulatory Commission Expenses directly related to transmission service.

F Property Insurance excludes prior period adjustment in the first year of the formula's operation and reconciliation for the first year.

G The calculation of the Reconciliation revenue requirement according to Step 7 of Attachment 6 ("Estimate and Reconciliation Worksheet") shall reflect the actual tax rates in effect for the Rate Year, as defined in Attachment H-2, being reconciled ("Test Year"). When statutory marginal tax rates change during such Test Year, the effective tax rates used in the formula shall be weighted by the number of days each such rate was in effect. For example, a 35% rate in effect for 120 days superseded by a 40% rate in effect for the remainder of the year will be calculated as: ((.3500 x 120) + (.4000 x 245))/365 = .3836.

H No change in ROE will be made absent a filing at FERC.

PBOP expense is fixed until changed as the result of a filing at FERC.

Depreciation rates shown in Attachment ~~9~~ 8 are fixed until changed as the result of a filing at FERC.

I The 12 CP monthly peak is the average of the 12 monthly system peaks calculated as the Network customers Monthly Network Load (Section 34.2 of the OATT) plus the reserve capacity of all long term firm point-to-point customers.

J Amount of transmission plant excluded from rates per Attachment 5.

K Adjustment reflects exclusion of tax receivables due to 2008 NOLs, which resulted in MidAmerican Energy Holdings Company delivering refund to PacifiCorp.

L Any gain from the sale of land included in Land Held for Future Use in the Formula Rate received during the Rate Year, as defined in Attachment H-2, shall be used to reduce the ATRR in the Rate Year. The Formula Rate shall not include any losses on sales of such land.

M The Update uses end of year balances and the True-up uses 13 monthly averages shown on Attachment 5.

N The Update uses end of year balances and the True-up uses the average of beginning of year and end of year ~~averages~~ balances shown on ~~Attachment 5~~ Attachments.

O Placeholder that is zero until PacifiCorp receives authorization by FERC to include amounts.

P Projected capital additions will include only the capital costs associated with plant expected to be energized and placed in service (as defined by the Uniform System of Accounts) in that month. The True-Up Adjustm

Q The equity ratio is capped at 53%, and if the actual equity ratio exceeds 53%, then the debt ratio will be equal to 1 minus the preferred stock ratio minus 53%.

R PacifiCorp will include only the gains and losses on interest rate locks for new debt issuances. Attachment 14 – Cost of Capital Detail will list the unamortized balance and annual amortization for all gains and losses

S PacifiCorp shall use FERC's 1/8th method for cash working capital subject to the following limitations:
(a) PacifiCorp shall be required to file a lead-lag study justifying the appropriate cash working capital allowance to be effective, subject to refund, as of June 1, 2014; provided, however, that if PacifiCorp does not file
(b) PacifiCorp shall provide a draft to the other Parties of any such lead-lag study at least sixty (60) days prior to making any filing described in (a) with the Commission; and
(c) Filing of the lead-lag study in (a) above, but not any subsequent filing affecting or relating to PacifiCorp's cash working capital allowance as permitted in subsection (a) above, may be a single issue FPA Section 2

T These line items will include only the balances associated with long-term debt and shall exclude balances associated with short-term debt.

New worksheet

PacifiCorp
Appendix B - Schedule 1: Scheduling, System Control and Dispatch Service

Calculated from historical data--no true-up

Line	Description	FERC Form 1 page # / Reference	Amount
1	(561.1) Load Dispatch-Reliability	pg. 321.85b	
2	(561.2) Load Dispatch-Monitor and Operate Transmission System	pg. 321.86b	
3	(561.3) Load Dispatch-Transmission Service and Scheduling	pg. 321.87b	
4	(561.4) Scheduling, System Control and Dispatch Services	pg. 321.88b	
5	(561.5) Reliability, Planning and Standards Development	pg. 321.89b	
6	Total 561 Costs for Schedule 1 Annual Revenue Requirement	(Sum Lines 1 through 5)	0
7	Schedule 1 Annual Revenue Requirement	(Line 6)	0
	Schedule 1 - Rate Calculations		
8	Average 12-Month Demand - Current Year (kW)	Divisor	
9	Rate in $/kW - Yearly	(Line 7 / Line 8)	0.000
10	Rate in $/kW - Monthly	((Line 7 / Line 8) / 12)	0.000
11	Rate in $/kW - Weekly	((Line 7 / Line 8) / 52)	0.000
12	Rate in $/kW - Daily On-Peak	(Line 11 / 5)	0.000
13	Rate in $/kW - Daily Off-Peak	(Line 11 / 7)	0.000
14	Rate in $/MW - Hourly On-Peak	((Line 12 / 16) * 1000)	0.000
15	Rate in $/MW - Hourly Off-Peak	((Line 13 / 24) * 1000)	0.000

PacifiCorp

OATT Transmission Rate Formula Template Using Form 1 Data

Summary of Rates

Line	Description	Reference	Amount
1	Adjusted Gross Revenue Requirement	Appendix A, Line ~~141~~ 151	~~-~~ 0
	Revenue Credits:		
2	Acct 454 - Allocable to Transmission	Attachment 3, Line 6	~~-~~ 0
3	Acct 456 - Allocable to Transmission	Attachment 3, Line 12	~~-~~ 0
4	Total Revenue Credits	Line 2 + Line 3	~~-~~ 0
5	Interest on Network Upgrades	Attachment 5	~~-~~ 0
6	Transmission Incentive Credit	Attachment 7	~~-~~ 0
7	Annual Transmission Revenue Requirement	~~(~~Line 1 - Line 4 + Line 5 + Line 6~~)~~	~~-~~ 0
8	Divisor - 12 Month Average Transmission Peak (MW)	Appendix A, Line ~~161~~ 170	~~-~~ 0
	Rates:		
9	Transmission Rate ($/kW - ~~Year~~year)	Line 7 / Line 8 / 1000	~~$0.000~~ 0
10	Transmission Rate ($/kW - ~~Month~~month)	12 months	~~$0.000~~ 0
11	Weekly Firm/Non-Firm Rate ($/kW - ~~Week~~week)	Line ~~10~~ 9 / 52 weeks	~~$0.000~~ 0
	Daily Firm/Non-Firm Rates ~~($/kW)~~:		
12	On-Peak Days ($/kW)	Line 11 / 5 days	~~$0.000~~ 0
13	Off-Peak Days ($/kW)	Line 11 / 7 days	~~$0.000~~ 0
	Non-Firm Hourly Rates ~~($/MWh)~~:		
14	On-Peak Hours ($/MWh)	Line 12 / 16 hours * 1000	~~$0.000~~ 0
15	Off-Peak Hours ($/MWh)	Line 13 / 24 hours * 1000	~~$0.000~~ 0

PacifiCorp							
eferred Income Taxes (ADIT) Worksheet							
Beginning of Current Year							
						~~Total~~	
Line	Description	Reference	Transmission	Plant ~~-~~ related	Labor related	Total Transmission ADIT	
	(A)	(B)	~~Related~~(C)	~~Related~~(D)	~~Related~~(E)	~~ADIT~~ (F)	
1	ADIT- 282	Sch. 282 Below	~~-~~0	~~-~~0	~~-~~0		
2	ADIT-281	Sch. 281 Below	0	0	0		
~~2~~3	ADIT-283	Sch. 283 Below	~~-~~0	~~-~~0	~~-~~0		
~~3~~4	ADIT-190	Sch. 190 Below	~~-~~0	~~-~~0	~~-~~0		
~~4~~5	Subtotal ADIT	Sum (Lines 1 to ~~3~~ 4)	~~-~~0	~~-~~0	~~-~~0		
~~5~~	~~Wages & Salary Allocator~~	~~Appendix A, Line 5~~			~~0.0000%~~		
6	Allocator (100% Transmission; Net Plant ~~Allocator~~; Wages & Salary)	Appendix A~~, Line 14~~	1	~~0.0000%~~0	0		
7	Sub-total Transmission Related ADIT	Line ~~4~~ 5 * Allocator	~~-~~0	~~-~~0	~~-~~0		
8	Total Transmission ADIT	Sum~~(~~Cols. ~~D,E,F~~ (C), (D), (E)				~~-~~0	~~Enter as negative Appendix A, line 41.~~ Attachment 1a input

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-F and each separate ADIT item will be listed, dissimilar items with amounts exceeding $100,000 will be listed separately.

A	A	B	C	D	E	F	G
			Gas, Prod,				
Schedule ADIT-190		Total	Dist Or Other	Transmission	Plant	Labor	
			Related	Related	Related	Related	**Justification** ~~(SUMMARIES - WORK IN PROGRESS)~~
Account 190							
Subtotal - p234		~~-~~0	~~-~~0	~~-~~0	~~-~~0	~~-~~0	
Less FASB 109 Above if not separately removed		~~-~~	~~-~~	~~-~~	~~-~~	~~-~~	
Less FASB 106 Above if not separately removed		~~-~~	~~-~~	~~-~~	~~-~~	~~-~~	
Total		~~-~~0	~~-~~0	~~-~~0	~~-~~0	~~-~~0	

Instructions for Account 190:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F

income taxes arise periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

PacifiCorp

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

	A	B	C	D	E	F	G
			Gas, Prod,				
Schedule ADIT-281		Total	Dist Or Other	Transmission	Plant	Labor	
			Related	Related	Related	Related	Justification
Account 281							
Subtotal - p275		~~-~~0	~~-~~0	~~-~~0	~~-~~0	~~-~~0	
Less FASB 109 Above if not separately removed		~~-~~	~~-~~	~~-~~	~~-~~	~~-~~	
Less FASB 106 Above if not separately removed		~~-~~	~~-~~	~~-~~	~~-~~	~~-~~	
Total		~~-~~0	~~-~~0	~~-~~0	~~-~~0	~~-~~0	

Instructions for Account 282:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F

income taxes arise periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

PacifiCorp

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

	A	B	C	D	E	F	G
			Gas, Prod,				
Schedule ADIT-282		Total	Dist Or Other	Transmission	Plant	Labor	
			Related	Related	Related	Related	Justification
Account 282							

		B	C	D	E	F	G
Subtotal - p275		- 0	- 0	- 0	- 0	- 0	
Less FASB 109 Above if not separately removed		-	-	-	-	-	
Less FASB 106 Above if not separately removed		-	-	-	-	-	
Total		- 0	- 0	- 0	- 0	- 0	
	Instructions for Account 282:						
1. ADIT	1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or						
	2. ADIT items related only to Transmission are directly assigned to Column D						
	3. ADIT items related to Plant and not in Columns C & D are included in Column E						
	4. ADIT items related to labor and not in Columns C & D are included in Column F						
5. Deferred income	5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is						
A							

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

	A	B	C	D	E	F	G
			Gas, Prod,				
Schedule ADIT-283		Total	Dist Or Other	Transmission	Plant	Labor	
			Related	Related	Related	Related	Justification
Account 283							
Subtotal - p277		- 0	- 0	- 0	- 0	- 0	
Less FASB 109 Above if not separately removed		-	-	-	-	-	
Less FASB 106 Above if not separately removed		-	-	-	-	-	
Total		- 0	- 0	- 0	- 0	- 0	
	Instructions for Account 283:						
1. ADIT	1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or						
	2. ADIT items related only to Transmission are directly assigned to Column D						
	3. ADIT items related to Plant and not in Columns C & D are included in Column E						
	4. ADIT items related to labor and not in Columns C & D are included in Column F						
5. Deferred income	5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is						

PacifiCorp

eferred Income Taxes (ADIT) Worksheet

End of Current Year for Projection and Average of Beginning and End of Current Year for True-up

Line	Description (A)	Reference (B)	Total Company	~~Transmission~~Gas, P ~~Related~~	~~Plant~~ Transmission Related ~~Related~~(C)	~~Labor~~Plant Related ~~Related~~(D)	~~Total Transmission~~Labor Related ~~ADIT~~ (E)	Total Transmission ADIT (F)
1	ADIT- 282	Sch. 282 Below	0	~~–~~0	~~–~~0	~~–~~0	0	
2	ADIT-281	Sch. 281 Below	0	0	0	0	0	
~~2~~3	ADIT-283	Sch. 283 Below	0	~~–~~0	~~–~~0	~~–~~0	0	
~~3~~4	ADIT-190	Sch. 190 Below	0	~~–~~0	~~–~~0	~~–~~0	0	
~~4~~5	Subtotal ADIT	Sum (Lines 1 to ~~3~~ 4)	0	~~–~~0	~~–~~0	~~–~~0	0	
~~5~~	~~Wages & Salary Allocator~~	~~Appendix A, Line 5~~				~~0.0000%~~		
6	Allocator (100% Transmission;Net Plant ~~Allocator~~; Wages & Salary)	Appendix A~~, Line 14~~			~~0.0000%~~1	0	0	
7	Sub-total Transmission Related ADIT	Line ~~4~~ 5 * Allocator		~~–~~	~~–~~0	~~–~~0	0	
8	**Total** End of Year **Transmission ADIT**	Sum~~(~~Cols. ~~D,E,F~~ (C), (D), (E)					~~–~~	~~Enter as negative Appendix A, line 41.~~0
9	Beginning of Year Total (Attachment 1)				0	0	0	0
10	Appendix A, line 33 input	Line 8 for Projection and average of Lines 8 & 9 for True-Up						0

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-F and each separate ADIT item will be listed, dissimilar items with amounts exceeding $100,000 will be listed separately.

Schedule ADIT-190

~~A~~	A	~~B~~	B	C	D	E	F	G
~~Schedule ADIT-190~~		~~Total~~	Total	Gas, Prod, Dist Or Other	Transmission	Plant	Labor	
Description	Form 1 Reference		Company	Related	Related	Related	Related	**Justification**
Account 190								
g								
Subtotal - p234		~~–~~	0	~~–~~0	~~–~~0	~~–~~0	~~–~~0	
Less FASB 109 Above if not separately removed		~~–~~		~~–~~	~~–~~	~~–~~	~~–~~	
Less FASB 106 Above if not separately removed		~~–~~		~~–~~	~~–~~	~~–~~	~~–~~	
Total		~~–~~	0	~~–~~0	~~–~~0	~~–~~0	~~–~~0	

Instructions for Account 190:
Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are

PacifiCorp

Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet

Schedule ADIT-281

	A	~~B~~	B	C	D	E	F	G
~~Schedule ADIT-281~~		~~Total~~	Total	Gas, Prod, Dist Or Other	Transmission	Plant	Labor	
				Related	Related	Related	Related	Justification
Account 281								
Rounding								
Subtotal - p275		~~–~~	0	~~–~~0	~~–~~0	~~–~~0	~~–~~0	
Less FASB 109 Above if not separately removed		~~–~~		~~–~~	~~–~~	~~–~~	~~–~~	
Less FASB 106 Above if not separately removed		~~–~~		~~–~~	~~–~~	~~–~~	~~–~~	
Total		~~–~~	0	~~–~~0	~~–~~0	~~–~~0	~~–~~0	

Instructions for Account ~~282~~ 281:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are

PacifiCorp

Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet

Schedule ADIT-282

	A		B	C	D	E	F	G

	A	B	Total	Gas, Prod, Dist Or Other Related	Transmission Related	Plant Related	Labor Related	Justification
Account 282								
Rounding								
Subtotal - p275		-	0	- 0	- 0	- 0	- 0	
Less FASB 109 Above if not separately removed		-		-	-	-	-	
Less FASB 106 Above if not separately removed		-		-	-	-	-	
Total		-	0	- 0	- 0	- 0	- 0	
	Instructions for Account 282:							
	1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C							
	2. ADIT items related only to Transmission are directly assigned to Column D							
	3. ADIT items related to Plant and not in Columns C & D are included in Column E							
	4. ADIT items related to labor and not in Columns C & D are included in Column F							
	5. Deferred income taxes arise when items are included in taxable income in different periods than they are							
p								

Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet

Schedule ADIT-283

	A	~~B~~	B	C	D	E	F	G
				Gas, Prod,				
~~Schedule ADIT-283~~		~~Total~~	Total	Dist Or Other	Transmission	Plant	Labor	
				Related	Related	Related	Related	Justification
Account 283								
Rounding								
Subtotal - p277		-	0	- 0	- 0	- 0	- 0	
Less FASB 109 Above if not separately removed		-		-	-	-	-	
Less FASB 106 Above if not separately removed		-		-	-	-	-	
Total		-	0	- 0	- 0	- 0	- 0	
	Instructions for Account 283:							
	1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C							
	2. ADIT items related only to Transmission are directly assigned to Column D							
	3. ADIT items related to Plant and not in Columns C & D are included in Column E							
	4. ADIT items related to labor and not in Columns C & D are included in Column F							
	5. Deferred income taxes arise when items are included in taxable income in different periods than they are							

PacifiCorp

Attachment 2 - Taxes Other Than Income Worksheet

Line		Other Taxes	~~Page 263~~ Page 263 Col (i)	Allocator	Allocated Amount	~~Allocated Amount~~
		Plant Related		Net Plant Allocator		
~~1~~		~~Real Property~~	~~-~~			
~~2~~		~~Possessory taxes~~	~~-~~			
~~3~~						
~~4~~						
~~5~~						
~~6~~1		Total Plant Related	~~-~~ 0	~~0.0000%~~0	0	~~-~~
		Labor Related		Wages & Salary Allocator		
~~7~~		~~Federal FICA~~	~~-~~			
~~8~~		~~Federal Unemployment~~	~~-~~			
~~9~~		~~State Unemployment~~	~~-~~			
~~10~~						
~~11~~						
~~12~~						
~~13~~2		Total Labor Related	~~-~~ 0	~~0.0000%~~0	0	~~-~~
		Other Included		Net Plant Allocator		
~~14~~		~~Annual Report~~	~~-~~	~~-~~		
~~15~~				~~-~~		
~~16~~						
~~17~~						
~~18~~3		Total Other Included	~~-~~ 0	~~0.0000%~~0	0	~~-~~
~~19~~4		Appendix A input: **Total Included** Taxes **(Lines ~~6~~ 1 + ~~13~~ 2 + ~~18~~ 3)**	~~-~~ 0		0	< - ~~-~~ Appendix A input
		Curre ~~Currently Excluded~~				
~~20~~		~~Local Franchise~~	~~-~~			
~~21~~		~~Energy License~~	~~-~~			
~~22~~		~~Wholesale Energy~~	~~-~~			
~~23~~		~~KW~~	~~-~~			
~~24~~		~~Department of Energy~~	~~-~~			
~~25~~		~~Franchise~~	~~-~~			
~~26~~		~~Public Utility~~	~~-~~			
~~27~~		~~Other (Navajo Nation, Business & Occupation, Land Use, Other)~~	~~-~~			
~~28~~5		Subt ~~Subtotal, Excluded~~	~~-~~ 0			
~~29~~6		**Total**~~,~~ Other Taxes **Included and Excluded (Line ~~19~~ 4 + Line ~~28~~ 5)**	~~-~~ 0			
~~30~~		**Total Other Taxes** ~~from p114.14.c~~	~~-~~			
7		114.14c				
~~31~~8		Difference (Line ~~29~~ 6 - Line ~~30~~ 7)	~~-~~ 0			

Criteria for Allocation:

A	Other taxes that are incurred through ownership of plant, including transmission plant, will be allocated based on the Net Plant Allocator. If the taxes are 100% recovered at retail, they shall not be included.
B	Other taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. If the taxes are 100% recovered at retail, they shall not be included.
C	Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator.
D	Other taxes, except as provided for in A, B and C above, which are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service, will be allocated based on the Net Plant Allocator; provided, however, that overheads shall be treated, as described in footnote B above.
E	Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year.

PacifiCorp

Attachment 3 - Revenue Credit Worksheet

e	Description	Notes	Reference	Value	
	Account 454 - Rent from Electric Property				
1	Rent from Electric Property - Transmission Related			0	~~-~~
2	Pole Attachments - Transmission Related				
3	Distribution Underbuild - Transmission Related		detail below		
4	Various Rents - Transmission Related				
5	Miscellaneous General Revenues		detail below		
6	Account 454 subtotal		(Sum Lines 1-5)	0	
	Account 456 - Other Electric Revenues (Note 1)				
~~2~~7	Transmission for Others ~~(Note 3)~~	Note 3	Attachment 13	0	~~-~~
~~3~~8	Net revenues associated with Network Integration Transmission Service (NITS) for which the lo	Note 3			
~~4~~9	Short-term firm and non-firm service revenues for which the load is not included in the divisor received by Transmission Owner		Attachment 13	0	~~-~~
~~5~~10	Facilities Charges including Interconnection Agreements ~~(Note 2)~~	Note 2			
11	Transmission maintenance revenue		Account 456.2		
12	Account 456 subtotal		(Sum Lines 7-11)	0	
~~6~~13	Appendix A input: Gross Revenue Credits		&12)	0	≤ - -Appendix A input

Detail for selected items above

Miscellaneous General Revenues

Total Miscellaneous General Revenue			0
Wages & Salary Allocator			0
Total Allocated Miscellaneous General Revenue			0

Distribution Underbuild

Common pole location fixed annual revenue credit		fixed	0
Distribution Underbuild - Transmission related			0

Notes

~~7~~Note 1 ~~Note 1:~~ All revenues related to transmission that are received as a transmission owner (i.e., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this Attachment or elsewhere in the f

~~8~~Note 2 ~~Note 2:~~ If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in

~~9~~Note 3 ~~Note 3:~~ If the facilities associated with the revenues are not included in the formula, the revenue is shown here, but not included in the total above and explained in the Cost Support, (e.g., revenues associated with distribution facilities).

PacifiCorp

Attachment 4 - Calculation of 100 Basis Point Increase in ROE

Line	Description		Notes	Reference	Value
	Return and Taxes with 100 Basis Point increase in ROE				
A	100 Basis Point increase in ROE and Income Taxes			Appendix A input: Line ~~28~~ 127 + Line ~~38~~ 137 from below	~~-~~ 0
B	~~0~~100 Basis Point increase in ROE				~~0.00%~~0.01
Return Calculation					
			Notes	Reference (**Appendix A Line or Source** ~~Reference~~)	
~~1~~	~~Rate Base~~			~~(Attachment A Line 58)~~	~~-~~
~~2~~	~~Long Term Interest~~			~~(Attachment A Line 95)~~	~~-~~
~~3~~	~~Preferred Dividends~~			~~Attachment 5~~	~~-~~
	~~Common Stock~~				
~~4~~	~~Proprietary Capital~~			~~Attachment 5~~	~~-~~
~~5~~	~~Less Accumulated Other Comprehensive Income Account 219~~			~~p112.15.c~~	~~-~~
~~6~~	~~Less Preferred Stock~~			~~(Attachment A Line 99)~~	~~-~~
~~7~~	~~Less Account 216.1~~			~~Attachment 5~~	~~-~~
~~10~~	~~Total Common Stock~~			~~(Line 4 - 5 - 6 - 7)~~	~~-~~
	~~Capitalization~~				
~~11~~	~~Long Term Debt~~			~~Attachment 5~~	~~-~~
~~12~~	~~Less Loss on Reacquired Debt~~			~~Attachment 5~~	~~-~~
~~13~~	~~Plus Gain on Reacquired Debt~~			~~Attachment 5~~	~~-~~
~~14~~	~~Total Long Term Debt~~			~~(Line 11 - 12 + 13)~~	~~-~~
~~15~~	~~Preferred Stock~~			~~Attachment 5~~	~~-~~
~~16~~	~~Common Stock~~			~~(Line 10)~~	~~-~~
~~17~~	~~Total Capitalization~~			~~(Sum Lines 14 to 16)~~	~~-~~
~~18~~117	Debt ~~%~~ percent	Total Long Term Debt	~~Total Long Term Debt~~(Notes Q & R)	(Line ~~14~~ 90 / ~~Line 17~~ (Lines 90 + 110 +116))	~~0.00%~~0
~~19~~118	Preferred ~~%~~ percent	Preferred Stock	~~Preferred Stock~~	(Line ~~15~~ 110 / ~~Line 17~~ (Lines 90 + 110 +116))	~~0.00%~~0
~~20~~119	Common ~~%~~ percent	Common Stock	~~Common Stock~~(Notes Q & R)	(Line ~~16~~ 116 / ~~Line 17~~ (Lines 90 + 110 +116))	~~0.00%~~0
~~21~~120	Debt Cost	Long Term Debt Cost = Long Term Debt Cost / Net Proceeds Long Term Debt	~~Total Long Term Debt~~	(Line ~~2~~ 103 / Line ~~14~~ 96)	~~0.00%~~0
~~22~~121	Preferred Cost	Preferred Stock cost = Preferred Dividends / Total Preferred Stock	~~Preferred Stock~~	(Line ~~3~~ 111 / Line ~~15~~ 110)	~~0.00%~~0
~~23~~122	Common Cost	Common Stock	~~Common Stock~~(Note H)	Fixed plus 100 basis points	~~0.00%~~0.01
~~24~~123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	~~Total Long Term Debt (WCLTD)~~	(Line ~~18~~ 117 * Line ~~21~~ 120)	~~0.00%~~0
~~25~~124	Weighted Cost of Preferred	Preferred Stock	~~Preferred Stock~~	(Line ~~19~~ 118 * Line ~~22~~ 121)	~~0.00%~~0
~~26~~125	Weighted Cost of Common	Common Stock	~~Common Stock~~	(Line ~~20~~ 119 * Line ~~23~~ 122)	~~0.00%~~0
~~27~~126	Rate of Return on Rate Base (ROR)			(Sum Lines ~~24~~ 123 to ~~26~~ 125)	~~0.00%~~0
~~28~~127	Investment Return = Rate Base * Rate of Return			**(Line ~~1~~ 52 * Line ~~27~~ 126)**	~~-~~ 0
Composite Income Taxes					
	Income Tax Rates				
~~29~~128	FIT=Federal Income Tax Rate				~~0.00%~~0
~~30~~129	SIT=State Income Tax Rate or Composite				~~0.00%~~0
~~31~~130	p = percent of federal income tax deductible for state purposes			Per ~~State Tax Code~~ state tax code	~~0.00%~~0
~~32~~131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			~~0.00%~~0
~~33~~132	CIT = T / (1-T)				~~0.00%~~0
~~34~~133	1 / (1-T)				~~0.00%~~1
	ITC Adjustment				
~~35~~134	Amortized Investment Tax Credit			Attachment 5	~~-~~ 0
~~36~~135	ITC Adjust. Allocated to Trans. - Grossed Up			(Line ~~35~~ 134 * (1 / (1 - Line ~~32~~ 131)	~~-~~ 0
~~37~~136	Income Tax Component =	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =			~~-~~ 0
~~38~~137	Total Income Taxes				~~-~~ 0

~~PacifiCorp~~

~~Attachment 5 - Cost Support~~

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					Detail/notes
~~Plant in Service Worksheet~~					
~~1~~	Calculation of Transmission Plant In Service	Source	Year	Balance	
~~2~~1	December	p206.58.b	2009		
~~3~~2	January	Monthly Balances	2010		
~~4~~3	February	Monthly Balances	2010		
~~5~~4	March	Monthly Balances	2010		
~~6~~5	April	Monthly Balances	2010		
~~7~~6	May	Monthly Balances	2010		
~~8~~7	June	Monthly Balances	2010		
~~9~~8	July	Monthly Balances	2010		
~~10~~9	August	Monthly Balances	2010		
~~11~~10	September	Monthly Balances	2010		
~~12~~11	October	Monthly Balances	2010		
~~13~~12	November	Monthly Balances	2010		
~~14~~13	December	p207.58.g	2010	~~—~~	
~~15~~14	Transmission Plant In Service	(~~sum lines 2-14) /~~line13)	Projection	~~—~~0	Appendix A input
~~16~~	Calculation of Distribution Plant In Service	Source	Year	Balance	
~~17~~15	December	p206.75.b	2009		
~~18~~16	January	Monthly Balances	2010		
~~19~~17	February	Monthly Balances	2010		
~~20~~18	March	Monthly Balances	2010		
~~21~~19	April	Monthly Balances	2010		
~~22~~20	May	Monthly Balances	2010		
~~23~~21	June	Monthly Balances	2010		
~~24~~22	July	Monthly Balances	2010		
~~25~~23	August	Monthly Balances	2010		
~~26~~24	September	Monthly Balances	2010		
~~27~~25	October	Monthly Balances	2010		
~~28~~26	November	Monthly Balances	2010		
~~29~~27	December	p207.75.g	2010	~~—~~	
~~30~~28	Distribution Plant In Service	(~~sum lines 17-29~~line 27) ~~/13~~	Projection	~~—~~0	
~~31~~	Calculation of Intangible Plant In Service	Source	Year	Balance	
~~32~~29	December	p204.5.b	2009		
~~33~~30	December	p205.5.g	2010	~~—~~	
~~34~~31	Intangible Plant In Service	(~~sum lines 32 & 33~~line 30) ~~/2~~	Projection	~~—~~0	Appendix A input
~~35~~	Calculation of General Plant In Service	Source	Year	Balance	
~~36~~32	December	p206.99.b	2009		
~~37~~33	December	p207.99.g	2010	~~—~~	
~~38~~34	General Plant In Service	(~~sum lines 36 & 37~~line 33) ~~/2~~	Projection	~~—~~0	Appendix A input
~~39~~	Calculation of Production Plant In Service	Source	Year	Balance	
~~40~~35	December	p204.46b	2009		
~~41~~36	January	Monthly Balances	2010		
~~42~~37	February	Monthly Balances	2010		
~~43~~38	March	Monthly Balances	2010		
~~44~~39	April	Monthly Balances	2010		
~~45~~40	May	Monthly Balances	2010		
~~46~~41	March	Monthly Balances	2010		
~~47~~42	April	Monthly Balances	2010		
~~48~~43	August	Monthly Balances	2010		
~~49~~44	September	Monthly Balances	2010		
~~50~~45	October	Monthly Balances	2010		
~~51~~46	November	Monthly Balances	2010		
~~52~~47	December	p205.46.g	2010	~~—~~	
~~53~~48	Production Plant In Service	(~~sum lines 40-52~~line 47) ~~/13~~	Projection	~~—~~0	
~~54~~49	Electric Plant Sold	p207.102.g		~~—~~0	
~~55~~50	Total Plant In Service	(sum lines ~~15~~ 14, ~~30~~ 28, 31, 34	Projection	~~—~~0	Appendix A input
~~Accumulated Depreciation Worksheet~~					

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					Notes
~~56~~	Calculation of Transmission Accumulated Depreciation	Source	Year	Balance	
~~57~~51	December	Prior year p219.25	2009		
~~58~~52	January	Monthly Balances	2010		
~~59~~53	February	Monthly Balances	2010		
~~60~~54	March	Monthly Balances	2010		
~~61~~55	April	Monthly Balances	2010		
~~62~~56	May	Monthly Balances	2010		
~~63~~57	June	Monthly Balances	2010		
~~64~~58	July	Monthly Balances	2010		
~~65~~59	August	Monthly Balances	2010		
~~66~~60	September	Monthly Balances	2010		
~~67~~61	October	Monthly Balances	2010		
~~68~~62	November	Monthly Balances	2010		
~~69~~63	December	p219.25	2010	~~—~~	
~~70~~64	Transmission Accumulated Depreciation	(~~sum lines 57-69~~line 63) ~~/13~~	Projection	~~—~~0	Appendix A input
~~71~~	Calculation of Distribution Accumulated Depreciation	Source	Year	Balance	
~~72~~65	December	Prior year p219.26	2009		
~~73~~66	January	Monthly Balances	2010		
~~74~~67	February	Monthly Balances	2010		
~~75~~68	March	Monthly Balances	2010		
~~76~~69	April	Monthly Balances	2010		
~~77~~70	May	Monthly Balances	2010		
~~78~~71	June	Monthly Balances	2010		
~~79~~72	July	Monthly Balances	2010		
~~80~~73	August	Monthly Balances	2010		
~~81~~74	September	Monthly Balances	2010		

~~Details~~

					~~PacifiCorp~~		
					~~Attachment 5 - Cost Support~~		
~~82~~75	October	Monthly Balances	2010				
~~83~~76	November	Monthly Balances	2010				
~~84~~77	December	p219.26	2010	~~-~~			
~~85~~78	Distribution Accumulated Depreciation	(~~sum lines 72-84~~line 77) ~~/13~~	Projection	~~-~~0			
~~86~~	Calculation of Intangible Accumulated Depreciation	Source	Year	Balance			
~~87~~79	December	Prior year p200.21.c	2009				
~~88~~80	December	p200.21c	2010	~~-~~0			
~~89~~81	Accumulated Intangible Depreciation	(~~sum lines 87 & 88~~line 80) ~~/2~~	Projection	~~-~~0	Appendix A input		
~~90~~	Calculation of General Accumulated Depreciation	Source	Year	Balance			
~~91~~82	December	Prior year p219.28	2009				
~~92~~83	December	p219.28	2010	~~-~~			
~~93~~84	Accumulated General Depreciation	(~~sum lines 91 & 92~~line 83) ~~/2~~	Projection	~~-~~0	Appendix A input		
~~94~~	Calculation of Production Accumulated Depreciation	Source	Year	Balance			
~~95~~85	December	Prior year p219	2009				
~~96~~86	January	Monthly Balances	2010				
~~97~~87	February	Monthly Balances	2010				
~~98~~88	March	Monthly Balances	2010				
~~99~~89	April	Monthly Balances	2010				
~~100~~90	May	Monthly Balances	2010				
~~101~~91	June	Monthly Balances	2010				
~~102~~92	July	Monthly Balances	2010				
~~103~~93	August	Monthly Balances	2010				
~~104~~94	September	Monthly Balances	2010				
~~105~~95	October	Monthly Balances	2010				
~~106~~96	November	Monthly Balances	2010				
~~107~~97	December	p219.20 ~~thru~~ through	2010	~~-~~			
~~108~~98	Production Accumulated Depreciation	(~~sum lines 95-107~~line 97) ~~/13~~	Projection	~~-~~0			
99	Accumulated Depreciation (Total Electric Plant)	(sum lines 64, 78, 84, & 98)	Projection	0	Appendix A input		
0	Total Accumulated Depreciation	(sum lines ~~70~~ 64, ~~85~~ 78, ~~89~~ 81,	Projection	~~-~~0			

~~Materials & Supplies~~

~~45~~	Undistributed Stores Expense	Prior Year	227.16c	~~#REF!~~0		
		Current Year	227.16c	~~#REF!~~0		
		Appendix A input	Projection	0	current end-of-year balance	
		~~Average~~		~~#REF!~~		
~~48~~	Construction Materials & Supplies	Prior Year	227.5c	0		
		Current Year	227.5c	~~-~~0		
		Appendix A input	Projection	0	current end-of-year balance	
		~~Average~~				
~~51~~	Transmission Materials & Supplies	Prior Year	227.8c	0		
		Current Year	227.8c	~~-~~0		
		Appendix A input	Projection	0	current end-of-year balance	
		~~Average~~				

~~ITC Adjustment~~

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				Form No. 1	Transmission ~~Re~~	~~Non-transmission~~	~~Details~~
Amortized Investment Tax Credit					Net Plant Allocator		
~~125~~ ~~Am~~	Utility Investment Tax Credit Adj. - Net (411.4)		~~Company Records /~~	~~-~~0	~~-~~0	~~-~~0	~~Enter Negative~~
Rate Base Adjustment							
	Internal Revenue Code (IRC) 46(f)(1) adjustment to rate base						
		Current beg of year bal	266.6b	0			
		Current end of year bal	266.6h	0			
	Internal Revenue Code (IRC) 46(f)(1) adjustment to rate base		Average	0	0	0	(enter negative in Appendix A)

~~Transmission / Non-transmission Cost Support~~

~~Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions~~					~~Form No. 1~~	~~Transmission~~	~~Non-transmission~~	~~Details~~
~~28~~Land	~~Land Held for Future Use~~	~~(Note B)~~	~~Prior Year~~	~~p.214.47d &~~			~~-~~	
		~~(Note K)~~	~~Current Year~~	~~p.214.47d &~~				
			~~Average~~					
								~~Balance for Appendix A~~

~~Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions~~				~~Form No. 1 Amount~~	~~Transmission Related~~	~~General Related~~	~~W&S Allocator~~	~~General Related Func to Tx~~	~~TOTAL ASSIGNED~~	~~Details~~
~~26~~	~~General Plant Account 397 Directly Assigned to Transmission~~	~~(Note H)~~	~~p.207.94g Prior Year~~							
			~~p.207.94g Current Year~~				~~0.0000%~~			
			~~Average~~							
~~32~~	~~Accumulated General Depreciation Associated with Account 397~~	~~(Note H)~~Prior Year	~~Prior Year~~214.47d	0	0	0				~~Detail for transmission-related value on Attachment 12~~
		Current Year	~~Current Year~~214.47d	~~-~~0	~~-~~0	~~-~~0	~~0.0000%~~			Detail for transmission-related value on Attachment 12
			~~Average~~							
~~83~~	~~Amount of General Depreciation Expense Associated with Account 397~~	~~(Note H)~~Appendix A input	~~Prior Year~~Projection		0					~~current end-of-year balance~~

PacifiCorp
Attachment 5 - Cost Support

Current Year Average				0.0000%

Adjustments to A & G Expense

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Total	Adjusted Total	Adjusted Total	Details
	Allocated Administrative & General Expenses						
Excluded Membership Dues Expense							
					0		
					0		
					0		
					0		
	Total		Appendix A Input		0		
PBOP							
	Fixed PBOP expense		FERC Authorized	-	0		
	Actual PBOP expense		Attachment 17		0		
64	- Actual PBOP expense Adjusted total (Current year actual)		Company Records Appendix A	-	0	- Authorized minus Ac	Current year actual PBOP expense
Property Insurance							
75	Property Insurance Account 924		323.185b	-	0	-	
			Appendix A Input		0		

Regulatory Expense Related to Transmission Cost Support

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1	Transmission Re	Non-transmission	Details
Directly	Directly Assigned A&G						
	Federal Energy Regulatory Commission:						
	Annual Fee		350.30d	0			
72	Regulatory Commission Exp Account 928 Annual Land Use	(Note E)	p323.189b 350.31d	- 0	-	-	Transmission-related items include annual fee, annual land use fee, and transmission rate case expenses
	Transmission Rate Case		350.32d	0			
	Total		sum	0	0	0	

Safety Related Advertising Cost Support

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions		Form No. 1	Safety Related Ap	Non-safety	Details
Directly	Directly Assigned A&G					
76	General Advertising Exp Account 930.1 - Safety-related	p323.191.b	- 0	- 0	- 0	Based on FERC 930.1 download

MultiState Workpaper

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions		State 1	State 2	State 3	State 4	State 5	Details
-	Income Tax Rates							
121	SIT=State Income Tax Rate or Composite	(Note G)	0.00%					

Education and Out Reach Cost Support

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions		Form No. 1	Education & Outr	Other	Details
Directly	Directly Assigned A&G					
73	General Advertising Exp Account 930.1 - Education and	p323.191.b	- 0	- 0	- 0	Based on FERC 930.1 download

Excluded Plant Cost Support

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
139	Excluded Transmission Facilities		(Note J)		General Description of the Facilities
	Instructions:			Enter $	
1	Remove book value of investments not to be included in transmission plant in service for filing				
2	If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher, as well as below 69 kV, the following formula will be used:	Example		Or Enter $	
A	Total investment in substation	1,000,000			
B	Identifiable investment in Transmission (provide workpapers)	500,000			
C	Identifiable investment in Distribution (provide workpapers)	400,000			
D	Amount to be excluded (A x (C / (B + C)))	444,444			
					Add more lines if necessary

Prepayments and Prepaid Pension Asset

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				Form No. 1	Adjustments Detail		Prepayments	W&S Allocator	Functionalized to	Description of the Prepayments
43 Incl	Prepayments										
	Prepayments SIT = State Income Tax Rate or Composite	(Note K & N)	Current Year	Form 1 -- p111.57.c	- 0	- Enter Average State Income Tax Rate			0.0000%		Removes intercompany tax prepayments. See note K.
			Prior Year	Form 1 -- p111.57.c							
			Average								

~~PacifiCorp~~
~~Attachment 5 - Cost Support~~

~~Adjustments to Transmission O&M~~

Line	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form 1	Total	~~Adjustments~~Plus	Transmission Rel	~~Details~~
~~59~~	Transmission O&M			~~p.~~321.112~~.~~b	~~—~~0	0	~~—~~0	
	Adjustment for Ancillary Services Accounts 561-561.5							
	(561) Load Dispatching			321.84b	0			
	(561.1) Load Dispatch-Reliability			321.85b	0			
	(561.2) Load Dispatch-Monitor and Operate Transmission System			321.86b	0			
	(561.3) Load Dispatch-Transmission Service and Scheduling			321.87b	0			
	(561.4) Scheduling, System Control and Dispatch Services			321.88b	0			
	(561.5) Reliability, Planning and Standards Development			321.89b	0			
~~60~~	Less: Cost of Providing Ancillary Services Accounts 561.0-5			~~p.321.84-89b~~sum	~~—~~0	0	~~—~~0	~~Adjustment for Ancillary Services Accounts 561-561.5~~
~~61~~	Less: Account 565			~~p.321.96.b~~	~~—~~0	0	~~—~~0	~~None~~

~~Facility Credits under Section 30.9 of the OATT~~

Line	Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Amount	Description & Documentation
Net Re	~~Net Revenue Requirement~~		
~~159~~	Facility Credits under Section 30.9 of the OATT	~~—~~0	~~None~~Appendix A Input
~~161~~	Interest on Network Upgrade Facilities	~~—~~0	~~None~~Appendix A Input

~~Other adjustments to rate base~~

Line	~~Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions~~			Amount	~~Description & Documentation~~
Networ	~~Network Upgrade Balance~~				
		Prior Year	Enter negative	~~—~~0	
		Current Year	Enter negative	~~—~~0	
~~56~~	Network Upgrade Balance	Appendix A input	~~Average~~Projection	0	current end-of-year balance

~~Load Cost Support~~

Line	~~Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions~~			~~12 CP Monthly~~	~~Description & Documentation~~
	~~Network Zonal Service Rate~~				
Transmission Plant					
~~163~~	~~12 CP Monthly Peak~~Depreciation expense (~~MW~~403)	~~(Note I)~~	~~FERC Form 1 page 400~~ 336.7b	~~—~~0	~~FERC Form 1 page 400~~

~~Depreciation Expense~~

Line	~~Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions~~			~~Total~~	~~Description & Documentation~~
	Amortization of limited term electric plant (404)		336.7d	0	
~~81~~	Transmission Depreciation Expense Including Amortization of Limited Term Plant	~~(Note H)~~	~~336.7bd~~sum	~~—~~0	Appendix A Input
General Plant					
	Depreciation expense (403)		336.10b	0	
	Amortization of limited term electric plant (404)		336.10d	0	
~~82~~	General Depreciation Expense Including Amortization of Limited Term Plant	~~(Note H)~~	~~336.10bd~~sum	~~—~~0	Appendix A Input
Intangible plant					
	Amortization of limited term electric plant (404)		336.1d	0	
	Amortization of other electric plant (405)		336.1e	0	
	Total Intangible Amortization		sum	0	Appendix A Input

~~Captial Structure~~

Line	~~Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions~~			~~Beginning of Year~~	~~End of~~	~~Average~~	~~Description & Documentation~~
~~95~~	~~Long Term Interest~~	~~117.62-66.c~~					
					0		
~~96~~	~~Preferred Dividends~~	~~118.29c~~	~~(enter positive)~~				
					0		
	~~Common Stock~~						
~~97~~	~~Proprietary Capital~~	~~112.16c~~					
~~98~~	~~Less Accumulated Other Comprehensive Income Accour~~	~~112.15c~~					
~~99~~	~~Less Preferred Stock~~	~~(Line 106)~~					
~~100~~	~~Less Account 216.1~~	~~112.12c~~					
~~101~~	~~Total Common Stock~~	~~(Line 97 - 98 - 99 - 100)~~					
					0		
	~~Capitalization~~						
~~102~~	~~Long Term Debt~~	~~112.18-19c, 112.21c~~					
~~103~~	~~Less Loss on Reacquired Debt~~	~~111.81c~~					
~~104~~	~~Plus Gain on Reacquired Debt~~	~~113.61c~~					
~~105~~	~~Total Long Term Debt~~	~~(Line 102 - 103 + 104)~~					
~~106~~	~~Preferred Stock~~	~~112.3c~~					
~~107~~	~~Common Stock~~	~~(Line 101)~~		~~—~~	~~—~~0	~~—~~	
~~108~~	**Total** ~~Capitalization~~	~~(Sum Lines 105 to 107)~~		~~—~~sum	~~—~~0	~~—~~Appendix A Input	

PacifiCorp

Attachment 5 - Cost Support

Plant i

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions

Footnotes

15 (Note M)

19 (Note N)

18 (Note N)

6 (Note M)

Accumulated Depreciation Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions

25 (Note M)

8 (Note N)

26 (Note N)

7 (Note M)

Materials & Supplies
Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions

39 (Note N)

42 (Note N)

45 (Note N)

ITC Adjustment
Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions

133

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Transmission / Non-transmission Cost Support
Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions

23 (Notes B & L)

Adjustments to A & G Expense
Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions

63 (Note C)

58

70 (Note F)

Regulatory Expense Related to Transmission Cost Support
Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions

Specific Transmission related Regulatory Expenses

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Safety Related Advertising Cost Support
Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions

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Education and Out Reach Cost Support
Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions

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Multistate worksheet

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions

129 (Note G)

Adjustments to Transmission O&M
Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions

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54

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Facility Credits under Section 30.9 of the OATT
Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions

166
168

Other adjustments to rate base
Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions

50 (Note N)

Depreciation Expense
Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions

(Note H)

(Note H)
76 (Note H)

(Note H)
(Note H)
77 (Note H)

(Note H)
(Note H)
78 (Note H)

Less Regulatory Asset Amortizations Account 930.2
Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions

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PacifiCorp

Attachment 6 - Estimate and Reconciliation Worksheet

Instruction Summary

Step	Month	Year	Action
~~Exec Summary~~			
1	April	Year 2	TO populates the formula with Year 1 data from FERC Form No. 1 data for Year 1 (e.g., 2010)
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2011)
3	April	Year 2	TO adds weighted Cap Adds to plant in service in Formula
4	May	Year 2	Post results of Step 3
5	June	Year 2	Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2011 - May 31, 2012)
6	April	Year 3	TO populates the formula with Year 2 data from FERC Form No. 1 for Year 2 (e.g., 2011)
7	April	Year 3	Reconciliation - ~~TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2~~ actual ~~Cap Adds and CWIP in Reconciliation~~ data
			~~(adjusted to include any Reconciliation amount from prior year)~~
8	April	Year 3	TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2012)
~~9~~	~~April~~	~~Year 3~~	~~Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)~~
~~10~~	~~May~~	~~Year 3~~	~~Post results of Step 9 on PacifiCorp OASIS web site~~

Worksheet

~~11~~Step	Month	Year ~~3~~	~~Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2012 - May 31, 2013)~~ Action
1	April	Year 2	TO populates the formula with Year 1 data from FERC Form No. 1 data for Year 1 (e.g., 2010)
			~~$ -~~ 0 — Rev Req based on Year 1 data — Must run Appendix A to get this number (without inputs in lines 16~~, 17~~ or ~~35~~ 34 of Appendix A)
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2011) in projection and populates for actuals as inputs to Attachment 7 (but not Appendix A) for true up.

Plant In Service / CWIP

	(A) Monthly Additions Other Transmission PIS (EXCLUDING GATEWAY)	(B) Monthly Additions Energy Gateway	(C) Monthly Additions Energy Gateway Segment B	(D) Monthly Additions Energy Gateway Segment C	(E) Monthly Additions Energy Gateway Segment D	(F) Monthly Additions Energy Gateway Segment E	(G) Monthly Additions Energy Gateway Segment F	(H) Monthly Additions Energy Gateway Segment G	(I) Monthly Additions Energy Gateway Segment H	(J) Monthly Additions ~~Transmission CWIP~~ Energy Gateway Total ~~(Gateway only~~ Segments A-H)	(K) Monthly Additions ~~Energy Gateway~~ Transmission CWIP ~~Total (Segments A-H~~ Gateway only)	(L) Weighting	~~(M) Other Transmission PIS Amount (A x L)~~	Plant In Service (~~N~~M) ~~Energy Gateway~~ Other Amount (~~K~~A x L) ~~(b0171.2)~~	(~~O~~N) ~~Transmission CWIP~~ Energy Gateway Amount (J x L) ~~(b0487)~~	(~~P~~O) Other Transmission PIS (M / ~~12~~ 13)	(~~Q~~P) Energy Gateway (N / ~~12~~ 13) ~~(b0171.2)~~	CWIP (Q) Transmission CWIP Amount (K x L)	(R) Transmission CWIP (O / ~~12~~ 13) ~~(b0487)~~	(S) Input/Total
CWIP	0	0	0	0	0	0	0	0	0	–0	0	~~12~~13		0	–0	0	0	0	–0	
Jan	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	~~11.5~~12		–0	–0	–0	–0	0	–0	
Feb	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	~~10.5~~11		–0	–0	–0	–0	0	–0	
Mar	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	~~9.5~~10		–0	–0	–0	–0	0	–0	
Apr	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	~~8.5~~9		–0	–0	–0	–0	0	–0	
May	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	~~7.5~~8		–0	–0	–0	–0	0	–0	
Jun	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	~~6.5~~7		–0	–0	–0	–0	0	–0	
Jul	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	~~5.5~~6		–0	–0	–0	–0	0	–0	
Aug	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	~~4.5~~5		–0	–0	–0	–0	0	–0	
Sep	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	~~3.5~~4		–0	–0	–0	–0	0	–0	
Oct	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	~~2.5~~3		–0	–0	–0	–0	0	–0	
Nov	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	~~1.5~~2		–0	–0	–0	–0	0	–0	
Dec	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	~~0.5~~1		–0	–0	–0	–0	0	–0	
Total	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0	–0			–0	–0	–0	–0	0	–0	–

New Transmission Plant Additions and CWIP (weighted by months in service)

Input to Line ~~17~~ 16 of Appendix A		–	–	– / –0
Input to Line ~~35~~ 34 of Appendix A				– / –0
~~Month In Service~~		–	–	–

Estimated Life

Estimated Depreciation for Attachment 7

Jan	11.5	0
Feb	10.5	0
Mar	9.5	0
Apr	8.5	0
May	7.5	0
Jun	6.5	0
Jul	5.5	0
Oct	2.5	0
Nov	1.5	0
Dec	0.5	0
Total Estimated Depreciation for Attachment 7		0

Step	Month	Year	Action
3	April	Year 2	TO adds weighted Cap Adds to plant in service in Formula
			~~$ -~~ 0 — Must run Appendix A to get this number (with inputs ~~on~~ in lines ~~17~~ 16 and ~~35~~ 34 of ~~Attachment~~ Appendix A)
4	May	Year 2	Post results of Step 3
			~~$ -~~ 0 — Must run Appendix A to get this number (with inputs ~~on~~ in lines ~~17~~ 16 and ~~35~~ 34 of ~~Attachment~~ Appendix A)
5	June	Year 2	Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2011 - May 31, 2012)
			~~$ -~~ 0
6	April	Year 3	TO populates the formula with Year 2 data from FERC Form No. 1 for Year 2 (e.g., 2011)
			~~$ -~~ 0 — Rev Req based on Prior Year data — Must run Appendix A to get this number (without inputs in lines 16~~, 17~~ or ~~35~~ 34 of Appendix A)
7	April	Year 3	Reconciliation - ~~TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2~~ actual ~~Cap Adds and CWIP in Reconciliation~~ data
			~~(adjusted to include any Reconciliation amount from prior year)~~

~~Remove all Cap Adds placed in service in Year 2~~

~~For Reconciliation only - remove actual New Transmission Plant Additions for Year 2~~ ~~$ Input to Formula Line 16~~

~~Add weighted Cap Adds actually placed in service in Year 2~~

	~~(A) Monthly Additions Other Transmission PIS (EXCLUDING GATEWAY)~~	~~(B) Monthly Additions Energy Gateway~~	~~(C) Monthly Additions Energy Gateway Segment B~~	~~(D) Monthly Additions Energy Gateway Segment C~~	~~(E) Monthly Additions Energy Gateway Segment D~~	~~(F) Monthly Additions Energy Gateway Segment E~~	~~(G) Monthly Additions Energy Gateway Segment F~~	~~(H) Monthly Additions Energy Gateway Segment G~~	~~(I) Monthly Additions Energy Gateway Segment H~~	~~(J) Monthly Additions Transmission CWIP (Gateway only)~~	~~(K) Monthly Additions Energy Gateway Total (Segments A-H)~~	~~(L) Weighting~~	~~(M) Other Transmission PIS Amount (A x L)~~	~~(N) Energy Gateway Amount (K x L) (b0171.2)~~	~~(O) Transmission CWIP Amount (J x L) (b0487)~~	~~(P) Other Transmission PIS (M / 12)~~	~~(Q) Energy Gateway (N / 12) (b0171.2)~~	~~(R) Transmission CWIP (O / 12) (b0487)~~	~~(S) Total~~
~~CWIP Balance Dec (prior yr.)~~		~~PLACEHOLDERS~~								~~#REF!~~		~~12~~			~~#REF!~~			~~#REF!~~	
~~Jan~~												~~11.5~~							
~~Feb~~												~~10.5~~							
~~Mar~~												~~9.5~~							
~~Apr~~												~~8.5~~							
~~May~~												~~7.5~~							
~~Jun~~												~~6.5~~							
~~Jul~~												~~5.5~~							
~~Aug~~												~~4.5~~							
~~Sep~~												~~3.5~~							
~~Oct~~												~~2.5~~							
~~Nov~~												~~1.5~~							
~~Dec~~												~~0.5~~							
~~Total~~										~~#REF!~~					~~#REF!~~			~~#REF!~~	

~~New Transmission Plant Additions and CWIP (weighted by months in service)~~

~~Input to Line 17 of Appe~~ ~~#REF!~~ ~~#REF!~~

~~Input to Line 35 of Appendix A~~ ~~#REF!~~ ~~#REF!~~

~~Month In Service or Mon~~

~~$ -~~ 0	Result of Formula for Reconciliation	Must run Appendix A to get this number (with inputs in lines 16~~, 17~~ and ~~35~~ 34 of Appendix A)
	~~(Year 2 data with total of Year 2 Cap Adds removed and monthly weighted average of Year 2 actual Cap Adds added in)~~	
~~$ -~~ 0	Schedule 1 Reconciliation	

8	April	Year 3	Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)						
			Transmission						
				Rates in effect in Prior Year times actual loads in each Month					
				Month	Rates Charged	Actual Monthly Loads	Rate x Loads	Less any Prior Year True	Actual Revenues Received
				Jan		–	–		–
				Feb		–	–		–
				Mar		–	–		–
				Apr		–	–		–
				May		–	–		–
				Jun		–	–		–
				Jul		–	–		–
				Aug		–	–		–
				Sep		–	–		–
				Oct		–	–		–
				Nov		–	–		–
				Dec		–	–		–
				Sum					–
			Schedule 1						
				Rates in effect in Prior Year times actual loads in each Month					
				Month	Rates Charged	Actual Monthly Loads	Rate x Loads	Less any Prior Year True	Actual Revenues Received
				Jan		–	–		–
				Feb		–	–		–
				Mar		–	–		–
				Apr		–	–		–
				May		–	–		–
				Jun		–	–		–
				Jul		–	–		–
				Aug		–	–		–
				Sep		–	–		–
				Oct		–	–		–
				Nov		–	–		–
				Dec		–	–		–
				Sum					–

	The Reconciliation in Step 8		Actual Revenues Received		
Transmission Rate	–	-	–	=	–
Schedule 1	–	-	–	=	–
Total	–	-	–	=	–

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March of the Current Yr: 0.0000%

Month	Yr	1/12 of Step 8 (See Note #1)	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jan	Year 1	–	0.0000%	12	–	–
Feb	Year 1	–	0.0000%	11	–	–
Mar	Year 1	–	0.0000%	10	–	–
Apr	Year 1	–	0.0000%	9	–	–
May	Year 1	–	0.0000%	8	–	–
Jun	Year 1	–	0.0000%	7	–	–
Jul	Year 1	–	0.0000%	6	–	–
Aug	Year 2	–	0.0000%	5	–	–
Sep	Year 2	–	0.0000%	4	–	–
Oct	Year 2	–	0.0000%	3	–	–
Nov	Year 2	–	0.0000%	2	–	–
Dec	Year 2	–	0.0000%	1	–	–
Total		–				–

Note #1: For the initial rate year, enter zero for the first five months, June Year 1 through October Year 1. Enter 1/12 of Step 8 for the months Nov Year 1 through May Year 2.

Month	Yr	Balance	Interest rate from above	Amortization over Rate Year	Interest	Balance
Jan	Year 2	–	0.0000%	0	–	
Feb	Year 2	–	0.0000%	0	–	
Mar	Year 2	–	0.0000%	0	–	
Apr	Year 2	–	0.0000%	0	–	
May	Year 2	–	0.0000%	0	–	–
Jun	Year 2	–	0.0000%	–		–
Jul	Year 2	–	0.0000%	–		–
Aug	Year 2	–	0.0000%	–		–
Sep	Year 2	–	0.0000%	–		–
Oct	Year 2	–	0.0000%	–		–
Nov	Year 2	–	0.0000%	–		–
Dec	Year 2	–	0.0000%	–		–
Jan	Year 3	–	0.0000%	–		–
Feb	Year 3	–	0.0000%	–		–
Mar	Year 3	–	0.0000%	–		–
Apr	Year 3	–	0.0000%	–		–
May	Year 3	–	0.0000%	–		–
Total with interest				–		

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest	–
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 9)	$ –
Revenue Requirement for Year 3	–

9	April	Year 3	TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2012)

	(A) Monthly Additions Other Transmission PIS (EXCLUDING GATEWAY)	(B) Monthly Additions Energy Gateway	(C) Monthly Additions Energy Gateway Segment B	(D) Monthly Additions Energy Gateway Segment C	(E) Monthly Additions Energy Gateway Segment D	(F) Monthly Additions Energy Gateway Segment E	(G) Monthly Additions Energy Gateway Segment F	(H) Monthly Additions Energy Gateway Segment G	(I) Monthly Additions Energy Gateway Segment H	(J) Monthly Additions Transmission CWIP (Gateway only)	(K) Monthly Additions Energy Gateway Total (Segments A-H)	(L) Weighting	(M) Other Transmission PIS Amount (A x L)	(N) Energy Gateway Amount (K x L) (b0171.2)	(O) Transmission CWIP Amount (J x L) (b0487)	(P) Other Transmission PIS (M / 12)	(Q) Energy Gateway (N / 12) (b0171.2)	(R) Transmission CWIP (O / 12) (b0487)	(S) Total
CWIP Balance Dec (prior yr.)										–		12			–			–	
Jan	–	–	–	–	–	–	–	–	–	–	–	11.5		–	–	–	–	–	
Feb	–	–	–	–	–	–	–	–	–	–	–	10.5		–	–	–	–	–	
Mar	–	–	–	–	–	–	–	–	–	–	–	9.5		–	–	–	–	–	
Apr	–	–	–	–	–	–	–	–	–	–	–	8.5		–	–	–	–	–	
May	–	–	–	–	–	–	–	–	–	–	–	7.5		–	–	–	–	–	
Jun	–	–	–	–	–	–	–	–	–	–	–	6.5		–	–	–	–	–	
Jul	–	–	–	–	–	–	–	–	–	–	–	5.5		–	–	–	–	–	

	~~Aug~~	–	–	–	–	–	–	–	–	–	–	–	~~4.5~~	–	–	–	–	–	
	~~Sep~~	–	–	–	–	–	–	–	–	–	–	–	~~3.5~~	–	–	–	–	–	
	~~Oct~~	–	–	–	–	–	–	–	–	–	–	–	~~2.5~~	–	–	–	–	–	
	~~Nov~~	–	–	–	–	–	–	–	–	–	–	–	~~1.5~~	–	–	–	–	–	
	~~Dec~~	–	–	–	–	–	–	–	–	–	–	–	~~0.5~~	–	–	–	–	–	
	~~Total~~	–	–	–	–	–	–	–	–	–	–	–		–	–	–	–	–	
	~~New Transmission Plant Additions and CWIP (weighted by months in service)~~																		
															~~Input to Line 17 of Apper~~	–	–	–	–
															~~Input to Line 35 of Appendix A~~			–	–
~~10~~	~~May~~	~~Year 3~~	~~Post results of Step 9 on PacifiCorp OASIS web site~~												~~Month In Service or Mon~~	–	–	–	
			~~$ –~~	~~Post results of Step 3~~															
~~11~~	~~June~~	~~Year 3~~	~~Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2012 - May 31, 2013)~~																
			~~$ –~~																

PacifiCorp

Attachment 7 - Transmission Enhancement Charge Worksheet

Line				
1	New Plant Carrying Charge			
2	Fixed Charge Rate (FCR) if not ~~a~~ Contributions in Aid of Construction (CIAC)			
		Formula Line		
3	A	~~149~~157	Net Plant Carrying Charge without Depreciation	~~0.0000%~~
4	B	~~156~~164	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	~~0.0000%~~
5	C		Line B less Line A	~~0.0000%~~
6	FCR if ~~a~~ CIAC			
7	D	~~150~~158	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	~~0.0000%~~

~~8~~ ~~The FCR resulting from Formula in a given year is used for that year only.~~

~~9~~ ~~Therefore actual revenues collected in a year do not change based on cost data for subsequent years~~

In the True-up, the actual depreciation expense will be used.

Columns and rows may be added to accommodate more projects

Line		Details		Transmission CWIP (EnergyGateway only)				Transmission PIS Projection (Energy Gateway Segment			Transmission PIS Actuals (Energy Gateway Segment B-H)
~~10~~		~~Details~~									
~~11~~8	Useful life of the project	~~Life~~						58			58
~~12~~9	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	~~CIAC~~	~~(Yes or No)~~	No				No			No
~~13~~10	Input the allowed increase in ROE	Increased ROE (~~Basis Points~~basis points)		0				0			0
~~14~~11	From line 3 above if "No" on line 13 and from line 7 above if "Yes" on line 13	~~0% ROE~~		~~0.0000%~~ 0		~~0.0000%~~		~~0.0000%~~ 0	~~0.0000%~~		~~0.0000%~~ 0
~~15~~12	Line 14 plus (line 5 times line 13)/100	~~FCR for This Project~~		~~0.0000%~~ 0		~~0.0000%~~		~~0.0000%~~ 0	~~0.0000%~~		~~0.0000%~~ 0
~~16~~13	~~EOY of PIS from Project subaccount in Account 101~~13 Month Net Plant or ~~106 if not yet classified, average balance~~ CWIP ~~-~~ Balance	~~Investment~~		~~–~~0		–		~~–~~0	–		~~–~~0
~~17~~14	~~Line 16 divided by line 11~~Actual or estimated depreciation expense	Annual Depreciation ~~Exp~~ Expense		~~–~~0		–		~~–~~0	–		~~–~~0
~~18~~	~~Month in which project is placed in service (e.g. Jan=1)~~	~~Month In Service~~		~~–~~		–		~~–~~	–		~~–~~

Line		Details	Invest Yr	~~Beginning~~13 Mo	Depreciation	~~Ending~~	~~Revenue~~	~~Beginning~~	~~Depreciation~~	~~Ending~~	Revenue	~~Beginning~~13 Month	~~Depreciation~~	~~Ending~~	~~Revenue~~	~~Beginning~~	Depreciation	~~Ending~~	Revenue	~~Beginning~~13 Month	~~Depreciation~~	~~Ending~~	~~Revenue~~	Total	Incentive Charged	Without Incentive
~~19~~																										
15		W 0 % ROE	2010	0	0						0	0					0		0	0				0		0
16		W Increased ROE	2010	0	0						0	0					0		0	0				0	0	
~~20~~17		W 0 % ROE	2011	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~	–	–	–	~~$ –~~0		~~$ –~~0
~~21~~18		W Increased ROE	2011	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0	~~$ –~~0	
~~22~~19		W 0 % ROE	2012	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0		~~$ –~~0
~~23~~20		W Increased ROE	2012	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0	~~$ –~~0	
~~24~~21		W 0 % ROE	2013	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0		~~$ –~~0
~~25~~22		W Increased ROE	2013	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0	~~$ –~~0	
~~26~~23		W 0 % ROE	2014	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0		~~$ –~~0
~~27~~24		W Increased ROE	2014	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0	~~$ –~~0	
~~28~~25		W 0 % ROE	2015	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0		~~$ –~~0
~~29~~26		W Increased ROE	2015	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0	~~$ –~~0	
~~30~~27		W 0 % ROE	2016	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0		~~$ –~~0
~~31~~28		W Increased ROE	2016	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0	~~$ –~~0	
~~32~~29		W 0 % ROE	2017	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0		~~$ –~~0
~~33~~30		W Increased ROE	2017	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0	~~$ –~~0	
~~34~~31		W 0 % ROE	2018	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0		~~$ –~~0
~~35~~32		W Increased ROE	2018	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0	~~$ –~~0	
~~36~~33		W 0 % ROE	2019	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0		~~$ –~~0
~~37~~34		W Increased ROE	2019	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0	~~$ –~~0	
~~38~~35		W 0 % ROE	2020	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0		~~$ –~~0
~~39~~36		W Increased ROE	2020	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0	~~$ –~~0	
~~40~~37		W 0 % ROE	2021	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0		~~$ –~~0
~~41~~38		W Increased ROE	2021	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0	~~$ –~~0	
~~42~~39		W 0 % ROE	2022	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0		~~$ –~~0
~~43~~40		W Increased ROE	2022	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0	~~$ –~~0	
~~44~~41		W 0 % ROE	2023	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0		~~$ –~~0
~~45~~42		W Increased ROE	2023	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0	~~$ –~~0	
~~46~~43		W 0 % ROE	2024	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0		~~$ –~~0
~~47~~44		W Increased ROE	2024	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0	~~$ –~~0	
~~48~~45		W 0 % ROE	2025	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0		~~$ –~~0
~~49~~46		W Increased ROE	2025	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0	~~$ –~~0	
~~50~~47		W 0 % ROE	2026	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0		~~$ –~~0
~~51~~48		W Increased ROE	2026	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0	~~$ –~~0	
~~52~~49		W 0 % ROE	2027	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0		~~$ –~~0
~~53~~50		W Increased ROE	2027	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0	~~$ –~~0	
~~54~~51		W 0 % ROE	2028	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0		~~$ –~~0
~~55~~52		W Increased ROE	2028	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0	~~$ –~~0	
~~56~~53		W 0 % ROE	2029	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0		~~$ –~~0
~~57~~54		W Increased ROE	2029	~~–~~0	~~–~~0	–	–	–	–	–	~~–~~0	~~–~~0	–	–	–	–	~~–~~0	–	~~–~~0	~~–~~0	–	–	–	~~$ –~~0	~~$ –~~0	
~~58~~		~~W 0 % ROE~~	~~2030~~	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	~~$ –~~		~~$ –~~
~~59~~		~~W Increased ROE~~	~~2030~~	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	~~$ –~~	~~$ –~~	
~~60~~55			....					~~....~~	–	~~....~~	~~....~~	~~....~~0	~~....~~	~~....~~	~~....~~	~~....~~	~~–~~0	~~....~~	~~....~~	~~....~~0	~~....~~	~~....~~	~~....~~			~~$ –~~0
~~61~~56			....					~~....~~	~~....~~	~~....~~	~~....~~	~~....~~0	~~....~~	~~....~~	~~....~~	~~....~~		~~....~~	~~....~~	~~....~~0	~~....~~	~~....~~	~~....~~		~~$ –~~0	

~~On the formulas used in the Columns for lines 22+ are as follows~~

~~For Plant in service: (first year means first year the project is placed in service)~~

~~"Beginning" is the investment on line 17 for the first year and is the "Ending" for the prior year after the first year~~

~~"Depreciation" is the annual depreciation in line 18 divided by twelve times the difference of thirteen minus line 19 in the first year and line 18 thereafter if "no" on line 13. "Depreciation" is "0" (zero) if "Yes" on line 13~~

~~"Ending" is "Beginning" less "Depreciation"~~

~~Revenue is "Ending" times line 16 for the current year times the quotient line 19 divided by 13 plus "Depreciation" for the first year and "Ending" times line 16 plus "Depreciation" thereafter~~

PacifiCorp

Attachment 8 - Depreciation Rates

Applied Depreciation Rates by State ~~(%)~~

~~Composite Depreciation Weighting for FY 2010 and Forward~~

~~LN~~Row	A/C	Description	Oregon ~~Allocation Factor~~Balance (a)	Rate (b)		Washington ~~Allocation Factor~~Balance (c)	Rate (d)		California ~~Allocation Factor~~Balance (e)	Rate (f)		Utah ~~Allocation Factor~~Balance (g)	Rate (h)		Wyoming ~~UPL~~ ~~Allocation Factor~~Balance (i)	Rate (j)		~~Wyoming PPL~~AZ, CO, ~~Allocation Factor~~Balance (~~i~~k)	Rate (~~j~~l)		Idaho ~~Allocation Factor~~Balance (~~k~~m)	Rate (~~l~~n)		~~FERC Total Allocation Factor (m)~~	Company ~~Composite~~ Rate (~~n~~o)		~~Formula Depreciation rate~~
1	350.2	Land Rights	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.0135	~~0~~	~~0.00%~~
2	352	Structures and Improvements	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.0131	~~0~~	~~0.00%~~
3	353	Station Equipment	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.0175	~~0~~	~~0.00%~~
4	353.7	Supervisory Equipment	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.0378	~~0~~	~~0.00%~~
5	354	Towers and Fixtures	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.0156	~~0~~	~~0.00%~~
6	355	Poles and Fixtures	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.0263	~~0~~	~~0.00%~~
7	356	Overhead Conductors and Devices	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.0225	~~0~~	~~0.00%~~
8	356.2	Clearing & Grading	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.014	~~0~~	~~0.00%~~
9	357	Underground Conduit	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.0165	~~0~~	~~0.00%~~
10	358	Underground Conductors and Devices	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.0164	~~0~~	~~0.00%~~
11	359	Roads & Trails	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.0139	~~0~~	~~0.00%~~
12		Unclassified Transmission																							0.0203		
			~~0.00%~~	~~0.00~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~
13	389.2	Land Rights	~~0.00%~~	~~0.00%~~0	~~0~~	~~0.00%~~	~~0.00%~~0	~~0~~	~~0.00%~~	~~0.00%~~0	~~0~~	~~0.00%~~	~~0.00%~~0.0232	~~0~~	~~0.00%~~	~~0.00%~~0.0201	~~0~~	~~0.00%~~	~~0.00%~~0	~~0~~	~~0.00%~~	~~0.00%~~0.0201	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~
14	390	Structures and Improvements	~~0.00%~~	~~0.00%~~0.0221	~~0~~	~~0.00%~~	~~0.00%~~0.038	~~0~~	~~0.00%~~	~~0.00%~~0.0238	~~0~~	~~0.00%~~	~~0.00%~~0.0218	~~0~~	~~0.00%~~	~~0.00%~~0.0303	~~0~~	~~0.00%~~	~~0.00%~~0.0206	~~0~~	~~0.00%~~	~~0.00%~~0.0212	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~
15	390.3	Structures and Improvements - Office Panels	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.0667	~~0~~	~~0.00%~~
16	391	Office Furniture and Equipment	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.05	~~0~~	~~0.00%~~
~~17~~	~~391.1~~	~~Office Furniture and Equipment - Mainframe Computers~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~
~~18~~17	391.2	Office Furniture and Equipment - Personal Computers	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.2	~~0~~	~~0.00%~~
~~19~~	~~391.3~~	~~Office Furniture and Equipment - Office Equipment~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~
~~20~~	~~392.1~~	~~Transportation Equipment - Light Trucks & Vans~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~
~~21~~	~~392.3~~	~~Transportation Equipment - Aircraft~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~
~~22~~	~~392.5~~	~~Transportation Equipment - Medium Trucks~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~
~~23~~	~~392.9~~	~~Transportation Equipment - Trailers~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~
~~24~~18	393	Store Equipment	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.04	~~0~~	~~0.00%~~
~~25~~19	394	Tools, Shop and Garage Equipment	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.0417	~~0~~	~~0.00%~~
~~26~~20	395	Laboratory Equipment	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.05	~~0~~	~~0.00%~~
~~27~~	~~396.3~~	~~Power Operated Equipment - Light Power Operated Equipment~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~
~~28~~	~~396.7~~	~~Power Operated Equipment - Heavy Power Operated Equipment~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~
~~29~~21	397	Communication Equipment	~~0.00%~~	~~0.00%~~0.0406	~~0~~	~~0.00%~~	~~0.00%~~0.0524	~~0~~	~~0.00%~~	~~0.00%~~0.0415	~~0~~	~~0.00%~~	~~0.00%~~0.0409	~~0~~	~~0.00%~~	~~0.00%~~0.054	~~0~~	~~0.00%~~	~~0.00%~~0.0318	~~0~~	~~0.00%~~	~~0.00%~~0.0379	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~
~~30~~22	397.2	Communication Equipment - Mobile Radio Equipment	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.0909	~~0~~	~~0.00%~~
~~31~~23	398	Miscellaneous Equipment	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.05	~~0~~	~~0.00%~~
24		Unclassified General		0.0437			0.0549			0.0515			0.043			0.0546			0.0317			0.0381					
			~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~
~~33~~25	302	~~FERC Licensing~~Franchises and Consents	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.0273	~~0~~	~~0.00%~~
~~34~~	~~302.3~~	~~Hydro settlement agreements~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~
~~35~~	~~303~~	~~Misc Intangibles - Major Software~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~
~~36~~	~~303~~	~~Misc Intangibles - SAP~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~
~~37~~	~~303~~	~~Misc Intangibles - Minor Software~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~
~~38~~	~~303~~	~~Misc Intangibles - Other~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~
~~39~~26	303	~~Misc Intangibles - Mining~~Miscellaneous Intangible Plant	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.0485	~~0~~	~~0.00%~~
~~40~~27	390.1	Leasehold Improvements - Gen	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~	~~0~~	~~0.00%~~	~~0.00%~~0.0713	~~0~~	~~0.00%~~

Notes:

1 Depreciation Rates shown in rows 1 through 24 were approved by each of the Company's respective state jurisdictions during the last depreciation study.

2 The columns labeled "Balance" are the amount of investment physically located in each state.

3 The plant balance is updated each month as new plant is added.

4 The balances to be reported in the columns labeled "Balances" in any update are the weighted 13-month average balances for the rate year.

5 "Company Rate" shows the depreciation rate approved by all of the jurisdictions on a total company basis.

6 Unclassified Transmission represents the transmission additions placed in service but not yet classified to a FERC level account. Monthly depreciation is calculated by multiplying the month's beginni

~~1~~7 ~~As~~Unclassified General represents the ~~formula rate is updated each year, the above table will be populated with allocation factors reflecting the approved methods~~ general plant additions placed in ~~o~~

8 Transfers into the General amortized accounts (rows 15 through 20, 22, and 23) are depreciated over the remaining life based on the account life.

9 Depreciation expense for General plant is decreased by the amount that is billed to joint owners for computer hardware.

10 Intangible and Leasehold Improvements (rows 25 through 27) are composite rates based on the 13 month average balance divided into the 2010 amortization expense for each account.

11 Amortization expense for Intangible is decreased by the amount that is billed to joint owners for computer software.

~~2~~12 ~~The Allocation Basis codes in~~If the ~~above table represent the weighting methods to apply to the approved jurisdictional~~ depreciation rates shown differ from the depreciation rates used to calculate ~~c~~

~~SG~~ ~~Site generation~~

New worksheet

PacifiCorp
Attachment 9a - Load Divisor for Projection
Average of current year and prior two years

	OATT (Part III - Network Service)													
Column	e	f1	f2	f3	f4	f5	f6	f7	f8	f9	f10	f11	f12	f
Customer Class RS / SA														Total NFO
Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sept	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ave 12CP	-	-	-	-	-	-	-	-	-	-	-	-	-	-

	Other Service					
Column	j1	j2	j3	j4	j5	j
Customer Class RS / SA						Total OS
Jan	-	-	-	-		-
Feb	-	-	-	-		-
March	-	-	-	-		-
April	-	-	-	-		-
May	-	-	-	-		-
Jun	-	-	-	-		-
Jul	-	-	-	-		-
Aug	-	-	-	-		-
Sept	-	-	-	-		-
Oct	-	-	-	-		-
Nov	-	-	-	-		-
Dec	-	-	-	-		-
Total	-	-	-	-		-
Ave 12CP	-	-	-	-		-

	OATT Part II Long-Term Firm Point-to-Point Transmission Service 2011													
Column	g1	g2	g3	g4	g5	g6	g7	g8	g9	g10	g12	g13	g13	g
Customer Class RS / SA														Total LTP
Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sept	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ave 12CP	-	-	-	-	-	-	-	-	-	-	-	-	-	-

	Total Network & OS	1% Growth	Behind-the Meter	Total Network Load	**Divisor** **Network + OS + LTP**
Jan	-	-	-	-	-
Feb	-	-	-	-	-
March	-	-	-	-	-
April	-	-	-	-	-
May	-	-	-	-	-
Jun	-	-	-	-	-
Jul	-	-	-	-	-
Aug	-	-	-	-	-
Sept	-	-	-	-	-
Oct	-	-	-	-	-
Nov	-	-	-	-	-
Dec	-	-	-	-	-
Total	-	-	-	-	-
Ave 12CP	-	-	-	-	-

New worksheet

PacifiCorp
Attachment 9a1 - Load (Current Year)
YYYY

Column			OATT (Part III - Network Service)													
			e	f1	f2	f3	f4	f5	f6	f7	f8	f9	f10	f11	f12	f
Customer Class RS / SA	Day	Time														Total NFO
Jan			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb			-	-	-	-	-	-	-	-	-	-	-	-	-	-
March			-	-	-	-	-	-	-	-	-	-	-	-	-	-
April			-	-	-	-	-	-	-	-	-	-	-	-	-	-
May			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sept			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oct			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total			-	-	-	-	-	-	-	-	-	-	-	-	-	-

Column			Other Service					
			j1	j2	j3	j4	j5	j
Customer Class RS / SA	Day	Time						Total OS
Jan			-	-	-	-	-	-
Feb			-	-	-	-	-	-
March			-	-	-	-	-	-
April			-	-	-	-	-	-
May			-	-	-	-	-	-
Jun			-	-	-	-	-	-
Jul			-	-	-	-	-	-
Aug			-	-	-	-	-	-
Sept			-	-	-	-	-	-
Oct			-	-	-	-	-	-
Nov			-	-	-	-	-	-
Dec			-	-	-	-	-	-
Total			-	-	-	-	-	-

New worksheet

PacifiCorp

Attachment 9a1 - Load (One Year Prior)

YYYY

Column			OATT (Part III - Network Service)													
			e	f1	f2	f3	f4	f5	f6	f7	f8	f9	f10	f11	f12	f
Customer Class RS / SA	Day	Time														Total NFO
Jan			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb			-	-	-	-	-	-	-	-	-	-	-	-	-	-
March			-	-	-	-	-	-	-	-	-	-	-	-	-	-
April			-	-	-	-	-	-	-	-	-	-	-	-	-	-
May			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sept			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oct			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total			-	-	-	-	-	-	-	-	-	-	-	-	-	-

Column			Other Service					
			j1	j2	j3	j4	j5	j
Customer Class RS / SA	Day	Time						Total OS
Jan			-	-	-	-	-	-
Feb			-	-	-	-	-	-
March			-	-	-	-	-	-
April			-	-	-	-	-	-
May			-	-	-	-	-	-
Jun			-	-	-	-	-	-
Jul			-	-	-	-	-	-
Aug			-	-	-	-	-	-
Sept			-	-	-	-	-	-
Oct			-	-	-	-	-	-
Nov			-	-	-	-	-	-
Dec			-	-	-	-	-	-
Total			-	-	-	-	-	-

New worksheet

PacifiCorp

Attachment 9a1 - Load (Two Years Prior)

YYYY

			OATT (Part III - Network Service)													
Column			e	f1	f2	f3	f4	f5	f6	f7	f8	f9	f10	f11	f12	f
Customer Class RS / SA	Day	Time														Total NFO
Jan			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb			-	-	-	-	-	-	-	-	-	-	-	-	-	-
March			-	-	-	-	-	-	-	-	-	-	-	-	-	-
April			-	-	-	-	-	-	-	-	-	-	-	-	-	-
May			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sept			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oct			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total			-	-	-	-	-	-	-	-	-	-	-	-	-	-

			Other Service					
Column			j1	j2	j3	j4	j5	j
Customer Class RS / SA	Day	Time						Total OS
Jan			-	-	-	-	-	-
Feb			-	-	-	-	-	-
March			-	-	-	-	-	-
April			-	-	-	-	-	-
May			-	-	-	-	-	-
Jun			-	-	-	-	-	-
Jul			-	-	-	-	-	-
Aug			-	-	-	-	-	-
Sept			-	-	-	-	-	-
Oct			-	-	-	-	-	-
Nov			-	-	-	-	-	-
Dec			-	-	-	-	-	-
Total			-	-	-	-	-	-

New worksheet

PacifiCorp
Attachment 9b - Load Divisor for True up

Column	OATT (Part III - Network Service)													
Column	e	f1	f2	f3	f4	f5	f6	f7	f8	f9	f10	f11	f12	f
Customer Class RS / SA														Total NFO
Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sept	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ave 12CP	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Other Service					
j1	j2	j3	j4	j5	j
					Total OS
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-
-	-	-	-		-

Column	OATT Part II Long-Term Firm Point-to-Point Transmission Service														
Column	g1	g2	g3	g4	g5	g6	g7	g8	g19	g10	g11	g12	g13	g14	g15	g
Customer Class RS / SA																Total LTP
Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sept	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ave 12CP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Total Network & OS	Behind-the Meter	Total Network Load
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-

Divisor
Network + OS + LTP
-
-
-
-
-
-
-
-
-
-
-
-
-
-

PacifiCorp

Attachment 10 - Accumulated Amortization of Plant in Service

New worksheet

Plant in Service - Accumulated Amortization Detail

FERC Account	Account Number	Description	Balance
		Attachment 5 input: **Total Accumulated Amortization**	**0**

New worksheet

PacifiCorp
Attachment 11 - Prepayments

Prepayments Detail

FERC Account	Account Number	Account Description	Category	Prior Year-end Balance	Current Year-end Balance	BoY-EoY Average	Other	100% Transmission	Plant-related	Labor-related
		Total Prepayments		$ -	$ -	$ -	$ -	$ -	$ -	$ -

		Other	100% Transmission	Plant-related	Labor-related
Allocator		0.000%	100.000%	0.000%	0.000%
Total Allocated to Transmission by Category		$ -	$ -	$ -	$ -
Appendix A input: **Total Allocated to Transmission**	**$ -**				

New worksheet

PacifiCorp
Attachment 12 - Plant Held for Future Use

Plant/Land Held For Future Use - Assets associated with Transmission at December 31

	Prior year	Current year
Attachment 5 input: **Total - Transmission**	**0**	**0**

		Prior year	Current year
Total - PacifiCorp	214.47d		

New worksheet

PacifiCorp
Attachment 13 - Revenue Credit Detail

Revenue Credit Detail

Other Service (OS) contracts

Description	Revenue	MW	As Filed 1=Revenue credit 0=Denominator Treatment
Att 3 input: **Total OS contract revenue credits**	**0**	0.0	

Short-term revenue

Short-term firm	
PacifiCorp Commercial and Trading (C&T)	
Third parties	
Total short-term firm	0
Short-term non-firm	
PacifiCorp Commercial and Trading (C&T)	
Third parties	
Total short-term non-firm	0

Short term firm and non-firm

PacifiCorp Commercial and Trading (C&T)	0
Third parties	0
Att. 3 input: **Total short term-firm and non-firm revenue**	**0**

New worksheet

PacifiCorp
Attachment 14 - Cost of Capital Detail

					Prior Year (month end)	**Current Year** (month end)											
Appendix A Line	**Operation** to apply to monthly input columns at right	**Appendix A input value** (result of operation specified in column to left on monthly data)	**Description** (Account)	**Reference**	**December**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
86	13-month average	0	Bonds (221)	Form 1, pg 112, ln 18 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
87	13-month average	0	Reacquired Bonds (222)	Form 1, pg 112, ln 19 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
88	13-month average	0	Advances from Associated Companies (223)	Form 1, pg 256, various ln, col a,b	0	0	0	0	0	0	0	0	0	0	0	0	0
89	13-month average	0	Other Long-Term Debt (224)	Form 1, pg 112, ln 21 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
91	13-month average	0	Unamortized Discount (226)	Form 1, pg 112, ln 23 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
92	13-month average	0	Unamortized Debt Expense (181)	Form 1, pg 111, ln 69 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
93	13-month average	0	Unamortized Loss On Reacquired Debt (189)	Form 1, pg 111, ln 81 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
94	13-month average	0	Unamortized Premium (225)	Form 1, pg 112, ln 22 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
95	13-month average	0	Unamortized Gain On Reacquired Debt (257)	Form 1, pg 113, ln 61 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
97	12-month sum	0	Interest on Long Term (427) and Associated Companies (430) **LONG TERM ONLY**	Form 1, pg 257, ln 33 i	0	0	0	0	0	0	0	0	0	0	0	0	0
98	12-month sum	0	Hedging Expense (as noted in Appendix A, Note R)	Company records	0	0	0	0	0	0	0	0	0	0	0	0	0
99	12-month sum	0	Amort Debt Discount and Expense (428)	Form 1, pg 117, ln 63 c (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
100	12-month sum	0	Amort Loss on Reacquired Debt (428.1)	Form 1, pg 117, ln 64 c (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
101	12-month sum	0	Amort Premium (429)	Form 1, pg 117, ln 65 c (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
102	12-month sum	0	Amort Gain on Reacquired Debt (429.1)	Form 1, pg 117, ln 66 c (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
104	13-month average	0	Preferred Stock Issued (204)	Form 1, pg 112, ln 3 c, d	0	0	0	0	0	0	0	0	0	0	0	0	0
105	13-month average	0	Reacquired Capital Stock (217) **PREFERRED ONLY**	Form 1, pg 112, ln 13 c, d (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
106	13-month average	0	Premium on Preferred Stock (207)	Form 1, pg 112, ln 6 c, d (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
107	13-month average	0	Other Paid-In Capital (207-208) **PREFERRED ONLY**	Form 1, pg 112, ln 7 c, d (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
108	13-month average	0	Discount on Capital Stock (213) **PREFERRED ONLY**	Form 1, pg 112, ln 9 c, d (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
109	13-month average	0	Capital Stock Expense (214) **PREFERRED ONLY**	Form 1, pg 112, ln 10 c, d (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
111	12-month sum (enter positive)	0	Preferred Dividend	Form 1, pg 118, ln 29 c	0	0	0	0	0	0	0	0	0	0	0	0	0
112	13-month average	0	Total proprietary Capital	Form 1, pg 112, ln 16 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
114	13-month average	0	Unappropriated Undistributed Subsidiary Earnings (216.1)	Form 1, pg 112, ln 12 c, d	0	0	0	0	0	0	0	0	0	0	0	0	0
115	13-month average (enter negative)	0	Accumulated Other Comprehensive Income (219)	Form 1, pg 112, ln 15 c, d	0	0	0	0	0	0	0	0	0	0	0	0	0
n/a	-	-	Common Stock Issued (201)	Company records	0	0	0	0	0	0	0	0	0	0	0	0	0
n/a	-	-	Other Paid-In Capital (211)	Company records	0	0	0	0	0	0	0	0	0	0	0	0	0

Description		**Total**	**Interest Locks**	**Other**
Unamortized balance for gains and losses on hedges.	(Note R)	0	0	0
Annual amortization for gains and losses on hedges.	(Note R)	0	0	0

PacifiCorp
Attachment 15 - GSU and Associated Equipment

New worksheet

Asset Class 353.40 - GSU (generator step-up) and Associated Equipment &
Asset Class 345 - Accessory Electrical Equipment
(At December 31)

353.4 Class Assets	Acquisition value
Total 353.4 Class Assets	**0**
Wind Generation Facilities	**0**
34.5 kV Facilities	**0**
Appendix A input: **Total Assets to Exclude**	**0**

New worksheet

PacifiCorp
Attachment 16 - Unfunded Reserves

Accounts with Unfunded Reserve Balances contributed by customers
(Dollar values in millions)

Description	Account Calculation	Reserve type	Accrued Liability: SAP Account	Accrued Liability: FERC Account	Charged to: SAP Account	Charged to: FERC Account	Prior year December month end	Current Year December month end	Projection Beg-/End-of-Year Average	Category	By Category 100% Transmission	By Category Plant	By Category Labor	By Category Other	Total Transmission-related Unfunded
Totals							0.0	0.0	0.0		0.000	0.000	0.000	0.000	
										Allocators	100.000%	0.000%	0.000%	0.000%	
										Total ($ millions)	0.000	0.000	0.000	0.000	0.000
										Appendix A input					0

PacifiCorp
Attachment 17 - Post-Retirement Benefits Other Than Pensions (PBOP)

New worksheet

FERC Acct	Description	Expense
	Attachment 5 input: **Total PBOP**	**0**

Notes:

Appendix 2
(Clean Version)

Attachment H-2 of PacifiCorp's OATT

(the Formula Rate Implementation Protocols)

ATTACHMENT H-2
Formula Rate Implementation Protocols
Projections are for Rate Years – June-May
True-Ups are for Calendar Years – January-December

The Transmission Provider's formula transmission rates, including those in Schedules 1, 7 and 8 of the Tariff (but excluding rates or charges in any other Schedule of the Tariff), shall be implemented in accordance with the Formula Rate Implementation Protocols ("Protocols") as set forth below.

For purposes of these Protocols, the term "Interested Party" means a transmission customer of PacifiCorp, a state commission in a state where PacifiCorp serves retail customers, any entity having standing in a Federal Energy Regulatory Commission ("Commission" or "FERC") proceeding investigating the Formula Rate (as defined in Section I.1, below), and staff of FERC.

I. Annual Updates

1. The formula rate template ("Formula") contained in Attachment H-1, which includes Schedule 1 – Scheduling System Control and Dispatch Service as Appendix B to Attachment H-1, and these Protocols together comprise the Transmission Provider's filed rate (collectively, the "Formula Rate") for Transmission Service under the Tariff or transmission agreements incorporating Tariff rates. The Transmission Provider will follow the instructions specified in the Formula Rate to annually calculate (project and subsequently true up as applicable) its Annual Transmission Revenue Requirement ("ATRR") and long-term firm loads to develop rates for Network Integration Transmission Service, Point-to-Point Transmission Service, and ancillary

service Schedule 1 – Scheduling System Control and Dispatch Service, for posting by the Transmission Provider (hereinafter the projection and true-up process is referred to as the "Annual Update").

2. The Formula Rate shall be applicable to service on and after June 1 of a given calendar year through May 31 of the subsequent calendar year ("Rate Year"), subject to review, challenge, and refunds or surcharges with interest, as provided herein. The commencement date of the Transmission Provider's Formula Rate in the first Rate Year shall be the effective date established by the Commission.

3. Each calendar year, the Transmission Provider shall:

(a) By May 15 of the current year, calculate the projected ATRR, and transmission rates for the next Rate Year ("Projection") and Schedule 1 rate for the next Rate Year in accordance with the Formula Rate. The Formula Rate specifies in detail the manner in which the immediately preceding calendar year FERC Form No. 1 data and actual data from the Transmission Provider' books and records shall be used as inputs to the Formula except that: (A) limited projections of current calendar year transmission plant will be forecasted for the applicable Rate Year in the Projection; and (B) limited projections of current calendar year long-term firm loads identified in Attachment 9A to the Formula Rate (columns e, f, g and j) will be calculated and adjusted as appropriate for the applicable Rate Year in the Projection in accordance with Attachment 5;

(b) By May 15 of the current year, calculate the true-up for the Projection for the preceding calendar year in accordance with the Formula Rate ("True-Up").

The True-Up shall use the actual data for such preceding calendar year to calculate the actual charges for that calendar year. The Schedule 1 rate shall not be subject to the True-Up. As part of the True-Up, the Transmission Provider shall calculate refunds or surcharges for each transmission customer identified in Attachment 9B taking service pursuant to the Formula Rate, as follows:

i. At the time of the Annual Update, the Transmission Provider shall recalculate the bills for transmission service of each transmission customer identified in Attachment 9B taking service pursuant to the Formula Rate during the preceding calendar year, based on the actual ATRR and long-term firm loads for that calendar year.

ii. The Transmission Provider shall refund or surcharge, as applicable, to each transmission customer identified in Attachment 9B taking service pursuant to the Formula Rate during the preceding calendar year, the difference between: (A) the amount(s) billed to the transmission customer during such preceding calendar year, and (B) the recalculated bill using PacifiCorp's actual ATRR and long-term firm loads for such preceding calendar year and the transmission customer's actual billing loads for such preceding calendar year. The refund or surcharge shall include interest applied through the date when the refund is paid or the invoice is due. The Schedule 1 rate shall not be subject to a refund or surcharge.

(c) Include with the Annual Update an identification and explanation of each material change ("Material Change"). A Material Change is: (i) any change in the Transmission Provider's accounting policies, practices or procedures (including changes resulting from revisions to FERC's Uniform System of Accounts and/or FERC Form No. 1 reporting requirements and inter-company cost allocation methodologies) from those in effect during the calendar year upon which the most recent actual ATRR was based and that, in the Transmission Provider's reasonable judgment, could impact the Formula Rate, including impact to the ATRR or load divisor; and (ii) any change in the classification of any transmission facility that has been directly assigned and the dollar value of the change that the Transmission Provider has made in the applicable Projection or True-Up; and

(d) Post such Annual Update on May 15, or if May 15 is a Saturday, Sunday or Federal holiday, the first business day thereafter, as well as a populated Formula in fully functional spreadsheets showing the calculation of such Annual Update with documentation supporting such calculation, which includes, but is not limited to, Appendices A and B and Attachments 1 through 18 to the Formula and information supporting the Projection as described in Section I.3(a), above, which information shall include a narrative, and worksheets where appropriate, explaining the source and derivation of any data input to the Formula that is not drawn directly from the Transmission Provider's FERC Form No. 1, as well as the following information for all transmission facilities included in the expected transmission plant additions: (i) expected date of completion; (ii) percent completion status as of the date of the Annual Update; (iii) a one-line diagram of facilities exceeding $5 million in cost; (iv) the estimated total installed cost of the facility; (v) the reason for the facility addition; and (vi) without identifying the transmission customer to the extent such customer information is not public information, upgrade costs paid by a generator or paid by a transmission customer directly to the Transmission Provider, in an accessible location on the Transmission Provider's OASIS website (the date of such posting is referred to herein as the "Publication Date");

(e) File such Annual Update with the Commission as an informational filing on the Publication Date; and

(f) On the Publication Date, notify Interested Parties by email (using the last known email addresses provided to the Transmission Provider) of the website address where the Annual Update posting is located. The Transmission Provider shall use the email list developed from the most recent Annual Update and any other email addresses of individuals who have requested to be included in the Annual Update distribution list.

4. A True-Up for a preceding calendar year shall:

(a) Be based upon the Transmission Provider's FERC Form No. 1 for that calendar year, and, to the extent specified in the Formula Rate, upon the books and records of the Transmission Provider consistent with the Commission's accounting policies and practices; and

(b) Include a variance analysis of the Formula Rate as compared with the projected Formula Rate components contained in the Annual Update establishing the rates for the Rate Year under review, which shows the percentage change of each input to the Formula Rate compared to the preceding Rate Year. The Transmission Provider shall address those changes which, in the Transmission Provider's reasonable judgment, are significant during the Customer Meeting (see Section II.1 below).

5. A change to the Formula Rate inputs related to unamortized abandoned plant, construction work in progress (which is currently set to zero), return on equity incentives, extraordinary property losses, return on equity, depreciation rates for each regulatory jurisdiction that are used to calculate the composite rates applied in the Formula Rate, or Post Employment Benefits Other than Pensions may not be made absent a filing with the Commission pursuant to Federal Power Act ("FPA") Sections 205 or 206. PacifiCorp shall have the right to propose a change to only the following items through a single issue filing under Section 205 of the FPA: (i) cash working capital as provided for in the settlement agreement filed and accepted in ER11-3643, and (ii) amortization rates, and depreciation rates. To the extent any State depreciation rate stated on Attachment 8 of the Formula Rate is modified by any State, PacifiCorp must make a single issue filing under Section 205 of the FPA to incorporate such modification to Attachment 8, to become effective on the same date the modified State depreciation rate became effective.

II. Annual Review Procedures

Each Annual Update shall be subject to the following review procedures ("Annual Review Procedures"). If any of the dates provided for herein fall on a Saturday, Sunday or Federal holiday, then the due date shall be the first business day thereafter:

1. Each year, with at least thirty (30) calendar days written notice, the Transmission Provider shall convene at least one meeting, which shall include at the Transmission Provider's option either video conferencing or webinar/internet conferencing, among Interested Parties ("Customer Meeting") during which the Transmission Provider shall present details about its Annual Update, including an explanation of those changes identified in the variance analysis (see Section I.4.b). The Customer Meeting shall provide Interested Parties the chance to seek information and clarifications from the Transmission Provider about the Annual Update. The first Customer Meeting of a Rate Year shall take place between June 23 and July 10 at a date and time convenient for a majority of the parties and posted on the Transmission Provider's internet website. The Transmission Provider shall also schedule subsequent Customer Meetings as appropriate ("Subsequent Meetings"). The date and time of such Subsequent Meetings shall be posted on the Transmission Provider's internet website and shall include at the Transmission Provider's option either video conferencing or webinar/internet conferencing.

2. Immediately following the Publication Date, Interested Parties may submit requests for information supporting the Annual Update. Interested Parties will have one-hundred and eighty (180) calendar days after the Publication Date to serve reasonable information requests to the Transmission Provider ("Information Request Period"). Such information requests shall be limited to that which is necessary to determine if

the Transmission Provider has properly calculated the Formula Rate for the Annual Update under review, whether the inputs to the True-Up are correct, prudent and otherwise appropriate costs and revenue credits, and whether there have been any Material Changes that affect the Formula Rate calculations.

3. The Transmission Provider shall make a good faith effort to respond to information requests pertaining to the Annual Update within ten (10) business days of receipt of such requests. Such data responses shall be served on all Interested Parties identifying themselves to the Transmission Provider (as set forth in Section I.3(f)). Information requests received after 4 p.m. Pacific Prevailing Time shall be considered received the next business day. In the event the Transmission Provider believes it cannot respond within the ten (10) business day timeframe, it shall notify the requesting party and shall provide an estimate of when the Transmission Provider will provide the requested information.

4. For any information requests under Section II.2 above submitted during the last thirty (30) days of the Information Request Period to which the Transmission Provider fails to respond within ten (10) business days, the Information Request Period shall be extended equal to the greatest number of days beyond the ten (10) business day timeframe that it takes the Transmission Provider to provide the requested information in response to a single information request or set of information requests. In addition, for other good cause, including actions pursuant to Section II.6 below, the Information Request Period may by extended with the written consent of the Transmission Provider, with such consent not to be unreasonably withheld.

5. The Transmission Provider shall make available in a central electronic location all information requests received and all responses to such requests. Each information request received by the Transmission Provider shall become available in the central electronic location within one business day of receipt of such request. Each response by the Transmission Provider shall become available in the central electronic location within one business day of distribution of such response to the party that submitted the information request. The Transmission Provider shall also maintain and post in the same central electronic location a list of Interested Parties identifying themselves to the Transmission Provider.

6. To the extent the Transmission Provider and any Interested Party(ies) are unable to resolve disputes related to information requests submitted during the Information Request Period in accordance with these Protocols, the Transmission Provider or any Interested Party may petition FERC to appoint an Administrative Law Judge as a discovery master after reasonable attempts to resolve the disputes have been made by the Transmission Provider and any Interested Parties. The discovery master shall have the authority to issue binding orders to resolve discovery disputes and compel the production of discovery, as appropriate, in accordance with the Protocols and consistent with FERC's discovery rules.

7. At any time throughout the Information Request Period (as such period may be extended pursuant to Section II.4 above) and up to thirty (30) calendar days after the later of: (i) the close of the Information Request Period, or (ii) receipt of all responses to information requests submitted during the Information Request Period , any Interested Party may review the calculations ("Review Period") and notify the

Transmission Provider in writing of any specific challenges to the application of the Formula Rate ("Preliminary Challenge"). Notice of such Preliminary Challenges shall be promptly posted (at the same location as the Annual Update) by the Transmission Provider.

8. Challenges to the Formula Rate itself shall not be considered a Preliminary Challenge for purposes of these Annual Review Procedures. Modifications to the Formula Rate itself can only be made pursuant to Sections 205 and 206 of the Federal Power Act, as set out in Article V below.

III. Resolution of Annual Update Challenges

1. If the Transmission Provider and any Interested Party have not resolved a Preliminary Challenge to an Annual Update within sixty (60) calendar days after written notification of a Preliminary Challenge, senior management of the Interested Parties may attempt to resolve any outstanding issues ("Senior Management Review"). If the Transmission Provider and any Interested Party's (or Parties') senior management are unable to resolve all issues raised in such party's Preliminary Challenge within thirty (30) calendar days after the Senior Management Review process begins, the Interested Party or Parties may, at any time thereafter, file a formal challenge with the Commission for a period up to three-hundred sixty five (365) calendar days after the Customer Meeting ("Formal Challenge"). An Interested Party may not file a Formal Challenge thereafter. However, any Party may at any time within the period specified above, with or without prior Senior Management Review or submission of a Preliminary Challenge, file a Formal Challenge with the Commission regarding the Formula Rate. For avoidance of doubt and as provided in Article V hereof, nothing

in this section is intended to limit the rights of any Interested Party to file a complaint under the FPA outside the Formal Challenge procedures provided by these Protocols.

2. The Transmission Provider shall promptly post notice of resolution of a Preliminary Challenge (at the same location as the notice of Preliminary Challenges) and shall notify all Interested Parties of such resolution, consistent with the procedures set forth in Section II.5, above.

3. Any and all information produced pursuant to these Protocols may be included in any proceeding concerning the PacifiCorp Formula Rate initiated at FERC pursuant to the FPA, including, but not limited to, a Formal Challenge. Information produced pursuant to these Protocols designated as confidential information and not otherwise publicly available shall be treated as confidential in any such proceeding referenced herein; provided that confidential treatment shall be subject to a later determination by the presiding authority that the material is, in whole or in part, not entitled to confidential treatment.

4. Any Formal Challenge shall be served on the Transmission Provider by electronic service on the date of such filing.

5. There shall be no need for an Interested Party to make a separate Formal Challenge with respect to any action initiated by the Commission *sua sponte*, regarding an Annual Update in order to participate in any resulting Commission proceeding.

6. Failure to make a Preliminary Challenge or Formal Challenge as to any Annual Update shall not act as a bar to a Preliminary Challenge or Formal Challenge related

to any other Annual Update. However, no Preliminary Challenge to an Annual Update shall be permitted after the deadline for written notification of Preliminary Challenges, described in Section II.6.

7. Failure to make a Preliminary Challenge or Formal Challenge with respect to a Material Change as to any Annual Update shall not act as a bar to a Preliminary Challenge or Formal Challenge related to that Material Change in any subsequent Annual Update.

IV. Adjustments to Charges to Reflect Correction of Errors and Resolution of Challenges

For purposes of this Article IV governing mid-Rate Year adjustments of the Annual Update, the following definition of "Material Correction" triggering such adjustment shall apply: adjustment shall be required if correcting the error or otherwise accounting for the change impacts a rate produced by the Formula Rate by +/- two and a half (+/- 2.5) percent or +/- $0.50 kw-yr, whichever is lower. Errors below this materiality threshold will be deferred to the True-Up.

1. If the Transmission Provider identifies an error in the Projection or the FERC Form No. 1 data or data based on the Transmission Provider's books and records that is used as an input to the Projection, or the Transmission Provider is required by applicable law or a court or regulatory body to correct an error, and such error constitutes a Material Correction, as defined above, the Transmission Provider shall correct the error by recalculating the Annual Update in good faith within two (2) calendar months (or such period specifically directed by applicable law, court or regulatory body) and without regard to whether the correction increases or decreases

the Transmission Provider's revenue requirements. All identified errors shall reset the rights of Interested Parties to make information requests and challenges including the deadlines set out in Articles II and III, above, as to the specific errors and related corrective revisions. Invoices sent prior to the correction of the error shall be corrected as part of the True-Up. Notwithstanding the foregoing provisions, inaccuracies in the limited projections provided for in Section I.3.a(A) and (B) are not errors subject to the procedures set forth in this Article IV.

2. Any correction(s) or modification(s) to the Formula Rate True-Up that is (are) determined through the Annual Review Procedures, including resolution(s) of Preliminary Challenges and Formal Challenges, shall be refunded or surcharged the earlier of (i) the next monthly billing cycle after the conclusion of the time to file a Formal Challenge or (ii) the next monthly billing cycle after it is clear that there will be no Formal Challenges. Should a Commission order refunds or surcharges, such refunds or surcharges will be made pursuant to the Commission's order.

3. If the Transmission Provider files any corrections or modifications to its FERC Form No. 1 for any prior year after the window for submitting a Formal Challenge to an Annual Update has expired, and such corrections or modifications affect the charges produced by the True-Up for prior Rate Year(s), the Transmission Provider shall correct the error by recalculating the True-Up for the affected Rate Year(s) in good faith within two (2) calendar months (or such period specifically directed by applicable law, court or regulatory body) and without regard to whether the correction increases or decreases the Transmission Provider's revenue requirements for the affected Rate Year(s). All identified errors shall reset the rights of Interested Parties

and the deadlines set out in Articles II and III, above, only as to such errors and the associated corrective revisions.

4. Except as otherwise specified pursuant to a Commission order, all refunds or surcharges shall be determined with interest calculated in accordance with 18 C.F.R. § 35.19a.

V. Party's Rights and Burden of Proof

1. Nothing in these Protocols affects any rights the Transmission Provider, FERC, or any Interested Party may have under the FPA, including the right of the Transmission Provider to file a change in rates under Section 205 of the FPA or the right of an Interested Party to file a complaint that is not a Formal Challenge at any time under Section 206 of the FPA or other Commission regulation, or for an Interested Party to participate in any Commission proceeding relating to the Formula Rate. Nothing in these Protocols affects or modifies in any manner the procedural and substantive requirements, including requirements relating to the burden of proof, that are otherwise applicable under Commission precedent, regulations, and statute, in such a proceeding. The provisions of these Protocols addressing review and challenge of the Annual Update shall not be construed as limiting the Transmission Provider's, FERC's, or any Interested Party's rights under any applicable provision of the FPA.

2. Failure to have made a Preliminary Challenge or Formal Challenge pursuant to these Protocols shall neither, in any manner, be asserted against a complainant in a proceeding instituted under Section 206 of the FPA nor prejudice or otherwise limit

the complainant's right to relief that may be granted pursuant to Section 206 of the Federal Power Act.

3. Nothing herein is intended to alter the established burden(s) of going forward or burden(s) of proof as applied by the FERC at the time of any proceeding. Notwithstanding and without limiting the foregoing, in any proceeding ordered by FERC in response to a Formal Challenge raised under these Protocols or a proceeding initiated *sua sponte* by the Commission, the Transmission Provider shall have the ultimate burden of proof to establish that: (i) it reasonably applied the Formula Rate; (ii) it reasonably calculated the challenged Annual Update pursuant to the Formula Rate; and (iii) it reasonably adopted and applied any Material Change.

Appendix 2

(Redline Version)

Attachment H-2 of PacifiCorp's OATT

(the Formula Rate Implementation Protocols)

Appendix 2

ATTACHMENT H-2
Formula Rate Implementation Protocols
~~Annual Updates~~Projections are for Rate Years – June-May
True-~~Up Adjustments~~Ups are for Calendar Years – January-December

The Transmission Provider's formula transmission rates, including those in ~~Schedule 1,~~ Schedules 1, 7 and 8 of the Tariff (but excluding rates or charges in any other Schedule of the Tariff), shall be implemented in accordance with the ~~formula rate implementation protocols~~Formula Rate Implementation Protocols ("Protocols") as set forth below~~:~~ .

For purposes of these Protocols, the term "Interested Party" means a transmission customer of PacifiCorp, a state commission in a state where PacifiCorp serves retail customers, any entity having standing in a Federal Energy Regulatory Commission ("Commission" or "FERC") proceeding investigating the Formula Rate (as defined in Section I.1, below), and staff of FERC.

I. ~~I.~~ **Annual Updates**

1. ~~1.~~ The formula rate template (~~"~~"Formula~~"~~") contained in Attachment H-~~1~~1, which includes Schedule 1 – Scheduling System Control and Dispatch Service as Appendix B to Attachment H-1, and these Protocols together comprise the Transmission Provider's filed rate (collectively, the ~~"~~"Formula Rate~~"~~") for Transmission Service under the Tariff~~, as applicable~~ or transmission agreements incorporating Tariff rates. The Transmission Provider will follow the instructions specified in the Formula Rate to annually calculate ~~annually its ATRR for~~(project and subsequently true up as applicable) its Annual Transmission

Revenue Requirement (“ATRR”) and long-term firm loads to develop rates for Network Integration Transmission Service~~ and~~, Point-to-Point Transmission Service, and ancillary service Schedule 1 – Scheduling System Control and Dispatch Service, for posting by the Transmission Provider~~, as applicable.~~ (hereinafter the projection and true-up process is referred to as the “Annual Update”).

2. ~~2.~~ The Formula Rate shall be applicable to service on and after June 1 of a given calendar year through May 31 of the subsequent calendar year (~~"~~“Rate Year~~"~~”), subject to review, challenge, and refunds or surcharges with interest, as provided herein. The commencement date of the Transmission Provider’s Formula ~~Rates under Attachment H-1 and Schedule 1~~Rate in the first Rate Year shall be the effective date established by the Commission.

3. ~~3.~~ Each calendar year, the Transmission Provider shall:

~~(a) Calculate the ATRR by May 15 for the next Rate Year in accordance with the Formula Rate ("Annual Update"). The Formula Rate specifies in detail the manner in which:~~

(a) ~~i. the most recent FERC Form No. 1 data~~By May 15 of the current year, calculate the projected ATRR, and transmission rates for the next Rate Year (“Projection”) and Schedule 1 rate for the next Rate Year in accordance with the Formula Rate. The Formula Rate specifies in detail the manner in which the immediately preceding calendar year FERC Form No. 1 data and actual data from the Transmission Provider’ books and records shall be used as inputs ~~and~~to the Formula except that: (A) limited projections of current calendar year transmission plant will be ~~forecast for the next Rate Year in~~

~~the Annual Update; and~~ forecasted for the applicable Rate Year in the Projection; and (B) limited projections of current calendar year long-term firm loads identified in Attachment 9A to the Formula Rate (columns e, f, g and j) will be calculated and adjusted as appropriate for the applicable Rate Year in the Projection in accordance with Attachment 5;

(b) By May 15 of the current year, calculate the true-up for the Projection for the preceding calendar year in accordance with the Formula Rate ("True-Up"). The True-Up shall use the actual data for such preceding calendar year to calculate the actual charges for that calendar year. The Schedule 1 rate shall not be subject to the True-Up. As part of the True-Up, the Transmission Provider shall calculate refunds or surcharges for each transmission customer identified in Attachment 9B taking service pursuant to the Formula Rate, as follows:

i. At the time of the Annual Update, the Transmission Provider shall recalculate the bills for transmission service of each transmission customer identified in Attachment 9B taking service pursuant to the Formula Rate during the preceding calendar year, based on the actual ATRR and long-term firm loads for that calendar year.

ii. ~~any true-up calculated in accordance with the Formula Rate ("True-Up Adjustment") for the prior calendar year shall be incorporated into the Annual Update for the next Rate Year;~~ The Transmission Provider shall refund or surcharge, as applicable, to each transmission customer identified in Attachment 9B taking service pursuant to the Formula Rate during the preceding calendar year, the difference between: (A) the amount(s) billed to the transmission customer during such preceding calendar year, and (B) the recalculated bill using PacifiCorp's actual ATRR and long-term firm loads for such preceding calendar year and the transmission customer's actual billing loads for such preceding calendar year. The refund or surcharge shall include interest applied through the date when the refund is paid or the invoice is due. The Schedule 1 rate shall not be subject to a refund or surcharge.

~~(b) Interest on any over-recovery or under-recovery of the net revenue requirements shall be calculated in accordance with the Formula true-up worksheet (Attachment 6) in Attachment H-1;~~

~~(c) Calculate the True-Up Adjustment by May 15, which adjustment will be reflected in the next Annual Update. The True-Up Adjustment shall include the actual data for the prior calendar year compared to the data projected in the Annual Updates for the same calendar year (including the penultimate Annual Update for the months of January through May and the most recent Annual Update for the months of June through December);~~

~~(d) Calculate the ATRR values for Transmission Service for the following year which shall be the Annual Update for the following year, plus or minus the True-up Adjustment from the previous year, if any, including interest as explained above;~~

(c) Include with the Annual Update an identification and explanation of each material change ("Material Change"). A Material Change is: (i) any change in the Transmission Provider's accounting policies, practices or procedures (including changes resulting from revisions to FERC's Uniform System of Accounts and/or FERC Form No. 1 reporting requirements and inter-company cost allocation methodologies) from those in effect during the calendar year upon which the most recent actual ATRR was based and that, in the Transmission Provider's reasonable judgment, could impact the Formula Rate, including impact to the ATRR or load divisor; and (ii) any change in the classification of any transmission facility that has been directly assigned and the dollar value of the change that the Transmission Provider has made in the applicable Projection or True-Up; and

(d) ~~(e)~~ Post such Annual Update ~~(each June)~~on May 15, or if May 15 is a Saturday, Sunday or Federal holiday, the first business day thereafter, as well as a populated ~~formula~~Formula in fully functional spreadsheets showing the calculation of such Annual Update ~~and True-Up Adjustment~~ with documentation supporting such calculation ~~as provided in Section I.4, below~~, which includes, but is not limited to, Appendices A and B and Attachments 1 through 18 to the Formula and information supporting the Projection as described in Section I.3(a), above, which information shall include a narrative, and worksheets where appropriate, explaining the source and derivation of any data input to the Formula that is not drawn directly from the Transmission Provider's FERC Form No. 1, as well as the following information for all transmission facilities included in the expected transmission plant additions: (i) expected date of completion; (ii) percent completion status as of the date of the Annual Update; (iii) a one-line diagram of facilities exceeding $5 million in cost;

(iv) the estimated total installed cost of the facility; (v) the reason for the facility addition; and (vi) without identifying the transmission customer to the extent such customer information is not public information, upgrade costs paid by a generator or paid by a transmission customer directly to the Transmission Provider, in an accessible location on the Transmission Provider~~'~~'s OASIS website (the date of such posting is referred to herein as the ~~"~~"Publication Date~~"~~");

(e) ~~(f)~~ File such Annual Update with the Commission as an informational filing on the Publication Date; and

(f) ~~(g) Notify its Transmission Customers~~On the Publication Date, notify Interested Parties by email (using the last known email addresses provided to the Transmission Provider) of the website address where the Annual Update ~~and True-Up Adjustment postings are located.~~ posting is located. The Transmission Provider shall use the email list developed from the most recent Annual Update and any other email addresses of individuals who have requested to be included in the Annual Update distribution list.

4. ~~4. The~~A True-Up ~~Adjustment~~ for ~~the prior~~a preceding calendar year shall:

(a) ~~(a)~~ Be based upon the Transmission Provider's FERC Form No. 1 for that calendar year, and, to the extent specified in the Formula Rate, upon the books and records of the Transmission Provider consistent with the Commission's accounting policies and practices; and

~~(b) Be calculated pro rata based on the months during the calendar year when the ATRR was in effect by multiplying the True-Up Adjustment by the number of months that the ATRR was in effect divided by 12;~~

~~(c) As and to the extent specified in the Formula Rate, provide sufficiently detailed supporting documentation for data (and all adjustments thereto or allocations thereof) that are used to develop the Formula Rate and are not otherwise available directly from the FERC Form No.1; and~~

~~(d) Be subject to review in accordance with the procedures set forth in these Protocols.~~

(b) Include a variance analysis of the Formula Rate as compared with the projected Formula Rate components contained in the Annual Update establishing the rates for the Rate Year under review, which shows the percentage change of each input to the Formula Rate compared to the preceding Rate Year. The Transmission Provider shall address those changes which, in the Transmission Provider's reasonable judgment, are significant during the Customer Meeting (see Section II.1 below).

5. ~~5.~~ A change to the Formula Rate inputs related to unamortized abandoned plant, construction work in progress (which is currently set to zero), return on equity incentives, extraordinary property losses, return on equity, depreciation rates for each regulatory jurisdiction that are used to calculate the composite rates applied in the Formula Rate, or Post Employment Benefits Other than Pensions may not be made absent ~~an appropriate~~a filing with the Commission~~.~~ pursuant to Federal Power Act ("FPA") Sections 205 or 206. PacifiCorp shall have the right to propose a change to only the following items through a single issue filing under Section 205 of the FPA: (i) cash working capital as provided for in the settlement agreement filed and accepted in ER11-3643, and (ii) amortization rates, and depreciation rates. To the

extent any State depreciation rate stated on Attachment 8 of the Formula Rate is modified by any State, PacifiCorp must make a single issue filing under Section 205 of the FPA to incorporate such modification to Attachment 8, to become effective on the same date the modified State depreciation rate became effective.

~~6. If the Transmission Provider files any corrections to its FERC Form No. 1 after the Publication Date of its Annual Update and such corrections would affect the True-Up Adjustment for the prior calendar year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next Rate Year and True-Up Adjustment for the next calendar year, with interest.~~

II. ~~II.~~ Annual Review Procedures

Each Annual Update shall be subject to the following review procedures (~~"~~"Annual Review Procedures~~"~~"). If any of the dates provided for herein fall on a Saturday, Sunday or Federal holiday, then the due date shall be the first business day thereafter:

1. Each year, with at least thirty (30) calendar days written notice, the Transmission Provider shall ~~organize a meeting or conference call among interested parties~~convene at least one meeting, which shall include at the Transmission Provider's option either video conferencing or webinar/internet conferencing, among Interested Parties ("Customer Meeting") during which the Transmission Provider shall present details about its Annual Update~~.~~, including an explanation of those changes identified in the variance analysis (see Section I.4.b). The Customer Meeting shall ~~also~~ provide ~~interested parties~~Interested Parties the chance to seek information and clarifications from the Transmission Provider about the Annual Update. The first Customer Meeting of a Rate Year shall

take place ~~no sooner than ten (10) days after the Publication Date and no later than thirty (30) days after the Publication Date, at a date and time posted on the Transmission Provider's internet website.~~between June 23 and July 10 at a date and time convenient for a majority of the parties and posted on the Transmission Provider's internet website. The Transmission Provider shall also schedule subsequent Customer Meetings as appropriate ("Subsequent Meetings"). The date and time of such Subsequent Meetings shall be posted on the Transmission Provider's internet website and shall include at the Transmission Provider's option either video conferencing or webinar/internet conferencing.

2. ~~Interested parties will have seventy-five (75~~Immediately following the Publication Date, Interested Parties may submit requests for information supporting the Annual Update. Interested Parties will have one-hundred and eighty (180) calendar days after the ~~Customer Meeting~~Publication Date to serve reasonable information requests to the Transmission Provider ~~for information and work papers supporting the Annual Update.~~("Information Request Period"). Such information requests shall be limited to that which is necessary to determine if the Transmission Provider has properly calculated the Formula Rate ~~under review.~~for the Annual Update under review, whether the inputs to the True-Up are correct, prudent and otherwise appropriate costs and revenue credits, and whether there have been any Material Changes that affect the Formula Rate calculations.

3. The Transmission Provider shall make a good faith effort to respond to information requests pertaining to the Annual Update within ~~fifteen~~ten (~~15~~10) business days of receipt of such requests. Such data responses shall be served on all ~~customers~~Interested Parties identifying themselves to the Transmission Provider ~~as interested.~~(as set forth in Section I.3(f)). Information requests received after 4 p.m. Pacific Prevailing Time shall be considered received the next business day. In the event the Transmission Provider believes it cannot respond within the ten (10) business day timeframe, it shall notify the requesting party and shall provide an estimate of when the Transmission Provider will provide the requested information.

4. For any information requests under Section II.2 above submitted during the last thirty (30) days of the Information Request Period to which the Transmission Provider fails to respond within ten (10) business days, the Information Request Period shall be extended equal to the greatest number of days beyond the ten (10) business day timeframe that it takes the Transmission Provider to provide the requested information in response to a single information request or set of information requests. In addition, for other good cause, including actions pursuant to Section II.6 below, the Information Request Period may by extended with the written consent of the Transmission Provider, with such consent not to be unreasonably withheld.

5. The Transmission Provider shall make available in a central electronic location all information requests received and all responses to such requests. Each information request received by the Transmission Provider shall become available in the central electronic location within one business day of receipt of such request. Each response by the Transmission Provider shall become available in the central electronic location

within one business day of distribution of such response to the party that submitted the information request. The Transmission Provider shall also maintain and post in the same central electronic location a list of Interested Parties identifying themselves to the Transmission Provider.

6. To the extent the Transmission Provider and any Interested Party(ies) are unable to resolve disputes related to information requests submitted during the Information Request Period in accordance with these Protocols, the Transmission Provider or any Interested Party may petition FERC to appoint an Administrative Law Judge as a discovery master after reasonable attempts to resolve the disputes have been made by the Transmission Provider and any Interested Parties. The discovery master shall have the authority to issue binding orders to resolve discovery disputes and compel the production of discovery, as appropriate, in accordance with the Protocols and consistent with FERC's discovery rules.

7. ~~4. Any interested party shall have up to one hundred twenty (120) days after the Publication Date (unless such period is extended with the written consent of the Transmission Provider) to~~At any time throughout the Information Request Period (as such period may be extended pursuant to Section II.4 above) and up to thirty (30) calendar days after the later of: (i) the close of the Information Request Period, or (ii) receipt of all responses to information requests submitted during the Information Request Period , any Interested Party may review the calculations (~~"~~"Review Period~~"~~") and~~ to~~ notify the Transmission Provider in writing of any specific challenges~~,~~ to the application of the Formula Rate (~~"~~"Preliminary

Challenge~~"~~”). Notice of such Preliminary Challenges shall be promptly posted (at the same location as the Annual Update) by the Transmission Provider.

8. ~~5.~~ Challenges to the Formula Rate itself shall not be considered a Preliminary Challenge for purposes of these Annual Review Procedures. Modifications to the Formula Rate itself can only be made pursuant to Sections 205 and 206 of the Federal Power Act, as set out in Article V below.

III. ~~III.~~ Resolution of Annual Update Challenges

1. If the Transmission Provider and ~~an interested party who has raised a Preliminary Challenge~~any Interested Party have not resolved a Preliminary Challenge to an Annual Update within sixty (60) calendar days after ~~the deadline for~~ written notification of a Preliminary ~~Challenges, the interested party shall have the right to make a Formal Challenge with the Commission, pursuant to 18 C.F.R. § 385.206, and Sections 206 and/or 306 of the Federal Power Act for a limited~~Challenge, senior management of the Interested Parties may attempt to resolve any outstanding issues (“Senior Management Review”). If the Transmission Provider and any Interested Party’s (or Parties’) senior management are unable to resolve all issues raised in such party’s Preliminary Challenge within thirty (30) calendar days after the Senior Management Review process begins, the Interested Party or Parties may, at any time thereafter, file a formal challenge with the Commission for a period up to ~~eighteen (18) months~~three-hundred sixty five (365) calendar days after the Customer Meeting~~. A party~~ (“Formal Challenge”).

An Interested Party may not file a Formal Challenge thereafter. ~~Challenges to the Formula Rate itself shall not be considered a Formal Challenge for purposes of these Annual Review Procedures~~ However, any Party may at any time within the period specified above, with or without prior Senior Management Review or submission of a Preliminary Challenge, file a Formal Challenge with the Commission regarding the Formula Rate. For avoidance of doubt and as provided in Article V hereof, nothing in this section is intended to limit the rights of any Interested Party to file a complaint under the FPA outside the Formal Challenge procedures provided by these Protocols.

2. The Transmission Provider shall promptly post notice of resolution of a Preliminary Challenge (at the same location as the notice of Preliminary Challenges) and shall notify all Interested Parties of such resolution, consistent with the procedures set forth in Section II.5, above.

3. Any and all information produced pursuant to these Protocols may be included in any proceeding concerning the PacifiCorp Formula Rate initiated at FERC pursuant to the FPA, including, but not limited to, a Formal Challenge. Information produced pursuant to these Protocols designated as confidential information and not otherwise publicly available shall be treated as confidential in any such proceeding referenced herein; provided that confidential treatment shall be subject to a later determination by the presiding authority that the material is, in whole or in part, not entitled to confidential treatment.

4. ~~2.~~ Any Formal Challenge shall be served on the Transmission Provider by electronic service on the date of such filing. ~~However, there shall be no need to make a Formal Challenge or to await conclusion of the time periods in Section II if the Commission already has initiated a proceeding to consider the Annual Update.~~

5. There shall be no need for an Interested Party to make a separate Formal Challenge with respect to any action initiated by the Commission *sua sponte*, regarding an Annual Update in order to participate in any resulting Commission proceeding.

6. Failure to make a Preliminary Challenge or Formal Challenge as to any Annual Update shall not act as a bar to a Preliminary Challenge or Formal Challenge related to any other Annual Update. However, no Preliminary Challenge to an Annual Update shall be permitted after the deadline for written notification of Preliminary Challenges, described in Section II.6.

7. Failure to make a Preliminary Challenge or Formal Challenge with respect to a Material Change as to any Annual Update shall not act as a bar to a Preliminary Challenge or Formal Challenge related to that Material Change in any subsequent Annual Update.

IV. Adjustments to Charges to Reflect Correction of Errors and Resolution of Challenges

For purposes of this Article IV governing mid-Rate Year adjustments of the Annual Update, the following definition of "Material Correction" triggering such adjustment shall apply: adjustment shall be required if correcting the error or otherwise accounting for the change impacts a rate produced by the Formula Rate by +/- two and a half (+/- 2.5) percent or +/- $0.50 kw-yr, whichever is lower. Errors below this materiality threshold will be deferred to the True-Up.

1. If the Transmission Provider identifies an error in the Projection or the FERC Form No. 1 data or data based on the Transmission Provider's books and records that is used as an input to the Projection, or the Transmission Provider is required by applicable law or a court or regulatory body to correct an error, and such error constitutes a Material Correction, as defined above, the Transmission Provider shall correct the error by recalculating the Annual Update in good faith within two (2) calendar months (or such period specifically directed by applicable law, court or regulatory body) and without regard to whether the correction increases or decreases the Transmission Provider's revenue requirements. All identified errors shall reset the rights of Interested Parties to make information requests and challenges including the deadlines set out in Articles II and III, above, as to the specific errors and related corrective revisions. Invoices sent prior to the correction of the error shall be corrected as part of the True-Up. Notwithstanding the foregoing provisions, inaccuracies in the limited projections provided for in Section I.3.a(A) and (B) are not errors subject to the procedures set forth in this Article IV.

2. Any correction(s) or modification(s) to the Formula Rate True-Up that is (are) determined through the Annual Review Procedures, including resolution(s) of Preliminary Challenges and Formal Challenges, shall be refunded or surcharged the earlier of (i) the next monthly billing cycle after the conclusion of the time to file a Formal Challenge or (ii) the next monthly billing cycle after it is clear that there will

be no Formal Challenges. Should a Commission order refunds or surcharges, such refunds or surcharges will be made pursuant to the Commission's order.

3. If the Transmission Provider files any corrections or modifications to its FERC Form No. 1 for any prior year after the window for submitting a Formal Challenge to an Annual Update has expired, and such corrections or modifications affect the charges produced by the True-Up for prior Rate Year(s), the Transmission Provider shall correct the error by recalculating the True-Up for the affected Rate Year(s) in good faith within two (2) calendar months (or such period specifically directed by applicable law, court or regulatory body) and without regard to whether the correction increases or decreases the Transmission Provider's revenue requirements for the affected Rate Year(s). All identified errors shall reset the rights of Interested Parties and the deadlines set out in Articles II and III, above, only as to such errors and the associated corrective revisions.

4. Except as otherwise specified pursuant to a Commission order, all refunds or surcharges shall be determined with interest calculated in accordance with 18 C.F.R. § 35.19a.

V. Party's Rights and Burden of Proof

1. Nothing in these Protocols affects any rights the Transmission Provider, FERC, or any Interested Party may have under the FPA, including the right of the Transmission Provider to file a change in rates under Section 205 of the FPA or the right of an Interested Party to file a complaint that is not a Formal Challenge at any time under Section 206 of the FPA or other Commission regulation, or for an Interested Party to

participate in any Commission proceeding relating to the Formula Rate. Nothing in these Protocols affects or modifies in any manner the procedural and substantive requirements, including requirements relating to the burden of proof, that are otherwise applicable under Commission precedent, regulations, and statute, in such a proceeding. The provisions of these Protocols addressing review and challenge of the Annual Update shall not be construed as limiting the Transmission Provider's, FERC's, or any Interested Party's rights under any applicable provision of the FPA.

2. Failure to have made a Preliminary Challenge or Formal Challenge pursuant to these Protocols shall neither, in any manner, be asserted against a complainant in a proceeding instituted under Section 206 of the FPA nor prejudice or otherwise limit the complainant's right to relief that may be granted pursuant to Section 206 of the Federal Power Act.

3. ~~In~~Nothing herein is intended to alter the established burden(s) of going forward or burden(s) of proof as applied by the FERC at the time of any proceeding. Notwithstanding and without limiting the foregoing, in any proceeding ordered by ~~the Commission~~FERC in response to a Formal Challenge raised under these Protocols or a proceeding initiated *sua sponte* by the Commission, the Transmission Provider ~~will bear~~shall have the ultimate burden of ~~proving that it has properly~~proof to establish that: (i) it reasonably applied the Formula Rate; (ii) it reasonably calculated the challenged Annual Update pursuant to the Formula Rate~~.~~; and (iii) it reasonably adopted and applied any Material Change.

4. ~~In any proceeding initiated under Federal Power Act Sections 206 and/or 306, interested parties seeking to change the Formula Rate shall bear the burden of proof.~~

5. ~~Notwithstanding any refund effective date that may be assigned to such Section 206 or Section 306 proceeding, any change to the Formula Rate or input data that results from such proceeding shall be implemented using the same procedures included in Section IV.~~

6. ~~Each Annual Update shall become final and shall no longer be subject to challenge on the later of: (i) passage of the period for a Formal Challenge, as such period is defined under Section III.1, if no Formal Challenge has been filed and the Commission has not itself initiated a proceeding to consider the True-Up Adjustment; or (ii) a final Commission order issued in response to a Formal Challenge or to a proceeding initiated by the Commission to consider the True-Up Adjustment.~~

7. ~~Any refunds or surcharges resulting from a Formal Challenge shall be calculated, with interest, pursuant to Section IV.~~

8. ~~In the event that the Transmission Provider identifies an error in the Annual Update (or its FERC Form No. 1 or successor form which is used as an input to the Formula Rate), or is required by applicable law or a court or regulatory body to correct an error, the Transmission Provider shall correct such error in good faith and without regard to whether the correction increases or decreases the Transmission Provider's revenue requirements. There will be no mid-Rate Year adjustments. Any such correction will be implemented in the True-Up Adjustment for the next calendar year and Annual Update for the next Rate Year, with interest. Nothing in these Protocols should or may be construed as preventing a customer or the Commission from protesting such correction as inappropriate.~~

~~IV. Adjustments to Charges to Reflect Resolution of Challenges~~

1. ~~Any increase or decrease in charges paid or payable for transmission services that results from the procedures set forth herein shall be incorporated into the Formula Rate and the charges produced by the Formula Rate (with interest)in the Annual Update for the next effective Rate Period. For example, if the procedures set forth herein result in a determination that an increase or decrease in~~

~~the charges paid during year 1 is warranted, the charges payable during year 2 shall reflect: (i) the recovery of any underpayment during year 1 or the rebate of any repayment during year 1, plus (ii) interest. This reconciliation mechanism shall apply in lieu of a mid-Rate Year adjustment and any refunds or surcharges.~~

~~V. Miscellaneous~~

~~Except as specifically provided herein, nothing in these Protocols limits or deprives the Transmission Provider or any interested party of any rights it may otherwise have under Sections 205 or 206 of the Federal Power Act.~~

Appendix 3
(Clean Version)

Schedule 1 of PacifiCorp's OATT

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Transmission Customers Obligated to acquire Scheduling, System Control and Dispatch Service: All Transmission Customers purchasing Long-Term Firm Point-to-Point Transmission Service, Short-Term Firm Point-to-Point Transmission Service, Non-Firm Point-to-Point Transmission Service, or Network Integration Transmission Service from the Transmission Provider shall be required to acquire Scheduling, System Control and Dispatch Service from the Transmission Provider.

Charge for Scheduling, System Control and Dispatch Service: All Transmission Customers required to acquire Scheduling, System Control and Dispatch Service shall pay a charge invoiced monthly for Scheduling, System Control and Dispatch Service equal to the amount set forth below. Charges shall be calculated on an annual basis using the annual revenue requirement derived from the populated formula in this Schedule 1. Annual updates to the Schedule 1 rate shall follow the procedures set forth in Attachment H-2.

1) For Yearly Service, one-twelfth of the Yearly Rate determined pursuant to this Schedule 1 multiplied by either: (1) Reserved Capacity for Point-to-Point Transmission Service or (2) Monthly Network Load calculated

pursuant to Section 34.2 of the Tariff for Network Integration Transmission Service.

2) For Monthly Service, the Monthly Rate determined pursuant to this Schedule 1 multiplied by Reserved Capacity.

3) For Weekly Service, the Weekly Rate determined pursuant to this Schedule 1 multiplied by Reserved Capacity.

4) For Daily On-Peak Service, the Daily On-Peak determined pursuant to this Schedule 1 multiplied by Reserved Capacity.

5) For Daily Off-Peak Service, the Daily Off-Peak determined pursuant to this Schedule 1 multiplied by Reserved Capacity.

6) For Hourly On-Peak Service, the Hourly On-Peak determined pursuant to this Schedule 1 multiplied by Reserved Capacity.

7) For Hourly Off-Peak Service, the Hourly Off-Peak Rate determined pursuant to this Schedule 1 multiplied by Reserved Capacity.

For purposes of charging the rates set forth in this Schedule 1 to Transmission Customers purchasing Point-to-Point Transmission Service, the billing determinants shall be the amount at system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff. The total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 1 times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 1 times the highest amount in megawatts of Reserved Capacity in any hour during such week.

Scheduling, System Control and Dispatch Service to be provided: The Transmission Provider shall ensure that personnel and equipment are adequate to allow for pre-schedules and real-time schedule changes of power deliveries through, out of, within, or into a Transmission Provider's Transmission System in accordance with Sections 13.8 and 14.6 of the Tariff and any scheduling arrangements contained in Network Interconnection and Operating Agreements.

Additional Charges for Use of PacifiCorp Facilities in other Control Areas. A Transmission Customer will be responsible for making its own transmission arrangements to the extent a Transmission Customer takes transmission service on a portion of PacifiCorp's transmission system located in another Control Area. The Transmission Customer will be responsible for a proportionate share of any charges assessed to PacifiCorp by the other Control Area operator for scheduling, system control and dispatch service associated with the Transmission Customer's transmission service. PacifiCorp will directly pass-through the costs it incurs from the Control Areas listed above without additional mark-up.

SCHEDULE 1 FORMULA RATE FOR
SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

See Appendix B of Attachment H-1.

Appendix 3
(Redline Version)

Schedule 1 of PacifiCorp's OATT

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Transmission Customers Obligated to acquire Scheduling, System Control and Dispatch Service: All Transmission Customers purchasing Long-Term Firm Point-to-Point Transmission Service, Short-Term Firm Point-to-Point Transmission Service, Non-Firm Point-to-Point Transmission Service, or Network Integration Transmission Service from the Transmission Provider shall be required to acquire Scheduling, System Control and Dispatch Service from the Transmission Provider.

Charge for Scheduling, System Control and Dispatch Service: All Transmission Customers required to acquire Scheduling, System Control and Dispatch Service shall pay a charge invoiced monthly for Scheduling, System Control and Dispatch Service equal to the amount set forth below. Charges shall be calculated on an annual basis using the annual revenue requirement derived from the populated formula in this Schedule 1. Annual updates to the Schedule 1 rate shall follow the procedures set forth in Attachment H-2.

1) For Yearly Service, one-twelfth of the Yearly Rate determined pursuant to this Schedule 1 multiplied by either: (1) Reserved Capacity for Point-to-Point Transmission Service or (2) Monthly Network Load calculated

pursuant to Section 34.2 of the Tariff for Network Integration Transmission Service.

2) For Monthly Service, the Monthly Rate determined pursuant to this Schedule 1 multiplied by Reserved Capacity.

3) For Weekly Service, the Weekly Rate determined pursuant to this Schedule 1 multiplied by Reserved Capacity.

4) For Daily On-Peak Service, the Daily On-Peak determined pursuant to this Schedule 1 multiplied by Reserved Capacity.

5) For Daily Off-Peak Service, the Daily Off-Peak determined pursuant to this Schedule 1 multiplied by Reserved Capacity.

6) For Hourly On-Peak Service, the Hourly On-Peak determined pursuant to this Schedule 1 multiplied by Reserved Capacity.

7) For Hourly Off-Peak Service, the Hourly Off-Peak Rate determined pursuant to this Schedule 1 multiplied by Reserved Capacity.

For purposes of charging the rates set forth in this Schedule 1 to Transmission Customers purchasing Point-to-Point Transmission Service, the billing determinants shall be the amount at system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff. The total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 1 times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 1 times the highest amount in megawatts of Reserved Capacity in any hour during such week.

Scheduling, System Control and Dispatch Service to be provided: The Transmission Provider shall ensure that personnel and equipment are adequate to allow for pre-schedules and real-time schedule changes of power deliveries through, out of, within, or into a Transmission Provider's Transmission System in accordance with Sections 13.8 and 14.6 of the Tariff and any scheduling arrangements contained in Network Interconnection and Operating Agreements.

Appendix 3

Additional Charges for Use of PacifiCorp Facilities in other Control Areas. A Transmission Customer will be responsible for making its own transmission arrangements to the extent a Transmission Customer takes transmission service on a portion of PacifiCorp's transmission system located in another Control Area. The Transmission Customer will be responsible for a proportionate share of any charges assessed to PacifiCorp by the other Control Area operator for scheduling, system control and dispatch service associated with the Transmission Customer's transmission service. PacifiCorp will directly pass-through the costs it incurs from the Control Areas listed above without additional mark-up.

Appendix 3

SCHEDULE 1 FORMULA RATE FOR SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

See Appendix B of Attachment H-1.

~~PacifiCorp~~
~~Scheduling, System Control and Dispatch Service~~
~~Schedule 1~~

~~Line~~	~~Description~~	~~FERC Form 1 page #/ Ref.~~	~~Amount~~
~~1~~	~~(561.0) Load Dispatching~~	~~pg. 321.84b~~	~~-~~
~~2~~	~~(561.1) Load Dispatch-Reliability~~	~~pg. 321.85b~~	~~-~~
~~3~~	~~(561.2) Load Dispatch-Monitor and Operate Transmission System~~	~~pg. 321.86b~~	~~-~~
~~4~~	~~561.3) Load Dispatch-Transmission Service and Scheduling~~	~~pg. 321.87b~~	~~-~~
~~5~~	~~(561.4) Scheduling, System Control and Dispatch Services~~	~~pg. 321.88b~~	~~-~~
~~6~~	~~(561.5) Reliability, Planning and Standards Development~~	~~pg. 321.89b~~	~~-~~
~~7~~	~~Total 561 Costs for Schedule 1 Annual Revenue Requirement~~	~~(sum of Ln 1 through Ln 6)~~	~~-~~
~~8~~	~~Schedule 1 Annual Costs~~	~~(Ln 7)~~	~~-~~
~~9~~	~~Prior Year True Up~~	~~Attachment 6 of OATT Attachment H-1~~	~~-~~
~~10~~	~~Schedule 1 Annual Revenue Requirement~~	~~(ln 8 + Ln 9)~~	~~-~~
	~~**Schedule 1 - Rate Calculations**~~		
~~11~~	~~Average 12-Month Demand - Current Year (kW)~~	~~Divisor~~	
~~12~~	~~Rate in $/kW - Yearly~~	~~(Ln 10/Ln 11)~~	~~-~~
~~13~~	~~Rate in $/kW - Monthly~~	~~((Ln 10/Ln 11)/12)~~	~~-~~
~~14~~	~~Rate in $/kW - Weekly~~	~~((Ln 10/Ln 11)/52)~~	~~-~~
~~15~~	~~Rate in $/kW - Daily On-Peak~~	~~(Ln 14/5)~~	~~-~~
~~16~~	~~Rate in $/kW - Daily Off-Peak~~	~~(Ln 14/7)~~	~~-~~
~~17~~	~~Rate in $/MW - Hourly On-Peak~~	~~((Ln 15/16) * 1000)~~	~~-~~
~~18~~	~~Rate in $/MW - Hourly Off-Peak~~	~~((Ln 16/24) * 1000)~~	~~-~~

~~Notes:~~
~~1 Projected Annual Revenue Requirement ("ARR") is based on prior year FERC Form 1 data (lines 1-6 for the prior year) and becomes effective with the projected ATRR.~~

Appendix 3

~~2 Prior year True-up Adjustment is calculated on Attachment 6 to Attachment H-1 of this Tariff as well as the related interest on prior year true-up.~~

Appendix 4
(Clean Version)

Schedule 2 of PacifiCorp's OATT

SCHEDULE 2

Reactive Supply and Voltage Control from Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator subject to any credits provided pursuant to applicable PacifiCorp business practices. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator.

Transmission Customers Obligated to acquire Reactive Supply and Voltage Control from Generation Sources Service: All Transmission Customers purchasing Long-Term Firm Point-to-Point Transmission Service, Short-Term Firm Point-to-Point Transmission Service, Non-Firm Point-to-Point Transmission Service, or Network Integration Transmission Service from the Transmission Provider shall be required to acquire Reactive Supply and Voltage Control from Generation Sources Service from the Transmission Provider.

Charge for Reactive Supply and Voltage Control from Generation Sources Service: For Point-To-Point Transmission Service, the rate shall be applied to the Transmission Customer's Reserved Capacity. For purposes of charging the rates set forth in this Schedule 2 to Transmission Customers purchasing Point-to-Point Transmission Service, the billing determinants shall be the amount at system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff. For Network Integration Transmission Service, the rate shall be applied to the Transmission Customer's Monthly Network Load.

1.	Yearly Rate	$0.55/kW/Year
2.	Monthly Rate	$0.046/kW/Month
3.	Weekly Rate	$0.011/kW/Week
4.	Daily Rate	$0.001/kW/Day
5.	Hourly Rate	$0.063/MWh

The total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 2 times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 2 times the highest amount in megawatts of Reserved Capacity in any hour during such week

Reactive Supply and Voltage Control from Generation Sources Service to be Provided: The Transmission Provider shall ensure that generation interconnected with its Transmission System meets the voltage support and reactive control requirements of the Western Electricity Coordinating Council.

Appendix 4
(Redline Version)

Schedule 2 of PacifiCorp's OATT

SCHEDULE 2

Reactive Supply and Voltage Control from Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator subject to any credits provided pursuant to applicable PacifiCorp business practices. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator.

Transmission Customers Obligated to acquire Reactive Supply and Voltage Control from Generation Sources Service: All Transmission Customers purchasing Long-Term Firm Point-to-Point Transmission Service, Short-Term Firm Point-to-Point Transmission Service, Non-Firm Point-to-Point Transmission Service, or Network Integration Transmission Service from the Transmission Provider shall be required to acquire Reactive Supply and Voltage Control from Generation Sources Service from the Transmission Provider.

Appendix 4

Charge for Reactive Supply and Voltage Control from Generation Sources Service: For Point-To-Point Transmission Service, the rate shall be applied to the Transmission Customer's Reserved Capacity. For purposes of charging the rates set forth in this Schedule 2 to Transmission Customers purchasing Point-to-Point Transmission Service, the billing determinants shall be the amount at system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff. For Network Integration Transmission Service, the rate shall be applied to the Transmission Customer's Monthly Network Load.

1.	Yearly Rate	$~~1.136~~0.55/kW/Year
2.	Monthly Rate	$~~0.095~~0.046/kW/Month
3.	Weekly Rate	$~~0.022~~0.011/kW/Week
4.	Daily Rate~~, On-Peak~~	$~~0.004~~0.001/kW/Day
5.	~~Daily~~Hourly Rate~~, Off-Peak~~	~~$0.003/kW/Day~~

~~6. Hourly Rate, On-Peak $0.273/MWh7. Hourly Rate, Off-Peak $0.130~~ $0.063/MWh

The total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 2 times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 2 times the highest amount in megawatts of Reserved Capacity in any hour during such week

Reactive Supply and Voltage Control from Generation Sources Service to be ~~provided~~Provided: The Transmission Provider shall ensure that generation interconnected with its Transmission System meets the voltage support and reactive control requirements of the Western Electricity Coordinating Council.

Appendix 5
(Clean Version)

Schedule 3 of PacifiCorp’s OATT

SCHEDULE 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the Transmission Service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation as further described in applicable PacifiCorp business practices. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Charge for Regulation and Frequency Response Service: The charges below apply to all Network Integration Transmission Service. Firm imports do not reduce the load obligation.

The rates below are applied to the Transmission Customer's Monthly Network Load for Network Integration Transmission Service.

1.	Yearly Rate	$2.900/kW/Year
2.	Monthly Rate	$0.242/kW/Month
3.	Weekly Rate	$0.056/kW/Week
4.	Daily Rate, On-Peak	$0.011/kW/Day
5.	Daily Rate, Off-Peak	$0.008/kW/Day
6.	Hourly Rate, On-Peak	$0.697/MWh
7.	Hourly Rate, Off-Peak	$0.332/MWh

The total charge in any day, including any charges for failure to self-supply as described in the following section, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 3 times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 3 times the highest amount in megawatts of Reserved Capacity in any hour during such week.

Self-Supply: A Network Customer may choose to self-supply its Regulation and Frequency Response Service obligation. Due to the nature of this service a Network Customer must either purchase 100% of its requirements or self-supply 100% of its requirements.

The total Regulation and Frequency Response Service obligation for a Transmission Customer who self-supplies is determined by the currently-effective version of NERC Reliability Standard BAL-001. The requirement is such that the Transmission Customer that is self-supplying Regulation and Frequency Response Service must show, on no less than an annual basis, that it is capable of meeting the requirements of the currently-effective version of BAL-001 consistent with PacifiCorp business practices.

Appendix 5
(Redline Version)

Schedule 3 of PacifiCorp's OATT

SCHEDULE 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the Transmission Service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation as further described in applicable PacifiCorp business practices. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Charge for Regulation and Frequency Response Service: ~~A Transmission Customer purchasing Regulation and Frequency Response Service will be required to purchase an amount of reserved capacity equal to 4.24 percent of the Transmission Customer's Reserved Capacity for Point-to-Point Transmission Service or 4.24 percent of the Transmission Customer's Monthly Network Load for~~The charges below apply to all Network Integration Transmission Service.~~ The billing determinants for this service shall be reduced by any portion of the 4.24 percent purchase obligation that a Transmission Customer obtains from third-parties or supplies itself.The rates below reflect the percentage purchase obligation stated above multiplied by the cost of providing the ancillary services described in this Schedule 3. Accordingly, the~~ Firm imports do not reduce the load obligation.

Appendix 5

The rates below are applied to the ~~amount of the Transmission Customer's Reserved Capacity for Point-to-Point Transmission Service or the~~ Transmission Customer's Monthly Network Load for Network Integration Transmission Service.

1.	Yearly Rate	$~~4.021~~2.900/kW/Year
2.	Monthly Rate	$~~0.335~~0.242/kW/Month
3.	Weekly Rate	$~~0.077~~0.056/kW/Week
4.	Daily Rate, On-Peak	$~~0.015~~0.011/kW/Day
5.	Daily Rate, Off-Peak	$~~0.011~~0.008/kW/Day
6.	Hourly Rate, On-Peak	$~~0.967~~0.697/MWh
7.	Hourly Rate, Off-Peak	$~~0.460~~0.332/MWh

The total charge in any day, including any charges for failure to self-supply as described in the following section, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 3 times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 3 times the highest amount in megawatts of Reserved Capacity in any hour during such week.

Self-Supply: A Network Customer may choose to self-supply its Regulation and Frequency Response Service obligation. Due to the nature of this service a Network Customer must either purchase 100% of its requirements or self-supply 100% of its requirements.

The total Regulation and Frequency Response Service obligation for a Transmission Customer who self-supplies is determined by the currently-effective version of NERC Reliability Standard BAL-001. The requirement is such that the Transmission Customer that is self-supplying Regulation and Frequency Response Service must show, on no less than an annual basis, that it is capable of meeting the requirements of the currently-effective version of BAL-001 consistent with PacifiCorp business practices.

Appendix 6
(Clean Version)

Schedule 3A of PacifiCorp's OATT

SCHEDULE 3A

Generator Regulation and Frequency Response Service

Generator Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Generator Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes for a generator located within the Control Area. The obligation to maintain this balance between resources and the generator's schedule lies with the Transmission Provider (or the Control Area that performs this function for the Transmission Provider).

The Transmission Provider must offer this service when transmission service is provided for a generator physically or electrically located in the Transmission Provider's Control Area. Generator Regulation and Frequency Response Service applies to the extent that a Transmission Customer is not already subject to Regulation and Frequency Response Service provided under Schedule 3. When applicable, the Transmission Customer must either purchase Generator Regulation and Frequency Response Service from the Transmission Provider, self supply the service, or make alternative comparable arrangements, as further described in applicable PacifiCorp business practices which may include self-supplying regulation reserve capacity from generation or non-generation resources or through dynamically scheduling its generation to another Control Area.

The amount of and charges for Generator Regulation and Frequency Response Service are set forth below. To the extent a Control Area performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority. The Transmission Provider may not charge a Transmission Customer for regulation reserves under both Schedule 3 and Schedule 3A for the same transaction.

Charge for Regulation and Frequency Response Service: The charges below apply to service that originates in the PacifiCorp Control Area and terminates in another Control Area including: 1) Long-Term Firm Point-to-Point Transmission Service and 2) Short-Term Firm and Non-Firm Point-to-Point Transmission

Service, assessed based upon the Transmission Customer's hourly usage. The rates below are applied to the amount of the Transmission Customer's Reserved Capacity for Point-to-Point Transmission Service or the Transmission Customer's hourly schedules for Short-Term Firm or Non-Firm Point-to-Point Transmission Service exported from the PacifiCorp Control Area. For purposes of charging the rates set forth in this Schedule 3A to Transmission Customers purchasing Point-to-Point Transmission Service, the billing determinants shall be the amount at system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff.

1.	Yearly Rate	$2.900/kW/Year
2.	Monthly Rate	$0.242/kW/Month
3.	Weekly Rate	$0.056/kW/Week
4.	Daily Rate, On-Peak	$0.011/kW/Day
5.	Daily Rate, Off-Peak	$0.008/kW/Day
6.	Hourly Rate, On-Peak	$0.697/MWh
7.	Hourly Rate, Off-Peak	$0.332/MWh

The total charge in any day, including any charges for failure to self-supply as described in the following section, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 3A times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 3A times the highest amount in megawatts of Reserved Capacity in any hour during such week.

Self-Supply:

A Transmission Customer may choose to self-supply its Generator Regulation and Frequency Response Service obligation. Due to the nature of this service a Transmission Customer must either purchase 100% of its requirements or self-supply 100% of its requirements.

The total Generator Regulation and Frequency Response Service obligation for a Transmission Customer who self-supplies is determined by the currently-effective version of NERC Reliability Standard BAL-001. The requirement is such that the Transmission Customer that is self-supplying Generator Regulation and Frequency Response Service must show, on no less than an annual basis, that it is capable of meeting the requirements of the currently–effective version of BAL-001 consistent with PacifiCorp business practices.

Appendix 6
(Redline Version)

Schedule 3A of PacifiCorp's OATT

SCHEDULE 3A

Generator Regulation and Frequency Response Service

Generator Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Generator Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes for a generator located within the Control Area. The obligation to maintain this balance between resources and the generator’s schedule lies with the Transmission Provider (or the Control Area that performs this function for the Transmission Provider).

The Transmission Provider must offer this service when transmission service is provided for a generator physically or electrically located in the Transmission Provider’s Control Area. Generator Regulation and Frequency Response Service applies to the extent that a Transmission Customer is not already subject to Regulation and Frequency Response Service provided under Schedule 3. When applicable, the Transmission Customer must either purchase Generator Regulation and Frequency Response Service from the Transmission Provider, self supply the service, or make alternative comparable arrangements, as further described in applicable PacifiCorp business practices which may include self-supplying regulation reserve capacity from generation or non-generation resources or through dynamically scheduling its generation to another Control Area.

The amount of and charges for Generator Regulation and Frequency Response Service are set forth below. To the extent a Control Area performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority. The Transmission Provider may not charge a Transmission Customer for regulation reserves under both Schedule 3 and Schedule 3A for the same transaction.

Charge for Regulation and Frequency Response Service:

~~A Transmission Customer purchasing Generator Regulation and Frequency Response Service will be required to purchase an amount of reserved capacity equal to 4.24 percent of~~The charges below apply to service that originates in the PacifiCorp Control Area and terminates in another Control Area including: 1) Long-Term Firm Point-to-Point Transmission Service and 2) Short-Term Firm and Non-Firm Point-to-Point Transmission Service, assessed based upon the Transmission Customer's ~~Reserved Capacity for Point-to-Point Transmission Service or 4.24 percent of the Transmission Customer's Monthly Network Load for Network Integration Transmission Service. The billing determinants for this service shall be reduced by any portion of the 4.24 percent purchase obligation that a Transmission Customer obtains from third parties or supplies itself. The rates below reflect the percentage purchase obligation stated above multiplied by the cost of providing the ancillary services described in this Schedule 3A. Accordingly, the~~hourly usage. The rates below are applied to the amount of the Transmission Customer's Reserved Capacity for Point-to-Point Transmission Service or the Transmission Customer's ~~Monthly Network Load for Network Integration Transmission Service.~~ hourly schedules for Short-Term Firm or Non-Firm Point-to-Point Transmission Service exported from the PacifiCorp Control Area. For purposes of charging the rates set forth in this Schedule 3A to Transmission Customers purchasing Point-to-Point Transmission Service, the billing determinants shall be the amount at system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff.

1.	Yearly Rate	$~~4.021~~2.900/kW/Year
2.	Monthly Rate	$~~0.335~~0.242/kW/Month
3.	Weekly Rate	$~~0.077~~0.056/kW/Week
4.	Daily Rate, On-Peak	$~~0.015~~0.011/kW/Day
5.	Daily Rate, Off-Peak	$~~0.011~~0.008/kW/Day
6.	Hourly Rate, On-Peak	$~~0.967/kW/Day~~0.697/MWh
7.	Hourly Rate, Off-Peak	$~~0.460~~0.332/MWh

The total charge in any day, including any charges for failure to self-supply as described in the following section, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 3A times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 3A times the highest amount in megawatts of Reserved Capacity in any hour during such week.

Self-Supply:

Appendix 6

A Transmission Customer may choose to self-supply its Generator Regulation and Frequency Response Service obligation. Due to the nature of this service a Transmission Customer must either purchase 100% of its requirements or self-supply 100% of its requirements.

The total Generator Regulation and Frequency Response Service obligation for a Transmission Customer who self-supplies is determined by the currently-effective version of NERC Reliability Standard BAL-001. The requirement is such that the Transmission Customer that is self-supplying Generator Regulation and Frequency Response Service must show, on no less than an annual basis, that it is capable of meeting the requirements of the currently–effective version of BAL-001 consistent with PacifiCorp business practices.

Appendix 7
(Clean Version)

Schedule 5 of PacifiCorp's OATT

SCHEDULE 5

Operating Reserve - Spinning Reserve Service

Spinning Reserve Service is needed to serve load in the Control Area (other than load supplied by firm imports for which the reserve capacity is provided by the supplier) and to support exports from the Control Area immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area (other than load supplied by firm imports for which the reserve capacity is provided by the supplier) and to support sales from generators located within the PacifiCorp Control Area. The Transmission Customer must either purchase this service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Charges for Spinning Reserve Service:

The charges below apply to: (1) Network Integration Transmission Service; (2) Long-Term Firm Point-to-Point Transmission Service; (3) Short-Term Firm Point-to-Point Transmission Service; and (4) Short-Term Non-Firm Point-to-Point Transmission Service, assessed based upon hourly usage, for service that requires Spinning Reserve Service, as described in the preceding section and as further described in applicable PacifiCorp business practices.

The rates below are applied to the amount of the Transmission Customer’s hourly load for Network Integration Transmission Service or schedules for Point-to-Point Transmission Service.

For purposes of charging the rates set forth in this Schedule 5 to Transmission Customers purchasing Firm Point-to-Point Transmission Service, the billing determinants shall be the amount at system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff.

The rate to be effective from January 1, 2012 through May 31, 2013 shall be an Hourly Rate of:

- $0.32 MWh

The rate to be effective as of June 1, 2013 shall be an Hourly Rate of:

- $0.39 MWh

Self-Supply:

A Transmission Customer may choose to self-supply all or a portion of its reserve obligation.

The total reserve obligation for a Transmission Customer who self-supplies is determined by the currently-effective version of WECC Regional Reliability Standard BAL-STD-002. The requirement is currently 5% of the hourly load responsibility served by hydro and wind resources and 7% served by thermal resources with at least half required to be Spinning Reserves. For a Transmission Customer choosing to self-supply a portion of its reserve obligation, the billing determinants for supplemental purchases of Schedule 5 reserve service shall be determined by: (1) identifying the difference between the amount self-supplied during each hour each month and the Transmission Customer’s full requirement, as determined by WECC Standard BAL-STD-002; (2) charging the Transmission Customer the Hourly Rate multiplied by the amount of MWs identified in (1) where the Transmission Customer failed to supply its full requirement for each hour, if any failure occurred.

The Transmission Customer shall schedule that portion which it will self-supply and/or supply from third parties up to seven days in advance pursuant to procedures set forth in the business practices of the Transmission Provider. During any period that a Transmission Customer has scheduled self-supply and/or supply from third parties but fails to provide the full amount scheduled due to partial or full forced outage of the generation source or a transmission curtailment or interruption, the Transmission Customer shall purchase the shortfall at the Hourly Rate, as described in the proceeding section.

Charge for Unauthorized Spinning Reserve Service:

A Transmission Customer’s assessment of an unauthorized use charge will include a charge for Spinning Reserve Service in accordance with Schedule 11 to the Tariff. Additionally, any Transmission Customer purchasing Transmission Service from the Transmission Provider in order to serve firm load within the Transmission Provider’s Control Area or firm exports from the Transmission Provider’s Control Area using an import from another Control Area that is found to be interruptible shall be assessed a charge for unauthorized Spinning Reserve Service under this Schedule 5. For the purposes of this Schedule 5, an interruptible import is an import where any generation or transmission element of such import to the Transmission Provider’s Transmission System is interruptible or where any transmission element through, out of, within, or into the Transmission Provider’s Transmission System is interruptible (excluding system contingencies resulting in transmission outages). Any Transmission Customer making such use of the Transmission Provider’s Transmission System and not self-supplying or supplying from third parties such associated spinning reserve requirement shall be responsible to compensate the Transmission Provider for unauthorized Spinning Reserve under this Schedule 5 for the amount of energy scheduled for delivery to the Transmission Provider from such interruptible import at twice the hourly rates set forth above. In addition, upon any actual interruption of such import (excluding system contingencies resulting in transmission outages), the amount of energy scheduled to be delivered from such interruptible import during the time period that Unauthorized Spinning Reserve Service was provided shall be included as part of Energy Imbalance in Schedule 4. Such amount shall be in addition to any amount paid for any other Transmission Service.

Spinning Reserve Service to be Provided:

The Transmission Provider, using its generators controlled by automatic generation control, will provide the capacity required to provide Spinning Reserve Service for a Transmission Customer. Upon an outage of a generation resource for which Spinning Reserve Service has been purchased from the Transmission Provider, the Transmission Provider will provide replacement capacity commencing immediately upon such outage until the earlier of (1) the restoration of such resource to service by the Transmission Customer or (2) the end of ten (10) full minutes after the occurrence of such outage. To the extent that the Transmission Provider determines that a Transmission

Customer's specific Spinning Reserve Requirements are not being fully met through the purchase of Spinning Reserve Service as provided above, the Transmission Provider reserves the right (upon filing with the Commission) to require such Transmission Customer to purchase a greater amount of Spinning Reserve Service.

Appendix 7
(Redline Version)

Schedule 5 of PacifiCorp's OATT

SCHEDULE 5

Operating Reserve - Spinning Reserve Service

Spinning Reserve Service is needed to serve load in the ~~control area~~Control Area (other than load supplied by firm imports for which the reserve capacity is provided by the supplier) and to support ~~firm generation~~ exports from the ~~control area~~Control Area immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area (other than load supplied by firm imports for which the reserve capacity is provided by the supplier) and to support ~~firm~~ sales from generators located within the PacifiCorp ~~control area~~Control Area. The Transmission Customer must either purchase this service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Charges for Spinning Reserve Service:

~~A Transmission Customer purchasing Spinning Reserve Service will be required to purchase an amount of reserved capacity equal to 1.75 percent of the Transmission Customer's Reserved Capacity for Point-to-Point Transmission Service or 1.75 percent of the Transmission Customer's Monthly Network Load for Network Integration Transmission Service. The billing determinants for this service shall be reduced by any portion of the 1.75 percent purchase obligation that a Transmission Customer obtains from third-parties or supplies itself.~~

The charges below apply to: (1) Network Integration Transmission Service; (2) Long-Term Firm Point-to-Point Transmission Service; (3) Short-Term Firm Point-to-Point Transmission Service; and (4) Short-Term Non-Firm Point-to-Point Transmission Service, assessed based upon hourly usage, for service that requires Spinning Reserve Service, as described in the preceding section and as further described in applicable PacifiCorp business practices.

Appendix 7

~~The rates below reflect the percentage purchase obligation stated above multiplied by the cost of providing the ancillary services described in this Schedule 5. Accordingly, the~~The rates below are applied to the amount of the Transmission Customer's ~~Reserved Capacity for Point-to-Point Transmission Service or the Transmission Customer's Monthly Network Load~~hourly load for Network Integration Transmission Service or schedules for Point-to-Point Transmission Service.

For purposes of charging the rates set forth in this Schedule 5 to Transmission Customers purchasing Firm Point-to-Point Transmission Service, the billing determinants shall be the amount at system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff.

The rate to be effective from January 1, 2012 through May 31, 2013 shall be an Hourly Rate of:

- $0.32 MWh

The rate to be effective as of June 1, 2013 shall be an Hourly Rate of:

- $0.39 MWh

Self-Supply:

A Transmission Customer may choose to self-supply all or a portion of its reserve obligation.

The total reserve obligation for a Transmission Customer who self-supplies is determined by the currently-effective version of WECC Regional Reliability Standard BAL-STD-002. The requirement is currently 5% of the hourly load responsibility served by hydro and wind resources and 7% served by thermal resources with at least half required to be Spinning Reserves. For a Transmission Customer choosing to self-supply a portion of its reserve obligation, the billing determinants for supplemental purchases of Schedule 5 reserve service shall be determined by: (1) identifying the difference between the amount self-supplied during each hour each month and the Transmission Customer's full requirement, as determined by WECC Standard BAL-STD-002; (2) charging the Transmission Customer the Hourly Rate multiplied by the amount of MWs identified in (1) where the Transmission Customer failed to supply its full requirement for each hour, if any failure occurred.

Appendix 7

The Transmission Customer shall schedule that portion which it will self-supply and/or supply from third parties up to seven days in advance pursuant to procedures set forth in the business practices of the Transmission Provider. During any period that a Transmission Customer has scheduled self-supply and/or supply from third parties but fails to provide the full amount scheduled due to partial or full forced outage of the generation source or a transmission curtailment or interruption, the Transmission Customer shall purchase the shortfall at the Hourly Rate, as described in the proceeding section.

~~1.~~	~~Yearly Rate~~	~~$1.853/kW/Year~~
~~2.~~	~~Monthly Rate~~	~~$0.154/kW/Month~~
~~3.~~	~~Weekly Rate~~	~~$0.036/kW/Week~~
~~4.~~	~~Daily Rate, On-Peak~~	~~$0.007/kW/Day~~
~~5.~~	~~Daily Rate, Off-Peak~~	~~$0.005/kW/Day~~
~~6.~~	~~Hourly Rate, On-Peak~~	~~$0.445/MWh~~
~~7.~~	~~Hourly Rate, Off-Peak~~	~~$0.212/MWh~~

~~The total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 5 times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 5 times the highest amount in megawatts of Reserved Capacity in any hour during such week.~~

Charge for Unauthorized Spinning Reserve Service:

A Transmission Customer’s assessment of an unauthorized use charge will include a charge for Spinning Reserve Service in accordance with Schedule 11 to the Tariff. Additionally, any Transmission Customer purchasing Transmission Service from the Transmission Provider in order to serve firm load within the Transmission Provider~~'~~’s Control Area or firm exports from the Transmission Provider~~'~~’s Control Area using an import from another Control Area that is found to be interruptible shall be assessed a charge for unauthorized Spinning Reserve Service under this Schedule 5. For the purposes of this Schedule 5, an interruptible import is an import where any generation or transmission element of such import to the Transmission Provider~~'~~’s Transmission System is interruptible or where any transmission element through, out of, within, or into the Transmission Provider~~'~~’s Transmission System is interruptible (excluding system contingencies resulting in transmission outages). Any Transmission Customer making such use of the Transmission Provider~~'~~’s Transmission System and not self-supplying or supplying from third parties such associated spinning reserve requirement shall be responsible to compensate the Transmission Provider for unauthorized Spinning Reserve under this Schedule 5 for the amount of energy scheduled for delivery to the Transmission Provider from such interruptible import at twice the hourly rates set forth above. In addition, upon any actual interruption of such import (excluding system contingencies resulting in transmission outages), the amount of energy scheduled to be delivered from such interruptible import during the time period that Unauthorized Spinning Reserve Service was provided shall be included as part of Energy Imbalance in Schedule 4. Such amount shall be in addition to any amount paid for any other Transmission Service.

Spinning Reserve Service to be Provided:

The Transmission Provider, using its generators controlled by automatic generation control, will provide the capacity required to provide Spinning Reserve Service for a Transmission Customer. Upon an outage of a generation resource for which Spinning Reserve Service has been purchased from the Transmission Provider, the Transmission Provider will provide replacement capacity commencing immediately upon such outage until the earlier of (1) the restoration of such resource to service by the Transmission Customer or (2) the end of ten (10) full minutes after the occurrence of such outage. To the extent that the Transmission Provider determines that a Transmission Customer’s specific Spinning Reserve Requirements are not being fully met through the purchase of Spinning Reserve Service as provided above, the Transmission Provider reserves the right (upon filing with the Commission) to require such Transmission Customer to purchase a greater amount of Spinning Reserve Service.

Appendix 8
(Clean Version)

Schedule 6 of PacifiCorp's OATT

SCHEDULE 6

Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the Control Area (other than load supplied by firm imports for which the reserve capacity is provided by the supplier) and to support exports from the Control Area in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area (other than load supplied by firm imports for which the reserve capacity is provided by the supplier) and to support sales from generators located within the PacifiCorp Control Area. The Transmission Customer must either purchase this service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Charges for Supplemental Reserve Service:

The charges below apply to: 1) Network Integration Transmission Service; 2) Long-Term Firm Point-to-Point Transmission Service; 3) Short-Term Firm Point-to-Point Transmission Service, and (4) Short-Term Non-Firm Point-to-Point Transmission Service, assessed based upon hourly usage, for service that requires Supplemental Reserve Service, as described in the preceding section and as further described in applicable PacifiCorp business practices.

The rates below are applied to the amount of the Transmission Customer’s hourly load for Network Integration Transmission Service or schedules for Point-to-Point Transmission Service. For purposes of charging the rates set forth in this Schedule 6 to Transmission Customers purchasing Firm Point-to-Point Transmission Service, the billing determinants shall be the amount at system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff.

The rate to be effective from January 1, 2012 through May 31, 2013 shall be an Hourly Rate of:

- $0.29 MWh

The rate to be effective as of June 1, 2013 shall be an Hourly Rate of:

- $0.34 MWh

Self-Supply:

A Transmission Customer may choose to self-supply all or a portion of its reserve obligation.

The total reserve obligation for a Transmission Customer who self-supplies is determined by the currently-effective version of WECC Regional Reliability Standard BAL-STD-002. The requirement is currently 5% of the hourly load responsibility served by hydro and wind resources and 7% served by thermal resources with at least half required to be Spinning Reserves. For a Transmission Customer choosing to self-supply a portion of its reserve obligation, the billing determinants for supplemental purchases of Schedule 6 reserve service shall be determined by: (1) identifying the difference between the amount self-supplied during each hour each month and the Transmission Customer's full requirement, as determined by WECC Standard BAL-STD-002; (2) charging the Transmission Customer the Hourly Rate multiplied by the amount of MWs identified in (1) where the Transmission Customer failed to supply its full requirement for each hour, if any failure occurred.

The Transmission Customer shall schedule that portion which it will self-supply and/or supply from third parties up to seven days in advance pursuant to procedures set forth in the Business Practices of the Transmission Provider. During any period that a Transmission Customer has scheduled self-supply and/or supply from third parties but fails to provide the full amount scheduled due to partial or full forced outage of the generation source or a transmission curtailment or interruption, the Transmission Customer shall purchase the shortfall at the hourly rate.

Charge for Unauthorized Supplemental Reserve Service:

A Transmission Customer assessment of an unauthorized use charge will include a charge for Supplemental Reserve Service in accordance with Schedule 11 to the Tariff. Additionally, any Transmission Customer purchasing Transmission Service from the Transmission Provider in order to serve firm load within the Transmission Provider's Control Area or firm exports from the Transmission Provider's Control Area using an import from another Control Area that is found to be interruptible shall be assessed a charge for unauthorized Supplemental Reserve Service under this Schedule 6. For the purposes of this Schedule 6, an interruptible import is an import where any generation or transmission element of such import to the Transmission Provider's Transmission System is interruptible or where any transmission element through, out of, within, or into the Transmission Provider's Transmission System and not self-supplying or supplying from third parties such associated supplemental reserve requirement is interruptible (excluding system contingencies resulting in transmission outages). Any Transmission Customer making such use of the Transmission Provider's Transmission System shall be responsible to compensate the Transmission Provider for unauthorized Supplement Reserve under this Schedule 6 for the amount of energy scheduled for delivery to the Transmission Provider from such interruptible import at twice the hourly rates set forth above. In addition, upon any actual interruption of such import (excluding system contingencies resulting in transmission outages), the amount of energy scheduled to be delivered from such interruptible import during the time period that Unauthorized Supplemental Reserve Service was provided shall be included as part of Energy Imbalance in Schedule 4. Such amount shall be in addition to any amount paid for any other transmission service.

Supplemental Reserve Service to be Provided:

The Transmission Provider, using its generators controlled by automatic generation control, will provide the capacity required to provide Supplemental Reserve Service for a Transmission Customer. Upon an outage of a generation resource for which Supplemental Reserve Service has been purchased from the Transmission Provider, the Transmission Provider will provide replacement capacity commencing at the end of ten (10) full minutes after such outage until the earlier of (1) the restoration of such resource to service by the Transmission

Customer or (2) the end of the first full hour immediately following such outage.

To the extent that the Transmission Provider determines that a Transmission Customer’s specific Supplemental Reserve Requirements are not being fully met through the purchase of Supplemental Reserve Service as provided above, the Transmission Provider reserves the right (upon filing with the Commission) to require such Transmission Customer to purchase a greater amount of Supplemental Reserve Service.

Appendix 8
(Redline Version)

Schedule 6 of PacifiCorp's OATT

Appendix 8

SCHEDULE 6

Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the ~~control area~~Control Area (other than load supplied by firm imports for which the reserve capacity is provided by the supplier) and to support ~~firm generation~~ exports from the ~~control area~~Control Area in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area (other than load supplied by firm imports for which the reserve capacity is provided by the supplier) and to support ~~firm~~ sales from generators located within the PacifiCorp ~~control area~~Control Area. The Transmission Customer must either purchase this service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Charges for Supplemental Reserve Service:

~~A Transmission Customer purchasing Supplemental Reserve Service will be required to purchase an amount of reserved capacity equal to 1.75 percent of the Transmission Customer's Reserved Capacity for Point-to-Point Transmission Service or 1.75 percent of the Transmission Customer's Monthly Network Load for Network Integration Transmission Service. The billing determinants for this service shall be reduced by any portion of the 1.75 percent purchase obligation that a Transmission Customer obtains from third parties or supplies itself.~~
The charges below apply to: 1) Network Integration Transmission Service; 2) Long-Term Firm Point-to-Point Transmission Service; 3) Short-Term Firm Point-to-Point Transmission Service, and (4) Short-Term Non-Firm Point-to-Point Transmission Service, assessed based upon hourly usage, for service that requires Supplemental Reserve Service, as described in the preceding

section and as further described in applicable PacifiCorp business practices.

~~The rates below reflect the percentage purchase obligation stated above multiplied by the cost of providing the ancillary services described in this Schedule 6. Accordingly, the~~The rates below are applied to the amount of the Transmission Customer's ~~Reserved Capacity for Point-to-Point Transmission Service or the Transmission Customer's Monthly Network Load~~hourly load for Network Integration Transmission Service~~.~~ or schedules for Point-to-Point Transmission Service. For purposes of charging the rates set forth in this Schedule 6 to Transmission Customers purchasing Firm Point-to-Point Transmission Service, the billing determinants shall be the amount at system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff.

The rate to be effective from January 1, 2012 through May 31, 2013 shall be an Hourly Rate of:

- $0.29 MWh

The rate to be effective as of June 1, 2013 shall be an Hourly Rate of:

- $0.34 MWh

Self-Supply:

A Transmission Customer may choose to self-supply all or a portion of its reserve obligation.

The total reserve obligation for a Transmission Customer who self-supplies is determined by the currently-effective version of WECC Regional Reliability Standard BAL-STD-002. The requirement is currently 5% of the hourly load responsibility served by hydro and wind resources and 7% served by thermal resources with at least half required to be Spinning Reserves. For a Transmission Customer choosing to self-supply a portion of its reserve obligation, the billing determinants for supplemental purchases of Schedule 6 reserve service shall be determined by: (1) identifying the difference between the amount self-supplied during each hour each month and the Transmission Customer's full requirement, as determined by WECC Standard BAL-STD-002; (2) charging the Transmission Customer the Hourly Rate multiplied by the amount of MWs identified in (1) where the

Transmission Customer failed to supply its full requirement for each hour, if any failure occurred.

The Transmission Customer shall schedule that portion which it will self-supply and/or supply from third parties up to seven days in advance pursuant to procedures set forth in the Business Practices of the Transmission Provider. During any period that a Transmission Customer has scheduled self-supply and/or supply from third parties but fails to provide the full amount scheduled due to partial or full forced outage of the generation source or a transmission curtailment or interruption, the Transmission Customer shall purchase the shortfall at the hourly rate.

~~1.~~	~~Yearly Rate~~	~~$1.566/kW/Year~~
~~2.~~	~~Monthly Rate~~	~~$0.131/kW/Month~~
~~3.~~	~~Weekly Rate~~	~~$0.030/kW/Week~~
~~4.~~	~~Daily Rate, On-Peak~~	~~$0.006/kW/Day~~
~~5.~~	~~Daily Rate, Off-Peak~~	~~$0.004/kW/Day~~
~~6.~~	~~Hourly Rate, On-Peak~~	~~$0.377/MWh~~
~~7.~~	~~Hourly Rate, Off-Peak~~	~~$0.179/MWh~~

~~The total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 6 times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 6 times the highest amount in megawatts of Reserved Capacity in any hour during such week.~~

Charge for Unauthorized Supplemental Reserve Service:

A Transmission Customer assessment of an unauthorized use charge will include a charge for Supplemental Reserve Service in accordance with Schedule 11 to the Tariff. Additionally, any Transmission Customer purchasing Transmission Service from the Transmission Provider in order to serve firm load within the Transmission Provider's Control Area or firm exports from the Transmission Provider's Control Area using an import from another Control Area that is found to be interruptible shall be assessed a charge for unauthorized Supplemental Reserve Service under this Schedule ~~5.~~6. For the purposes of this Schedule 6, an interruptible import is an import where any generation or transmission element of such import to the Transmission Provider's Transmission System is interruptible or where any transmission element through, out of, within, or into the Transmission Provider's Transmission System and not self-supplying or supplying from third parties such associated supplemental reserve requirement is interruptible (excluding system contingencies resulting in transmission outages). Any Transmission Customer making such use of the Transmission Provider's Transmission System shall ~~shall~~ be responsible to compensate the Transmission Provider for unauthorized Supplement Reserve under this Schedule 6 for the amount of energy scheduled for delivery to the Transmission Provider from such interruptible import at twice the hourly rates set forth above. In addition, upon any actual interruption of such import (excluding system contingencies resulting in transmission outages), the amount of energy scheduled to be delivered from such interruptible import during the time period that Unauthorized Supplemental Reserve Service was provided shall be included as part of Energy Imbalance in Schedule 4. Such amount shall be in addition to any amount paid for any other transmission service.

Supplemental Reserve Service to be Provided:

The Transmission Provider, using its generators controlled by automatic generation control, will provide the capacity required to provide Supplemental Reserve Service for a Transmission Customer. Upon an outage of a generation resource for which Supplemental Reserve Service has been purchased from the Transmission Provider, the Transmission Provider will provide replacement capacity commencing at the end of ten (10) full minutes after such outage until the earlier of (1) the restoration of such resource to service by the Transmission Customer or (2) the end of the first full hour immediately following such outage.

To the extent that the Transmission Provider determines that a Transmission Customer’s specific Supplemental Reserve Requirements are not being fully met through the purchase of Supplemental Reserve Service as provided above, the Transmission Provider reserves the right (upon filing with the Commission) to require such Transmission Customer to purchase a greater amount of Supplemental Reserve Service.

Appendix 9
(Clean Version)

Schedule 7 of PacifiCorp's OATT

SCHEDULE 7

Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

Charges under this Schedule 7 shall be calculated annually using the populated Formula Rate in Attachment H-1. Charges shall be posted on Transmission Provider’s OASIS on the publication date of the annual update of the ATRR, as indicated in the Protocols included in Attachment H-2.

For Transmission Service, the Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below and posted on OASIS:

1) **Annual Update:** The rates for Schedule 7 shall be updated annually on June 1 of each year in accordance with the Protocols in Attachment H-2.

2) **Partial delivery:** (an amount equal to the Reserved Capacity per period pro-rated by the amount of Partial Service provided): This service is for partial reservations pursuant to Section 19.7 of the Tariff. This service shall only be available when a Transmission Customer’s requested reservation cannot be provided except during limited amounts of time (i.e. only during on-peak or off-peak hours, seasonally, etc.) without the construction of new transmission facilities. Any amount of Reserved Capacity that can be provided at all times on a firm basis shall be as priced in accordance with Attachment H-1. This service shall be available until additional facilities are installed or until other firm utilization diminishes to the extent that firm non-time constrained transmission service is available. Any limitations or restrictions shall be specified in the relevant Transmission Customer’s Service Agreement.

3) **Yearly delivery:** The amount identified in the posted Formula Rate/kW-year of Reserved Capacity.

4) **Monthly delivery:** The amount identified in the posted Formula Rate/kW-month of Reserved Capacity.

5) **Weekly delivery:** The amount identified in the posted Formula Rate/kW-week of Reserved Capacity.

6) **Daily On-Peak Delivery:** The amount identified in the posted Formula Rate/kW-day of Reserved Capacity.

7) **Daily Off-Peak Delivery:** The amount identified in the posted Formula Rate/kW-day of Reserved Capacity.

8) **Hourly On-Peak Delivery:** The amount identified in the posted Formula Rate/MWh of Reserved Capacity.

9) **Hourly Off-Peak Delivery:** The amount identified in the posted Formula Rate/MWh of Reserved Capacity.

10) The total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 7 times the highest amount in megawatts of Reserved Capacity in any hour during such week. In addition, the total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 7 times the highest amount in megawatts of Reserved Capacity in any hour during such day. For purposes of charging the rates set forth in this Schedule 7 to Transmission Customers purchasing Firm Point-to-Point Transmission Service, the billing determinants shall be the amount at system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff. The amount to be reserved for Long-Term Firm Point-to-Point Transmission Service is the amount delivered at system output.

11) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one’s wholesale merchant or an affiliate’s use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

12) Resales: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

13) Unauthorized Use of Transmission Service: The penalty charge for a Transmission Customer that engages in unauthorized use is calculated in accordance with Schedule 11.

Appendix 9
(Redline Version)

Schedule 7 of PacifiCorp's OATT

SCHEDULE 7

Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

Charges under this Schedule 7 shall be calculated annually using the populated Formula Rate in Attachment H-1. Charges shall be posted on Transmission Provider's OASIS on the publication date of the annual update of the ATRR, as indicated in the Protocols included in Attachment H-2.

For Transmission Service, the Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below and posted on OASIS:

1) **Annual Update:** The rates for Schedule 7 shall be updated annually on June 1 of each year in accordance with the Protocols in Attachment H-2.

2) **Partial delivery:** (an amount equal to the Reserved Capacity per period pro-rated by the amount of Partial Service provided): This service is for partial reservations pursuant to Section 19.7 of the Tariff. This service shall only be available when a Transmission Customer's requested reservation cannot be provided except during limited amounts of time (i.e. only during on-peak or off-peak hours, seasonally, etc.) without the construction of new transmission facilities. Any amount of Reserved Capacity that can be provided at all times on a firm basis shall be as priced in accordance with Attachment H-1. This service shall be available until additional facilities are installed or until other firm utilization diminishes to the extent that firm non-time constrained transmission service is available. Any limitations or restrictions shall be specified in the relevant Transmission Customer's Service Agreement.

3) **Yearly delivery:** The amount identified in the posted Formula Rate/kW-year of Reserved Capacity.

4) **Monthly delivery:** The amount identified in the posted Formula Rate/kW-month of Reserved Capacity.

5) **Weekly delivery:** The amount identified in the posted Formula Rate/kW-week of Reserved Capacity.

6) **Daily On-Peak Delivery:** The amount identified in the posted Formula Rate/kW-day of Reserved Capacity.

7) **Daily Off-Peak Delivery:** The amount identified in the posted Formula Rate/kW-day of Reserved Capacity.

8) **Hourly On-Peak Delivery:** The amount identified in the posted Formula Rate/MWh of Reserved Capacity.

9) **Hourly Off-Peak Delivery:** The amount identified in the posted Formula Rate/MWh of Reserved Capacity.

10) The total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 7 times the highest amount in megawatts of Reserved Capacity in any hour during such week. In addition, the total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 7 times the highest amount in megawatts of Reserved Capacity in any hour during such day. For purposes of charging the rates set forth in this Schedule 7 to Transmission Customers purchasing Firm Point-to-Point Transmission Service, the billing determinants shall be the amount at system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff. The amount to be reserved for Long-Term Firm Point-to-Point Transmission Service is the amount delivered at system output.

11) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one’s wholesale merchant or an affiliate’s use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Appendix 9

12) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

13) **Unauthorized Use of Transmission Service:** The penalty charge for a Transmission Customer that engages in unauthorized use is calculated in accordance with Schedule 11.

Appendix 10
(Clean Version)

Schedule 8 of PacifiCorp's OATT

SCHEDULE 8

Non-Firm Point-To-Point Transmission Service

Charges under this Schedule 8 shall be calculated annually using the populated Formula Rate in Attachment H-1. Charges shall be posted on Transmission Provider's OASIS on the publication date of the annual update of the ATRR, as indicated in the Protocols included in Attachment H-2.

For Transmission Service, the Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below and posted on OASIS.

1) **Annual Update**: The rates for Schedule 8 shall be updated annually on June 1 of each year in accordance with the Protocols in Attachment H-2.

2) **Monthly Delivery**: The amount identified in the posted Formula Rate/kW-month of Reserved Capacity.

3) **Weekly Delivery**: The amount identified in the posted Formula Rate/kW-week of Reserved Capacity.

4) **Daily On-Peak Delivery**: The amount identified in the posted Formula Rate/kW-day of Reserved Capacity.

5) **Daily Off-Peak Delivery**: The amount identified in the posted Formula Rate/kW-day of Reserved Capacity.

6) **Hourly On-Peak Delivery**: The amount identified in the posted Formula Rate/MWh of Reserved Capacity.

7) **Hourly Off-Peak Delivery**: The amount identified in the posted Formula Rate/MWh of Reserved Capacity.

8) The total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 8 times the highest amount in megawatts of Reserved Capacity in any hour during such week. In addition, the total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 8 times the highest amount in megawatts of Reserved Capacity in any hour during such day. For purposes of charging the rates set forth in this Schedule 8 to Transmission Customers purchasing Non-

Firm Point-to-Point Transmission Service, the billing determinants shall be the amount at system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff. The amount to be reserved for Non-Firm Point-to-Point Transmission Service is the amount delivered at system output.

9) **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one’s wholesale merchant or an affiliate’s use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

10) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

11) **Unauthorized Use of Transmission Service**: The penalty charge for a Transmission Customer that engages in unauthorized use is calculated in accordance with Schedule 11.

Appendix 10
(Redline Version)

Schedule 8 of PacifiCorp's OATT

SCHEDULE 8

Non-Firm Point-To-Point Transmission Service

Charges under this Schedule 8 shall be calculated annually using the populated Formula Rate in Attachment H-1. Charges shall be posted on Transmission Provider's OASIS on the publication date of the annual update of the ATRR, as indicated in the Protocols included in Attachment H-2.

For Transmission Service, the Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below and posted on OASIS.

1) **Annual Update**: The rates for Schedule 8 shall be updated annually on June 1 of each year in accordance with the Protocols in Attachment H-2.

2) **Monthly Delivery**: The amount identified in the posted Formula Rate/kW-month of Reserved Capacity.

3) **Weekly Delivery**: The amount identified in the posted Formula Rate/kW-week of Reserved Capacity.

4) **Daily On-Peak Delivery**: The amount identified in the posted Formula Rate/kW-day of Reserved Capacity.

5) **Daily Off-Peak Delivery**: The amount identified in the posted Formula Rate/kW-day of Reserved Capacity.

6) **Hourly On-Peak Delivery**: The amount identified in the posted Formula Rate/MWh of Reserved Capacity.

7) **Hourly Off-Peak Delivery**: The amount identified in the posted Formula Rate/MWh of Reserved Capacity.

8) The total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 8 times the highest amount in megawatts of Reserved Capacity in any hour during such week. In addition, the total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 8 times the highest amount in megawatts of Reserved Capacity in any hour during such day. For purposes of charging the rates set forth in this Schedule 8 to Transmission Customers purchasing Non-

Firm Point-to-Point Transmission Service, the billing determinants shall be the amount at system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff. The amount to be reserved for Non-Firm Point-to-Point Transmission Service is the amount delivered at system output.

9) **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

10) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

11) **Unauthorized Use of Transmission Service**: The penalty charge for a Transmission Customer that engages in unauthorized use is calculated in accordance with Schedule 11.

Appendix 11
(Clean Version)

Schedule 10 of PacifiCorp's OATT

Schedule 10

Real Power Losses

<u>For Service Over the Transmission Provider’s Transmission System</u>:

Any use of the Transmission Provider's Transmission System shall be assessed Real Power Losses in the following amounts:

Use of any portion of the Transmission System at a voltage of 46kV or greater	4.26%
Use of any portion of the Distribution System at a voltage 34.5 kV or less	3.56%
Use of a combination of the Transmission System and the Distribution System	7.82%

<u>For Service on the PacifiCorp COI Segment</u>:

Real Power Losses shall be calculated in accordance with Attachment S for Transmission Service on the PacifiCorp COI Segment.

<u>Service Over PacifiCorp Facilities in Other Control Areas</u>: For Transmission Service provided over PacifiCorp lines located in another control area, any Real Power Losses assessed to PacifiCorp by the adjacent control area associated with the Customer’s service will be passed through to the Transmission Customer. In instances where service is provided by PacifiCorp and an adjacent control area, any Real Power Losses assessed by the adjacent control area to PacifiCorp will be passed through to the Transmission Customer in addition to PacifiCorp Real Power Losses identified in this section.

<u>Settlement of Transmission Losses</u>: Unless Transmission Service is subject to Attachment S of the Tariff, a Transmission Customer taking Firm or Non-Firm Point-to-Point Transmission Service shall be responsible for Real Power Losses as provided for in Section 15.7 of the Tariff, this Schedule 10 and the Transmission Provider’s business practices posted on OASIS. A Transmission Customer shall have the option to settle Real Power Losses pursuant to section (a) (Financial Settlement) or section (b) (Physical Delivery) subject to the Transmission Provider’s business practices posted on OASIS.

(a) **Financial Settlement**.

(i) **Charges for Transmission Losses**. For each hour where the Transmission Provider provides loss service, the Transmission Customer shall compensate the Transmission Provider at a rate equal to the "Hourly Pricing Proxy" for energy for such hour. "Hourly Pricing Proxy" is defined in Schedules 4 and 9.

(b) **Physical Delivery**. Transmission Customers opting for physical delivery shall schedule losses to the Transmission Provider concurrently with transmission schedules. The Transmission Provider shall deliver to the Point(s) of Delivery the amount of power received from a Transmission Customer at Point(s) of Receipt, reduced for losses from the Point(s) of Receipt to the Point(s) of Delivery. The amount delivered to the Point(s) of Delivery shall be determined to be the amount of power received from a Transmission Customer at the Point(s) of Receipt divided by (1 + Real Power Losses rate) and the amount of losses shall be determined to be the amount of power received from a Transmission Customer at Point(s) of Receipt multiplied by (1 – 1/ (1 + Real Power Losses rate). Any hourly differences between the amounts of power scheduled to be delivered at Point(s) of Delivery (plus applicable Real Power Losses) and the actual amounts of energy received at Point(s) of Receipt shall be accounted for as Energy Imbalance subject to charges pursuant to Schedule 4.

Real Power Losses Updates: PacifiCorp shall update Schedule 10 factors for Real Power Losses following completion of every two Energy Gateway Project segments (or substantially similar transmission segments or combination thereof) which have been placed into commercial operation for at least one full calendar year. PacifiCorp's update to the Transmission System loss factor shall be filed on or before April 1 following the full calendar year of commercial operation for the second of every two Energy Gateway Project segments (or substantially similar transmission segments or combination thereof) with a request to the Commission that the updated Transmission System loss factor be made effective June 1 of the calendar year in which the filing is made. Such filing shall be based on the most recent FERC Form No. 1 data for the prior calendar year. The update calculation shall be consistent with the methodology agreed upon in ER11-3643 and shall be based on annual sources and uses of energy from FERC Form No. 1, p. 401a, with adjustments to remove any energy source and corresponding energy use (i) which is not scheduled or otherwise transacted using PacifiCorp's transmission system, (ii) which is duplicative of, in part or whole, another energy source or energy use already represented in the data on FERC Form No. 1, p. 401a, and (iii) which represent financially settled losses (i.e., no actual physical losses).

Appendix 11
(Redline Version)

Schedule 10 of PacifiCorp's OATT

Appendix 11

Schedule 10

Real Power Losses

For Service Over the Transmission Provider's Transmission System:

Any use of the Transmission Provider's Transmission System shall be assessed Real Power Losses in the following amounts:

Use of any portion of the Transmission System at a voltage of 46kV or greater	~~5.00~~4.26%
Use of any portion of the Distribution System at a voltage 34.5 kV or less	3.56%
Use of a combination of the Transmission System and the Distribution System	~~8.56~~7.82%

For Service on the PacifiCorp COI Segment:

Real Power Losses shall be calculated in accordance with Attachment S for Transmission Service on the PacifiCorp COI Segment.

Service Over PacifiCorp Facilities in Other Control Areas: For Transmission ~~service~~Service provided over PacifiCorp lines located in another control area, any Real Power Losses assessed to PacifiCorp by the adjacent control area associated with the Customer's service will be passed through to the Transmission Customer. In instances where service is provided by PacifiCorp and an adjacent control area, any Real Power Losses assessed by the adjacent control area to PacifiCorp will be passed through to the Transmission Customer in addition to PacifiCorp Real Power Losses identified in this section.

Settlement of Transmission Losses: Unless Transmission Service is subject to Attachment S of the Tariff, a Transmission Customer taking Firm or Non-Firm Point-to-Point Transmission Service shall be responsible for Real Power Losses as provided for in Section 15.7 of the Tariff, this Schedule 10 and the Transmission Provider's business practices posted on OASIS. A Transmission Customer shall have the option to settle Real Power Losses pursuant to section (a) (Financial Settlement) or section (b) (Physical Delivery) subject to the Transmission Provider's business practices posted on OASIS.

(a) **Financial Settlement**.

(i) **Charges for Transmission Losses**. For each hour where the Transmission Provider provides loss service, the Transmission Customer shall compensate the Transmission Provider at a rate equal to the "Hourly Pricing Proxy" for energy for such hour. "Hourly Pricing Proxy" is defined in Schedules 4 and 9.

(b) **Physical Delivery**. Transmission Customers opting for physical delivery shall schedule losses to the Transmission Provider concurrently with transmission schedules. The Transmission Provider shall deliver to the Point(s) of Delivery the amount of power received from a Transmission Customer at Point(s) of Receipt ~~less losses~~, reduced for losses from the Point(s) of Receipt to the Point(s) of Delivery. The amount delivered to the Point(s) of Delivery shall be determined to be the amount of power received from a Transmission Customer at the Point(s) of Receipt divided by (1 + Real Power Losses rate) and the amount of losses shall be determined to be the amount of power received from a Transmission Customer at Point(s) of Receipt multiplied by (1 – 1/ (1 + Real Power Losses rate). Any hourly differences between the amounts of power scheduled to be delivered at Point(s) of Delivery (plus applicable Real Power Losses) and the actual amounts of energy received at Point(s) of Receipt shall be accounted for as Energy Imbalance subject to charges pursuant to Schedule 4.

Real Power Losses Updates: PacifiCorp shall update Schedule 10 factors for Real Power Losses following completion of every two Energy Gateway Project segments (or substantially similar transmission segments or combination thereof) which have been placed into commercial operation for at least one full calendar year. PacifiCorp's update to the Transmission System loss factor shall be filed on or before April 1 following the full calendar year of commercial operation for the second of every two Energy Gateway Project segments (or substantially similar transmission segments or combination thereof) with a request to the Commission that the updated Transmission System loss factor be made effective June 1 of the calendar year in which the filing is made. Such filing shall be based on the most recent FERC Form No. 1 data for the prior calendar year. The update calculation shall be consistent with the methodology agreed upon in ER11-3643 and shall be based on annual sources and uses of energy from FERC Form No. 1, p. 401a, with adjustments to remove any energy source and corresponding energy use (i) which is not scheduled or otherwise transacted using PacifiCorp’s transmission system, (ii) which is duplicative of, in part or whole, another energy source or energy use already represented in the data on FERC Form No. 1, p. 401a, and (iii) which represent financially settled losses (i.e., no actual physical losses).

Appendix 12
(Clean Version)

Section 1 of PacifiCorp's OATT

I. COMMON SERVICE PROVISIONS

1 Definitions

1.1 Affiliate:

With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

1.2 Ancillary Services:

Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.3 Annual Transmission Costs:

The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider or modified by the Commission.

1.3A Annual Transmission Revenue Requirement (ATRR):

The transmission revenue requirement calculated annually using the formula rate set forth in Attachment H-1.

1.4 Application:

A request by an Eligible Customer for Transmission Service, Network Integration Transmission Service or Generation Interconnection Service pursuant to the provisions of the Tariff.

1.5 Commission:

The Federal Energy Regulatory Commission.

1.6 Completed Application:

An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.7 Control Area:

An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

1. match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

2. maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

3. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

4. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

The term Control Area as used throughout this Tariff shall be understood to be equivalent to a Balancing Authority Area, as defined by the North American Electric Reliability Corporation.

1.8 Curtailment:

A reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions (also “Curtail”).

1.9 Delivering Party:

The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.10 Designated Agent:

Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.11 Direct Assignment Facilities:

Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer or Generation Interconnection Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer or the Generation Interconnection Customer and shall be subject to Commission approval.

1.11A Disturbance Recovery Event

Any abnormal system condition occurring in a neighboring Balancing Authority that requires automatic or immediate action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Transmission Provider’s Transmission System or other Transmission Systems in the Western Electricity Coordinating Council.

1.12 Eligible Customer:

(i) Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider offer the unbundled transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider, is an Eligible Customer under the Tariff.

1.13 Facilities Study:

An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider’s Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.14 Firm Point-To-Point Transmission Service:

Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.15 Good Utility Practice:

Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

1.15A Interconnection Customer:

Any Eligible Customer (or its Designated Agent) that executes an agreement to receive generation interconnection service pursuant to Part IV or Part V of this Tariff.

1.16 Interruption:

A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7 (also “Interrupt”).

1.17 [RESERVED]

1.18 Load Shedding:

The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.19 Long-Term Firm Point-To-Point Transmission Service:

The firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

1.20 Native Load Customers:

The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.21 Network Customer:

An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.22 Network Integration Transmission Service:

The transmission service provided under Part III of the Tariff.

1.23 Network Load:

The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.24 Network Operating Agreement:

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.25 Network Operating Committee:

A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part III of this Tariff.

1.26 Network Resource:

Any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

1.27 Network Upgrades:

Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.28 Non-Firm Point-To-Point Transmission Service:

Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.29 Non-Firm Sale:

An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

1.30 Open Access Same-Time Information System (OASIS):

The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

1.30A PacifiCorp COI Segment:

The eastern most portion of the two Pacific AC Intertie lines on the California-Oregon Intertie.

1.31 Part I:

Tariff definitions and Common Service Provisions contained in Sections 2 through 12.

1.32 Part II:

Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.33 Part III:

Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.34 Part IV:

Tariff Section 36 to Section 48 pertaining to Standard Generation Interconnection Procedures for generation greater than twenty (20) megawatts in conjunction with the applicable Common Service Provisions of Part I and appropriate schedules and attachments.

1.35 Part V:

Tariff Section 49 pertaining to Generation Interconnection Service lesser than or equal to twenty (20) megawatts in conjunction with the applicable Common Service Provisions of Part I and appropriate schedules and attachments.

1.36 Parties:

The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.37 Point(s) of Delivery:

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.38 Point(s) of Receipt:

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.39 Point-To-Point Transmission Service:

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.40 Power Purchaser:

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.41 Pre-Confirmed Application:

An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

1.42 Real Power Losses:

Electrical losses associated with the use of the Transmission Provider's Transmission System and, where applicable, the use of the Transmission Provider's distribution system. Such losses are provided for in Section 15.7, Section 28.5, Schedule 10 and Attachment S of the Tariff.

1.43 Receiving Party:

The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.44 Regional Transmission Group (RTG):

A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.45 Reserved Capacity:

The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the

Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.46 Retail Access:

Unbundled Transmission Service pursuant to a state requirement that the Transmission Provider offer transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider providing Retail End-Users of electricity (or their designated agent) the ability to acquire transmission service directly from the Transmission Provider.

1.47 Retail End-User:

A consumer of electric energy receiving either (i) bundled electric service from the Transmission Provider under a retail service tariff subject to state jurisdiction or (ii) Retail Access from the Transmission Provider in lieu of bundled electric service from the Transmission Provider under a retail service tariff subject to state jurisdiction.

1.48 Secondary Receipt and Delivery Points:

The use of alternate delivery or receipt points in Point-to-Point Transmission Service on a non-firm basis in accordance with Section 22 of the Tariff.

1.49 Service Agreement:

The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.50 Service Commencement Date:

The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.51 Short-Term Firm Point-To-Point Transmission Service:

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year. Short-Term Firm Point-To-Point Transmission Service of duration of less than one calendar day is sometimes referred to as Hourly Firm Point-To-Point Transmission Service.

1.52 System Condition:

A specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

1.53 System Impact Study:

An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.54 Third-Party Sale:

Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service Agreement.

1.55 Transmission Customer:

Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

1.56 Transmission Provider:

PacifiCorp (or its designated agent), which owns, controls, or operates transmission or distribution facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff.

1.57 Transmission Provider's Monthly Transmission System Peak:

The maximum firm usage of Transmission Provider's Transmission System in a calendar month.

1.58 Transmission Service:

Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.59 Transmission System:

The facilities (for PacifiCorp that are generally operated at a voltage greater than 34.5 kV) that are owned, controlled or operated by the Transmission Provider; that are used to provide Transmission Service under Part II and Part III of the Tariff; and that are included in the Transmission Provider's transmission revenue requirement periodically filed with the Commission.

1.60 Umbrella Service Agreement:

An executed agreement allowing a Transmission Customer to purchase transmission service from the Transmission Provider in amounts and for prices as posted on the Transmission Provider's OASIS for a term up to one year in length.

1.61 Working Day:

Monday through Friday excluding holidays.

Appendix 12
(Redline Version)

Section 1 of PacifiCorp's OATT

I. COMMON SERVICE PROVISIONS

1 Definitions

1.1 Affiliate:

With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

1.2 Ancillary Services:

Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.3 Annual Transmission Costs:

The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider or modified by the Commission.

1.3A Annual Transmission Revenue Requirement (ATRR):

The transmission revenue requirement calculated annually using the formula rate set forth in Attachment H-1.

1.4 Application:

A request by an Eligible Customer for Transmission Service, Network Integration Transmission Service or Generation Interconnection Service pursuant to the provisions of the Tariff.

1.5 Commission:

The Federal Energy Regulatory Commission.

1.6 Completed Application:

An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.7 Control Area:

An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

1. match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

2. maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

3. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

4. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

The term Control Area as used throughout this Tariff shall be understood to be equivalent to a Balancing Authority Area, as defined by the North American Electric Reliability Corporation.

1.8 Curtailment:

A reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions (also “Curtail”).

1.9 Delivering Party:

The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.10 Designated Agent:

Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.11 Direct Assignment Facilities:

Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer or Generation Interconnection Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer or the Generation Interconnection Customer and shall be subject to Commission approval.

1.11A Disturbance Recovery Event

Any abnormal system condition occurring in a neighboring Balancing Authority that requires automatic or immediate action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Transmission Provider's Transmission System or other Transmission Systems in the Western Electricity Coordinating Council.

1.12 Eligible Customer:

(i) Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider offer the unbundled transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider, is an Eligible Customer under the Tariff.

1.13 Facilities Study:

An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.14 Firm Point-To-Point Transmission Service:

Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.15 Good Utility Practice:

Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

1.15A Interconnection Customer:

Any Eligible Customer (or its Designated Agent) that executes an agreement to receive generation interconnection service pursuant to Part IV or Part V of this Tariff.

1.16 Interruption:

A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7 (also “Interrupt”).

1.17 [RESERVED]

1.18 Load Shedding:

The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.19 Long-Term Firm Point-To-Point Transmission Service:

The firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

1.20 Native Load Customers:

The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.21 Network Customer:

An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.22 Network Integration Transmission Service:

The transmission service provided under Part III of the Tariff.

1.23 Network Load:

The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.24 Network Operating Agreement:

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.25 Network Operating Committee:

A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part III of this Tariff.

1.26 Network Resource:

Any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

1.27 Network Upgrades:

Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.28 Non-Firm Point-To-Point Transmission Service:

Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.29 Non-Firm Sale:

An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

1.30 Open Access Same-Time Information System (OASIS):

The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

1.30A PacifiCorp COI Segment:

The eastern most portion of the two Pacific AC Intertie lines on the California-Oregon Intertie.

1.31 Part I:

Tariff definitions and Common Service Provisions contained in Sections 2 through 12.

1.32 Part II:

Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.33 Part III:

Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.34 Part IV:

Tariff Section 36 to Section 48 pertaining to Standard Generation Interconnection Procedures for generation greater than twenty (20) megawatts in conjunction with the applicable Common Service Provisions of Part I and appropriate schedules and attachments.

1.35 Part V:

Tariff Section 49 pertaining to Generation Interconnection Service lesser than or equal to twenty (20) megawatts in conjunction with the applicable Common Service Provisions of Part I and appropriate schedules and attachments.

1.36 Parties:

The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.37 Point(s) of Delivery:

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.38 Point(s) of Receipt:

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.39 Point-To-Point Transmission Service:

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.40 Power Purchaser:

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.41 Pre-Confirmed Application:

An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

1.42 Real Power Losses:

Electrical losses associated with the use of the Transmission Provider's Transmission System and, where applicable, the use of the Transmission Provider's distribution system. Such losses are provided for in Section 15.7, Section 28.5, Schedule 10 and Attachment S of the Tariff.

1.43 Receiving Party:

The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.44 Regional Transmission Group (RTG):

A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.45 Reserved Capacity:

The maximum amount of capacity and energy~~ (including losses)~~ that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.46 Retail Access:

Unbundled Transmission Service pursuant to a state requirement that the Transmission Provider offer transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider providing Retail End-Users of electricity (or their designated agent) the ability to acquire transmission service directly from the Transmission Provider.

1.47 Retail End-User:

A consumer of electric energy receiving either (i) bundled electric service from the Transmission Provider under a retail service tariff subject to state jurisdiction or (ii) Retail Access from the Transmission Provider in lieu of bundled electric service from the Transmission Provider under a retail service tariff subject to state jurisdiction.

1.48 Secondary Receipt and Delivery Points:

The use of alternate delivery or receipt points in Point-to-Point Transmission Service on a non-firm basis in accordance with Section 22 of the Tariff.

1.49 Service Agreement:

The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.50 Service Commencement Date:

The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.51 Short-Term Firm Point-To-Point Transmission Service:

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year. Short-Term Firm Point-To-Point Transmission Service of duration of less than one calendar day is sometimes referred to as Hourly Firm Point-To-Point Transmission Service.

1.52 System Condition:

A specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

1.53 System Impact Study:

An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.54 Third-Party Sale:

Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service Agreement.

1.55 Transmission Customer:

Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service

Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

1.56 Transmission Provider:

PacifiCorp (or its designated agent), which owns, controls, or operates transmission or distribution facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff.

1.57 Transmission Provider's Monthly Transmission System Peak:

The maximum firm usage of Transmission Provider's Transmission System in a calendar month.

1.58 Transmission Service:

Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.59 Transmission System:

The facilities (for PacifiCorp that are generally operated at a voltage greater than 34.5 kV) that are owned, controlled or operated by the Transmission Provider; that are used to provide Transmission Service under Part II and Part III of the Tariff; and that are included in the Transmission Provider's transmission revenue requirement periodically filed with the Commission.

1.60 Umbrella Service Agreement:

An executed agreement allowing a Transmission Customer to purchase transmission service from the Transmission Provider in amounts and for prices as posted on the Transmission Provider's OASIS for a term up to one year in length.

1.61 Working Day:

Monday through Friday excluding holidays.

Appendix 13

Documentation Supporting Schedule 5 and 6 Rate Calculations

		As Filed	Aver Reserves Held (kW - 2010)	Revenue Requirment	Total 2010 Generation for Rates	Rates (mwh)	Settlement rates (Jan 1, 2012 through May 2013)
Spinning_ Schedule 5							
	Cost per kW weighted	$ 102.06	260,000	$ 26,535,860.00	67,588,143.51	$ 0.39	$ 0.32
Supplemental_Schedule 6							
	Cost per kW weighted	$ 88.81	260,000	$ 23,089,300.00	67,588,143.51	$ 0.34	$ 0.29

Generation Summary
2010

PAC Merchant Net Gen	57,639,191.000	(A) 1
PAC Merchant Purchases	11,417,024.682	(A) 1
Subtotal		
Adjustments		
Off-System Purchases	(4,948,616.68)	(A) 2 and (B)2
Stateline - PAC Energy Exchange	315,090.85	(A) 3
Cowlitz - Swift #2 - PAC Energy Exchange	213,594.00	(A) 4
Purchased Reserves	(1,756,344.00)	(A) 5
3rd Party On-System Generation	6,103,846.52	(C) 1
3rd Party Self-Supply	(1,395,642.86)	(E) 1
	67,588,143.51	

	2013 (MWH)
Sche 5	0.37
Sche 6	0.31

2010 - PAC Merchant - Generation &		Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10
Name	Type	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
PAC Generation (On System)											
SWIFT #1	Hydro	114,790	40,517	67,234	74,211	66,453	82,305	30,227	16,202	25,633	40,243
YALE	Hydro	98,368	28,696	63,616	57,304	55,983	67,435	23,311	14,443	26,680	41,653
MERWIN	Hydro	85,263	39,453	41,857	49,456	48,693	60,498	19,219	10,804	21,735	36,336
Subtotal - LEWIS RIVER		298,421	108,666	172,707	180,971	171,129	210,238	72,757	41,449	74,048	118,232
COPCO #1	Hydro	6,039	5,563	6,668	5,711	5,441	5,056	3,760	5,178	5,082	5,465
COPCO #2	Hydro	7,867	7,283	8,768	7,605	6,806	6,499	4,994	6,771	6,672	7,248
IRON GATE	Hydro	9,649	8,706	10,489	9,494	5,097	6,909	5,120	6,945	6,877	7,100
FALL CREEK	Hydro	1,126	968	1,113	1,044	997	568	759	782	808	877
EAST SIDE	Hydro	782	551	887	685	575	339	580	0	0	0
WEST SIDE	Hydro	314	(2)	(5)	(3)	(3)	(2)	(2)	(1)	(1)	(1)
J.C. BOYLE	Hydro	20,225	17,451	22,680	19,154	15,323	11,427	9,523	14,122	13,128	13,520
Subtotal - KLAMATH RIVER		46,002	40,520	50,600	43,690	34,236	30,796	24,734	33,797	32,566	34,209
PROSPECT #1	Hydro	3,375	2,255	3,301	2,695	3,176	2,987	2,518	0	0	0
PROSPECT #2	Hydro	23,135	21,212	20,398	23,589	25,421	24,424	15,309	6,365	9,615	10,367
PROSPECT #3	Hydro	3,047	2,138	2,468	3,066	4,653	4,583	3,802	1,737	1,419	1,440
PROSPECT #4	Hydro	309	481	728	566	445	433	555	0	0	0
EAGLE POINT	Hydro	1,777	1,561	1,854	1,891	1,579	1,374	1,251	1,291	1,122	394
Subtotal - ROGUE RIVER		31,643	27,647	28,749	31,807	35,274	33,801	23,435	9,393	12,156	12,201
SODA SPRINGS	Hydro	5,966	3,516	3,363	4,920	6,674	6,605	3,260	2,431	2,568	2,817
SLIDE CREEK	Hydro	8,739	6,096	5,748	7,327	9,530	8,355	5,510	4,258	4,480	4,833
CLEARWATER #2	Hydro	3,577	2,383	2,444	1,210	3,573	4,274	2,413	1,567	1,584	1,547
CLEARWATER #1	Hydro	3,200	2,497	2,630	2,238	2,957	3,573	3,007	2,036	2,042	2,180
LEMOLO #2	Hydro	15,625	11,589	9,023	8,141	11,288	16,021	10,507	7,857	10,775	11,570
LEMOLO #1	Hydro	12,886	10,364	7,520	5,232	4,525	14,203	9,087	6,647	10,205	11,057
FISH CREEK	Hydro	5,353	2,046	2,627	6,061	7,332	4,746	831	0	0	83
TOKETEE	Hydro	19,776	13,678	14,455	15,932	20,865	20,855	14,540	8,594	10,422	13,556
Subtotal - UMPQUA RIVER		75,122	52,169	47,810	51,061	66,744	78,632	49,155	33,390	42,076	47,643
GRACE	Hydro	930	1,022	2,574	5,829	3,544	7,294	18,083	16,121	2,103	1,469
ONEIDA	Hydro	(96)	(55)	476	2,331	2,146	3,350	7,028	6,715	1,754	1,421
SODA	Hydro	(210)	(158)	67	649	570	2,018	5,209	3,800	1,040	283
CUTLER	Hydro	4,955	4,350	5,820	8,476	4,178	8,384	(540)	(541)	(387)	1,457
LIFTON	Hydro	(30)	(26)	(27)	(22)	(20)	(47)	(1,115)	(1,138)	(143)	(164)
Subtotal - BEAR RIVER		5,549	5,133	8,910	17,263	10,418	20,999	28,665	24,957	4,367	4,466
ASHTON	Hydro	2,470	2,177	2,162	1,715	2,208	2,369	2,218	2,081	1,529	1,373
LAST CHANCE	Hydro	96	105	207	253	243	372	662	603	195	93
GUNLOCK	Hydro	140	111	132	0	163	312	165	105	87	119
SANDCOVE	Hydro	97	79	109	159	278	270	136	78	65	85
VEYO	Hydro	75	71	34	85	215	206	104	13	25	106
GRANITE	Hydro	350	277	370	629	817	888	914	267	549	435
OLMSTED	Hydro	2,023	1,190	750	2,125	4,612	1,480	1,240	1,408	987	413
PIONEER	Hydro	2,897	584	0	0	1,216	2,362	1,997	1,943	1,942	977
SNAKE CREEK	Hydro	162	132	162	169	224	467	423	382	291	249
STAIRS	Hydro	170	138	182	551	885	890	897	556	455	319
WEBER	Hydro	35	85	508	1,661	2,210	2,263	2,276	2,254	2,037	1,069
BIG FORK	Hydro	1,666	1,352	2,174	3,219	3,382	2,145	3,269	3,215	3,141	2,634
PARIS	Hydro	111	86	74	82	267	506	359	256	189	138

2010 - PAC Merchant - Generation &		Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10
Name	Type	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
FOUNTAIN GREEN	Hydro	66	58	53	37	31	40	58	65	51	56
VIVA NAUGHTON	Hydro	70	49	54	44	81	263	298	108	210	90
Subtotal - SM. HYDRO UT-ID		10,428	6,494	6,971	10,729	16,832	14,833	15,016	13,334	11,753	8,156
CONDIT	Hydro	10,041	9,249	9,947	10,392	10,537	9,502	6,175	5,283	4,823	4,856
WALLOWA FALLS	Hydro	594	477	498	568	665	814	742	766	795	766
BEND	Hydro	103	39	71	209	465	324	453	374	293	108
Subtotal - SM. HYDRO OTHER		10,738	9,765	10,516	11,169	11,667	10,640	7,370	6,423	5,911	5,730
Subtotal - Hydro		477,903	250,394	326,263	346,690	346,300	399,939	221,132	162,743	182,877	230,637
BLUNDELL	Non Hydro	17,052	15,426	16,529	16,588	14,193	16,736	17,088	17,361	16,749	17,332
Blundell 2	Non Hydro	7,885	7,401	7,746	7,425	4,939	5,912	5,750	6,012	5,882	7,623
CAMAS COGEN (James River	Non Hydro	9,909	8,877	3,616	5,987	9,352	7,592	8,680	7,490	6,222	8,100
CARBON 1	Non Hydro	44,945	44,190	46,219	44,647	43,899	46,222	48,404	38,936	41,012	40,668
CARBON 2	Non Hydro	64,677	63,631	65,950	70,658	67,170	66,492	74,158	71,869	68,694	52,371
CHOLLA 4	Non Hydro	232,266	168,446	267,384	182,012	246,773	225,423	227,780	172,331	225,744	197,254
COLSTRIP 3	Non Hydro	104,895	99,426	105,135	97,080	104,221	83,883	102,730	102,475	104,519	102,993
CRAIG 1	Non Hydro	55,034	54,993	56,449	58,294	55,806	57,140	59,662	58,542	51,883	54,953
CRAIG 2	Non Hydro	60,142	54,501	20,595	46,222	55,171	41,948	60,384	60,007	58,387	49,676
DAVE JOHNSTON 1	Non Hydro	64,264	58,749	46,698	62,479	58,438	63,249	62,376	62,755	52,858	57,041
DAVE JOHNSTON 2	Non Hydro	65,717	61,562	55,814	65,442	62,818	60,732	64,840	67,345	55,286	49,172
DAVE JOHNSTON 3	Non Hydro	127,909	121,031	89,680	(2,666)	7,831	105,058	76,062	51,411	136,789	109,473
DAVE JOHNSTON 4	Non Hydro	197,894	206,081	207,041	191,088	212,116	184,863	212,962	193,048	162,759	158,962
HAYDEN 1	Non Hydro	33,059	30,015	29,972	32,400	32,764	31,827	29,137	33,462	32,211	31,270
HAYDEN 2	Non Hydro	24,552	20,534	23,357	23,742	23,739	23,709	24,535	23,974	23,760	22,458
HUNTER 1	Non Hydro	240,902	180,893	(1,414)	111,386	243,839	224,506	251,607	252,207	270,168	278,194
HUNTER 2	Non Hydro	115,710	150,664	120,954	167,857	154,118	135,032	123,579	152,789	133,330	148,809
HUNTER 3	Non Hydro	320,828	282,571	294,300	283,678	283,117	290,460	279,105	248,462	167,990	295,243
HUNTINGTON 1	Non Hydro	261,068	279,906	313,953	301,041	269,657	270,764	304,373	305,912	134,500	(767)
HUNTINGTON 2	Non Hydro	299,960	240,486	306,614	195,944	286,537	301,212	312,767	314,277	269,855	260,563
JIM BRIDGER 1	Non Hydro	908,164	891,711	870,995	665,795	678,730	461,723	918,055	879,750	918,183	803,061
NAUGHTON 1	Non Hydro	98,118	83,814	94,889	92,248	101,798	102,466	99,178	101,203	106,320	106,750
NAUGHTON 2	Non Hydro	133,393	110,725	135,098	131,987	128,795	134,425	119,334	122,537	140,071	140,124
NAUGHTON 3	Non Hydro	217,669	199,803	205,648	233,114	207,431	213,955	232,372	233,091	202,995	191,593
WYODAK	Non Hydro	197,953	154,223	131,530	193,614	199,284	165,730	174,461	178,980	153,657	163,588
Chehalis	Non Hydro	2,998	40,086	179,921	159,431	32,428	(278)	122,396	201,674	201,588	209,226
CURRANT CREEK #1	Non Hydro	78,268	80,620	75,391	79,083	71,026	71,182	63,096	59,021	71,570	59,387
CURRANT CREEK #2	Non Hydro	80,554	58,858	80,549	71,440	56,391	48,433	68,897	65,244	58,132	46,386
CURRANT CR STEAM GEN	Non Hydro	85,276	75,278	84,015	83,368	70,230	68,416	75,262	69,943	73,652	58,977
Subtotal - CURRANT CREEK CC 1A		244,098	214,756	239,955	233,891	197,647	188,031	207,255	194,208	203,354	164,750
GADSBY 1	Non Hydro	(180)	(159)	(169)	(161)	(154)	750	4,935	6,839	1,922	(110)
GADSBY 2	Non Hydro	(265)	(158)	(93)	(182)	(98)	(125)	7,482	8,442	4,473	290
GADSBY 3	Non Hydro	2,970	(118)	(193)	(110)	(175)	4,541	17,659	20,714	12,199	6,760
GADSBY 4	Non Hydro	10,418	8,666	10,438	10,049	2,957	3,431	9,391	10,597	9,040	5,394
GADSBY 5	Non Hydro	9,896	8,509	8,976	9,482	2,522	3,360	9,612	10,617	8,932	3,288
GADSBY 6	Non Hydro	10,015	8,643	9,727	9,908	2,934	3,067	9,072	9,981	8,588	5,409
HERMISTON 1	Non Hydro	146,054	142,899	143,284	150,226	139,825	29,175	116,912	149,430	154,358	146,715
Lake Side	Non Hydro	67,601	73,926	82,917	73,338	61,416	49,354	69,317	84,411	64,340	66,846
Lake Side Augmentation	Non Hydro	96,034	67,569	72,251	51,936	60,306	35,717	58,243	70,987	60,417	66,271

2010 - PAC Merchant - Generation &		Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10
Name	Type	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Lake Side Duct Firing	Non Hydro	92,772	79,733	87,365	69,522	69,542	49,515	75,907	91,985	72,303	79,096
LITTLE MTN	Non Hydro	10,457	7,093	10,022	9,454	9,723	8,424	8,902	5,253	1,034	10,115
FOOTE CREEK	Non Hydro	8,717	9,135	8,327	8,550	6,991	5,930	6,105	4,482	6,722	6,620
LEANING JUNIPER	Non Hydro	7,968	4,095	19,651	29,723	29,663	28,513	28,305	27,808	15,688	14,639
Marengo	Non Hydro	22,013	13,324	32,046	44,129	33,506	32,534	25,030	22,192	17,532	24,097
Marengo Expansion	Non Hydro	11,007	6,661	16,023	22,065	16,753	16,267	12,515	11,096	8,768	12,049
Glenrock	Non Hydro	35,099	21,971	27,448	30,189	24,494	18,187	17,119	15,810	14,819	23,245
Rolling Hills	Non Hydro	28,859	18,412	23,272	27,764	23,448	16,348	15,494	14,551	12,613	20,382
Glenrock III	Non Hydro	10,669	6,685	8,146	9,868	9,496	6,983	6,364	5,838	5,350	8,644
Goodnoe Hills East	Non Hydro	9,949	4,723	18,766	30,002	25,054	24,114	21,417	21,921	15,769	13,591
Seven Mile Hill	Non Hydro	34,407	28,003	29,424	31,217	25,820	21,144	21,441	22,029	22,844	25,452
Seven Mile Hill II	Non Hydro	5,633	6,030	6,089	6,324	5,402	4,429	4,684	4,813	5,092	5,667
High Plains	Non Hydro	19,100	22,911	16,074	28,641	25,489	17,620	19,198	12,411	19,932	21,576
McFadden Ridge	Non Hydro	6,450	7,089	4,832	8,761	7,928	5,487	5,871	4,076	5,979	6,483
Dunlap	Non Hydro	-	-	-	-	-	-	-	-	-	29,542
3rd Party Purchase (On System)											
IRP Wind - Wyoming - 2011 - PPA (Top of th	Non Hydro	0	0	0	0	0	0	0	0	20,405	48,034
EURUS COMBINE HILLS	Non Hydro	7,000	4,154	9,010	12,612	11,320	11,232	8,554	9,427	6,392	8,312
ROCK RIVER WIND	Non Hydro	14,198	12,085	11,697	13,045	11,021	8,176	8,358	5,535	9,650	12,860
WOLVERINE CREEK	Non Hydro	12,889	5,424	11,991	16,768	15,416	13,244	10,866	14,105	14,725	11,954
Mountain Wind 2 QF	Non Hydro	16,240	13,219	14,805	20,615	16,029	17,060	15,568	11,612	15,725	13,586
Mountain Wind QF	Non Hydro	12,221	9,926	11,263	16,096	12,259	12,285	11,431	8,561	11,230	10,368
Spanish Fork Wind QF	Non Hydro	4,824	2,928	3,539	2,166	2,312	3,437	4,783	4,538	5,433	4,715
PROVO CITY	Non Hydro	17	14	13	12	11	10	9	3	180	6
BEAVER CITY	Non Hydro	6	6	6	5	8	2	5	5	6	6
FILLMORE CITY	Non Hydro	15	15	15	15	15	15	15	15	15	15
GRAND VALLEY	Non Hydro	28	18	16	13	10	5	4	5	6	4
MORGAN CITY	Non Hydro	4	4	4	2	1	1	1	1	1	2
NEPHI CITY	Non Hydro	2	2	2	2	1	1	1	1	2	1
SPANISH FORK CITY	Non Hydro	4	3	4	3	3	1	1	2	0	1
SPRINGVILLE CITY	Non Hydro	6	7	6	5	5	4	3	4	5	4
STRAWBERRY ELEC SERV	Non Hydro	1	1	22	1	1	1	1	1	24	1
HEBER LIGHT & POWER	Non Hydro	605	560	554	523	457	450	476	409	394	394
PAYSON CITY CORP	Non Hydro	1	1	1	0	0	0	0	0	4	1
Duke Energy Wind (Cambell Hill_Three Butt	Non Hydro	28,929	19,190	26,046	29,647	27,803	18,523	16,786	20,159	22,430	25,837
BIG TOP ENERGY	Non Hydro	103	65	280	459	396	242	265	380	235	241
BUTTER CREEK PWR ENG	Non Hydro	437	244	1,142	1,541	1,405	1,467	1,347	1,321	817	793
4 CORNERS WINDFM ENG	Non Hydro	795	558	2,406	3,378	2,892	3,065	2,698	2,498	1,921	1,767
4 MILE CNYN WIND ENG	Non Hydro	747	419	1,823	3,054	2,670	2,924	2,557	2,672	1,636	1,587
OR TRAIL WINDFRM ENG	Non Hydro	776	461	2,175	3,041	2,784	2,970	2,615	2,521	1,657	1,580
PACIFC CNYN WIND ENG	Non Hydro	585	308	1,451	2,277	1,975	2,188	1,824	1,872	1,221	1,210
SAND RANCH WNDFM ENG	Non Hydro	734	428	1,774	2,669	2,395	2,653	2,338	2,312	1,502	1,436
WAGON TRAIL ENERGY	Non Hydro	262	126	574	921	772	872	727	725	451	477
WARD BUTTE WNDFM ENG	Non Hydro	590	311	1,542	2,077	1,762	2,064	1,858	1,806	1,167	1,092
3 MILE CANYON WIND E	Non Hydro	661	299	1,812	3,047	2,677	2,935	2,364	1,975	1,450	1,344
Subtotal - Oregon Wind Farm		5,689	3,219	14,980	22,463	19,729	21,379	18,592	18,081	12,057	11,528

2010 - PAC Merchant - Generation &		Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10
Name	Type	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
MID-COL POND EXCH	Hydro	-	-	-	-	-	(900)	(300)	-	-	-
ROCKY REACH	Hydro	20,088	18,903	19,541	19,998	39,079	46,882	33,956	22,277	15,195	19,739
HERMISTON 1 PURCHASE		146,055	142,898	143,285	150,226	139,825	29,175	116,913	148,911	153,799	146,185
Douglas - Wells	Hydro	14,061	12,775	12,539	12,553	21,409	28,727	23,251	15,803	10,069	13,345
Grant - Wanapum	Hydro	17,701	16,005	15,159	14,208	23,301	18,001	21,986	14,587	10,175	16,665
Grant Priest Rapids Meaningful Priority	Hydro	28,421	24,807	25,070	24,782	33,167	26,668	32,314	25,290	20,976	26,127
GRANT COUNTY	Hydro	6,394	4,990	5,818	7,409	9,342	9,996	10,278	9,559	7,096	5,900
GEMSTATE	Hydro	0	0	0	0	0	15,126	12,979	11,708	0	0
Foster & Walker (Bogus Crk)		91	78	70	114	75	66	75	53	48	41
KEI Power Management Inc. (Box Canyon)		1,154	2,090	1,934	3,354	3,543	3,675	2,355	475	332	310
Paul Luckey		21	22	19	21	21	20	24	18	19	19
Ralphs Ranch, Inc.		19	(37)	16	16	16	19	0	(30)	0	-
Slate Creek Hydro Company, Inc.		1,194	1,948	1,880	2,317	2,674	2,355	797	21	-	96
Subtotal - California QF	Hydro	2,479	4,101	3,920	5,821	6,328	6,135	3,251	537	399	465
Amy Ranch Hydro		129	121	116	128	121	225	205	159	169	165
Bell Mountain Hydro, LLC		51	45	51	107	62	121	142	107	90	86
Birch Creek Hydro		803	1,093	1,275	1,062	1,320	1,217	1,177	1,217	1,209	1,312
CDM Hydroelectric Company		1,736	1,542	1,738	2,615	2,290	3,200	2,553	2,166	2,166	2,126
City of Preston Idaho		64	55	156	154	164	163	173	129	158	89
Commercial Energy Management(CEM), Inc.		69	69	119	150	178	280	281	222	86	31
Dry Creek LLC		563	415	442	597	783	2,056	2,221	1,448	1,054	898
Georgetown Irrigation Company		239	204	214	197	217	233	1	-	129	225
L&M Angus Ranch(INGRAM WS), LLC		207	194	220	186	90	28	5	2	84	137
Marsh Valley Hydro & Electric Company		513	456	625	685	402	468	(2)	(2)	2	373
Mink Creek Hydro		388	299	303	373	797	1,703	1,175	859	705	568
Nicholson Sunnybar Ranch		131	125	62	142	138	187	198	160	167	158
O.J. Power Company		62	55	62	67	24	67	67	67	55	64
Subtotal - Idaho QF	Hydro	4,955	4,672	5,382	6,463	6,586	9,948	8,197	6,534	6,074	6,231
Albany, City of		148	22	39	132	415	147	-	-	-	-
Cameron A. Curtiss		11	10	4	9	4	2	2	3	2	3
Central Oregon Irrigation District		1,434	1,120	1,675	2,805	3,051	2,319	2,716	2,568	2,491	1,318
JUNIPER RIDGE HYDRO		-	-	-	-	-	-	-	-	-	52
Deschutes Valley Water District		2,375	2,254	2,340	3,510	3,167	2,984	2,134	2,198	2,332	2,477
GALESVILLE HYDRO		491	135	318	339	301	227	194	240	399	715
Eagle Point Irrigation District		516	527	525	569	192	-	-	-	-	-
Falls Creek H.P. Limited Partnership		2,254	1,059	1,219	2,503	2,923	2,186	94	-	31	396
Farmers Irrigation District		2,963	2,730	2,704	2,898	2,842	2,310	906	729	1,187	1,078
HDI Associates V, LP		-	1	95	404	669	642	224	106	130	11
Lacomb Irrigation District		616	307	650	661	693	567	-	-	-	-
Loyd Fery		22	24	22	20	23	23	17	17	23	18
Roush Hydro Inc.		16	13	-	7	22	25	25	29	26	23
Santiam Water Control District		109	124	139	132	130	118	134	136	129	134
Swalley Irrigation District		-	-	-	53	345	433	433	450	336	172
Stahlbush Island Farms, Inc.		161	208	343	338	253	218	294	350	363	367
Warm Springs Forest Products		0	2	14	25	0	0	0	0	0	0
DRY CREEK LANDFILL (Env. Ind.)		1,789	1,673	1,906	1,631	1,867	1,721	1,601	1,520	1,645	1,938
OIT		0	36	51	56	61	36	24	28	30	22

2010 - PAC Merchant - Generation &		Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10
Name	Type	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Subtotal - Oregon QF	Hydro	12,905	10,248	12,044	16,093	16,957	13,958	8,799	8,374	9,124	8,724
Cottonwood Hydro LLC		135	115	146	243	331	222	319	315	201	232
Thayn Hydro LLC		92	23	203	290	224	149	214	249	250	290
Ballard Hog Farms Inc.	Biogas	0	1	3	6	10	15	5	4	0	0
Hill Air Force Base	Biogas	1,268	1,288	1,346	1,154	1,323	1,227	996	1,173	940	1,106
Sunderland Dairy Inc.	Biogas	4	4	7	17	21	17	18	15	6	0
Weber County, State of Utah	Biogas	478	326	595	(2)	(1)	0	0	0	0	0
DAVIS CO. WASTE MGMT		42	42	60	100	59	27	2	78	55	57
Subtotal - Utah QF	Hydro	2,019	1,800	2,360	1,808	1,967	1,658	1,554	1,834	1,452	1,685
City of Walla Walla		880	839	914	992	1,104	1,124	1,374	1,262	1,046	881
Yakima-Tieton Irrigation District		-	-	-	56	558	466	1,435	1,637	1,366	254
George DeRuyter & Sons Dairy	Biogas	442	473	692	622	655	584	600	599	563	536
Subtotal - Washington QF	Hydro	1,321	1,311	1,606	1,671	2,318	2,174	3,409	3,498	2,975	1,671
Lower Valley Energy(Swift Crk), Inc.		179	116	91	344	372	954	1,015	656	408	400
Shoshone Irrigation District		-	-	-	422	1,732	1,678	1,808	1,812	1,562	699
The Town of the City of Buffalo		143	102	162	157	152	90	160	159	154	161
Subtotal - Wyoming QF	Hydro	322	218	253	923	2,255	2,722	2,982	2,627	2,124	1,260
Chevron Wind QF	Non Hydro	3,055	2,421	3,102	3,892	3,645	2,507	2,366	3,095	2,825	2,882
Blanding Purchase	Non Hydro	44	49	42	34	27	30	30	26	26	25
GENERAL CHEMICAL	Non Hydro	607	683	121	95	107	32	30	21	62	80
Hurricane Purchase	Non Hydro	219	205	167	152	114	108	163	248	204	147
QF BIOMASS	Non Hydro	15,995	15,995	15,994	15,992	0	0	13,788	15,996	15,995	13,225
QF EXXON	Non Hydro	61,260	62,216	70,871	59,520	49,669	30,814	45,724	47,202	48,351	48,324
QF Kennecott	Non Hydro	11,517	12,970	13,862	14,082	817	17,217	16,536	17,191	16,189	17,474
QF SF PHOSPHATE	Non Hydro	7,395	6,543	6,926	6,917	6,278	7,136	7,648	5,949	7,577	7,207
Sunnyside (QF)	Non Hydro	36,473	34,560	36,341	12,238	10,293	36,090	37,856	38,315	32,106	28,672
QF Tesoro	Non Hydro	2,944	2,246	6,203	6,213	2,250	2,365	3,881	3,368	3,720	3,637
DC Forest Prod QF	Non Hydro	50	99	276	86	135	149	60	74	72	243
Roseburg Forest Products	Non Hydro	14,083	13,351	14,719	14,046	14,378	14,324	14,799	14,807	12,643	14,829
QF MAGCORP	Non Hydro	16,251	17,810	13,417	12,250	14,411	11,875	12,567	14,655	16,711	18,935
EVERGREEN BIOPWR	Non Hydro	2,896	3,039	3,125	3,239	3,498	3,671	4,117	4,869	3,902	4,350
Rough and Ready Lumber QF	Non Hydro	758	775	845	705	538	737	616	673	596	818
TOTAL ON SYSTEM		*5,807,556*	*5,127,004*	*5,432,475*	*5,224,178*	*5,236,849*	*4,736,671*	*5,546,346*	*5,481,626*	*5,195,479*	*5,109,651*
3rd Party Purchase (Off System)		249,496	235,662	271,461	130,255	378,397	678,952	754,895	719,126	400,730	375,329
TOTAL (FERC Form 1 - Page 401a)		6,057,052	5,362,666	5,703,937	5,354,433	5,615,247	5,415,623	6,301,241	6,200,752	5,596,209	5,484,980

2010 - PAC Merchant - Generation &		Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10
Name	Type	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Off System Purchases		(249,496)	(235,662)	(271,461)	(130,255)	(378,397)	(678,952)	(754,895)	(719,126)	(400,730)	(375,329)
On System Exchange											
Stateline Included in Interchange											
Stateline	Non Hydro	26,233	13,381	39,940	61,373	48,011	48,364	38,069	41,563	27,682	32,916
Avista	Non Hydro	(3,232)	(2,140)	(5,641)	(9,546)	(8,026)	(8,070)	(6,349)	(6,863)	(3,484)	(5,482)
PPM	Non Hydro	(4,252)	(1,678)	(5,754)	(7,964)	-	-	-	-	-	-
SCL	Non Hydro	-	-	-	-	(5,672)	(5,728)	(4,513)	(4,995)	(3,297)	(3,921)
JPM	Non Hydro	-	-	-	-	-	-	-	-	(1,117)	12
PAC Merchant - Net		18,748	9,563	28,545	43,863	34,313	34,565	27,207	29,705	19,784	23,525
Cowlitz Cty - Swift #2		34,738	11,993	19,107	20,698	17,329	21,970	7,825	4,358	7,313	12,429
Adjustments											
Transalta - Centralia (Buy CRO from BPA and and reimbursed from TEMU											
Big Fork	Hydro	(1,666)	(1,352)	(2,174)	(3,219)	(3,382)	(2,145)	(3,269)	(3,215)	(3,141)	(2,634)
Leaning Juniper	Non Hydro	(7,968)	(4,095)	(19,651)	(29,723)	(29,663)	(28,513)	(28,305)	(27,808)	(15,688)	(14,639)
Goodnoe Hills	Non Hydro	(9,949)	(4,723)	(18,766)	(30,002)	(25,054)	(24,114)	(21,417)	(21,921)	(15,769)	(13,591)
Chehalis	Non Hydro	(2,998)	(40,086)	(179,921)	(159,431)	(32,428)	278	(122,396)	(201,674)	(201,588)	(209,226)
Total Purchased Reserves		(22,581)	(50,256)	(220,512)	(222,375)	(90,527)	(54,494)	(175,387)	(254,618)	(236,186)	(240,090)
Total Resources Requiring Reserves		5,838,461	5,098,304	5,259,615	5,066,364	5,197,965	4,738,712	5,405,991	5,261,071	4,986,390	4,905,515

2010 - PAC Merchant - Generation &		Nov-10	Dec-10	2010	FERC Gen	FERC Purch	Ref.
Name	Type	MW	MW	MW	MW	MW	
PAC Generation (On System)							
SWIFT #1	Hydro	69,062	107,074	733,951	733,951		
YALE	Hydro	66,225	86,218	629,932	629,932		
MERWIN	Hydro	68,205	77,863	559,382	559,382		
Subtotal - LEWIS RIVER		203,492	271,155	1,923,265	1,923,265		
COPCO #1	Hydro	6,839	6,742	67,544	67,544		
COPCO #2	Hydro	9,110	9,178	88,801	88,801		
IRON GATE	Hydro	9,382	10,488	96,256	96,256		
FALL CREEK	Hydro	948	1,096	11,086	11,086		
EAST SIDE	Hydro	0	(2)	4,397	4,399		
WEST SIDE	Hydro	(3)	(3)	288	288		
J.C. BOYLE	Hydro	21,147	15,433	193,133	193,133		
Subtotal - KLAMATH RIVER		47,423	42,932	461,505	461,507		
PROSPECT #1	Hydro	0	2,148	22,455	22,455		
PROSPECT #2	Hydro	18,900	26,373	225,108	225,108		
PROSPECT #3	Hydro	2,451	4,526	35,330	35,330		
PROSPECT #4	Hydro	0	400	3,917	3,917		
EAGLE POINT	Hydro	1,204	1,908	17,206	17,206		
Subtotal - ROGUE RIVER		22,555	35,355	304,016	304,016		
SODA SPRINGS	Hydro	3,464	6,312	51,896	51,896		
SLIDE CREEK	Hydro	5,648	8,535	79,059	79,059		
CLEARWATER #2	Hydro	1,954	3,179	29,705	29,705		
CLEARWATER #1	Hydro	2,230	2,886	31,476	31,476		
LEMOLO #2	Hydro	12,276	13,801	138,473	138,473		
LEMOLO #1	Hydro	10,865	8,803	111,394	111,394		
FISH CREEK	Hydro	2,479	5,919	37,477	37,477		
TOKETEE	Hydro	14,865	21,412	188,950	188,950		
Subtotal - UMPQUA RIVER		53,781	70,847	668,430	668,430		
GRACE	Hydro	2,080	2,441	63,490	63,490		
ONEIDA	Hydro	1,439	1,826	28,335	28,335		
SODA	Hydro	174	150	13,592	13,592		
CUTLER	Hydro	3,912	8,923	48,987	48,987		
LIFTON	Hydro	(24)	(28)	-2,784	(2,784)		
Subtotal - BEAR RIVER		7,581	13,312	151,620	151,620		
ASHTON	Hydro	904	1,522	22,728	22,728		
LAST CHANCE	Hydro	158	245	3,232	3,232		
GUNLOCK	Hydro	98	95	1,527	1,527		
SANDCOVE	Hydro	94	92	1,542	1,542		
VEYO	Hydro	120	76	1,130	1,130		
GRANITE	Hydro	443	464	6,403	6,403		
OLMSTED	Hydro	501	1,722	18,451	18,451		
PIONEER	Hydro	(7)	1,573	15,484	15,484		
SNAKE CREEK	Hydro	217	201	3,079	3,079		
STAIRS	Hydro	263	281	5,587	5,587		
WEBER	Hydro	160	758	15,316	15,316		
BIG FORK	Hydro	3,048	3,017	32,262	32,262		
PARIS	Hydro	107	100	2,275	2,275		

2010 - PAC Merchant - Generation &		Nov-10	Dec-10	2010	FERC Gen	FERC Purch	Ref.
Name	Type	MW	MW	MW	MW	MW	
FOUNTAIN GREEN	Hydro	66	65	646	646		
VIVA NAUGHTON	Hydro	78	95	1,440	1,440		
Subtotal - SM. HYDRO UT-ID		6,250	10,306	131,102	131,102		
CONDIT	Hydro	5,679	8,736	95,220	95,220		
WALLOWA FALLS	Hydro	626	614	7,925	7,925		
BEND	Hydro	0	-	2,439	2,439		
Subtotal - SM. HYDRO OTHER		6,305	9,350	105,584	105,584		
Subtotal - Hydro		347,387	453,257	3,745,522	3,745,524		
BLUNDELL	Non Hydro	16,549	17,243	198,846	274,359		
Blundell 2	Non Hydro	3,500	5,438	75,513			
CAMAS COGEN (James River	Non Hydro	8,789	9,447	94,061	94,061		
CARBON 1	Non Hydro	39,370	46,715	525,227	1,296,004		
CARBON 2	Non Hydro	32,004	73,103	770,777			
CHOLLA 4	Non Hydro	236,404	239,343	2,621,160	2,621,160		
COLSTRIP 3	Non Hydro	94,980	90,315	1,192,652	1,192,652		
CRAIG 1	Non Hydro	57,130	46,625	666,511	1,280,372		
CRAIG 2	Non Hydro	49,534	57,294	613,861			
DAVE JOHNSTON 1	Non Hydro	48,837	45,972	683,716	4,699,767		
DAVE JOHNSTON 2	Non Hydro	52,488	47,886	709,102			
DAVE JOHNSTON 3	Non Hydro	123,457	115,992	1,062,027			
DAVE JOHNSTON 4	Non Hydro	128,613	189,497	2,244,924			
HAYDEN 1	Non Hydro	28,033	32,916	377,066	658,624		
HAYDEN 2	Non Hydro	23,311	23,887	281,558			
HUNTER 1	Non Hydro	255,528	265,138	2,572,954	7,536,395		
HUNTER 2	Non Hydro	115,519	148,699	1,667,060			
HUNTER 3	Non Hydro	259,118	291,508	3,296,380			
HUNTINGTON 1	Non Hydro	67,356	288,453	2,796,216	6,107,379		
HUNTINGTON 2	Non Hydro	222,733	300,215	3,311,163			
JIM BRIDGER 1	Non Hydro	882,989	953,844	9,833,000	9,833,000		
NAUGHTON 1	Non Hydro	109,898	113,400	1,210,082	5,339,603		
NAUGHTON 2	Non Hydro	134,890	145,231	1,576,610			
NAUGHTON 3	Non Hydro	204,168	211,072	2,552,911			
WYODAK	Non Hydro	164,536	169,952	2,047,508	2,047,508		
Chehalis	Non Hydro	80,486	58,300	1,288,256	1,288,256		
CURRANT CREEK #1	Non Hydro	60,051	79,095	847,790	2,536,660		
CURRANT CREEK #2	Non Hydro	67,466	79,036	781,386			
CURRANT CR STEAM GEN	Non Hydro	75,055	88,012	907,484			
Subtotal - CURRANT CREEK CC 1A		202,572	246,143	2,536,660	2,536,660		
GADSBY 1	Non Hydro	(188)	(175)	13,150	104,123		
GADSBY 2	Non Hydro	(201)	(166)	19,399			
GADSBY 3	Non Hydro	7,504	(177)	71,574			
GADSBY 4	Non Hydro	4,861	3,253	88,495	255,281		
GADSBY 5	Non Hydro	4,134	2,566	81,894			
GADSBY 6	Non Hydro	4,661	2,887	84,892			
HERMISTON 1	Non Hydro	137,299	139,512	1,595,689	1,595,689		
Lake Side	Non Hydro	88,872	75,209	857,547	2,537,046		
Lake Side Augmentation	Non Hydro	73,962	39,651	753,344			

2010 - PAC Merchant - Generation &		Nov-10	Dec-10	2010	FERC Gen	FERC Purch	Ref.
Name	Type	MW	MW	MW	MW	MW	
Lake Side Duct Firing	Non Hydro	94,010	64,405	926,155			
LITTLE MTN	Non Hydro	10,048	10,248	100,773	100,773		
FOOTE CREEK	Non Hydro	10,626	10,941	93,146	93,145		
LEANING JUNIPER	Non Hydro	11,190	6,315	223,558	223,558		
Marengo	Non Hydro	29,925	34,615	330,943	330,943		
Marengo Expansion	Non Hydro	14,963	17,308	165,475	165,475		
Glenrock	Non Hydro	28,165	31,395	287,941	287,941		
Rolling Hills	Non Hydro	24,734	26,792	252,669	252,669		
Glenrock III	Non Hydro	10,543	11,381	99,967	99,967		
Goodnoe Hills East	Non Hydro	16,424	10,538	212,268	212,268		
Seven Mile Hill	Non Hydro	32,040	30,302	324,123	324,123		
Seven Mile Hill II	Non Hydro	6,527	7,032	67,722	67,722		
High Plains	Non Hydro	25,671	28,726	257,349	257,349		
McFadden Ridge	Non Hydro	6,965	7,445	77,366	77,366		
Dunlap	Non Hydro	36,928	35,959	102,429	102,429		
<u>3rd Party Purchase (On System)</u>							
IRP Wind - Wyoming - 2011 - PPA (Top of th	Non Hydro	59,878	60,508	188,825		188,825	
EURUS COMBINE HILLS	Non Hydro	8,467	8,182	104,663		104,663	
ROCK RIVER WIND	Non Hydro	13,885	17,693	138,204		138,204	
WOLVERINE CREEK	Non Hydro	15,524	19,400	162,305		162,305	
Mountain Wind 2 QF	Non Hydro	26,419	21,194	202,072		202,072	
Mountain Wind QF	Non Hydro	19,279	14,506	149,425		149,425	
Spanish Fork Wind QF	Non Hydro	3,923	4,329	46,928		46,929	
PROVO CITY	Non Hydro	14	13	301		301	
BEAVER CITY	Non Hydro	6	8	72		72	
FILLMORE CITY	Non Hydro	15	15	182		182	
GRAND VALLEY	Non Hydro	7	14	132		132	
MORGAN CITY	Non Hydro	2	2	25		25	
NEPHI CITY	Non Hydro	2	2	19		19	
SPANISH FORK CITY	Non Hydro	2	0	25		25	
SPRINGVILLE CITY	Non Hydro	6	6	60		60	
STRAWBERRY ELEC SERV	Non Hydro	1	1	58		58	
HEBER LIGHT & POWER	Non Hydro	472	743	6,037		6,037	
PAYSON CITY CORP	Non Hydro	1	(1)	7		7	
Duke Energy Wind (Cambell Hill_Three Butt	Non Hydro	31,453	33,187	299,990		299,990	
BIG TOP ENERGY	Non Hydro	110	153	2,928		2,928	
BUTTER CREEK PWR ENG	Non Hydro	344	458	11,316		11,316	
4 CORNERS WINDFM ENG	Non Hydro	703	466	23,146		23,146	
4 MILE CNYN WIND ENG	Non Hydro	695	1,065	21,849		21,849	
OR TRAIL WINDFRM ENG	Non Hydro	642	835	22,057		22,057	
PACIFC CNYN WIND ENG	Non Hydro	519	813	16,243		16,242	
SAND RANCH WNDFM ENG	Non Hydro	652	995	19,888		19,888	
WAGON TRAIL ENERGY	Non Hydro	195	215	6,319		6,319	
WARD BUTTE WNDFM ENG	Non Hydro	468	584	15,323		15,323	
3 MILE CANYON WIND E	Non Hydro	1,354	773	20,689		20,689	
Subtotal - Oregon Wind Farm		5,683	6,357	159,758		159,757	

2010 - PAC Merchant - Generation &		Nov-10	Dec-10	2010	FERC Gen	FERC Purch	Ref.
Name	Type	MW	MW	MW	MW	MW	
MID-COL POND EXCH	Hydro	-	-	-1,200		(1,200)	
ROCKY REACH	Hydro	25,365	24,986	306,009		306,009	
HERMISTON 1 PURCHASE		136,580	139,005	1,592,857		1,592,857	
Douglas - Wells	Hydro	17,077	17,361	198,970		198,970	
Grant - Wanapum	Hydro	21,041	23,473	212,302		212,302	
Grant Priest Rapids Meaningful Priority	Hydro	28,489	33,553	329,664		329,664	
GRANT COUNTY	Hydro	4,728	6,090	87,600		87,600	
GEMSTATE	Hydro	0	(1)	39,812		39,813	
Foster & Walker (Bogus Crk)		60	71	843		843	
KEI Power Management Inc. (Box Canyon)		1,338	2,424	22,983		22,983	
Paul Luckey		23	25	253		253	
Ralphs Ranch, Inc.		0	0	18		18	
Slate Creek Hydro Company, Inc.		244	1,764	15,289		15,289	
Subtotal - California QF	Hydro	1,665	4,283	39,386		39,386	
Amy Ranch Hydro		184	140	1,862		1,862	
Bell Mountain Hydro, LLC		80	55	996		996	
Birch Creek Hydro		1,137	1,025	13,847		13,847	
CDM Hydroelectric Company		1,585	1,849	25,566		25,566	
City of Preston Idaho		110	164	1,579		1,579	
Commercial Energy Management(CEM), Inc.		61	81	1,627		1,627	
Dry Creek LLC		761	742	11,980		11,980	
Georgetown Irrigation Company		226	227	2,112		2,112	
L&M Angus Ranch(INGRAM WS), LLC		152	205	1,511		1,511	
Marsh Valley Hydro & Electric Company		486	548	4,555		4,555	
Mink Creek Hydro		462	403	8,036		8,036	
Nicholson Sunnybar Ranch		185	161	1,814		1,814	
O.J. Power Company		58	60	708		708	
Subtotal - Idaho QF	Hydro	5,489	5,660	76,193		76,193	
Albany, City of		172	146	1,222		1,223	
Cameron A. Curtiss		4	14	69		69	
Central Oregon Irrigation District		-	617	22,115		22,115	
JUNIPER RIDGE HYDRO		11	483	546		545	
Deschutes Valley Water District		2,379	3,177	31,327		31,327	
GALESVILLE HYDRO		305	725	4,388		4,388	
Eagle Point Irrigation District		343	577	3,248		3,248	
Falls Creek H.P. Limited Partnership		2,072	2,566	17,303		17,303	
Farmers Irrigation District		2,421	1,616	24,385		24,385	
HDI Associates V, LP		-	-	2,282		2,282	
Lacomb Irrigation District		567	673	4,733		4,733	
Loyd Fery		6	17	232		232	
Roush Hydro Inc.		28	22	236		236	
Santiam Water Control District		128	108	1,521		1,521	
Swalley Irrigation District		3	-	2,225		2,225	
Stahlbush Island Farms, Inc.		297	470	3,660		3,660	
Warm Springs Forest Products		0	3	45		45	
DRY CREEK LANDFILL (Env. Ind.)		1,879	1,806	20,978		20,978	
OIT		0	-22	322		322	

2010 - PAC Merchant - Generation &		Nov-10	Dec-10	2010	FERC Gen	FERC Purch	Ref.
Name	Type	MW	MW	MW	MW	MW	
Subtotal - Oregon QF	Hydro	10,615	12,997	140,839		140,837	
Cottonwood Hydro LLC		229	213	2,704		2,704	
Thayn Hydro LLC		237	302	2,525		2,525	
Ballard Hog Farms Inc.	Biogas	4	3	49		49	
Hill Air Force Base	Biogas	1,259	1,105	14,185		14,185	
Sunderland Dairy Inc.	Biogas	0	0	109		109	
Weber County, State of Utah	Biogas	1,273	629	3,298		3,298	
DAVIS CO. WASTE MGMT		22	17	560		560	
Subtotal - Utah QF	Hydro	3,025	2,269	23,431		23,430	
City of Walla Walla		703	1,016	12,135		12,135	
Yakima-Tieton Irrigation District		-	-	5,773		5,773	
George DeRuyter & Sons Dairy	Biogas	1	933	6,699		6,698	
Subtotal - Washington QF	Hydro	704	1,949	24,606		24,606	
Lower Valley Energy(Swift Crk), Inc.		319	310	5,163		5,164	
Shoshone Irrigation District		-	-	9,713		9,713	
The Town of the City of Buffalo		155	160	1,753		1,753	
Subtotal - Wyoming QF	Hydro	474	469	16,630		16,630	
Chevron Wind QF	Non Hydro	4,119	4,674	38,583		38,584	
Blanding Purchase	Non Hydro	46	41	422		423	
GENERAL CHEMICAL	Non Hydro	336	410	2,584		2,583	
Hurricane Purchase	Non Hydro	113	152	1,992		1,992	
QF BIOMASS	Non Hydro	12,021	7,999	143,000		143,000	
QF EXXON	Non Hydro	55,948	72,514	652,410		652,410	
QF Kennecott	Non Hydro	15,381	16,177	169,414		169,414	
QF SF PHOSPHATE	Non Hydro	5,703	7,173	82,451		82,452	
Sunnyside (QF)	Non Hydro	36,358	38,423	377,727		377,727	
QF Tesoro	Non Hydro	4,944	5,882	47,654		47,654	
DC Forest Prod QF	Non Hydro	182	4	1,428		1,427	
Roseburg Forest Products	Non Hydro	12,713	13,956	168,649		168,649	
QF MAGCORP	Non Hydro	19,117	16,521	184,521		184,521	
				0			
EVERGREEN BIOPWR	Non Hydro	3,135	3,084	42,924		42,924	
Rough and Ready Lumber QF	Non Hydro	819	583	8,464		8,463	
TOTAL ON SYSTEM		*5,281,069*	*5,928,694*	***64,107,599***	*57,639,191*	*6,468,408*	(B) 1
3rd Party Purchase (Off System)		450,052	304,261	4,948,617		4,948,617	(B) 2
TOTAL (FERC Form 1 - Page 401a)		5,731,121	6,232,956	69,056,216	*57,639,191*	*11,417,025*	(A) 1

2010 - PAC Merchant - Generation &		Nov-10	Dec-10		2010	FERC Gen	FERC Purch	Ref.
Name	Type	**MW**	**MW**		**MW**	**MW**	**MW**	
Off System Purchases		(450,052)	(304,261)		(4,948,617)	(A) 2		
On System Exchange								
Stateline Included in Interchange								
Stateline	Non Hydro	33,123	30,222					
Avista	Non Hydro	(5,317)	(5,034)					
PPM	Non Hydro	-	-					
SCL	Non Hydro	(3,927)	(3,583)					
JPM	Non Hydro	(207)	(6)					
PAC Merchant - Net		23,673	21,599	*	315,091	(A) 3		
Cowlitz Cty - Swift #2		22,688	33,146		213,594	(A) 4		
Adjustments								
Transalta - Centralia (Buy CRO from BPA and and reimb								
Big Fork	Hydro	(3,048)	(3,017)					
Leaning Juniper	Non Hydro	(11,190)	(6,315)					
Goodnoe Hills	Non Hydro	(16,424)	(10,538)					
Chehalis	Non Hydro	(80,486)	(58,300)					
Total Purchased Reserves		(111,148)	(78,170)		(1,756,344)	(A) 5		
Total Resources Requiring Reserves		5,216,282	5,905,270		**62,879,940**			

2010 - PAC Merchant - Purchases

Seq Title	On System	Total 2010 MWh	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ref.
Purchased Power															
OWC															
BPA STF		85,144	0	0	0	0	0	38,500	0	2,800	2,050	26,594	14,675	525	
BPA RESERVE SHARE		4,220	124	231	251	318	305	22	580	410	273	417	973	316	
BPA CHELIS CTGCY RSV		1,674	230	0	292	10	43	0	147	169	0	402	381	0	
Sub-Total		**91,038**	**354**	**231**	**543**	**328**	**348**	**38,522**	**727**	**3,379**	**2,323**	**27,413**	**16,029**	**841**	
WELLS	BA	198,970	14,061	12,775	12,539	12,553	21,409	28,727	23,251	15,803	10,069	13,345	17,077	17,361	
DOUG PUD SETTLEMENT		34,958	311	301	761	1,529	6,963	11,075	5,696	2,151	1,384	2,102	1,618	1,067	
DOUGLAS PUD STF		33,345	4,400	1,200	2,000	1,200	4,400	7,100	480	1,200	1,260	7,600	800	1,705	
DOUGLAS RESERV SHARE		44	0	3	1	5	4	0	7	6	2	3	9	4	
Sub-Total		**267,317**	**18,772**	**14,279**	**15,301**	**15,287**	**32,776**	**46,902**	**29,434**	**19,160**	**12,715**	**23,050**	**19,504**	**20,137**	
ROCKY REACH	BA	306,009	20,088	18,903	19,541	19,998	39,079	46,882	33,956	22,277	15,195	19,739	25,365	24,986	
CHELAN PUD STF		43,200	2,400	0	400	1,600	8,000	17,400	7,400	2,200	0	2,800	1,000	0	
CHELAN RESERVE SHARE		146	4	10	7	12	15	2	19	14	9	8	34	12	
Sub-Total		**349,355**	**22,492**	**18,913**	**19,948**	**21,610**	**47,094**	**64,284**	**41,375**	**24,491**	**15,204**	**22,547**	**26,399**	**24,998**	
WANAPUM	BA	212,302	17,701	16,005	15,159	14,208	23,301	18,001	21,986	14,587	10,175	16,665	21,041	23,473	
PRIEST RAPIDS	BA	329,664	28,421	24,807	25,070	24,782	33,167	26,668	32,314	25,290	20,976	26,127	28,489	33,553	
GRANT FIRM ENERGY	BA	87,600	6,394	4,990	5,818	7,409	9,342	9,996	10,278	9,559	7,096	5,900	4,728	6,090	
GRANT PUD STF		31,905	4,785	3,550	1,325	1,245	2,750	6,555	3,475	800	275	1,420	2,675	3,050	
GRANT RESERVE SHARE		183	6	12	10	14	17	2	29	17	12	12	35	17	
GRANT DISP (PR) FIRM		439,840	29,411	26,744	29,769	42,693	53,655	51,540	46,501	33,186	30,962	31,597	31,391	32,391	
Sub-Total		**1,101,494**	**86,718**	**76,108**	**77,151**	**90,351**	**122,232**	**112,762**	**114,583**	**83,439**	**69,496**	**81,721**	**88,359**	**98,574**	
COVE REPLACEMENT		12,001	1,014	942	1,013	990	1,014	990	1,014	1,014	990	1,014	992	1,014	
PGE STF		52,541	2,545	7,995	3,661	2,880	7,665	4,375	3,100	4,550	2,875	6,375	5,045	1,475	
PGE POND PURCHASE		1,200	0	0	0	0	0	900	300	0	0	0	0	0	
PGE RESERVE SHARE		618	26	43	43	63	35	2	84	44	47	74	102	55	
Sub-Total		**66,360**	**3,585**	**8,980**	**4,717**	**3,933**	**8,714**	**6,267**	**4,498**	**5,608**	**3,912**	**7,463**	**6,139**	**2,544**	
AVISTA CORP STF		128,378	13,408	11,780	2,815	8,000	10,615	4,760	8,550	15,745	6,420	20,715	19,020	6,550	
AVISTA CORP RES SHAR		422	13	25	22	37	37	2	58	35	29	40	96	28	
Sub-Total		**128,800**	**13,421**	**11,805**	**2,837**	**8,037**	**10,652**	**4,762**	**8,608**	**15,780**	**6,449**	**20,755**	**19,116**	**6,578**	
PUGET STF		167,118	15,550	14,405	10,840	7,025	17,575	7,610	15,625	16,075	9,350	14,925	24,663	13,475	
PUGET RESERVE SHARE		698	15	30	45	60	44	2	84	80	60	75	153	50	
Sub-Total		**167,816**	**15,565**	**14,435**	**10,885**	**7,085**	**17,619**	**7,612**	**15,709**	**16,155**	**9,410**	**15,000**	**24,816**	**13,525**	
IDAHO STF		1,800	600	0	0	0	800	0	0	0	0	400	0	0	
IDAHO WHEEL LOSS		12,979	5,438	3,950	3,591	0	0	0	0	0	0	0	0	0	
IDAHO WHEEL LOSS	*	-12,979	0	0	0	-12,979	0	0	0	0	0	0	0	0	
Sub-Total		**1,800**	**6,038**	**3,950**	**3,591**	**-12,979**	**800**	**0**	**0**	**0**	**0**	**400**	**0**	**0**	
SEATTLE STF		119,223	4,315	4,815	493	3,530	30,265	21,875	16,615	5,995	2,800	8,175	5,145	15,200	
SEATTLE RESERVE SHAR		278	8	16	11	17	24	2	48	21	21	33	58	19	
Sub-Total		**119,501**	**4,323**	**4,831**	**504**	**3,547**	**30,289**	**21,877**	**16,663**	**6,016**	**2,821**	**8,208**	**5,203**	**15,219**	
BLACK HILLS STF		165	0	165	0	0	0	0	0	0	0	0	0	0	
SDG&E STF		9,489	800	2,400	2,282	1,200	0	7	0	1,600	0	0	1,200	0	
NORTHWSTRN RESV SHAR		507	17	31	25	42	48	2	73	46	38	60	82	43	
WAPA STF		3,885	0	185	290	1,400	1,960	50	0	0	0	0	0	0	
WAPA RESERVE SHARE		4	0	0	0	0	0	0	0	1	0	2	0	1	

Sub-Total		**3,889**	**0**	**185**	**290**	**1,400**	**1,960**	**50**	**0**	**1**	**0**	**2**	**0**	**1**
OWC SYS DEV - REC		79,944	6,393	5,335	5,064	6,176	6,171	4,873	7,709	2,790	7,196	6,278	9,779	12,180
OWC SYS DEV - DEL		-90,364	-8,899	-5,027	-4,703	-6,336	-6,300	-8,015	-6,608	-7,591	-3,437	-5,499	-13,542	-14,407
MID-COL POND PURCH	BA	-1,200	0	0	0	0	0	-900	-300	0	0	0	0	0
BOOKOUT PURCHASES		-5,211,346	-537,080	-495,839	-490,757	-347,796	-465,743	-324,843	-428,572	-344,377	-441,423	-556,156	-410,129	-368,631
BOOKOUT PURCHASES	*	-4,729	0	0	0	0	0	-2,291	-214	-844	-127	-120	-1,133	0
Sub-Total		**-5,227,695**	**-539,586**	**-495,531**	**-490,396**	**-347,956**	**-465,872**	**-331,176**	**-427,985**	**-350,022**	**-437,791**	**-555,497**	**-415,025**	**-370,858**
POWEREX STF		100,559	16,000	1,225	2,674	2,694	7,214	6,202	4,913	15,000	1,407	8,525	30,805	3,900
PAC GAS & ELEC STF		1,600	0	0	0	0	0	0	0	0	0	0	0	1,600
SO CAL EDISON STF		27,484	2,827	400	6	1,200	4,800	7,314	859	68	810	7,200	0	2,000
SIERRA WHEEL LOSS		152	0	0	0	0	40	44	44	0	0	0	23	0
SIERRA RESERVE SHARE		8	0	0	0	0	0	0	0	0	0	0	8	0
Sub-Total		**160**	**0**	**0**	**0**	**0**	**40**	**44**	**44**	**0**	**0**	**0**	**31**	**0**
EWEB STF		18,796	3,800	600	1,000	0	2,400	3,736	512	1,548	400	4,600	200	0
PSC OF COLORADO STF		3,200	0	800	0	2,400	0	0	0	0	0	0	0	0
TACOMA STF		20,770	8,090	800	535	50	1,010	1,200	1,205	525	1,135	560	4,030	1,630
TACOMA STF	*	21	21	0	0	0	0	0	0	0	0	0	0	0
TACOMA RESERVE SHARE		116	6	9	6	9	9	0	13	8	6	10	29	11
Sub-Total		**20,907**	**8,117**	**809**	**541**	**59**	**1,019**	**1,200**	**1,218**	**533**	**1,141**	**570**	**4,059**	**1,641**
WM SPR FOREST PROD	BA	45	0	2	14	25	0	0	0	0	0	0	0	3
ROSEBURG THERMAL PUR	BA	168,638	14,083	13,351	14,719	14,046	14,378	14,324	14,799	14,807	12,643	14,829	12,713	13,945
ROSEBRG-WEED THM PUR	BA	11	0	0	0	0	0	0	0	0	0	0	0	11
Sub-Total		**168,649**	**14,083**	**13,351**	**14,719**	**14,046**	**14,378**	**14,324**	**14,799**	**14,807**	**12,643**	**14,829**	**12,713**	**13,956**
SNOHOMISH PUD STF		79,893	5,743	3,460	5,055	1,620	2,870	22,380	6,015	5,630	4,985	10,030	8,300	3,805
C OF ALBANY HYD PUR	BA	881	148	22	39	6	200	147	0	0	0	0	172	146
C OF ALBANY HYD PUR	BA	342	0	0	0	126	215	0	0	0	0	0	0	0
Sub-Total		**1,223**	**148**	**22**	**39**	**132**	**415**	**147**	**0**	**0**	**0**	**0**	**172**	**146**
SMUD PROVISONAL FIRM		213,709	0	9,775	31,745	30,199	61,600	66,380	12,775	600	0	400	135	100
SACRAMENTO MUN STF		21,856	350	740	4,569	8,600	1,855	1,520	891	601	0	1,330	200	1,200
SACRAMENTO RESV SHAR		74	0	0	0	0	0	0	0	0	0	0	74	0
Sub-Total		**235,639**	**350**	**10,515**	**36,314**	**38,799**	**63,455**	**67,900**	**13,666**	**1,201**	**0**	**1,730**	**409**	**1,300**
GRAYS HARBOR STF		4,320	0	0	0	0	0	4,320	0	0	0	0	0	0
MODESTO IRRIG STF		1,200	0	0	1,200	0	0	0	0	0	0	0	0	0
TURLOCK IRRIG STF		800	0	0	400	0	0	0	0	200	0	0	0	200
TURLOCK RESERV SHARE		15	0	0	0	0	0	0	0	0	0	0	15	0
Sub-Total		**815**	**0**	**0**	**400**	**0**	**0**	**0**	**0**	**200**	**0**	**0**	**15**	**200**
REDDING STF		1,014	0	50	75	0	92	332	75	70	320	0	0	0
HERMISTON GEN ENERGY	BA	1,592,908	146,054	142,899	143,284	150,226	139,825	29,175	116,913	148,911	153,799	146,183	136,634	139,005
HERMISTON GEN ENERGY	BA	-51	1	-1	1	-1	0	0	0	0	-0	2	-54	0
Sub-Total		**1,592,857**	**146,055**	**142,898**	**143,285**	**150,226**	**139,825**	**29,175**	**116,913**	**148,911**	**153,799**	**146,185**	**136,580**	**139,005**
RAINBOW ENERGY STF		17,714	2,600	1,000	3,234	400	1,800	2,400	1,800	1,200	0	1,400	1,430	450
J ARON STF		7,800	0	0	0	0	1,600	1,600	800	3,000	400	0	0	400
IBERDROLA RENEW STF		477,751	36,907	19,069	40,934	13,923	54,878	77,303	42,275	48,585	15,825	38,810	60,387	28,855
SEMPRA ENG TRADE STF		236,995	5,039	33,800	7,196	3,200	16,000	17,003	45,800	45,557	52,800	10,600	0	0
PAC NW GEN COOP STF		10,075	600	850	0	350	0	0	3,600	875	1,000	1,800	1,000	0
TRANSALTA STF		97,444	19,758	5,945	9,177	7,450	14,290	4,804	11,565	9,800	1,675	4,825	5,155	3,000
TRANSALTA IF		1,315,200	148,800	134,400	148,600	0	0	0	148,800	148,800	144,000	148,800	144,200	148,800
Sub-Total		**1,412,644**	**168,558**	**140,345**	**157,777**	**7,450**	**14,290**	**4,804**	**160,365**	**158,600**	**145,675**	**153,625**	**149,355**	**151,800**

MORGAN STANLEY STF		517,719	4,840	9,000	16,790	2,400	9,809	55,402	146,020	119,233	119,600	19,184	5,200	10,241
MORGAN STANLEY STF	*	92	50	0	4	0	0	0	0	38	0	0	0	0
MORGAN STANLEY IF		245,575	20,000	19,200	21,600	20,800	20,000	20,800	20,800	20,800	19,975	20,800	20,000	20,800
Sub-Total		**763,386**	**24,890**	**28,200**	**38,394**	**23,200**	**29,809**	**76,202**	**166,820**	**140,071**	**139,575**	**39,984**	**25,200**	**31,041**
SHELL ENERGY STF		207,116	18,980	15,460	7,100	10,631	11,080	19,260	25,510	31,825	16,435	20,800	23,770	6,265
CONSTELLATION STF		7,124	1,200	0	2,584	400	400	2,000	500	40	0	0	0	0
ALBERT PWR P RES SHR		59	0	0	0	0	0	0	0	0	0	0	59	0
CALIFORNIA ISO STF		220,805	14,863	15,925	6,979	33,544	21,286	12,316	12,357	10,607	10,338	35,699	32,955	13,936
CALIFORNIA ISO STF	*	-1,872	0	0	0	-728	0	0	-200	-50	-100	323	-1,117	0
Sub-Total		**218,933**	**14,863**	**15,925**	**6,979**	**32,816**	**21,286**	**12,316**	**12,157**	**10,557**	**10,238**	**36,022**	**31,838**	**13,936**
LEWIS CO CHLS ST SRV		9,756	1,050	1,150	700	750	1,140	1,200	900	376	390	428	737	935
LEWIS CO CHLS ST SRV	*	-1,830	-178	68	0	-329	-469	-260	0	-662	0	0	0	0
Sub-Total		**7,926**	**872**	**1,218**	**700**	**421**	**671**	**940**	**900**	**-286**	**390**	**428**	**737**	**935**
CARGILL-ALLIANT STF		122,020	12,656	2,000	22,915	5,200	4,184	36,800	5,600	6,200	4,600	13,665	6,600	1,600
CARGILL-ALLIANT STF	*	24	24	0	0	0	0	0	0	0	0	0	0	0
Sub-Total		**122,044**	**12,680**	**2,000**	**22,915**	**5,200**	**4,184**	**36,800**	**5,600**	**6,200**	**4,600**	**13,665**	**6,600**	**1,600**
THE ENRGY AUTHOR STF		37,082	2,417	3,219	1,156	2,403	3,810	3,896	3,670	931	2,149	11,655	1,625	151
BP ENERGY STF		32,904	0	1,088	0	1,784	944	15,600	3,480	800	3,600	5,408	0	200
BP ENERGY STF	*	1	0	0	0	0	0	0	1	0	0	0	0	0
Sub-Total		**32,905**	**0**	**1,088**	**0**	**1,784**	**944**	**15,600**	**3,481**	**800**	**3,600**	**5,408**	**0**	**200**
OIT GEOTHERMAL PURCH	BA	343	0	36	51	56	61	36	24	28	30	22	0	0
OIT GEOTHERMAL PURCH	BA	-22	0	0	0	0	0	0	0	0	0	0	0	-22
Sub-Total		**322**	**0**	**36**	**51**	**56**	**61**	**36**	**24**	**28**	**30**	**22**	**0**	**-22**
NEXTERA ENERGY STF		600	400	200	0	0	0	0	0	0	0	0	0	0
PPL ENERGY PLUS STF		51,800	3,000	1,200	3,000	0	8,600	5,600	3,200	4,600	2,200	6,600	7,600	6,200
CONOCO STF		122,800	19,200	9,400	4,800	7,200	22,400	37,600	17,800	4,400	0	0	0	0
CONOCO STF	*	362	0	0	0	0	0	0	362	0	0	0	0	0
Sub-Total		**123,162**	**19,200**	**9,400**	**4,800**	**7,200**	**22,400**	**37,600**	**18,162**	**4,400**	**0**	**0**	**0**	**0**
CENT OR IRR DIST HYD	BA	22,115	1,434	1,120	1,675	2,805	3,051	2,319	2,716	2,568	2,491	1,318	0	617
CENT OR IRR DIST HYD	BA	0	0	0	0	0	0	0	-0	0	0	0	0	0
JUNIPER RIDGE HYDRO	BA	58	0	0	0	0	0	0	0	0	0	47	11	0
JUNIPER RIDGE HYDRO	BA	488	0	0	0	0	0	0	0	0	0	4	0	483
Sub-Total		**22,660**	**1,434**	**1,120**	**1,675**	**2,805**	**3,051**	**2,319**	**2,716**	**2,568**	**2,491**	**1,370**	**11**	**1,100**
EAGLE POINT HYD PUR	BA	3,248	516	527	525	569	192	0	0	0	0	0	343	577
FALLS CREEK HYD PUR	BA	16,141	2,254	1,059	1,219	2,503	2,923	2,186	94	0	0	396	941	2,566
FALLS CREEK HYD PUR	BA	1,162	0	0	0	0	0	0	0	0	0	0	31	1,131
Sub-Total		**17,303**	**2,254**	**1,059**	**1,219**	**2,503**	**2,923**	**2,186**	**94**	**0**	**0**	**396**	**972**	**3,697**
FARMERS IRR HYD PUR	BA	24,385	2,963	2,730	2,704	2,898	2,842	2,310	906	729	1,187	1,078	2,421	1,616
GALESVILLE HYDRO PUR	BA	4,388	491	135	318	339	301	227	194	240	399	715	305	725
SPRAGUE (HDI/N FK) E	BA	2,282	0	1	95	404	669	642	224	106	130	11	0	0
LACOMB (2) HYD PUR	BA	4,733	616	307	650	661	693	567	0	0	0	0	567	673
MIDDLEFORK HYDRO PUR		23,610	2,317	2,063	2,093	2,164	2,250	2,071	1,772	1,596	1,598	1,441	1,986	2,260
ODELL CREEK HYD PUR	BA	0	0	0	0	0	0	0	0	0	0	0	0	0
DESCHUTE VAL HYD PUR	BA	31,327	2,375	2,254	2,340	3,510	3,167	2,984	2,134	2,198	2,332	2,477	2,379	3,177
SANTIAM WCD HYD PUR	BA	1,521	109	124	139	132	130	118	134	136	129	134	128	108
SLATE CREEK HYD PUR	BA	15,289	1,194	1,948	1,880	2,317	2,674	2,355	797	21	0	96	244	1,764
WALLA WALLA HYD PUR	BA	12,135	880	839	914	992	1,104	1,124	1,374	1,262	1,046	881	703	1,016
YAKIMA TIETON ENERGY	BA	5,773	0	0	0	56	558	466	1,435	1,637	1,366	254	0	0

BOX CANYON HYDRO PUR	BA	22,983	1,154	2,090	1,934	3,354	3,543	3,675	2,355	475	332	310	1,338	2,424
BOGUS CREEK HYD PUR	BA	806	91	78	70	88	75	66	75	53	48	41	60	60
BOGUS CREEK HYD PUR	BA	36	0	0	0	25	0	0	0	0	0	0	0	11
Sub-Total		**843**	**91**	**78**	**70**	**114**	**75**	**66**	**75**	**53**	**48**	**41**	**60**	**71**
CURTIS LIVES HYD PUR	BA	69	11	10	4	9	4	2	2	3	2	3	4	14
LOYD FERY HYDRO PUR	BA	232	22	24	22	20	23	23	17	17	23	18	6	17
PAUL LUCKY HYDRO PUR	BA	253	21	22	19	21	21	20	24	18	19	19	23	25
RALPHS RANCH HYD PUR	BA	104	19	0	16	16	16	19	0	19	0	0	0	0
RALPHS RANCH HYD PUR	BA	-86	0	-37	0	0	0	0	0	-49	0	0	0	0
Sub-Total		**18**	**19**	**-37**	**16**	**16**	**16**	**19**	**0**	**-30**	**0**	**0**	**0**	**0**
ROUSH HYDRO PURCH	BA	236	16	13	0	7	22	25	25	29	26	23	28	22
BIOMASS THERMAL PUR	BA	143,000	15,995	15,995	15,994	15,992	0	0	13,788	15,996	15,995	13,225	12,021	7,999
COMBINE HILLS WIND	BA	104,663	7,000	4,154	9,010	12,612	11,320	11,232	8,554	9,427	6,392	8,312	8,467	8,182
BC TRANS RESRV SHARE		264	0	0	0	0	0	0	0	0	0	0	264	0
CLATSKANIE PUD STF		1,445	0	0	0	0	800	0	400	145	0	0	100	0
CITIGROUP STF		124,200	13,400	4,200	4,600	600	20,400	25,400	12,400	11,600	1,200	12,400	16,400	1,600
CITIGROUP STF	*	-15	-15	0	0	0	0	0	0	0	0	0	0	0
Sub-Total		**124,185**	**13,385**	**4,200**	**4,600**	**600**	**20,400**	**25,400**	**12,400**	**11,600**	**1,200**	**12,400**	**16,400**	**1,600**
DB ENERGY TRADE STF		133,800	14,000	18,000	19,600	2,000	26,800	6,200	11,800	10,400	11,200	10,200	3,600	0
NORTHPOINT STF		400	0	0	0	0	400	0	0	0	0	0	0	0
JP MORGAN VENTUR STF		75,600	3,000	12,200	7,600	1,200	17,600	13,600	7,200	1,200	0	6,000	4,400	1,600
DOUG CO FOREST PROD	BA	1,427	50	99	276	86	135	149	60	74	72	243	182	4
BARCLAYS STF		83,578	12,800	36,000	9,978	0	9,400	10,800	0	1,400	0	2,000	400	800
BNP PARIBAS ENG STF		5,600	1,600	1,200	0	0	1,000	600	400	0	0	0	0	800
DERUYTER DAIRY ENERG	BA	6,218	442	473	692	622	655	584	600	599	563	536	1	453
DERUYTER DAIRY ENERG	BA	480	0	0	0	0	0	0	0	0	0	0	0	480
Sub-Total		**6,698**	**442**	**473**	**692**	**622**	**655**	**584**	**600**	**599**	**563**	**536**	**1**	**933**
PACIFIC SUMMIT STF		12,348	2,800	1,600	1,148	0	6,000	0	0	800	0	0	0	0
DRY CREEK LANDFILL (Env. Ind.)	BA	20,978	1,789	1,673	1,906	1,631	1,867	1,721	1,601	1,520	1,645	1,938	1,879	1,806
EVERGREEN BIOPWR PUR	BA	42,924	2,896	3,039	3,125	3,239	3,498	3,671	4,117	4,869	3,902	4,350	3,135	3,084
FINLEY BIOENERGY PUR		27,071	2,230	2,072	2,422	2,232	2,278	2,224	2,313	2,311	2,189	2,311	2,194	2,295
ROUGH & READY LUMBER	BA	8,463	758	775	845	705	538	737	616	673	596	818	819	583
MACQUARIE STF		97,755	4,761	3,403	4,927	2,190	17,235	19,224	11,880	12,247	3,017	6,093	9,477	3,301
ENDURE ENERGY STF		11,600	400	400	400	1,600	4,800	800	2,000	200	1,000	0	0	0
BIG TOP ENERGY	BA	2,928	103	65	280	459	396	242	265	380	235	241	110	153
BUTTER CREEK WIND QF	BA	11,316	437	244	1,142	1,541	1,405	1,467	1,347	1,321	817	793	344	458
4 CORNERS WINDFM QF	BA	23,146	795	558	2,406	3,378	2,892	3,065	2,698	2,498	1,921	1,767	703	466
4 MILE CNYN WIND QF	BA	21,849	747	419	1,823	3,054	2,670	2,924	2,557	2,672	1,636	1,587	695	1,065
OR TRAIL WINDFARM QF	BA	22,057	776	461	2,175	3,041	2,784	2,970	2,615	2,521	1,657	1,580	642	835
PACIFIC CNYN WIND QF	BA	16,242	585	308	1,451	2,277	1,975	2,188	1,824	1,872	1,221	1,210	519	813
SAND RANCH WINDFM QF	BA	19,888	734	428	1,774	2,669	2,395	2,653	2,338	2,312	1,502	1,436	652	995
WAGON TRAIL WIND PUR	BA	6,319	262	126	574	921	772	872	727	725	451	477	195	215
WARD BUTTE WINDFM QF	BA	15,323	590	311	1,542	2,077	1,762	2,064	1,858	1,806	1,167	1,092	468	584
EDF TRADE STF		47,466	800	0	200	0	1,800	7,600	16,600	11,600	2,600	1,200	5,066	0
STAHLBUSH ISL FRM QF	BA	3,660	161	208	343	338	253	218	294	350	363	367	297	470
3 MILE CANYON WIND E	BA	20,689	661	299	1,812	3,047	2,677	2,935	2,364	1,975	1,450	1,344	1,354	773
SWALLEY IRR HYD PUR	BA	2,225	0	0	0	53	345	433	433	450	336	172	3	0
TOTAL OWC		**4,381,831**	**248,865**	**231,943**	**264,484**	**202,974**	**406,090**	**590,079**	**585,291**	**585,604**	**329,253**	**276,568**	**380,614**	**280,065**

WYOMING (PPL)

B HILLS RESERVE CAP		868	1	170	12	0	168	86	0	156	0	14	101	160
B HILLS RESERVE CAP	*	-550	0	-0	-65	-12	0	-168	-39	0	-153	0	-14	-100
BLACK HILLS NON-FIRM		130	0	0	0	0	115	15	0	0	0	0	0	0
BLACK HILLS STF		11,470	275	50	715	755	2,040	167	380	4,965	215	673	1,130	105
Sub-Total		**11,918**	**276**	**220**	**662**	**743**	**2,323**	**100**	**341**	**5,121**	**62**	**687**	**1,217**	**165**
WAPA STF		7,617	475	392	1,122	335	405	258	145	238	330	3,719	198	0
WYO SYS DEV - REC		407,572	4,770	12,224	46,742	56,956	61,280	22,739	54,495	39,817	17,305	35,528	21,524	34,192
WYO SYS DEV - DEL		-1,163,069	-159,435	-134,711	-100,508	-64,847	-40,003	-74,788	-71,533	-66,482	-117,445	-105,943	-114,580	-112,794
Sub-Total		**-755,497**	**-154,665**	**-122,487**	**-53,766**	**-7,891**	**21,277**	**-52,049**	**-17,038**	**-26,665**	**-100,140**	**-70,415**	**-93,056**	**-78,602**
POWEREX STF		933	0	0	0	0	0	0	0	0	0	0	0	933
TRI STATE FIRM ENERG		169,419	16,937	15,052	16,069	10,659	10,004	11,643	16,796	17,347	13,695	12,548	14,222	14,447
TRI-STATE STF		5,241	85	505	1,675	100	946	0	75	205	0	1,429	26	195
Sub-Total		**174,660**	**17,022**	**15,557**	**17,744**	**10,759**	**10,950**	**11,643**	**16,871**	**17,552**	**13,695**	**13,977**	**14,248**	**14,642**
PSC OF COLORADO STF		4,208	100	0	150	0	200	38	800	2,000	0	537	339	44
SALT RIVER STF		261	0	0	0	0	0	0	0	0	261	0	0	0
GENERAL CHEMICAL	BA	2,583	607	683	121	95	107	32	30	21	62	80	336	410
ROCK RVR1- FOOTE CR 6	BA	137,190	14,198	12,085	11,697	13,045	11,021	8,176	8,358	5,535	9,650	12,860	13,885	16,678
ROCK RVR1- FOOTE CR 6	BA	1,015	0	0	0	0	0	0	0	0	0	0	0	1,015
Sub-Total		**138,204**	**14,198**	**12,085**	**11,697**	**13,045**	**11,021**	**8,176**	**8,358**	**5,535**	**9,650**	**12,860**	**13,885**	**17,693**
SIMPLOT PHOSPHATE EN	BA	82,452	7,395	6,543	6,926	6,917	6,278	7,136	7,648	5,949	7,577	7,207	5,703	7,173
RMGC STF		5,815	562	193	765	531	250	0	40	529	627	2,043	115	160
RAINBOW ENERGY STF		2,562	0	0	0	0	0	0	0	1,600	0	800	0	162
MUN ELEC NEBRSKA STF		500	0	0	0	20	0	0	0	320	0	160	0	0
CARGILL-ALLIANT STF		8,720	1,132	0	610	420	528	567	50	2,995	475	1,673	250	20
CARGILL-ALLIANT STF	*	101	16	0	0	0	0	0	0	0	0	0	85	0
Sub-Total		**8,821**	**1,148**	**0**	**610**	**420**	**528**	**567**	**50**	**2,995**	**475**	**1,673**	**335**	**20**
EXXONMOBIL QF ENERGY	BA	652,410	61,260	62,216	70,871	59,520	49,669	30,814	45,724	47,202	48,351	48,324	55,948	72,514
PPL ENERGY PLUS STF		400	0	0	36	30	65	0	0	0	0	269	0	0
BUFFALO CITY HYD PUR	BA	1,753	143	102	162	157	152	90	160	159	154	161	155	160
SHOSHONE IRRIG ENERG	BA	9,713	0	0	0	422	1,732	1,678	1,808	1,812	1,562	699	0	0
BLK HILLS GENER STF		400	0	0	0	0	240	0	0	160	0	0	0	0
MACQUARIE STF		30	0	0	0	0	0	0	0	0	0	30	0	0
EDF TRADE STF		3,596	0	0	0	0	0	0	0	0	0	2,400	971	225
CHEVRON WIND	BA	38,584	3,055	2,421	3,102	3,892	3,645	2,507	2,366	3,095	2,825	2,882	4,119	4,674
CAMPBELL HILL WIND	BA	299,706	28,929	19,006	26,046	29,647	27,803	18,511	16,787	20,125	22,430	25,837	31,410	33,176
CAMPBELL HILL WIND	BA	284	0	184	0	0	0	12	-1	34	0	0	43	12
Sub-Total		**299,990**	**28,929**	**19,190**	**26,046**	**29,647**	**27,803**	**18,523**	**16,786**	**20,159**	**22,430**	**25,837**	**31,453**	**33,187**
TOP O THE WORLD WIND	BA	189,887	0	0	0	0	0	0	0	0	20,405	48,034	59,856	61,593
TOP O THE WORLD WIND	BA	-1,062	0	0	0	0	0	0	0	0	0	0	22	-1,084
Sub-Total		**188,825**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**20,405**	**48,034**	**59,878**	**60,508**
TOTAL WYOMING (PPL)		**880,737**	**-19,495**	**-2,886**	**86,248**	**118,642**	**136,644**	**29,513**	**84,088**	**87,780**	**28,326**	**101,963**	**95,845**	**134,068**
UTAH														
BPA RESERVE SHARE		588	12	0	63	19	107	0	68	119	58	0	121	21
BPA STF		108	0	0	0	0	108	0	0	0	0	0	0	0
Sub-Total		**696**	**12**	**0**	**63**	**19**	**215**	**0**	**68**	**119**	**58**	**0**	**121**	**21**
DOUGLAS RESERV SHARE		2	0	0	0	0	2	0	0	0	0	0	0	0
CHELAN RESERVE SHARE		14	0	0	2	1	4	0	0	3	0	0	4	0
GRANT RESERVE SHARE		19	0	0	2	1	6	0	3	3	1	0	2	1

PGE RESERVE SHARE		88	0	0	10	4	11	0	11	18	11	0	21	2
AVISTA CORP RES SHAR		50	0	0	5	2	11	0	6	10	4	0	11	1
PUGET STF		3	0	0	0	3	0	0	0	0	0	0	0	0
PUGET RESERVE SHARE		99	0	0	9	4	17	0	12	23	13	0	18	3
Sub-Total		**102**	**0**	**0**	**9**	**7**	**17**	**0**	**12**	**23**	**13**	**0**	**18**	**3**
IDAHO RESERVE SHARE		101	0	0	12	3	20	0	12	24	10	0	17	3
SEATTLE RESERVE SHAR		31	0	0	2	2	10	0	5	6	0	0	6	0
BLACK HILLS STF		3,000	0	0	0	0	1,200	0	1,000	0	400	400	0	0
SDG&E STF		20	0	0	0	20	0	0	0	0	0	0	0	0
SDG&E STF	*	357	0	357	0	0	0	0	0	0	0	0	0	0
Sub-Total		**377**	**0**	**357**	**0**	**20**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
LADWP NON-FIRM		3,150	0	0	0	0	0	0	0	0	0	3,136	14	0
LOS ANGELES STF		90,577	975	4,321	1,000	5,139	1,607	4,375	29,444	26,084	4,450	5,650	2,696	4,836
LOS ANGELES IF		23,000	0	0	0	0	0	4,000	7,500	7,750	3,750	0	0	0
Sub-Total		**116,727**	**975**	**4,321**	**1,000**	**5,139**	**1,607**	**8,375**	**36,944**	**33,834**	**8,200**	**8,786**	**2,710**	**4,836**
NORTHWSTRN RESV SHAR		81	0	0	6	3	13	0	12	19	10	0	16	2
WAPA STF		6,955	1,829	317	932	210	986	110	175	235	1,057	407	450	247
WAPA WHEEL LOSS		15,045	499	969	2,617	1,970	1,106	351	849	254	1,096	1,570	1,922	1,843
WAPA WHEEL LOSS	*	-836	87	0	0	0	0	0	0	0	29	0	-953	0
Sub-Total		**21,164**	**2,415**	**1,286**	**3,549**	**2,180**	**2,092**	**461**	**1,024**	**489**	**2,182**	**1,977**	**1,419**	**2,090**
UTAH SYS DEV - REC		1,159,889	162,438	135,084	100,995	65,422	39,959	75,037	71,403	59,486	117,513	106,418	113,953	112,181
UTAH SYS DEV - DEL		-421,945	-5,325	-12,434	-46,889	-57,640	-61,585	-22,808	-56,565	-46,332	-17,285	-36,264	-25,040	-33,778
IPP FIRM ENG BOOKOUT		-564,732	-52,454	-40,003	-51,340	-51,120	-50,064	-49,291	-52,824	-52,824	-51,114	-44,154	-30,923	-38,621
Sub-Total		**173,212**	**104,659**	**82,647**	**2,766**	**-43,338**	**-71,690**	**2,938**	**-37,986**	**-39,670**	**49,114**	**26,000**	**57,990**	**39,782**
POWEREX STF		48,765	2,932	3,781	14,120	1,304	5,344	540	8,860	8,250	775	2,039	820	0
POWEREX STF	*	31	31	0	0	0	0	0	0	0	0	0	0	0
Sub-Total		**48,796**	**2,963**	**3,781**	**14,120**	**1,304**	**5,344**	**540**	**8,860**	**8,250**	**775**	**2,039**	**820**	**0**
SO CAL EDISON NF		2,600	600	0	0	0	0	0	0	0	0	1,200	400	400
SO CAL EDISON STF		10,437	811	1,208	309	1,811	800	3,000	0	0	800	314	934	450
Sub-Total		**13,037**	**1,411**	**1,208**	**309**	**1,811**	**800**	**3,000**	**0**	**0**	**800**	**1,514**	**1,334**	**850**
SIERRA PACIFIC STF		9,725	1,645	670	375	100	1,275	265	200	200	775	2,500	1,570	150
SIERRA RESERVE SHARE		64	0	0	5	3	11	0	10	15	6	0	12	2
Sub-Total		**9,789**	**1,645**	**670**	**380**	**103**	**1,286**	**265**	**210**	**215**	**781**	**2,500**	**1,582**	**152**
BURBANK STF		22,800	0	3,200	1,200	600	3,600	0	7,200	3,400	1,000	1,800	0	800
GLENDALE STF		1,200	0	0	0	0	400	0	400	0	0	400	0	0
TRI-STATE STF		10,867	745	1,655	880	60	480	420	1,600	2,410	20	1,600	990	7
TRI-STATE STF	*	100	0	0	0	0	200	0	0	0	-100	0	0	0
TRI-STATE WHEEL LOSS		9,955	990	928	498	728	522	645	864	241	1,335	528	1,848	829
TRI-STATE WHEEL LOSS	*	3	0	0	0	0	0	0	3	0	0	0	0	0
Sub-Total		**20,925**	**1,735**	**2,583**	**1,378**	**788**	**1,202**	**1,065**	**2,467**	**2,651**	**1,255**	**2,128**	**2,838**	**836**
PSC OF COLORADO STF		13,312	100	0	437	0	1,275	0	0	200	0	11,300	0	0
COLORADO WHEEL LOSS	*	26	0	0	0	0	0	0	0	0	0	0	26	0
Sub-Total		**13,338**	**100**	**0**	**437**	**0**	**1,275**	**0**	**0**	**200**	**0**	**11,300**	**26**	**0**
NEVADA POWER STF		39,120	5,105	2,590	4,625	5,555	5,225	700	1,440	700	1,025	5,450	3,280	3,425
NEVADA WHEEL LOSS		1,798	158	175	148	10	42	48	270	367	147	170	167	96
NEVADA WHEEL LOSS	*	45	0	0	0	0	0	0	45	0	0	0	0	0
Sub-Total		**40,963**	**5,263**	**2,765**	**4,773**	**5,565**	**5,267**	**748**	**1,755**	**1,067**	**1,172**	**5,620**	**3,447**	**3,521**

TACOMA RESERVE SHARE		10	0	0	2	0	3	0	0	3	0	0	2	0
APS SUPP-COAL FIRM		20,750	4,300	7,850	3,100	950	0	0	300	150	0	0	0	4,100
ARIZONA PSC NON-FIRM		256	0	106	0	0	150	0	0	0	0	0	0	0
ARIZONA PSC STF		69,284	2,210	3,090	2,650	2,515	18,125	2,463	3,522	4,075	5,525	7,915	6,500	10,694
ARIZONA PSC STF	*	402	400	0	0	0	2	0	0	0	0	0	0	0
APS SUPP-OTHER FIRM		62,549	4,950	6,450	6,425	4,275	850	3,650	2,700	6,450	9,700	1,500	9,899	5,700
Sub-Total		**153,241**	**11,860**	**17,496**	**12,175**	**7,740**	**19,127**	**6,113**	**6,522**	**10,675**	**15,225**	**9,415**	**16,399**	**20,494**
PSC NEW MEXICO STF		68,517	6,025	2,596	3,295	4,623	4,595	3,420	5,250	4,250	9,185	16,864	5,704	2,710
N MEXICO WHEEL LOSS		4,587	255	163	168	272	442	436	465	525	518	444	492	407
Sub-Total		**73,104**	**6,280**	**2,759**	**3,463**	**4,895**	**5,037**	**3,856**	**5,715**	**4,775**	**9,703**	**17,308**	**6,196**	**3,117**
EL PASO ELECTRIC STF		25,485	1,400	4,525	3,600	400	120	1,400	4,800	640	650	3,200	770	3,980
EL PASO WHEEL LOSS		1	0	0	0	0	0	0	1	0	0	0	0	0
EL PASO WHEEL LOSS	*	1	0	0	0	0	0	0	0	0	0	0	0	1
Sub-Total		**25,487**	**1,400**	**4,525**	**3,600**	**400**	**120**	**1,400**	**4,801**	**640**	**650**	**3,200**	**770**	**3,981**
SALT RIVER STF		98,703	11,125	8,324	14,345	4,170	8,400	1,595	13,780	6,130	4,135	12,497	10,582	3,620
SALT RVR WHEEL LOSS		4	0	0	0	0	0	0	0	0	0	4	0	0
Sub-Total		**98,707**	**11,125**	**8,324**	**14,345**	**4,170**	**8,400**	**1,595**	**13,780**	**6,130**	**4,135**	**12,501**	**10,582**	**3,620**
TUCSON NON-FIRM		75	0	0	0	0	75	0	0	0	0	0	0	0
TUCSON STF		37,865	2,345	5,790	913	3,566	4,725	2,115	725	4,045	3,701	7,205	1,775	960
TUCSON STF	*	75	0	0	0	0	0	0	0	0	0	0	0	75
TUCSON WHEEL LOSS		7	0	0	0	0	4	0	3	0	0	0	0	0
Sub-Total		**38,022**	**2,345**	**5,790**	**913**	**3,566**	**4,804**	**2,115**	**728**	**4,045**	**3,701**	**7,205**	**1,775**	**1,035**
PLATTE RVR WHL LOSS		2,779	359	88	85	239	230	224	141	117	335	300	328	334
PLATTE RVR WHL LOSS	*	-4	0	0	0	0	0	0	0	0	-353	-4	353	0
Sub-Total		**2,776**	**359**	**88**	**85**	**239**	**230**	**224**	**141**	**117**	**-18**	**296**	**681**	**334**
DGT BONANZA LF ENERG		833,314	74,055	63,853	71,979	70,944	72,379	59,601	67,166	70,693	69,587	69,650	71,017	72,390
SNOHOMISH PUD STF		3	0	0	0	3	0	0	0	0	0	0	0	0
ANAHEIM STF		15	0	0	3	0	0	12	0	0	0	0	0	0
IPP FIRM ENERGY		564,732	52,454	40,003	51,340	51,120	50,064	49,291	52,824	52,824	51,114	44,154	30,923	38,621
PROVO CITY	BA	298	17	14	13	12	11	10	9	3	180	6	10	13
PROVO CITY	BA	3	0	0	0	0	0	0	0	0	0	0	3	0
Sub-Total		**301**	**17**	**14**	**13**	**12**	**11**	**10**	**9**	**3**	**180**	**6**	**14**	**13**
SOUTHWESTERN PSC STF		1,194	195	0	0	0	250	0	22	727	0	0	0	0
SOUTHWESTERN PSC STF	*	802	0	0	0	0	752	0	50	0	0	0	0	0
Sub-Total		**1,996**	**195**	**0**	**0**	**0**	**1,002**	**0**	**72**	**727**	**0**	**0**	**0**	**0**
UMPA STF		590	0	0	0	0	30	0	560	0	0	0	0	0
BEAVER CITY	BA	72	6	6	6	5	8	2	5	5	6	6	6	8
C OF BLANDING FIRM	BA	422	44	49	42	34	27	30	30	26	26	25	46	41
C OF BLANDING FIRM	BA	1	0	0	0	0	0	0	0	0	0	1	0	0
Sub-Total		**423**	**44**	**49**	**42**	**34**	**27**	**30**	**30**	**26**	**26**	**26**	**46**	**41**
FILLMORE CITY	BA	182	15	15	15	15	15	15	15	15	15	15	15	15
GRAND VALLEY	BA	132	28	18	16	13	10	5	4	5	6	4	7	14
MORGAN CITY	BA	25	4	4	4	2	1	1	1	1	1	2	2	2
NEPHI CITY	BA	18	2	2	2	2	1	1	1	1	1	1	2	2
NEPHI CITY	BA	1	0	0	0	0	0	0	0	0	1	0	0	0
Sub-Total		**19**	**2**	**2**	**2**	**2**	**1**	**1**	**1**	**1**	**2**	**1**	**2**	**2**
SPANISH FORK CITY	BA	25	4	3	4	3	3	1	1	2	0	1	2	0
SPRINGVILLE CITY	BA	60	6	7	6	5	5	4	3	4	5	4	6	6

COTTONWOOD HYDRO	BA	2,802	135	115	146	243	331	321	319	315	201	232	229	213
COTTONWOOD HYDRO	BA	-98	0	0	0	0	0	0	-98	0	0	0	0	0
Sub-Total		**2,704**	**135**	**115**	**146**	**243**	**331**	**321**	**221**	**315**	**201**	**232**	**229**	**213**
STRAWBERRY ELEC SERV	BA	58	1	1	22	1	1	1	1	1	24	1	1	1
HEBER LIGHT & POWER	BA	6,037	605	560	554	523	457	450	476	409	394	394	472	743
IDAHO FALL-GEM STATE	BA	39,813	0	0	0	0	0	15,126	12,979	11,708	0	0	0	0
UAMPS NON-FIRM		61,950	5,877	0	603	8,029	1,484	385	0	0	2,120	6,460	16,116	20,876
UAMPS STF		205	0	0	0	0	0	199	0	0	0	6	0	0
UAMPS STF	*	127	0	0	0	0	0	0	216	0	-89	0	0	0
Sub-Total		**62,282**	**5,877**	**0**	**603**	**8,029**	**1,484**	**584**	**216**	**0**	**2,031**	**6,466**	**16,116**	**20,876**
DAVIS CO. WASTE MGMT	BA	560	42	42	60	100	59	27	2	78	55	57	22	17
KENNECOTT QF PURCH	BA	169,414	11,517	12,970	13,862	14,082	817	17,217	16,536	17,191	16,189	17,474	15,381	16,177
RAINBOW ENERGY STF		55,587	0	1,800	12,800	2,806	24,194	6,985	3,400	1,456	0	286	1,860	0
J ARON STF		800	0	0	800	0	0	0	0	0	0	0	0	0
IBERDROLA RENEW STF		2,302	300	0	2	0	0	0	400	0	0	0	400	1,200
SEMPRA ENG TRADE STF		36,919	59	3,800	4	1,376	3,998	4,200	19,982	800	1,500	1,200	0	0
SEMPRA ENG TRADE STF	*	81	0	0	0	0	81	0	0	0	0	0	0	0
Sub-Total		**37,000**	**59**	**3,800**	**4**	**1,376**	**4,079**	**4,200**	**19,982**	**800**	**1,500**	**1,200**	**0**	**0**
TRANSALTA STF		23,064	675	450	3,200	533	823	1,650	5,715	3,600	2,800	3,600	0	18
TRANSALTA STF	*	122	0	0	0	0	0	0	0	0	0	0	122	0
Sub-Total		**23,186**	**675**	**450**	**3,200**	**533**	**823**	**1,650**	**5,715**	**3,600**	**2,800**	**3,600**	**122**	**18**
MORGAN STANLEY STF		613,018	15,089	17,022	45,207	40,823	36,298	53,983	47,248	87,445	67,487	39,811	80,555	82,050
MORGAN STANLEY STF	*	4,339	2,704	83	0	0	1,425	0	25	86	16	0	0	0
Sub-Total		**617,357**	**17,793**	**17,105**	**45,207**	**40,823**	**37,723**	**53,983**	**47,273**	**87,531**	**67,503**	**39,811**	**80,555**	**82,050**
SHELL ENERGY STF		84,330	10,235	12,000	11,329	8,910	16,424	4,544	5,592	1,023	2,936	2,228	6,355	2,754
SHELL ENERGY STF	*	90	90	0	0	0	0	0	0	0	0	0	0	0
Sub-Total		**84,420**	**10,325**	**12,000**	**11,329**	**8,910**	**16,424**	**4,544**	**5,592**	**1,023**	**2,936**	**2,228**	**6,355**	**2,754**
C OF HURRICANE FIRM	BA	1,992	219	205	167	152	114	108	163	248	204	147	113	152
METRO WATER DIST STF		41	0	0	41	0	0	0	0	0	0	0	0	0
CONSTELLATION NF		4,581	0	0	30	1,940	1,006	0	921	0	0	0	0	684
CONSTELLATION STF		180,417	8,620	8,512	600	4,073	5,945	13,771	39,505	25,669	25,815	21,215	24,176	2,516
CONSTELLATION STF	*	175	0	0	0	0	0	0	0	0	0	225	-50	0
Sub-Total		**185,173**	**8,620**	**8,512**	**630**	**6,013**	**6,951**	**13,771**	**40,426**	**25,669**	**25,815**	**21,440**	**24,126**	**3,200**
MAGCORP PURCHASE	BA	184,521	16,251	17,810	13,417	12,250	14,411	11,875	12,567	14,655	16,711	18,935	19,117	16,521
CALIFORNIA ISO STF		309,972	25,246	14,515	5,544	22,444	18,379	35,923	64,327	31,900	10,756	25,171	32,059	23,708
CALIFORNIA ISO STF	*	-16,424	0	0	-250	-15,639	0	-100	25	50	-90	30	-450	0
Sub-Total		**293,548**	**25,246**	**14,515**	**5,294**	**6,805**	**18,379**	**35,823**	**64,352**	**31,950**	**10,666**	**25,201**	**31,609**	**23,708**
CARGILL-ALLIANT STF		506,169	41,827	40,480	34,980	28,515	37,204	62,735	45,683	38,401	58,843	30,861	36,830	49,810
CARGILL-ALLIANT STF	*	2,213	31	1,786	0	0	-56	129	0	42	0	0	281	0
Sub-Total		**508,382**	**41,858**	**42,266**	**34,980**	**28,515**	**37,148**	**62,864**	**45,683**	**38,443**	**58,843**	**30,861**	**37,111**	**49,810**
PAYSON CITY CORP	BA	7	1	1	1	0	0	0	0	0	4	1	1	-1
HILL AIR QF PURCHASE	BA	14,185	1,268	1,288	1,346	1,154	1,323	1,227	996	1,173	940	1,106	1,259	1,105
PPL ENERGY PLUS STF		35	0	35	0	0	0	0	0	0	0	0	0	0
SEMPRA ENG RES STF		15	0	0	15	0	0	0	0	0	0	0	0	0
CONOCO STF		200	0	0	0	0	0	0	0	0	200	0	0	0
JAKE AMY HYDRO PURCH	BA	1,862	129	121	116	128	121	225	205	159	169	165	184	140
BIRCH CRK HYDRO PUR	BA	13,847	803	1,093	1,275	1,062	1,320	1,217	1,177	1,217	1,209	1,312	1,137	1,025
CDM HYDRO PURCH	BA	27,509	1,736	1,542	2,000	2,615	2,290	3,200	3,200	3,200	2,166	2,126	1,585	1,849

CDM HYDRO PURCH	BA	-1,944	0	0	0	-345	82	0	0	0	-1,681	0	0	0
Sub-Total		**25,566**	**1,736**	**1,542**	**2,000**	**2,271**	**2,373**	**3,200**	**3,200**	**3,200**	**484**	**2,126**	**1,585**	**1,849**
CEM HYDRO PURCH	BA	1,627	69	69	119	150	178	280	281	222	86	31	61	81
INGRAM WARM SP HYDRO	BA	1,511	207	194	220	186	90	28	5	2	84	137	152	205
DRY CREEK HYDRO PUR	BA	11,893	563	350	442	597	783	2,056	2,221	1,426	1,054	898	761	742
DRY CREEK HYDRO PUR	BA	88	0	0	65	0	0	0	0	0	23	0	0	0
Sub-Total		**11,980**	**563**	**350**	**507**	**597**	**783**	**2,056**	**2,221**	**1,426**	**1,076**	**898**	**761**	**742**
GEORGETOWN HYDRO PUR	BA	2,112	239	204	214	197	217	233	1	0	129	225	226	227
MARSH VALLEY HYD PUR	BA	4,783	513	456	625	685	630	468	-2	-2	2	373	486	548
MARSH VALLEY HYD PUR	BA	-228	0	0	0	0	0	-228	0	0	0	0	0	0
Sub-Total		**4,555**	**513**	**456**	**625**	**685**	**630**	**240**	**-2**	**-2**	**2**	**373**	**486**	**548**
MINK CREEK HYDRO PUR	BA	8,036	388	299	303	373	797	1,703	1,175	859	705	568	462	403
OJA POWER HYDRO PUR	BA	729	62	55	62	67	24	95	67	67	55	64	51	60
OJA POWER HYDRO PUR	BA	-21	0	0	0	0	0	0	-28	0	0	0	0	7
Sub-Total		**708**	**62**	**55**	**62**	**67**	**24**	**95**	**40**	**67**	**55**	**64**	**51**	**67**
BELL MTN II HYD PURC	BA	1,387	50	45	40	107	199	387	142	107	90	86	80	55
BELL MTN II HYD PURC	BA	-391	0	0	1	11	0	0	-403	0	0	0	0	0
Sub-Total		**996**	**50**	**45**	**41**	**118**	**199**	**387**	**-261**	**107**	**90**	**86**	**80**	**55**
PRESTON CITY HYDRO	BA	1,589	64	64	156	154	164	163	173	129	158	89	110	164
PRESTON CITY HYDRO	BA	-9	0	0	-9	0	0	0	0	0	0	0	0	0
Sub-Total		**1,579**	**64**	**64**	**147**	**154**	**164**	**163**	**173**	**129**	**158**	**89**	**110**	**164**
NICHLSON RANCH HYDRO	BA	1,852	131	125	100	142	138	187	198	160	167	158	185	161
NICHLSON RANCH HYDRO	BA	-38	0	0	-38	0	0	0	0	0	0	0	0	0
Sub-Total		**1,814**	**131**	**125**	**62**	**142**	**138**	**187**	**198**	**160**	**167**	**158**	**185**	**161**
THAYN RANCH ENERGY	BA	2,525	92	23	203	290	224	149	214	249	250	290	237	302
SUNNYSIDE THERML PUR	BA	377,727	36,473	34,560	36,341	12,238	10,293	36,090	37,856	38,315	32,106	28,672	36,358	38,423
TESORO THERMAL PURCH	BA	47,654	2,944	2,246	6,203	6,213	2,250	2,365	3,881	3,368	3,720	3,637	4,944	5,882
COL RVR COMMISON STF		113	0	0	0	100	0	13	0	0	0	0	0	0
COL RVR COMMISON STF	*	135	94	0	0	41	0	0	0	0	0	0	0	0
Sub-Total		**248**	**94**	**0**	**0**	**141**	**0**	**13**	**0**	**0**	**0**	**0**	**0**	**0**
GILA RIVER PWR STF		53,902	3,000	2,200	3,275	7,827	11,875	3,200	8,250	1,800	8,850	425	2,000	1,200
GILA RIVER PWR STF	*	646	0	0	671	0	0	0	0	0	0	0	-25	0
GILA RIVER PWR NF		150	0	0	0	0	0	150	0	0	0	0	0	0
Sub-Total		**54,698**	**3,000**	**2,200**	**3,946**	**7,827**	**11,875**	**3,350**	**8,250**	**1,800**	**8,850**	**425**	**1,975**	**1,200**
BALLARD HOG ENERGY	BA	49	0	1	3	6	10	15	5	4	0	0	4	3
WEBER COUNTY QF PUR	BA	2,675	478	326	595	-2	-1	0	0	0	0	0	650	629
WEBER COUNTY QF PUR	BA	623	0	0	0	0	0	0	0	0	0	0	623	0
Sub-Total		**3,298**	**478**	**326**	**595**	**-2**	**-1**	**0**	**0**	**0**	**0**	**0**	**1,273**	**629**
CITIGROUP STF		125,029	530	6,305	607	9,450	2,725	16,050	18,975	19,400	16,550	13,345	12,875	8,217
CITIGROUP STF	*	188	106	0	0	0	-100	0	0	7	0	-25	0	200
Sub-Total		**125,217**	**636**	**6,305**	**607**	**9,450**	**2,625**	**16,050**	**18,975**	**19,407**	**16,550**	**13,320**	**12,875**	**8,417**
SUNDERLAND DAIRY ENG	BA	109	4	4	7	17	21	17	18	15	6	0	0	0
WOLVERINE WIND PURCH	BA	162,915	12,889	5,424	11,991	16,768	15,416	13,244	10,866	14,105	14,725	12,564	15,524	19,400
WOLVERINE WIND PURCH	BA	-611	0	0	0	0	0	0	0	0	0	-611	0	0
Sub-Total		**162,305**	**12,889**	**5,424**	**11,991**	**16,768**	**15,416**	**13,244**	**10,866**	**14,105**	**14,725**	**11,954**	**15,524**	**19,400**
DB ENERGY TRADE STF		71,812	0	6,000	1,200	0	0	800	0	0	5,600	57,200	200	812
DB ENERGY TRADE STF	*	18	17	1	0	0	0	0	0	0	0	0	0	0

Sub-Total		**71,830**	**17**	**6,001**	**1,200**	**0**	**0**	**800**	**0**	**0**	**5,600**	**57,200**	**200**	**812**	
JP MORGAN VENTUR STF		66,958	21,258	19,200	23,200	0	0	0	1,500	100	1,050	650	0	0	
JP MORGAN VENTUR STF	*	20	0	20	0	0	0	0	0	0	0	0	0	0	
Sub-Total		**66,978**	**21,258**	**19,220**	**23,200**	**0**	**0**	**0**	**1,500**	**100**	**1,050**	**650**	**0**	**0**	
CREDIT SUISSE EN STF		400	0	0	400	0	0	0	0	0	0	0	0	0	
CREDIT SUISSE EN STF	*	50	50	0	0	0	0	0	0	0	0	0	0	0	
Sub-Total		**450**	**50**	**0**	**400**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
SPANISH FORK WIND	BA	46,929	4,824	2,928	3,539	2,166	2,312	3,437	4,783	4,538	5,433	4,715	3,923	4,329	
BARCLAYS STF		22,475	0	3,500	5,400	112	400	408	6,303	3,348	2,890	10	0	104	
BARCLAYS STF	*	350	0	350	0	0	0	0	0	0	0	0	0	0	
Sub-Total		**22,825**	**0**	**3,850**	**5,400**	**112**	**400**	**408**	**6,303**	**3,348**	**2,890**	**10**	**0**	**104**	
BNP PARIBAS ENG STF		400	0	0	0	0	0	0	0	0	0	0	400	0	
MTN WIND POWER I QF	BA	149,425	12,221	9,926	11,263	16,096	12,259	12,285	11,431	8,561	11,230	10,368	19,279	14,506	
MTN WIND POWER II QF	BA	202,072	16,240	13,219	14,805	20,615	16,029	17,060	15,568	11,612	15,725	13,586	26,419	21,194	
UNS ELECTRIC STF		8,271	50	0	0	0	0	0	0	0	0	196	8,025	0	
MACQUARIE STF		18,349	70	0	0	3,604	800	800	2,400	6,200	1,000	2,675	800	0	
EDF TRADE STF		120,933	14,430	0	0	2,002	200	12,000	29,800	52,607	8,650	1,244	0	0	
EDF TRADE STF	*	844	0	0	0	0	0	0	0	11	33	0	0	800	
Sub-Total		**121,777**	**14,430**	**0**	**0**	**2,002**	**200**	**12,000**	**29,800**	**52,618**	**8,683**	**1,244**	**0**	**800**	
TRANSCANADA ENG STF		20,600	0	2,800	0	0	400	1,200	8,200	7,200	800	0	0	0	
SWIFT CREEK HYD PUR	BA	5,105	179	135	91	267	372	954	1,015	656	408	400	319	310	
SWIFT CREEK HYD PUR	BA	59	0	-19	0	77	0	0	0	0	0	0	0	0	
Sub-Total		**5,164**	**179**	**116**	**91**	**344**	**372**	**954**	**1,015**	**656**	**408**	**400**	**319**	**310**	
TOTAL UTAH		**6,154,457**	**553,073**	**493,016**	**457,998**	**353,715**	**361,208**	**502,678**	**620,843**	**577,245**	**560,583**	**553,272**	**583,713**	**537,114**	
TOTAL Purchased Power		**11,417,025**	**782,443**	**722,073**	**808,731**	**675,331**	**903,942**	**1,122,270**	**1,290,222**	**1,250,630**	**918,162**	**931,803**	**1,060,172**	**951,247**	
On System	BA	**6,468,408**	**532,947**	**486,411**	**537,269**	**545,076**	**525,545**	**443,318**	**535,327**	**531,503**	**517,432**	**556,474**	**610,120**	**646,985**	(B) 1
Off System		**4,948,617**	**249,496**	**235,662**	**271,461**	**130,255**	**378,397**	**678,952**	**754,895**	**719,126**	**400,730**	**375,329**	**450,052**	**304,262**	(B) 2

3rd Party Generation
2010

Summary	Deseret MW	UMPA MW	UAMPS MW	Raser MW	Nextera MW	UINTA - UAMPS MW	UINTA - Iberdrola MW	Dynamic transfer to Avista, no reserves: Stateline - Avista MW	Dynamic transfer to Avista, no reserves: Avista - Telemetered MW	Stateline - Iberdrola MW	Stateline - Seattle City Light MW	Stateline JPMorgan (Leftover net Avista) MW	Tieton MW	Southern California Edison MW	Total MW
January	363,021.367	41,243.375	83,266.543	4,060.107	23,520.000	27,518.400	142.100	3,232.347	(3,232.347)	4,252.000	-	-	-	-	547,023.892
February	335,557.415	33,726.188	81,693.147	3,734.799	12,097.000	19,818.300	89.400	2,140.000	(2,140.000)	1,677.675	-	-	-	-	488,393.924
March	353,996.819	24,467.625	63,758.310	3,747.828	26,279.000	22,570.800	171.100	5,641.000	(5,641.000)	5,753.979	-	-	-	-	500,745.461
April	360,420.712	31,547.938	55,436.534	3,693.646	33,719.000	31,794.000	283.000	9,546.000	(9,546.000)	7,964.026	-	-	-	-	524,858.855
May	339,173.354	41,305.688	59,625.419	3,795.523	20,499.000	25,549.000	251.000	8,026.000	(8,026.000)	-	5,671.912	-	-	-	495,870.896
June	305,095.560	39,329.375	75,980.090	4,020.322	25,976.000	27,788.800	94.000	8,070.000	(8,070.000)	-	5,728.438	-	7,566.015	-	491,578.600
July	319,569.604	40,456.875	78,839.377	3,769.491	19,349.000	22,606.400	9.700	6,349.000	(6,349.000)	-	4,512.594	-	6,630.789	-	495,743.830
August	338,848.659	40,387.188	69,778.710	3,757.828	21,787.000	28,773.900	61.800	6,863.000	(6,863.000)	-	4,995.166	-	6,526.617	-	514,916.867
September	320,475.378	40,146.938	72,629.786	4,158.579	14,935.000	23,673.300	39.200	3,484.000	(3,484.000)	-	3,297.405	1,116.540	9,811.917	-	490,284.042
October	326,418.000	40,761.750	75,155.058	4,283.137	20,643.000	21,453.200	43.200	5,482.000	(5,482.000)	-	3,920.761	(11.754)	4,049.023	6,619.410	503,334.785
November	330,046.112	38,763.500	60,789.065	4,700.617	25,802.000	43,252.800	521.400	5,317.000	(5,317.000)	-	3,926.522	206.644	-	552.198	508,560.857
December	352,331.874	39,946.188	76,535.141	4,605.710	28,290.000	35,994.000	473.500	5,034.000	(5,034.000)	-	3,582.607	5.841	-	769.651	542,534.512
	4,044,954.854	452,082.625	853,487.180	48,327.587	272,896.000	330,792.900	2,179.400	69,184.347	(69,184.347)	19,647.680	35,635.405	1,317.270	34,584.361	7,941.260	6,103,846.522
	(D) 1	(D) 2	(D) 3												(C) 1

2013 (MWH)		4044955	452083	3181199	48328	272896	330793	2179	69184		19648	35635	1317	34584	7941
Sche 5	0.37	$ 1,219,825	$ 136,333	$ 959,345	$ 14,574	$ 82,296	$ 99,756	$ 657	$ 20,864		$ 5,925	$ 10,746	$ 397	$ 10,430	$ 2,395
															Estimated system amount
Sche 6	0.31	1254180.308	140172.9182	986363.8811	14984.47086	84614.24213	102565.7779	675.7456295	0		6091.96735	11049.12786	408.4333456	10723.24068	0

Generation Summary
2010

	DGT Bonanza Net Gen MW	BONANZA-UMPA NET GEN MW	TAYLOR DRAW MW	UINTAH HYDRO MW	YELLOWSTONE HYDRO #1,2,3 MW	Hunter II Net Generation MW	Deseret Total MW	UMPA-Bonanza MW	UMPA-Hunter MW	UMPA Total MW	UAMPS - Hunter II Net Generation MW	UAMPS - Nebo Net Generation MW	UAMPS - Idaho Falls MW	UAMPS Total MW
January	338,321.578	(25,198.000)	606.726	423.534	227.529	48,640.000	**363,021.367**	25,198.000	16,045.375	**41,243.375**	28,245.000	54,955.360	66.183	**83,266.543**
February	292,618.508	(21,673.000)	775.939	386.976	204.992	63,244.000	**335,557.415**	21,673.000	12,053.188	**33,726.188**	36,768.000	44,867.369	57.778	**81,693.147**
March	325,626.080	(24,556.000)	1,072.486	267.538	133.715	51,453.000	**353,996.819**	24,556.000	(88.375)	**24,467.625**	29,908.000	33,792.915	57.395	**63,758.310**
April	313,272.356	(24,113.000)	1,286.174	64.401	19.781	69,891.000	**360,420.712**	24,113.000	7,434.938	**31,547.938**	40,664.000	14,722.155	50.379	**55,436.534**
May	295,939.096	(25,016.000)	1,471.606	721.995	265.657	65,791.000	**339,173.354**	25,016.000	16,289.688	**41,305.688**	38,249.000	21,320.723	55.696	**59,625.419**
June	269,740.004	(24,361.000)	1,411.616	792.481	479.459	57,033.000	**305,095.560**	24,361.000	14,968.375	**39,329.375**	33,102.000	42,829.036	49.054	**75,980.090**
July	289,296.317	(23,445.000)	1,085.233	657.149	452.905	51,523.000	**319,569.604**	23,445.000	17,011.875	**40,456.875**	29,915.000	48,870.061	54.316	**78,839.377**
August	296,614.331	(23,385.000)	915.517	793.043	427.768	63,483.000	**338,848.659**	23,385.000	17,002.188	**40,387.188**	36,909.000	32,816.464	53.246	**69,778.710**
September	284,805.671	(22,118.000)	460.320	698.715	230.672	56,398.000	**320,475.378**	22,118.000	18,028.938	**40,146.938**	32,746.000	39,834.291	49.495	**72,629.786**
October	285,255.601	(22,166.000)	918.345	669.325	407.729	61,333.000	**326,418.000**	22,166.000	18,595.750	**40,761.750**	35,618.000	39,485.820	51.238	**75,155.058**
November	302,562.168	(21,632.000)	-	500.393	19.551	48,596.000	**330,046.112**	21,632.000	17,131.500	**38,763.500**	28,225.000	32,504.014	60.051	**60,789.065**
December	309,734.094	(22,237.000)	952.059	445.543	7.178	63,430.000	**352,331.874**	22,237.000	17,709.188	**39,946.188**	36,849.000	39,615.315	70.826	**76,535.141**
	3,603,785.804	(279,900.000)	10,956.021	6,421.093	2,876.936	700,815.000	**4,044,954.854**	279,900.000	172,182.625	**452,082.625**	407,198.000	445,613.523	675.657	**853,487.180**
							(D) 1			(D) 2				(D) 3

#REF!	#REF!	#REF!

	UMPA Tags (MW)	Gross-up at 7% (each hour) MW		UAMPS Tags (MW)	Gross-up at 7% (each hour) MW	Total MW	
January		29,600		5,022	71,743		
February		29,600		5,338	76,257		
March		29,600		4,337	61,957		
April		29,600		4,794	68,486		
May		29,600		5,617	80,243		
June		29,600		9,025	128,929		
July	412	29,600	Ave	5,547	79,243		
August	1,568	22,400	29,600	2,778	39,686		
September	1,862	26,600		7,535	107,643		
October	2,096	29,943		5,438	77,686		
November	2,276	32,514		14,036	200,514		
December	2,558	36,543		3,364	48,057		
	10,772	355,200		72,831	1,040,443	1,395,643	(E) 1

Note: no capacity tags available, used UMPA average for final 5 months pf 2010

Appendix 14

Explanation of Schedule 5 and 6 Energy Charge Calculations

PacifiCorp

Explanation of Schedule 5 and 6 Energy Charge Calculations

Docket No. ER11-3643-000

Pursuant to the settlement discussions August 31, 2012, PacifiCorp and the Core Intervenors have agreed to recalculate Schedule 5 and 6 rates into energy charges (MWh). These rates were originally filed and proposed as demand (kW-yr) rates. As part of this agreement, PacifiCorp committed to share the support for the recalculated rates. The attached supporting material consists of the following:

- Reproduction of page 401a from PacifiCorp's 2010 FERC Form No. 1
- "Exhibit 6C (Schedules 5_6 Rates).xlsx" spreadsheet with the following tabs:
    - Summary of Rate Calculation
    - Total Generation Summary
    - PAC Merchant (A)
    - Merchant Purchases (B)
    - 3rd Party Gen (C)
    - Legacy Cust. Gen (D)
    - 3rd Party Self Supply (E)

The intent of the supporting documentation is to explain the derivation of "Total 2010 Generation for Rates" set forth in the Summary of Rate Calculation tab (column L), including reconciliation of PacifiCorp Energy MWh values to the 2010 FERC Form No. 1. The value of 67,588,143.51 MWh for 2010 constitutes the proposed rate divisor for the Schedule 5 and 6 rates and represents the total MWh subject to reserve charges.

Also shown on the Summary of Rate Calculation tab, is a revenue requirement value (column J) which is the product of the average reserves held in 2010 for Schedules 5 and 6 in kW (260,000) multiplied by the cost per kW for each Schedule. The average reserves held (260,000 kW) is the amount identified in PacifiCorp's original filing for Schedules 5 and 6 established by the requirement equal to the sum of five (5) percent of the load responsibility served by hydroelectric and wind generation and seven (7) percent of the load responsibility served by thermal generation. The cost per kW is also sourced from PacifiCorp's original filing for Schedules 5 and 6. The rates shown represent the rates calculated with the values from the Summary of Rate Calculation tab (column O) as well as rates proposed for January 1, 2012 through May 31, 2013 (column Q), which are produced using the ratio of as-filed to adjusted capacity rates, as discussed and agreed to at the August 31, 2012 meeting.

FERC Form No. 1 Source Data

The Total 2010 Generation for Rates value of 67,588,143.51 MWh for the Schedule 5 and 6 rates is sourced from the information shown on Page 401a for the 2010 FERC Form No. 1 from the following locations:

Line 9, Net Generation (57,639,191 MWh) and Purchased Reserves: This amount includes PacifiCorp Energy generation for which reserves must be carried.

Line 10, Purchases (11,417,025 MWh) and Off-System Imports: This amount includes PacifiCorp Energy purchases which include on and off-system purchases.

Line 9 and Line 10 added together produce **69,056,216 MWh**, see tab "Total Generation Summary", cell E7. Please also refer to tab PAC Merchant (A) (see cell "Q235" showing 69,056,216 MWh).

Certain adjustments must be made to the value 69,056,216 MWh to remove generation amounts for which the Schedule 5 and 6 rate calculation should not apply, as explained below.

Summary of Derivation of Total 2010 Generation for Rates

The derivation of the Total 2010 Generation for Rates value of 67,588,143.51 MWh is shown on the tab "Total Generation Summary", cell E15. This value is produced by making various adjustments to the total generation for 2010 including PacifiCorp Energy and third parties.

First, as shown on the tab "Total Generation Summary", PacifiCorp adjusted total PacifiCorp Energy generation beginning with the amounts shown on the Page 401a for the 2010 FERC Form No. 1 of 57,639,191 MWh (cell E5 and cross reference (A)1) and 11,417,025 MWh (cell E6 and cross reference (A)1), which total 69,056,216 MWh, including the following adjustments:

1. **Adjustment for Off-System Purchases**: Off-system purchases must be removed for generation amounts where reserves are supplied by the sending control area. To distinguish between on and off-system purchases, a review was done of the underlying generation for the purchases by PacifiCorp transmission working with PacifiCorp Energy. Categories of purchases including those from qualified facilities and those located within the balancing area as on-system purchases were included in the overall amount of generation subject to the schedule 5 and 6 rates. As a result of this review, a total of 4,948,618 MWh was identified as being related to off-system purchases for which the Schedule 5 and 6 rate calculation should not apply. This amount is subtracted, as shown on tab "Total Generation Summary" cell E9. Cross references (A)2 refers to tab PAC Merchant (A), which provides additional detail. In addition, cross references (B)2 refers to tab Merchant Purchases (B), which includes transactional details of which

transactions were determined to be off-system as well as on-system (on-system transaction marked “BA” in column B).

2. **Adjustment for Storage Contracts**: PacifiCorp Energy has two agreements with Seattle City Light and PUD #1 of Cowlitz County covering storage relating to generation facilities located within the balancing area. The portion of generation related to these agreements for Stateline Wind and Swift #2 hydro facilities are reported as Power Exchanges in Purchased Power, Account 555, of the 2010 FERC Form No. 1 on pages 326.22 and 327.22, lines 1 and 2. The amount reported for Stateline includes a reduction for losses. The amount of generation related to these storage agreements has been added to spinning as supplemental reserve calculation as this generation is located within the balancing area and is subject to reserves.

    a. **Stateline - PAC Energy Exchange**: Addition of 315,090.848 MWh to add generation for PacifiCorp Energy’s Stateline storage contract, with supporting detail provided in tab PAC Merchant (A) (see cross reference (A)3).
    b. **Cowlitz - Swift #2 - PAC Energy Exchange**: Addition of 213,594 MWh to add generation for PacifiCorp Energy’s Swift #2 storage contract, with supporting detail provided in tab PAC Merchant (A) (see cross reference (A)4).

3. **Adjustment for Purchased Reserves:** As shown on the tab “Total Generation Summary” cell E12, PacifiCorp has subtracted of 1,756,344.000 MWh to remove amounts associated with purchased reserves. In 2010, PacifiCorp met some of its obligation by purchasing reserves. Accordingly, for purposes of designing Schedule 5 and 6 rates, the amount of generation for which reserves were purchased must be removed. To support this reduction, PacifiCorp identified PacifiCorp Energy purchased reserves during 2010. Such arrangements are listed in FERC Account 555 (Purchase Power, page 326 of the 2010 FERC Form 1). The FERC Form 1 does not specifically identify reserve purchase transactions. PacifiCorp used company records for 2010 to identify purchased reserves. PacifiCorp identified the applicable arrangements working with PacifiCorp Energy back office and used 2010 generation detail for the generation facilities subject to these transactions to determine the amount of purchased reserves. The supporting detail for purchased reserves totaling 1,756,344 MWh is contained on tab PAC Merchant (A) (see cross reference (A)5).

4. **Addition of Third-Party On-System Generation:** As shown on the tab “Total Generation Summary” cell E13, PacifiCorp has added 6,103,846.52 MWh. The supporting detail for this amount is contained on tab 3rd Party Gen (C) (see cross reference (C)1) and tab Legacy Cust. Gen (D) (see cross references (D) 1 through 3).

5. **Adjustment for Third-Party Self-Supply**: As shown on the tab "Total Generation Summary" cell E14, PacifiCorp has removed 1,395,642.86 MWh. The supporting detail for this amount is contained on tab 3rd Party Self Supply (E) (see cross reference (E)1). Third-party customer self-supply of reserves in 2010 was identified by compiling the total quantity of capacity tags submitted for self-supplied reserves and dividing the capacity values by 7% to convert them to equivalent MWhs. For UMPA, the first seven months of 2010 were missing capacity tags, therefore a proxy quantify was used by taking the average supplied in the final 5 months of year and applying those amounts to the early months.

Appendix 15

Cost Allocation Manual

PacifiCorp
Cost Allocation Manual
For the Year Ended December 31, 2011

Overview/Introduction

This section describes the allocation of costs between PacifiCorp and its affiliates.

On March 31, 2006, PacifiCorp entered into an Intercompany Administrative Services Agreement ("IASA") between MEHC and its subsidiaries. PacifiCorp is an indirect subsidiary of MEHC, a holding company based in Des Moines, Iowa, owning subsidiaries that are primarily engaged in the energy business. Refer to attached IASA. The IASA covers:

a) services by executive, management, professional, technical and clerical employees;
b) financial services, payroll processing services, employee benefits participation, supply chain and purchase order processing services, tax and accounting services, contract negotiation and administration services, risk management services, environmental services and engineering and technical services;
c) the use of office facilities, including but not limited to office space, conference rooms, furniture, equipment, machinery, supplies, computers and computer software, insurance policies and other personal property; and
d) the use of automobiles, airplanes, other vehicles and equipment.

In connection with the March 2006 acquisition of PacifiCorp by MEHC, MEHC committed to PacifiCorp's state regulatory commissions to limit the amount of affiliate services pursuant to the IASA that PacifiCorp pays to MEHC each year to $9,000,000. This acquisition commitment expired March 20, 2011. The $9,000,000 limit was prorated during the period from January 1, 2011 to March 20, 2011.

Allocation Amounts and Methods

<u>MEHC and subsidiaries to PacifiCorp</u>

During the year ended December 31, 2011, PacifiCorp was allocated costs by its non-regulated parent company, MEHC, and certain of MEHC's subsidiaries, some of which are non-regulated, as part of the affiliate services pursuant to the IASA. The amounts included in Section II – Transactions include both direct charges and allocated amounts. The allocated amounts were as follows:

Name of entity	Total services received as reported in Section II - Transactions	Amount of services based on allocations
MidAmerican Energy Holdings Company	$ 11,191,276	$ 2,511,372
MHC Inc.	730,726	302,448
MidAmerican Energy Company	3,717,182	1,698,442
Kern River Gas Transmission Company	150,711	-
Cordova Energy Company LLC	453	-
M&M Ranch Acquisition Company, LLC	1,340	-
Total	$ 15,791,688	$ 4,512,262

The amounts were allocated by MEHC and its subsidiaries to PacifiCorp using six different formulae during the year ended December 31, 2011. These formulae are as follows:

a) A two factor formula based on the labor and assets of each of MEHC's subsidiaries. PacifiCorp's allocation percentage during the year ended December 31, 2011 was 46.25%.
b) The same two factor formula as a) above, except excluding the labor and assets of HomeServices. PacifiCorp's allocation percentage during the year ended December 31, 2011 was 49.08%.
c) The same two factor formula as a) above, except excluding the labor and assets of MEHC's international subsidiaries. PacifiCorp's allocation percentage during the year ended December 31, 2011 was 52.70%.
d) The same two factor formula as c) above, except excluding the labor and assets of HomeServices. PacifiCorp's allocation percentage during the year ended December 31, 2011 was 56.50%.
e) A formula to allocate legislative and regulatory costs to each of MEHC's subsidiaries based on where the legislative and regulatory employees spent their time. PacifiCorp's allocation percentage during the year ended December 31, 2011 was 20.00%.
f) A formula based on the gross plant asset amounts of each of MEHC's subsidiaries. PacifiCorp's allocation percentage during the year ended December 31, 2011 was 49.09%.

PacifiCorp to MEHC and subsidiaries

During the year ended December 31, 2011, PacifiCorp allocated costs to its non-regulated parent company, MEHC, and certain of MEHC's subsidiaries, some of which are non-regulated, as part of the affiliate services pursuant to the IASA. The amounts included in Section II – Transactions include both direct charges and allocated amounts. The allocated amounts were as follows:

Name of entity	Total services provided as reported in Section II - Transactions	Amount of services based on allocations
MidAmerican Energy Holdings Company	$ 319,378	$ 47,579
MidAmerican Energy Company	862,267	509,696
HomeServices of America, Inc.	147,116	128,221
Kern River Gas Transmission Company	168,331	63,266
CalEnergy Generation Operating Company	133,593	18,282
Northern Natural Gas Company	191,604	161,499
Midwest Capital Group, Inc.	1,327	1,283
MEC Construction Services Co.	196	188
MEHC Investment, Inc.	185	180
Cordova Energy Company LLC	7,798	7,543
Northern Powergrid Holdings Company	20,647	18,626
CE Philippines Ltd.	2,817	971
Iowa Realty Co., Inc.	3,647	2,915
Total	$ 1,858,906	$ 960,249

The amounts were allocated by PacifiCorp to MEHC and its subsidiaries using five different formulae during the year ended December 31, 2011. These formulae are as follows:

a) A two factor formula based on the labor and assets of each of MEHC's subsidiaries. The percentage that PacifiCorp allocated to MEHC and its subsidiaries during the year ended December 31, 2011 was 53.75%.
b) The same two factor formula as a) above, except excluding the labor and assets of MEHC's international subsidiaries. The percentage that PacifiCorp allocated to MEHC and its subsidiaries during the year ended December 31, 2011 was 47.30%.
c) The same two factor formula as b) above, except excluding the labor and assets of HomeServices. The percentage that PacifiCorp allocated to MEHC and its subsidiaries during the year ended December 31, 2011 was 43.50%.

d) The same two factor formula as a) above, except excluding the labor and assets of PacifiCorp and HomeServices. The percentage that PacifiCorp allocated to MEHC and its subsidiaries during the year ended December 31, 2011 was 100%.

e) A formula based on shared Information Technology infrastructure that is owned and/or managed by MEC. The percentage that PacifiCorp allocated to MEHC and its subsidiaries was 100%.

Appendix 16

Loss Calculation

Amounts in thousands of MWh

Input Data from 2010 Form 1 Page 401a

			SOURCES		USES	
page 401a	69056.216	57,639	Net Genr, Ln 9	53,016	Sale to Ultimate, Ln 22	page 401a
page 401a		11,417	Purchases, Ln 10	221	Reqts, Ln 23	page 401a
page 401a		205	Net Exchange, Ln 14	11,194	Non-reqts, Ln 24	page 401a
				143	Company, Ln 26	page 401a
page 401a		13,164	Received, Ln 16	4,387	Losses, Ln 27	page 401a
page 401a		(13,164)	Delivered, Ln 17			
page 401a		(301)	Trans by Other Losses, Ln 19			
		68,960	Total	68,960		

Recalculated and Adjusted Received and Delivered Energy

	Sources		Uses	
	Generation, 401a lines 9 and 10	69,056	Sales to ultimate consumers, 401a line 22	53,016
	Net exchange, 401a line 14	205	Requirement Sales, line 23	221
	Transmission by others losses, 401a line 19	(301)		
		68,960		
	Transmission received/delivered corrected: lines 16/17		Non-requirement sales subject to losses	5,735
Attachment A	Transmission received -- losses financially settled	2,148		
Attachment B	WAPA RS 262 delivered	1,610	Company sales: 401a line 26	143
Attachment B	WAPA RS 263 delivered	84		
Attachment C	Black Hills received-losses settled with PacifiCorp Energy	238		
Attachment C	Transmission: losses phsically settled, other	469		
Attachment B	Transmission received -- supplied losses	8,629		
Attachment B	WAPA losses received	112		
	Total transmission received:	13,290	Transmission delivered without losses	12,686
	Gross Received	**82,250**	**Total delivered with on-system losses**	**71,799**
	Less third-party sales on-system (reported in energy received)	(322)	**Total received - total delivered = losses**	**5,104**
	Less off-system w/o losses	(5,025)	Total system delivered loss rate including off-system =	0.071
			Distribution Losses / Assumed 0.0464% Loss Rate =	7
	Net on-system received	**76,903**	Remaining losses = transmission losses	5,096
			Transmission deliveries = total deliveries + distribution losses =	71,807
			Transmission loss rate @ delivery =	**0.07097**

Transmission and Distribution Losses Adjustments and Allocation

			Current Tran Loss Factor		Distribution Loss Factor	
			4.48%		4.64%	Revised 2007 Distribution Loss Study
	Schedule 10 loss factor (prior to update)					
		FERC # w/ Current Loss Factor	Trans Loss imbedded in current #s	Adjusted to remove current loss Factor	Retail Load w/ Dist. Loss	Dist. Loss
Company Data	TRANSMISSION: Sales to ultimate consumers transmisison (including interdepartmental sales)	12,839		12,839	12,839	
Company Data	DISTRIBUTION: Sales to ultimate consumers distribution (including interdepartmental sales)			-	-	-
	Requirements sales for resale	221		221		
	Non-requirements sales for resale:	11,194				
	Adjustments to remove financial transactions, duplicate transactions and off-system activity:					
	Less losses included paid by Black Hills	-15				
Attachment D	less losses included financial losses by pt.pt in line 16,17	(97)				
Tag Data	off system sales w/o losses	-5,025				
Tag Data	Total third party sales to cust. Purchasing trans.	-322				
	Total Non-requirements sales for resale subject to losses	5,735		5,735		
			-			
	Energy used by the company (electric dept only, excluding station use)	143		143	150	7
	Transmission received -- losses financially settled	2,148	92	2,056		
	WAPA RS 262 & 263	1,806	112	1,695		
	Transmission pt to pt Black Hills	238	11	227		
	Transmission pt. to pt physical, other	469	20	449		
	Transmission network: supplied losses	8,629	370	8,259		
	Total Transmission: lines 16/17	13,290	604	12,686		
	Total	32,227	604	31,623	150	7

		erg_src_mwh	erg_disp_mwh
1	Sources of Energy		
2	Generation		
3	Steam	44,918,646	
4	Nuclear	0	
5	Hydro Generation	3,748,308	
6	Hydro Pum Starage	-2,784	
7	Other	8,975,021	
8	Less Energy for Pumping	0	
9	Net Generation	57,639,191	
10	Purchases	11,417,025	
11	Power Exchanges		
12	Received	14,493,755	
13	Delivered	14,289,088	
14	Net Exchanges	204,667	
15	Transmission For Other		
16	Received	13,164,045	
17	Delivered	13,164,045	
18	Net Transmission For Other	0	
19	Transmission By Others Losses	-300,756	
20	Total	68,960,127	
21	Disposidtion of Energy		
22	Sales to Ultimate Customers		53,015,534
23	Requirements Sales For Resale		220,852
24	Non-Requirements Sales For Resale		11,193,740
25	Energy Furnished Without Charge		0
26	Energy used by the Company		142,578
27	Total Energy Losses		4,387,423
28	Total		68,960,127

FF1 2010 328 MWH RECEIVED/DELIVERED
PT-TO-PT MW FINANCIAL SETTLEMENT

Page #	Line #	Customer	Statistical Classification	Rate Schedule Tariff Number	MWH
329	6	Basin Electric Power Cooperative	NF	7V11-8	25,789
329	8	Black Hills/Colorado Electric Utility Company	NF	7V11-8	88
329	9	Black Hills/Colorado Electric Utility Company, L.P.	SFP	7V11-7	90
329	29	Bonneville Power Administration	LFP	7V11-7	52,471
329	30	Bonneville Power Administration	AD	7V11-7	5,569
329.1	3	Bonneville Power Administration	SFP	7V11-7	24,791
329.1	7	Cargill Power Markets, LLC	NF	7V11-8	149,117
329.1	8	Cargill Power Markets, LLC	AD	7V11-8	7,432
329.1	9	Cargill Power Markets, LLC	SFP	7V11-7	11,430
329.1	11	Constellation Energy Commodities Group	NF	7V11-8, 9, 11	9,670
329.1	12	Constellation Energy Commodities Group	AD	7V11-8	4,330
329.1	19	Deseret Generation & Transmission	SFP	7V11-7	864
329.1	23	Eugene Water & Electric Board	NF	7V11-8	2,988
329.1	24	Eugene Water & Electric Board	AD	7V11-8	1,010
329.1	29	Gila River Power, L.P.	NF	7V11-8	682
329.1	30	Iberdrola Renewables Inc.	NF	7V11-8	33,286
329.1	31	Iberdrola Renewables Inc.	AD	7V11-8	3,010
329.2	2	Iberdrola Renewables Inc.	LFP	7V11-7	56,556
329.2	3	Iberdrola Renewables Inc.	AD	7V11-7	7,829
329.2	5	Idaho Power Company	LFP	7V11-7	61,018
329.2	6	Idaho Power Company	NF	7V11-8	27,680
329.2	7	Idaho Power Company	SFP	7V11-7	66,989
329.2	12	JP Morgan Ventures Energy Corp.	NF	7V11-8	36,957
329.2	15	Los Angeles Dept of Water & Power	NF	7V11-8	37,787
329.2	16	Macquarie Energy, LLC	NF	7V11-8	1,290
329.2	17	Macquarie Energy, LLC	AD	7V11-8	11
329.2	20	Morgan Stanley Capital Group, Inc.	NF	7V11-8	159,217
329.2	21	Morgan Stanley Capital Group, Inc.	AD	7V11-8	12,873
329.2	22	Morgan Stanley Capital Group, Inc.	SFP	7V11-7	2,647
329.2	23	Municipal Energy Agency of Nebraska	NF	7V11-8	1,935
329.2	24	NextEra Energy Resources, LLC	LFP	7V11-5, 6, 9, 11	255,567
329.2	25	NextEra Energy Resources, LLC	AD	7V11-5, 6, 9, 11	13,863
329.2	29	Pacific Gas & Electric Company	NF	7V11-8	9
329.2	30	Powerex Corporation	LFP	7V11-7	290,447
329.2	31	Powerex Corporation	AD	7V11-7	18,922
329.2	32	Powerex Corporation	NF	7V11-5,6,8	365,059
329.2	33	Powerex Corporation	AD	7V11-5,6,8	9,217
329.2	34	Powerex Corporation	SFP	7V11-7	948
329.3	1	PPL Energy Plus, LLC	NF	7V11-8	9,586
329.3	2	PPL Energy Plus, LLC	AD	7V11-8	1,066
329.3	3	PPL Energy Plus, LLC	SFP	7V11-7	3,688
329.3	4	Public Svc. Co. of CO	NF	7V11-8	8,685
329.3	5	Public Svc. Co. of CO	AD	7V11-8	32
329.3	6	Public Svc. Co. of CO	SFP	7V11-7	17,628
329.3	7	Rainbow Energy Marketing Corporation	NF	7V11-8	11,260
329.3	8	Rainbow Energy Marketing Corporation	AD	7V11-8	419
329.3	9	Rainbow Energy Marketing Corporation	SFP	7V11-7	17,866
329.3	10	Raser Power Systems, Inc.	LFP	7V11-5,6,7 9	45,680
329.3	11	Raser Power Systems, Inc.	AD	7V11-5,6,7 9	3,892
329.3	12	Salt River Project	NF	7V11-8	15,803
329.3	13	Seattle City & Light	LFP	7V11-5, 6, 7,9	46,496
329.3	14	Seattle City & Light	AD	7V11-5, 6, 7,9	1,883
329.3	15	Seattle City & Light	NF	7V11-8	17
329.3	18	Shell Energy North America	NF	7V11-8	530
329.3	19	Shell Energy North America	AD	7V11-8	448
329.3	21	Sierra Pacific Power Company	NF	7V11-8	1,891
329.3	22	Sierra Pacific Power Company	AD	7V11-8	947
329.3	23	Sierra Pacific Power Company	AD	7V11-7	1,000
329.3	24	Southern California Edison	SFP	7V11-5,6,7	5,845
329.3	25	Southern California Edison	NF	7V11-8,9,11	16,199
329.3	29	The Energy Authority	NF	7V11-8	25
329.3	30	The Energy Authority	AD	7V11-8	11
329.3	31	TransAlta Energy Marketing Corporation	NF	7V11-8	5,406
329.3	32	TransAlta Energy Marketing Corporation	AD	7V11-8	1,749
329.4	1	Tri-State Generation & Transmission	NF	7V11-8	436
329.4	10	Utah Associated Municipal Power Systems	SFP	7V11-8	3,174
329.4	19	Western Area Power Administration	NF	7V11-8	129,311
329.4	20	Western Area Power Administration	AD	7V11-8	13,208
		Total MWH			2,123,619
		Accruals, Adjustments			24,764
		Total point-to-point schedules subject to losses - as reported on 328 (financial settlement)			2,148,383

2010 Western Received/Delivered Reconcilation

2010 Transmission Received/Delivered

	Western Rec./Del. Reconciliation					
		RS 262	RS 263	Subtotal	Energy Return (Variation)	Net
	Energy Received	1,706,974	89,682	1,796,656	9,546	***1,806,202***
	Losses	(96,632)	(5,400)	(102,032)		(102,032)
	Deer Creek Energy Variation - actual energy received in exchange for water rights	-		-	(9,546)	(9,546)
	Correct Delivered	1,610,342	84,282	1,694,624	-	***1,694,624***
FF1 Pg 328.4	OS Reported	1,479,333	83,483	1,562,816	-	1,562,816
FF1 Pg 328.4	AD Reported	156,206	8,520	164,726	-	164,726
	Received (RS 262)/Delivered (RS 263)	1,635,539	92,003	1,727,542	-	1,727,542
Adjustments	Deer Creek Variation Accounting: accounting tracking - no energy impact reported in received amounts on page 328 and does not affect peak	(25,967)		(25,967)		(25,967)
	Losses		(5,400)	(5,400)		(5,400)
	Accrual/Adjustment	770	(2,321)	(1,551)		(1,551)
	Energy Return (Variation)			-		-
	Net Delivered	1,610,342	84,282	1,694,624	-	**1,694,624**

Total Received/Delivered per 328 and 401a-lines 16/17 as reported

	Received/ Delivered	Accruals/ Adjustments	Adjusted 2010 Received		
Received/Delivered as Reported on FF1 page 401a Lines 16/17	13,164				
Total point-to-point schedules subject to losses - as reported on 328 (final settlement)	2,123,619	24,754	2,148,373	2148.373	
Western RS 262 Delivered reported on page 328	1,635,539	(25,197)	1,610,342	1610.342	
Western RS 263 Received reported on page 328	92,003	(7,721)	84,282	84.282	
Black Hills (losses paid financially to PacifiCorp Merchant)	229,669	7934	237,603	237.603	
Physical returns/other contractual arrangements:			-	0	
BPA: Lost Creek point-to-point paid physically	230,995	15,983	246,978	246.978	
State of South Dakota paid physically	18,369	23	18,392	18.392	
Western Area Power Administration RS 664	178,904	24,952	203,856	203.856	469.226
Network/OS/other rate schedules	8,654,947	(26,396)	8,628,551	8628.551	
	13,164,045	14,332	13,178,377	13,178	
Adjustments	14,332				
Corrected Delivered	13,178,377				
Western Losses	111,578		111,578		
Corrected Received	13,289,955		13,289,955		

2010 328 MWH RECEIVED/DELIVERED
PT-TO-PT MW PHYSICAL SETTLEMENT, BLACK HILLS, and WAPA

Page #	Line #	Customer	Statistical Classification	Rate Schedule Tariff Number	MWH	Black Hills	Physical	WAPA	Total Physical WAPA
329	10	Black Hills, Inc.	FNO	7V11	32,344	32,344			
329	11	Black Hills, Inc.	AD	7V11	6,646	6,646			
329	12	Black Hills, Inc.	NF	7V11-8	12,374	12,374			
329	13	Black Hills, Inc.	AD	7V11-8	816	816			
329	14	Black Hills, Inc.	SFP	7V11-7	16,438	16,438			
329	15	Black Hills, Inc.	LFP	7V11-7	157,346	157,346			
329	16	Black Hills, Inc.	AD	7V11-7	3,705	3,705			
329	20	Bonneville Power Administration	LFP	7V11-3,4	51,289		51,289		51,289
329	21	Bonneville Power Administration	OS	R.S. 324	167,011		167,011		167,011
329	22	Bonneville Power Administration	AD	R.S. 324	12,695		12,695		12,695
329.3	27	State of South Dakota	LFP	7V11-7	16,864		16,864		16,864
329.3	28	State of South Dakota	AD	7V11-7	1,505		1,505		1,505
329.4	21	Western Area Power Administration	OS	R.S. 664	166,992			166,992	166,992
329.4	22	Western Area Power Administration	AD	R.S. 664	11,912			11,912	11,912
					657,937	229,669	249,364	178,904	428,268
			Accruals/ Adjustments			7934	16,006	24,952	40,958
			Total Black Hills, Physical and WAPA received/delivered			237,603	265,370	203,856	469,226

Amount of transmission point-to-point previously reported Exhibit 6B	2,548
Less Black Hill point-to-point	(191)
Less BPA tariff: physical	(51)
Less Western RS 664: variable losses	(179)
Other	(3)
	2,124
Accruals/adjustments	24
Total pt-to-pt corrected	2,148

SALES FOR RESALE (Account 447): Transmission Losses

Line No.	Name of Company or Public Authority [Footnote Affiliations] (a)	Statistical Classifi-cations (b)	Footnote for col (b)	FERC Rate Schedule or Tariff Number (c)	Megawatthours Sold (g)		Revenue: Demand Charges ($) (h)	Revenue: Energy Charges ($) (i)	Revenue: Other Charges ($) (j)	Footnotes for col (j)	Total ($) (h + i + j) (k)
24	Basin Electric Power Cooperative	AD	2	T-11	2,991				91,095	1	91,095
25	Basin Electric Power Cooperative	LF	3	T-11	232				9,766	3	9,766
27	Basin Electric Power Cooperative	SF		T-11	1,116				39,915	3	39,915
33	Bonneville Power Administration	AD	2	T-11	5				216	1	216
35	Bonneville Power Administration	LF	5	368	1,850				61,133	3	61,133
36	Bonneville Power Administration	LF	6	T-11	2,571				90,898	3	90,898
38	Bonneville Power Administration	SF		T-11	1				25	3	25
45	Cargill Power Markets, LLC	SF		T-11	6,754				196,574	3	196,574
55	Constellation Energy Commodities Group, Inc.	SF		T-11	512				17,987	3	17,987
56	Constellation Energy Commodities Group, Inc.	SF		T-11	55				2,064	4	2,064
62	Deseret Power Electric Cooperative	SF		T-11	39				1,305	3	1,305
66	Eugene Water & Electric Board	SF		T-11	140				4,707	3	4,707
69	Gila River Power, L.P.	SF		T-11	31				940	3	940
73	Iberdrola Renewables, Inc.	LF	9	T-11	2,884				95,640	3	95,640
74	Iberdrola Renewables, Inc.	SF		T-11	1,513				51,070	3	51,070
76	Idaho Power Company	LF	10	T-11	2,644				90,235	3	90,235
77	Idaho Power Company	SF		T-11	3,581				131,365	3	131,365
80	Intermountain Renewable Power, LLC	LF	11	T-11	1,411				43,199	3	43,199
81	Intermountain Renewable Power, LLC	LF	11	T-11	629				24,449	4	24,449
84	J.P. Morgan Ventures Energy Corporation	SF		T-11	1,881				53,987	3	53,987
87	Los Angeles Deptartment of Water and Power	SF		T-11	1,693				58,344	3	58,344
89	Macquarie Energy LLC	SF		T-11	58				1,526	3	1,526
94	Morgan Stanley Capital Group, Inc.	SF		T-11	7,656				251,595	3	251,595
96	Municipal Energy Agency of Nebraska	SF		T-11	87				2,883	3	2,883
101	NextEra Energy Power Marketing, LLC	AD	2	T-11	2				78	1	78
102	NextEra Energy Power Marketing, LLC	LF	14	T-11	10,897				347,368	3	347,368
103	NextEra Energy Power Marketing, LLC	SF		T-11	275				8,086	4	8,086
110	PPL Montana, LLC	SF		T-11	620				21,898	3	21,898
115	Portland General Electric Company	SF		T-11	369				12,044	3	12,044
119	Powerex Corporation	LF	16	T-11	14,932				477,737	3	477,737
120	Powerex Corporation	SF		T-11	13,177				389,753	3	389,753
124	Public Service Company of Colorado	SF		T-11	1,179				35,818	3	35,818
132	Rainbow Energy Marketing Corporation	SF		T-11	1,305				36,998	3	36,998
139	Salt River Project	SF		T-11	708				20,372	3	20,372
145	Seattle City Light	LF	21	T-11	2,249				69,711	3	69,711
146	Seattle City Light	SF		T-11	1				24	3	24
154	Shell Energy North America (US), L.P.	SF		T-11	24				875	3	875
156	NV Energy (Sierra Pacific Power Company)	LF	22	T-11	817				26,442	3	26,442
157	NV Energy (Sierra Pacific Power Company)	SF		T-11	84				3,531	3	3,531
161	Southern California Edison Company	SF		T-11	1,526				47,259	3	47,259
162	Southern California Edison Company	SF		T-11	433				12,832	4	12,832
167	The Energy Authority	SF		T-11	1				39	3	39
170	TransAlta Energy Marketing Inc.	SF		T-11	250				9,358	3	9,358
173	Tri-State Generation and Transmission Association	SF		T-11	19				645	3	645
179	Utah Associated Municipal Power Systems	SF		T-11	142				4,197	3	4,197
183	Western Area Power Administration	AD	2	T-11	142				59,501	1	59,501
184	Western Area Power Administration	LF	26	T-11	1,633				97,482	3	97,482
185	Western Area Power Administration	SF		T-11	5,801				99,338	3	99,338
					96,920				3,102,304		3,102,304

Appendix 17

Loss Methodology

PacifiCorp

Loss Analysis Methodology

Docket No. ER11-3643-000

<u>PURPOSE</u>

The purpose of this document is to provide an explanation of the methodology that will be used to update PacifiCorp's transmission system loss factor set forth in Schedule 10 of the Open Access Transmission Tariff ("OATT"). As part of settlement, PacifiCorp commits to use the methodology outlined in this document when PacifiCorp recalculates and updates its loss factor in the future (see section, entitled "TIMING FOR RE-CALCULATION"). For purposes of illustrating the methodology and explaining the derivation of the settlement loss factor, references to the loss calculation using 2010 data are made throughout the document. This methodology explanation accompanies the spreadsheet, entitled "Loss_Calculation.xlsx," which contains the proposed loss calculation using 2010 data to produce a transmission system loss factor of 4.259%.

The transmission loss factor is based on annual sources and uses of energy from FERC Form 1 ("FF1"), p. 401a, with adjustments as described below. The intent of these adjustments is to remove any energy source and corresponding energy use (i) which is not scheduled or otherwise transacted using PacifiCorp's transmission system, (ii) which is duplicative of, in part or whole, another energy source or energy use already represented in the data on FF1, p. 401a, and (iii) which represent financially settled losses (i.e., no actual physical losses).

In addition to the adjustments noted above, this document also provides an explanation for changes PacifiCorp will make to its FF1 reporting practices or to the loss calculation methodology so that data used in the loss calculation will more closely and transparently tie to the FF1 on a going forward basis. In sum, these changes include:

- FF1, p. 328 will include an accrual variance entry to reflect calendar year amounts of energy received and delivered. This change will be made and reflected in PacifiCorp's 2012 FF1 and on a going-forward basis for all subsequent FF1s. The Loss Calculation shall contain a reconciliation of the total p. 328 accrual variance entry to the components of the total which are used in the Loss Calculation;
- The Loss Calculation shall separately specify energy and loss amounts associated with Western Area Power ("WAPA") Administration Rate Schedules; and
- FF1, p. 328 will not include accounting amounts related to WAPA Rate Schedule 262 tracking for water rights which do not impact energy delivered or system peak and will

include amounts which constitute actual energy received. This change will be made and reflected in PacifiCorp's 2012 FF1 and on a going-forward basis for all subsequent FF1s.

TIMING FOR RE-CALCULATION

PacifiCorp will file an adjusted loss factor for Schedule 10, using the methodology identified below following completion of two Energy Gateway segments (or substantially similar transmission segments) which have been placed into commercial operation for at least one full calendar year. The update to the loss factor shall be filed on or before April 1 following the full calendar year of commercial operation for the second Energy Gateway segment (or substantially similar transmission segment) with a request that the updated loss factor be made effective June 1 of the calendar year in which the filing is made (for example, assuming Mona to Oquirrh is completed on May 1, 2013, PacifiCorp would file an updated Schedule 10 factor on or before April 1, 2015 with a request effective date of June 1, 2015. Such filing would be based on 2014 FF1 data, which would reflect at least one full calendar year of operation for Mona to Oquirrh and four full calendar years of operation for Populus to Terminal. Energy Gateway segments include:

1) Populus to Terminal (Segment B) (completed and in-service November 2010)
2) Mona to Oquirrh (Segment C)
3) Oquirrh to Terminal (Segment C)
4) Windstar to Populus (Segment D)
5) Sigurd to Red Butte (Segment G)
6) Aeolus to Mona (Segment F)
7) Populus to Hemingway (Segment E)
8) Boardman to Hemingway (Segment H)

CALCULATION METHODOLOGY

I. Loss Calculation Overview

The data utilized for calculating the transmission loss factor is based on amounts reported on FF1, p. 401a, as well as the underlying detail provided in or represented by data reported for Transmission of Electricity for Others (Account 456.1), FF1, pp. 328-330 and Sales for Resale (Account 447), FF1, pp. 310-311. In some cases, additional company data is also utilized and is specifically referenced and explained.

The accompanying spreadsheet, entitled "Loss_Calculation.xlsx." may be broken into the following components which contribute to the calculation of the resulting loss rate:

- **<u>Input Data from 2010 FF1, p. 401a</u>**: The purpose of the white-shaded section is to summarize data which is sourced directly from FF1, p. 401a and to provide a total for energy sources (received) and uses (delivered). The tab labeled "FF1 page 401a" is intended to reproduce the relevant inputs from the FF1 used in "Loss_Calculation.xlsx."
    - The total for 2010 energy sources (received) and uses (delivered) is 68,960M MWh and 68,961M MWh, respectively (1,000 MWh rounding difference).

- **<u>Recalculated and Adjusted Received and Delivered Energy</u>**: The purpose of the green-shaded section is to make adjustments to the received and delivered inputs reported on FF1, p. 401a as described in "PURPOSE". The green-shaded section produces a revised total for energy received and delivered. The difference between these values represents total losses (transmission and distribution combined). An amount representing distribution losses is then subtracted from total losses; the remaining amount represents transmission losses. A transmission loss factor is then developed by dividing total transmission losses by total transmission deliveries including distribution losses.
    - The resulting transmission loss factor using 2010 data is 4.259%.

- **<u>Transmission and Distribution Losses Adjustments and Allocation</u>**: The yellow highlighted area provides the supporting calculations for adjusted amounts utilized above in "Recalculated and Adjusted Received and Delivered Energy" and for losses as allocated between transmission and distribution, the results of which are used to calculate the transmission loss factor noted above.
    - Total distribution losses for 2010 are equal to: 1,962M MWh (using retail distribution loss factor of 4.64%)
    - Total transmission losses for 2010 are equal to: 3,139M MWh (1,000 MWh rounding difference).

II. Explanation of Recalculated and Adjusted Received and Delivered Energy

Energy received/delivered as reported on FF1, p. 401a, lines 16-17, can divided into three types of loss transactions: (1) wheeling for which losses are supplied by PacifiCorp and calculated and paid for by transmission customer based on the Schedule 10 loss factor; (2) wheeling for which losses are supplied to PacifiCorp by the transmission customer based on the Schedule 10 loss factor; and (3) wheeling for which losses are supplied by the transmission customer based on a loss factor other than that set forth, or equal to, the Schedule 10 loss factor. The assignment of energy received (line 16) and energy delivered (line 17) to one of these three categories, as reflected in Loss_Calculation.xlsx should be based on and consistent with the data recorded in Transmission of Electricity for Others (Account 456.1), FF1, p. 328-330 and Sales for Resale (Account 447), FF1, p. 310-311.

a. Adjustments to Sources/Energy Received

In order to derive total losses on PacifiCorp's transmission system, it is necessary to adjust amounts for energy received which are not reflected in the energy sources/received (FF1, p. 401a, line 16) total of 68,960M MWh as described below. Unless otherwise noted, the following adjustments to 2010 data will be made each time the Loss Calculation is updated using future date sets. For all noted accrual difference adjustments, on a going forward basis, FF1, p. 328 will include a total accrual variance entry to reflect calendar year amounts of energy received and delivered and the Loss Calculation will reflect the component of the total accrual variance entry associated with each adjustment.

- **Financially settled losses on point-to-point (2,148M MWh):** This amount was derived by identifying tariff point-to-point contracts which settle losses financially. Please refer to Attachment A, which also includes an adjustment for accrual differences.
- **Adjustments Related to Western Area Power ("WAPA") Administration Rate Schedules (1,694M MWh):**
  - Prior responses/materials did not adequately distinguish between losses associated with WAPA Rate Schedules 262 and 263, which have now been reconciled and are shown in Loss Calculation and Attachment B to Loss Calculation.
  - In accounting for the Deer Creek Energy Variation account, the 2010 FF1, p. 328 included an accounting amount related to tracking water rights (26m MWh) which does not impact energy delivered and does not affect system peak and did not include an amount which includes actual energy received (9.5m MWh). These amounts have been properly accounted for and reconciled as shown in Loss Calculation and Attachment B to Loss Calculation. This is a one-time adjustment for 2010 data. On a going forward basis, FF1, p. 328 will not include accounting amounts related to tracking water rights which do not impact energy delivered or system peak and will include amounts which do include energy received.
- The amounts for WAPA Rate Schedule 262 and 263, respectively, as reported on FF1 Page 328, prior to making accrual adjustments, are 1,635M MWh and 92M MWh. After making the adjustments, the corrected amounts for WAPA Rate Schedule 262 and 263, respectively, are 1,610M MWh and 84M MWh, to produce an overall amount for WAPA of 1,694M MWh. These corrected amounts are shown in the current version of the Loss Calculation as well as Attachment B to the Loss Calculation.

- **WAPA Losses received (111M MWh):** This amount is derived as the difference between energy received and delivered for Rates Schedules 262 and 263, shown in Attachment B to the Loss Calculation (as the product of 102,032 MWh + 9,546 MWh).

- **Black Hills received-losses settled with PacifiCorp Energy (238M MWh):** PacifiCorp Commercial and Trading has an agreement to assess losses on amounts sold to Black Hills under a long-term firm purchase power agreement, shown in Attachment C to the Loss Calculation, which also includes an adjustment for accrual differences.

- **Losses physically settled, other (469M MWh):** This amount was derived by identifying point-to-point contracts which settle losses physically and is shown in Attachment C to the Loss Calculation, including accrual adjustments, which also includes an adjustment for accrual differences.

- **Transmission Rc'd -- Supplied Losses (8,629M MWh):** The remaining amount of energy delivered consists of network and "other service" contract amounts which are reported in FF1 primarily through imbalance (Account 555), which also includes an adjustment for accrual differences.

These adjustments result in a total transmission received amount of 13,289M MWh, which is then added to the 2010 energy sources/received (FF1, p. 401a, line 16) total of 68,960M MWh to produce a total gross received amount of 82,249M MWh. Certain amounts of energy received are then removed from this total, as follows:

  - **Removal of third-party sales on-system (-322M MWh):** The purpose of this adjustment is to remove duplicate transactions which are reflected in both net generation and received/delivered energy (sales for resale by PacifiCorp merchant which are also accounted for as part of wheeling received and delivered). This amount represents transactions between third-parties and PacifiCorp Commercial & Trading and is sourced from tagging records which the company would provide supporting documentation to substantiate. The total for 2010 is -322. These sales are as follows:
    - UMPA: 215M MWh
    - Tri-State: 17M MWh
    - Morgan Stanley on Deseret's behalf: 36M MWh
    - Black Hills: 49M MWh
    - Cargill: 1M MWh

- **Removal of off-system sales without losses (-5,025M MWh):** The purpose of this adjustment is to remove transactions which occur at a generator bus and do not utilize PacifiCorp's transmission system. For 2010, PacifiCorp performed a query of etag data which shows a transfer from the PacifiCorp Balancing Authority to another Balancing

Authority on the first E-Tag line entry. The e-tag query consists of the following parameters:

- Path=CHOLLA500/CHOLLA500;Colstrip/Colstrip;HERMISTONGEN/HERMISTONGEN;JEFF/JEFF;UINTA/UINTA;WYODAK/WYODAK;YTP
- Scheduletype = Energy
- TagTransOwner = PAC01
- TagNotes does not = Coal Feed; Colstrip Startup
- LSE does not = PAC01
- LoadPoint does not = NWMTLosses
- TSSubClass does not = FCR_PHYSICAL;SECONDARY
- Assignment Ref = 201;204;205;207;215;216;217;218;NOR

For future loss factor updates, PacifiCorp would utilize a similar query rule, which may need to be adjusted depending on then-current system configuration, tagging rules or conventions. Any needed adjustments to the query would be disclosed and explained. The supporting data for these amounts are provided as an accompanying workpaper to this methodology, entitled “2010 Off System Sales Summary”.

PacifiCorp has confirmed that this adjustment does not include any financial or physical bookouts.

Total sales to third-parties at a generator bus not utilizing PacifiCorp transmission consist of the following transactions:

- Cholla generation is a PacifiCorp Commercial and Trading designated network resource interconnected to the Arizona Public Service (“APS”) Transmission System, but telemetered in to the PacifiCorp Balancing Authority. It is common for PacifiCorp Commercial and Trading to undesignate the Cholla resource at the bus to sell surplus generation into the market. When this occurs, there is no utilization of PacifiCorp transmission. Commercial and Trading will take the generation from the Cholla bus using its legacy APS transmission rights on the APS system to market locations where the buyers then take title to the energy. As such, the PacifiCorp system is not used and so these transactions should not be included in losses. In 2010, this category of transactions totals to 2,518,009 MWh.

- Mid-C generation (purchase contracts from BPA and Grant County) is a PacifiCorp Commercial and Trading designated network resource interconnected to the Bonneville Power Administration (“BPA”) Transmission System, but telemetered in to the PacifiCorp Balancing Authority. It is common for PacifiCorp Commercial and Trading to undesignate the Mid-C resource at the bus to sell surplus generation into the market. When this occurs, there is no utilization of PacifiCorp transmission. Buyers take title to the generation at the Mid-C bus and move the energy to their loads through acquired transmission rights on other transmission systems. In 2010, this category of transaction totals to 1,928,637 MWh.

- Colstrip generation is a PacifiCorp Commercial and Trading designated network resource interconnected to a jointly-owned transmission system and telemetered into the PacifiCorp Balancing Authority. From time to time, PacifiCorp Commercial and Trading undesignates the Colstrip resource at the bus and sells the generation to other Colstrip owners or into the market. When this occurs, there is no utilization of PacifiCorp transmission. Buyers take title to the generation at the Colstrip bus (common to other Colstrip owners) and move the energy to their loads through utilization of their respective owned shares of non-PacifiCorp transmission system. In 2010, this category of transaction totals to 1,780 MWh.

- Wyodak generation is a PacifiCorp Commercial and Trading designated network resource interconnected to a jointly-owned transmission system and metered into the PacifiCorp Balancing Authority. It is common for PacifiCorp Commercial and Trading to undesignated the Wyodak resource at the bus to sell surplus generation into the market. When this occurs, there is no utilization of PacifiCorp transmission. Buyers take title to the generation at the Wyodak bus (common to Basin and Black Hills) and move the energy to their loads through their own transmission system or through acquired third party-transmission rights on other transmission systems. In 2010, this category of transaction totals to 33,452 MWh.

- Bridger generation is a PacifiCorp Commercial and Trading designated network resource interconnected to a jointly-owned transmission system and metered into the PacifiCorp Balancing Authority. From time to time, PacifiCorp Commercial and Trading undesignates the Bridger resource and sells to Idaho Power or into the market. When this occurs, there is no utilization of PacifiCorp transmission. Buyers take title to the generation at the Bridger bus (common with Idaho) and move the energy to their loads through owned or acquired third-party transmission rights on other transmission systems. In 2010, this category of transaction totals to 1,668 MWh.

- Craig and Hayden generation are PacifiCorp Commercial and Trading designated network resources interconnected to the Western Area Power Administration and Public Service Company of Colorado transmission systems, respectively. These generation resources are not connected to the PacifiCorp transmission system nor telemetered into the PacifiCorp Balancing Authority, therefore, sales at the bus of

> Craig and Hayden to others never use the PacifiCorp transmission system. However, it is common for the Craig and Hayden generation resources to be undesignated and sold to others at the generator bus. The units are located on the Western Area Power Administration and Public Service of Colorado transmission systems, therefore sales at the bus of Craig and Hayden to others never use the PacifiCorp transmission system. Bus sales to others were not captured in the E-Tag query due to different tagging conventions for this resource. PacifiCorp back office accounting records show that in 2010, the quantity of these transactions totals 541,161 MWh.

These further adjustments result in a total net received of 76,902 M MWh, which must then be compared to net delivered energy to determine total system losses before losses are allocated between transmission and distribution.

I. Adjustments to Uses/Energy Delivered

In order to derive total losses on PacifiCorp's transmission system for 2010, it is necessary to calculate total energy as follows:

First, the calculation uses amounts reported on FF1, p. 401a, including sales to ultimate consumers (53,016M MWh) and company sales (143M MWh). To these amounts, on-system non-requirements sales for resale subject to losses are added, which is derived as follows:

- **On-system non-requirements sales subject to losses (5,735M MWh)**: The derivation of this amount is explained below:

    - **Less losses included paid by Black Hills (15,000 MWh):** This is the amount of financial losses paid by Black Hills to PacifiCorp Energy.

    - **Transmission financial losses (97,000 MWh):** Financial losses paid in 2010 by transmission customers who scheduled point to point transmission. Please refer to Attachment D to Loss Calculation which provides supporting detail.

    - **Total third-party sales to customers purchasing transmission (322M MWh):** See explanation above.

    Removal of off-system sales without losses (5,025M MWh): See explanation above.
- **Transmission delivered without losses (12,686M MWh):** This amount is produced by multiplying contractual amounts of energy received by the company's historical loss

factor (4.48%) to determine transmission delivered without losses. Explanations for the underlying energy delivered amounts for these contracts is provided above.

These adjustments result in a total net delivered of 71,801M MWh, which must then be compared to net received energy (76,902M MWh) to determine total system losses, which equal 5,101M MWh. This amount must then be allocated between transmission and distribution. This is achieved by applying a previously established distribution loss factor 4.64% to total system losses of 5,101M MWh and then removing that amount from the total.[1] The remaining amount of 3,104M MWh is ascribed as transmission losses. The resulting transmission loss factor is derived by dividing this amount by total net delivered energy plus transmission losses, which produces an overall transmission system loss factor of 4.259%.

II. Transmission and Distribution Losses Allocation

The yellow highlighted area provides the supporting calculations for losses allocated to distribution, which are used to calculate the transmission loss rate above.

- Sales to Ultimate Consumers (Transmission and Distribution): This portion of the calculation divides sales to ultimate consumers (FF1, p. 401a, line 22, and p. 304, line 43 (column b) totaling 53,016M MWh into transmission and distribution. The allocation is determined according to the following method:
  - MWh by voltage level are estimated based on 1) rate schedules with specific voltage types, such as residential and transmission service rate schedules, and 2) delivery voltage codes by customer in the company's billing system for rate schedules for which multiple voltage levels are applicable. The MWh results are cross-checked against the output from the revenue system (RVN 305 report). The break out between transmission and distribution (MWh by voltage level) is not readily discernible from data reported on FF1, page 304. Company data and supporting workpapers can be provided upon request to support the allocation.

Intervenor Issue 50

Adjustments going forward to the Form 1 data include:

[1] Intervenors propose to use the distribution loss factor from PacifiCorp's 2007 retail loss study as a proxy for allocating total losses between transmission and distribution and to utilize the resulting distribution factor for the 2010 result. The distribution loss rate applied to allocate losses was 4.78% from the 2007 PacifiCorp retail loss study. However, the 2007 study does not adjust for the bus sales to third-parties as noted above for line 24 adjustments. If the 2007 study is to be used for purposes of loss allocations, line 24 inputs in the 2007 study must be corrected in similar fashion to properly represent the true allocation between transmission and distribution losses. PacifiCorp proposes to allocate total system losses between transmission and distribution by applying a fixed distribution loss factor of 4.64%.

- Line 24 adjusted for, 1) bus sales at the locations where PacifiCorp transmission was not utilized with the source data for all adjustments coming from either E-Tag records or EQR entries, and 2) on system sales to others for purposes of load service within the BA.
- The ratio of distribution to transmission losses will be held fixed as a total to system at 49.3%
- Retail customers served at transmission voltages will not include distribution losses.

EQR Reconciliation

Upon review of the 2010 PacifiCorp EQR records, total sales at various busses were compared to the E-tag data used to form the basis of the line 24 adjustments described above. Busses identified from the EQR records and represented as Cholla include: Mead, PV, PPAPS, PPSRP and W. Wing.

Total sales identified on the EQR for Bridger, Wyodak, and Cholla are significantly higher than the E-Tag query totals and may represent additional sales or bookout transactions that do not utilize the PacifiCorp system. For purposes of the loss analysis, PacifiCorp only used the actual E-Tag data developed using the query rules as described above.

	Craig Hayden	Bridger	Wyodak	Cholla	MidC	Colstrip
EQR/Endur system	541,726	223,854	608,267	3,647,251	1,746,331	0
E-Tag Data Query	541,161	1,668	33,452	2,518,009	1,928,637	1,780

Appendix 18

Formula Attachment 8 Depreciation Rates
Effective June 1, 2012

PacifiCorp

Attachment 8 - Depreciation Rates

Applied Depreciation Rates by State - 2011

			Oregon		Washington		California		Utah		Wyoming		AZ, CO, MT, NM		Idaho		Company
Row	A/C	Description	Balance	Rate	Balance	Rate	Balance	Rate	Balance	Rate	Balance	Rate	Balance	Rate	Balance	Rate	Rate
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	350.2	Land Rights															1.35%
2	352	Structures and Improvements															1.31%
3	353	Station Equipment															1.75%
4	353.7	Supervisory Equipment															3.78%
5	354	Towers and Fixtures															1.56%
6	355	Poles and Fixtures															2.63%
7	356	Overhead Conductors and Devices															2.25%
8	356.2	Clearing & Grading															1.40%
9	357	Underground Conduit															1.65%
10	358	Underground Conductors and Devices															1.64%
11	359	Roads & Trails															1.39%
12		Unclassified Transmission															2.03%
13	389.2	Land Rights	-	0.00%	-	0.00%	-	0.00%	35,298.05	2.32%	74,341.83	2.01%	-	0.00%	4,867.64	2.01%	
14	390	Structures and Improvements	65,654,329.67	2.21%	11,054,273.54	3.80%	1,628,472.08	2.38%	87,290,261.03	2.18%	6,478,661.78	3.03%	383,797.68	2.06%	11,983,336.96	2.12%	
15	390.3	Structures and Improvements - Office Panels															6.67%
16	391	Office Furniture and Equipment															5.00%
17	391.2	Office Furniture and Equipment - Personal Computers															20.00%
18	393	Store Equipment															4.00%
19	394	Tools, Shop and Garage Equipment															4.17%
20	395	Laboratory Equipment															5.00%
21	397	Communication Equipment	92,582,136.60	4.06%	15,504,669.21	5.24%	5,396,538.41	4.15%	95,589,550.02	4.09%	39,453,102.07	5.40%	3,557,274.39	3.18%	18,090,090.43	3.79%	
22	397.2	Communication Equipment - Mobile Radio Equipment															9.09%
23	398	Miscellaneous Equipment															5.00%
24		Unclassified General	804,416.73	4.37%	245,153.73	5.49%	65,479.78	5.15%	816,080.03	4.30%	880,058.22	5.46%	9,009.37	3.17%	74,096.04	3.81%	
25	302	Franchises and Consents															6.04%
26	303	Miscellaneous Intangible Plant															4.92%
27	390.1	Leasehold Improvements - Gen															8.20%

Notes:

1 Depreciation Rates shown in rows 1 through 24 were approved by each of the Company's respective state jurisdictions during the last depreciation study.

2 The columns labeled "Balance" are the amount of investment physically located in each state.

3 The plant balance is updated each month as new plant is added.

4 The balances to be reported in the columns labeled "Balances" in any update are the weighted 13-month average balances for the rate year.

5 "Company Rate" shows the depreciation rate approved by all of the jurisdictions on a total company basis.

6 Unclassified Transmission represents the transmission additions placed in service but not yet classified to a FERC level account. Monthly depreciation is calculated by multiplying the month's beginning unclassified balance by the monthly transmission composite depreciation rate.

7 Unclassified General represents the general plant additions placed in service but not yet classified to a FERC level account. Monthly depreciation is calculated by multiplying the month's beginning unclassified balance by the monthly state general plant composite depreciation rate.

8 Transfers into the General amortized accounts (rows 15 through 20, 22, and 23) are depreciated over the remaining life based on the account life.

9 Depreciation expense for General plant is decreased by the amount that is billed to joint owners for computer hardware.

10 Intangible and Leasehold Improvements (rows 25 through 27) are composite rates based on the 13 month average balance divided into the 2011 amortization expense for each account.

11 Amortization expense for Intangible is decreased by the amount that is billed to joint owners for computer software.

12 If the depreciation rates shown differ from the depreciation rates used to calculate the depreciation expense reported in FN1, then PacifiCorp is required to file under Section 205 for a modification of this Attachment or the calculation of depreciation expense and accumulated depreciation under this formula

Appendix 19

Populated Formula
(Actual 2010 Data)

ATTACHMENT H-1
PacifiCorp
Appendix A - Formula Rate

	Shaded cells are inputs	Notes	Reference (FERC Form 1 reference, attachment, or instruction)	2010 data Projection
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		354.21b	21,424,172
2	Total Wages Expense		354.28b	352,150,935
3	Less A&G Wages Expense		354.27b	39,620,131
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	312,530,804
5	**Wages & Salary Allocator**		(Line 1 / Line 4)	**6.8551%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note M)	Attachment 5	21,775,587,040
7	Accumulated Depreciation (Total Electric Plant)	(Note M)	Attachment 5	6,893,664,705
8	Accumulated Amortization	(Note N)	Attachment 5	471,575,613
9	Total Accumulated Depreciation		(Line 7 + 8)	7,365,240,318
10	Net Plant		(Line 6 - Line 9)	14,410,346,722
11	Transmission Gross Plant (excluding Land Held for Future Use)		(Line 24 - Line 23)	4,613,500,986
12	**Gross Plant Allocator**		(Line 11 / Line 6)	**21.1866%**
13	Transmission Net Plant (excluding Land Held for Future Use)		(Line 32 - Line 23)	3,377,718,373
14	**Net Plant Allocator**		(Line 13 / Line 10)	**23.4395%**
	Plant Calculations			
	Plant In Service			
15	Transmission Plant In Service	(Note M)	Attachment 5	4,339,114,233
16	New Transmission Plant Additions for Current Calendar Year (weighted by months in service)	(Notes A & P)	Attachment 6	133,083,444
17	**Total Transmission Plant**		(Line 15 + Line 16)	**4,472,197,677**
18	General Plant	(Note N)	Attachment 5	1,213,647,890
19	Intangible Plant	(Note N)	Attachment 5	847,651,696
20	Total General and Intangible Plant		(Line 18 + Line 19)	2,061,299,586
21	Wage & Salary Allocator		(Line 5)	6.8551%
22	General and Intangible Allocated to Transmission		(Line 20 * Line 21)	141,303,309
23	**Land Held for Future Use**	(Notes B & L)	Attachment 5	**721,048**
24	**Total Plant In Rate Base**		(Line 17 + Line 22 + Line 23)	**4,614,222,035**

ATTACHMENT H-1
PacifiCorp
Appendix A - Formula Rate

	Shaded cells are inputs	Notes	Reference (FERC Form 1 reference, attachment, or instruction)	2010 data Projection
	Accumulated Depreciation and Amortization			
25	Transmission Accumulated Depreciation	(Note M)	Attachment 5	**1,172,814,664**
26	Accumulated General Depreciation	(Note N)	Attachment 5	446,986,081
27	Accumulated Amortization	(Note N)	(Line 8)	471,575,613
28	Accumulated General and Intangible Depreciation		(Line 26 + 27)	918,561,694
29	Wage & Salary Allocator		(Line 5)	6.8551%
30	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line 28 * Line 29)	62,967,949
31	**Total Accumulated Depreciation and Amortization**		Line 25 + Line 30)	**1,235,782,613**
32	**Total Net Property, Plant & Equipment**		(Line 24 - Line 31)	**3,378,439,422**
	Adjustments To Rate Base			
	Accumulated Deferred Income Taxes			
33	ADIT net of FASB 106 and 109		Attachment 1A	**(710,356,600)**
	CWIP for Incentive Transmission Projects			
34	CWIP Balances for Current Rate Year	(Note O)	Attachment 6	**0**
	ITC Adjustment			
35	IRC 46(f)1 adjustment		Attachment 5	**(1,519,350)**
	Unfunded Reserves			
36	Unfunded Reserves		Attachment 16	**(8,704,056)**
	Prepayments			
37	Prepayments	(Note K & N)	Attachment 11	**5,557,822**
	Abandoned Plant			
38	Unamortized Abandoned Plant	(Note O)		0
	Materials and Supplies			
39	Undistributed Stores Expense	(Note N)	Attachment 5	0
40	Wage & Salary Allocator		(Line 5)	6.8551%
41	Total Undistributed Stores Expense Allocated to Transmission		(Line 39 * Line 40)	0
42	Construction Materials & Supplies	(Note N)	Attachment 5	71,053,270
43	Wage & Salary Allocator		(Line 5)	6.8551%
44	Construction Materials & Supplies Allocated to Transmission		(Line 42 * Line 43)	4,870,744
45	Transmission Materials & Supplies	(Note N)	Attachment 5	718,031
46	**Total Materials & Supplies Allocated to Transmission**		(Line 41 + Line 44 + Line 45)	**5,588,775**
	Cash Working Capital			
47	Operation & Maintenance Expense		(Line 75)	64,059,769
48	1/8th Rule	(Note S)	1/8	12.5%
49	**Total Cash Working Capital Allocated to Transmission**		(Line 47 * Line 48)	**8,007,471**
	Network Upgrade Balance			
50	Network Upgrade Balance	(Note N)	Attachment 5	**(56,747,138)**
51	**Total Adjustment to Rate Base**		(Lines 33 + 34 + 35 + 36 + 37 + 38 + 46 + 49 + 50)	**(758,173,076)**
52	**Rate Base**		(Line 32 + Line 51)	**2,620,266,346**

ATTACHMENT H-1
PacifiCorp
Appendix A - Formula Rate

	Shaded cells are inputs	**Notes**	**Reference** (FERC Form 1 reference, attachment, or instruction)	**2010 data** Projection
	Operations & Maintenance Expense			
	Transmission O&M			
53	Transmission O&M		Attachment 5	195,628,269
54	Less: Cost of Providing Ancillary Services Accounts 561.0-5		Attachment 5	9,314,516
55	Less: Account 565		Attachment 5	136,854,649
56	**Transmission O&M**		(Lines 53 - 55)	**49,459,104**
	Allocated Administrative & General Expenses			
57	Total A&G		323.197b	146,076,484
58	Less Actual PBOP Expense Adjustment		Attachment 5	0
59	Less Property Insurance Account 924		323.185b	23,341,430
60	Less Regulatory Asset Amortizations Account 930.2		Attachment 5	2,450,460
61	Less Regulatory Commission Exp Account 928	(Note D)	323.189b	17,926,840
62	Less General Advertising Exp Account 930.1		323.191b	20,382
63	Less Membership Dues	(Note C)	Attachment 5	579,651
64	Administrative & General Expenses		(Line 57 - Sum (Lines 58 to 63)	101,757,721
65	Wage & Salary Allocator		(Line 5)	6.8551%
66	**Administrative & General Expenses Allocated to Transmission**		(Line 64 * Line 65)	**6,975,552**
	Directly Assigned A&G			
67	Regulatory Commission Exp Account 928	(Note E)	Attachment 5	2,679,863
68	General Advertising Exp Account 930.1 - Safety-related Advertising		Attachment 5	0
69	**Subtotal - Accounts 928 and 930.1 - Transmission Related**		(Line 67 + Line 68)	**2,679,863**
70	Property Insurance Account 924	(Note F)	Attachment 5	23,341,430
71	General Advertising Exp Account 930.1 - Education and Outreach		Attachment 5	0
72	Total Accounts 924 and 930.1 - General		(Line 70 + Line 71)	23,341,430
73	Gross Plant Allocator		(Line 12)	21.1866%
74	**A&G Directly Assigned to Transmission**		(Line 72 * Line 73)	**4,945,249**
75	**Total Transmission O&M**		(Lines 56 + 66 + 69 + 74)	**64,059,769**
	Depreciation & Amortization Expense			
	Depreciation Expense			
76	Transmission Depreciation Expense Including Amortization of Limited Term Plant	(Note H)	Attachment 5	**71,678,696**
77	General Depreciation Expense Including Amortization of Limited Term Plant	(Note H)	Attachment 5	37,247,165
78	Intangible Amortization	(Note H)	Attachment 5	31,747,938
79	Total		(Line 77 + Line 78)	68,995,103
80	Wage & Salary Allocator		(Line 5)	6.8551%
81	**General Depreciation and Intangible Amortization Functionalized to Transmission**		(Line 79 * Line 80)	**4,729,655**
82	Abandoned Plant Amortization	(Note O)		0
83	**Total Transmission Depreciation & Amortization**		(Lines 76 + 81 + 82)	**76,408,351**
	Taxes Other Than Income			
84	**Taxes Other than Income Taxes**		Attachment 2	**23,546,254**
85	**Total Taxes Other than Income Taxes**		(Line 84)	**23,546,254**

ATTACHMENT H-1
PacifiCorp
Appendix A - Formula Rate

	Shaded cells are inputs	Notes	Reference (FERC Form 1 reference, attachment, or instruction)		2010 data Projection
	Return \ Capitalization Calculations				
	Long-Term Debt				
86	Account 221 Bonds		Attachment 14		6,368,973,308
87	Less Account 222 Reaquired Bonds		Attachment 14		0
88	Account 223 Long-term Advances from Associated Cos.		Attachment 14		0
89	Account 224 Other Long-term Debt		Attachment 14		0
90	**Gross Proceeds Outstanding Long-term Debt**		Sum Lines 86 through 89		**6,368,973,308**
91	Less Account 226 Unamortizedized Discount	(Note T)	Attachment 14		14,897,359
92	Less Account 181 Unamortizedized Debt Expense	(Note T)	Attachment 14		34,639,691
93	Less Account 189 Unamortizedized Loss on Reaquired Debt	(Note T)	Attachment 14		12,567,578
94	Plus Account 225 Unamortizedized Premium	(Note T)	Attachment 14		34,204
95	Plus Account 257 Unamortizedized Gain on Reaquired Debt	(Note T)	Attachment 14		0
96	**Net Proceeds Long Term Debt**		Sum Lines 90 through 95		**6,306,902,884**
	Long Term Debt Cost				
97	Accounts 427 and 430 Long Term Interest Expense	(Notes R & T)	Attachment 14		363,203,396
98	Less Hedging Expense	(Note R)	Attachment 14		0
99	Account 428 Amortized Debt Discount and Expense	(Note T)	Attachment 14		3,727,614
100	Account 428.1 Amortized Loss on Reaquired Debt	(Note T)	Attachment 14		2,331,323
101	Less Account 429 Amortized Premium	(Note T)	Attachment 14		2,718
102	Less Account 429.1 Amortized Gain on Reaquired Debt	(Note T)	Attachment 14		0
103	**Total Long Term Debt Cost**		Sum Lines 97 through 102		**369,259,615**
	Preferred Stock and Dividend				
104	Account 204 Preferred Stock Issued		Attachment 14		41,013,946
105	Less Account 217 Reaquired Capital Stock (preferred)		Attachment 14		0
106	Account 207 Premium on Preferred Stock		Attachment 14		0
107	Account 207-208 Other Paid-In Capital (preferred)		Attachment 14		0
108	Less Account 213 Discount on Capital Stock (preferred)		Attachment 14		0
109	Less Account 214 Capital Stock Expense (preferred)		Attachment 14		184,901
110	**Total Preferred Stock**		Sum Lines 104 through 109		**40,829,045**
111	**Preferred Dividend**		Attachment 14	(Enter positive)	**2,058,333**
	Common Stock				
112	Proprietary Capital		Attachment 14		6,993,016,380
113	Less: Total Preferred Stock		(Line 110)		40,829,045
114	Less: Account 216.1 Unappropriated Undistributed Subsidiary Earnings		Attachment 14		132,098,350
115	Less: Account 219		Attachment 14		(2,374,513)
116	**Total Common Stock**		Sum Lines 112 through 115		**6,822,463,498**

ATTACHMENT H-1
PacifiCorp
Appendix A - Formula Rate

Shaded cells are inputs			Notes	Reference (FERC Form 1 reference, attachment, or instruction)	2010 data Projection
117	Debt percent	Total Long Term Debt	(Notes Q & R)	(Line 90 / (Lines 90 + 110 +116))	48.13%
118	Preferred percent	Preferred Stock		(Line 110 / (Lines 90 + 110 +116))	0.31%
119	Common percent	Common Stock	(Notes Q & R)	(Line 116 / (Lines 90 + 110 +116))	51.56%
120	Debt Cost	Long Term Debt Cost = Long Term Debt Cost / Net Proceeds Long Term Debt		(Line 103 / Line 96)	5.85%
121	Preferred Cost	Preferred Stock cost = Preferred Dividends / Total Preferred Stock		(Line 111 / Line 110)	5.04%
122	Common Cost	Common Stock	(Note H)	Fixed	9.80%
123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 117 * Line 120)	2.82%
124	Weighted Cost of Preferred	Preferred Stock		(Line 118 * Line 121)	0.02%
125	Weighted Cost of Common	Common Stock		(Line 119 * Line 122)	5.05%
126	**Rate of Return on Rate Base (ROR)**			(Sum Lines 123 to 125)	**7.89%**
127	**Investment Return = Rate Base * Rate of Return**			(Line 52 * Line 126)	**206,645,494**

Composite Income Taxes

	Income Tax Rates				
128	FIT = Federal Income Tax Rate		(Note G)		35.00%
129	SIT = State Income Tax Rate or Composite		(Note G)	Attachment 5	4.54%
130	p	(percent of federal income tax deductible for state purposes)		Per state tax code	0.00%
131	T	T = 1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			37.951%
132	T / (1-T)				61.163%
	ITC Adjustment				
133	Amortized Investment Tax Credit - Transmission Related			Attachment 5	(439,305)
134	**ITC Adjust. Allocated to Trans. - Grossed Up**	ITC Adjustment x 1 / (1-T)		Line 133 * (1 / (1 - Line 131))	**(707,996)**
135	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =		[Line 132 * Line 127 * (1- (Line 123 / Line 126))]	**81,227,279**
136	**Total Income Taxes**			(Line 134 + Line 135)	**80,519,282**

ATTACHMENT H-1
PacifiCorp
Appendix A - Formula Rate

Shaded cells are inputs		Notes	Reference (FERC Form 1 reference, attachment, or instruction)	2010 data Projection
Revenue Requirement				
	Summary			
137	Net Property, Plant & Equipment		(Line 32)	3,378,439,422
138	Total Adjustment to Rate Base		(Line 51)	(758,173,076)
139	Rate Base		(Line 52)	2,620,266,346
140	Total Transmission O&M		(Line 75)	64,059,769
141	Total Transmission Depreciation & Amortization		(Line 83)	76,408,351
142	Taxes Other than Income		(Line 85)	23,546,254
143	Investment Return		(Line 127)	206,645,494
144	Income Taxes		(Line 136)	80,519,282
145	**Gross Revenue Requirement**		(Sum Lines 140 to 144)	**451,179,151**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
146	Transmission Plant In Service		(Line 15)	4,339,114,233
147	Excluded Transmission Facilities	(Note J)	Attachment 15	211,943,759
148	Included Transmission Facilities		(Line 146 - Line 147)	4,127,170,474
149	Inclusion Ratio		(Line 148 / Line 146)	95.12%
150	Gross Revenue Requirement		(Line 145)	451,179,151
151	**Adjusted Gross Revenue Requirement**		(Line 149 * Line 150)	**429,141,334**
	Revenue Credits			
152	**Revenue Credits**		Attachment 3	**118,301,331**
153	**Net Revenue Requirement**		(Line 151 - Line 152)	**310,840,003**
	Net Plant Carrying Charge			
154	Gross Revenue Requirement		(Line 150)	451,179,151
155	Net Transmission Plant		(Line 17 - Line 25 + Line 34)	3,299,383,013
156	Net Plant Carrying Charge		(Line 154 / Line 155)	13.6747%
157	Net Plant Carrying Charge without Depreciation		(Line 154 - Line 76) / Line 155	11.5022%
158	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 154 - Line 76 - Line 127 - Line 136) / Line 155	2.7986%
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE			
159	Gross Revenue Requirement Less Return and Taxes		(Line 150 - Line 143 - Line 144)	164,014,374
160	Increased Return and Taxes		Attachment 4	308,937,746
161	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 159 + Line 160)	472,952,120
162	Net Transmission Plant		(Line 17 - Line 25 + Line 34)	3,299,383,013
163	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 161 / Line 162)	14.3346%
164	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation		(Line 161 - Line 76) / Line 162	12.1621%
165	**Net Revenue Requirement**		(Line 153)	310,840,003
166	Facility Credits under Section 30.9 of the OATT		Attachment 5	0
167	Transmission Incentive Credit		Attachment 7	2,645,210
168	Interest on Network Upgrade Facilities		Attachment 5	1,916,565
169	**Net Zonal Revenue Requirement**		(Line 165 + 166 + 167 + 168)	315,401,778
	Network Service Rate			
170	12 CP Monthly Peak (MW)	(Note I)	Attachment 9a/9b	**14,866**
171	Rate ($/MW-year)		(Line 169 / 170)	**21,217**
172	**Network Service Rate** ($/MW-year)		(Line 171)	**21,217**

Shaded cells are inputs	**Notes**	**Reference** (FERC Form 1 reference, attachment, or instruction)	**2010 data** Projection

Notes

A Line 16 includes New Transmission Plant to be placed in service in the current calendar year. Projected capital additions will include only the capital costs associated with plant expected to be energized and placed in service (as defined by the Uniform System of Accounts) in that month. The True-Up Adjustment will reflect the actual date the plant was energized and placed in service.

B Includes Transmission portion only.

C Annual membership dues (e.g., for EPRI, NEETRAC, SEPA and NCTA) are excluded from the calculation of the ATRR and charges under the Formula Rate and are subtracted from Total A&G. Total A&G does not include lobbying expenses.

D Includes all Regulatory Commission Expenses.

E Includes Regulatory Commission Expenses directly related to transmission service.

F Property Insurance excludes prior period adjustment in the first year of the formula's operation and reconciliation for the first year.

G The calculation of the Reconciliation revenue requirement according to Step 7 of Attachment 6 ("Estimate and Reconciliation Worksheet") shall reflect the actual tax rates in effect for the Rate Year, as defined in Attachment H-2, being reconciled ("Test Year"). When statutory marginal tax rates change during such Test Year, the effective tax rates used in the formula shall be weighted by the number of days each such rate was in effect. For example, a 35% rate in effect for 120 days superseded by a 40% rate in effect for the remainder of the year will be calculated as: ((.3500 x 120) + (.4000 x 245))/365 = .3836.

H No change in ROE will be made absent a filing at FERC.
PBOP expense is fixed until changed as the result of a filing at FERC.
Depreciation rates shown in Attachment 8 are fixed until changed as the result of a filing at FERC.

I The 12 CP monthly peak is the average of the 12 monthly system peaks calculated as the Network customers Monthly Network Load (Section 34.2 of the OATT) plus the reserve capacity of all long term firm point-to-point customers.

J Amount of transmission plant excluded from rates per Attachment 5.

K Adjustment reflects exclusion of tax receivables due to 2008 NOLs, which resulted in MidAmerican Energy Holdings Company delivering refund to PacifiCorp.

L Any gain from the sale of land included in Land Held for Future Use in the Formula Rate received during the Rate Year, as defined in Attachment H-2, shall be used to reduce the ATRR in the Rate Year. The Formula Rate shall not include any losses on sales of such land.

M The Update uses end of year balances and the True-up uses 13 monthly averages shown on Attachment 5.

N The Update uses end of year balances and the True-up uses the average of beginning of year and end of year balances shown on Attachments.

O Placeholder that is zero until PacifiCorp receives authorization by FERC to include amounts.

P Projected capital additions will include only the capital costs associated with plant expected to be energized and placed in service (as defined by the Uniform System of Accounts) in that month. The True-Up Adjustment will reflect the actual date the plant was energized and placed in service.

Q The equity ratio is capped at 53%, and if the actual equity ratio exceeds 53%, then the debt ratio will be equal to 1 minus the preferred stock ratio minus 53%.

R PacifiCorp will include only the gains and losses on interest rate locks for new debt issuances. Attachment 14 – Cost of Capital Detail will list the unamortized balance and annual amortization for all gains and losses on hedges.

S PacifiCorp shall use FERC's 1/8th method for cash working capital subject to the following limitations:
(a) PacifiCorp shall be required to file a lead-lag study justifying the appropriate cash working capital allowance to be effective, subject to refund, as of June 1, 2014; provided, however, that if PacifiCorp does not file a study in the time required, the amount of cash working capital allowance includable in the calculation of the ATRR under the Formula shall be zero dollars ($0.00) as of June 1, 2014, and shall remain at zero until such time as the Commission, in response to a PacifiCorp filing of a lead-lag study, authorizes a cash working capital allowance;
(b) PacifiCorp shall provide a draft to the other Parties of any such lead-lag study at least sixty (60) days prior to making any filing described in (a) with the Commission; and
(c) Filing of the lead-lag study in (a) above, but not any subsequent filing affecting or relating to PacifiCorp's cash working capital allowance as permitted in subsection (a) above, may be a single issue FPA Section 205 filing.

T These line items will include only the balances associated with long-term debt and shall exclude balances associated with short-term debt.

PacifiCorp

Appendix B - Schedule 1: Scheduling, System Control and Dispatch Service

Calculated from historical data--no true-up

Line	Description	FERC Form 1 page # / Reference	Amount
1	(561.1) Load Dispatch-Reliability	pg. 321.85b	0
2	(561.2) Load Dispatch-Monitor and Operate Transmission System	pg. 321.86b	7,794,035
3	(561.3) Load Dispatch-Transmission Service and Scheduling	pg. 321.87b	0
4	(561.4) Scheduling, System Control and Dispatch Services	pg. 321.88b	0
5	(561.5) Reliability, Planning and Standards Development	pg. 321.89b	984,307
6	Total 561 Costs for Schedule 1 Annual Revenue Requirement	(Sum Lines 1 through 5)	8,778,342
7	Schedule 1 Annual Revenue Requirement	(Line 6)	8,778,342
	Schedule 1 - Rate Calculations		
8	Average 12-Month Demand - Current Year (kW)	Divisor	14,599,833
9	Rate in $/kW - Yearly	(Line 7 / Line 8)	0.601
10	Rate in $/kW - Monthly	((Line 7 / Line 8) / 12)	0.050
11	Rate in $/kW - Weekly	((Line 7 / Line 8) / 52)	0.012
12	Rate in $/kW - Daily On-Peak	(Line 11 / 5)	0.002
13	Rate in $/kW - Daily Off-Peak	(Line 11 / 7)	0.002
14	Rate in $/MW - Hourly On-Peak	((Line 12 / 16) * 1000)	0.145
15	Rate in $/MW - Hourly Off-Peak	((Line 13 / 24) * 1000)	0.069

PacifiCorp
OATT Transmission Rate Formula Template Using Form 1 Data
Summary of Rates

Line	Description	Reference	Amount
1	Adjusted Gross Revenue Requirement	Appendix A, Line 151	$429,141,334
	Revenue Credits:		
2	Acct 454 - Allocable to Transmission	Attachment 3, Line 6	$5,555,728
3	Acct 456 - Allocable to Transmission	Attachment 3, Line 12	$112,745,603
4	Total Revenue Credits	Line 2 + Line 3	$118,301,331
5	Interest on Network Upgrades	Attachment 5	$1,916,565
6	Transmission Incentive Credit	Attachment 7	$2,645,210
7	Annual Transmission Revenue Requirement	Line 1 - Line 4 + Line 5 + Line 6	$315,401,778
8	Divisor - 12 Month Average Transmission Peak (MW)	Appendix A, Line 170	14,866
	Rates:		
9	Transmission Rate ($/kW-year)	Line 7 / Line 8 / 1000	$21.216822
10	Transmission Rate ($/kW-month)	Line 9 / 12 months	$1.768069
11	Weekly Firm/Non-Firm Rate ($/kW-week)	Line 9 / 52 weeks	$0.408016
	Daily Firm/Non-Firm Rates:		
12	On-Peak Days ($/kW)	Line 11 / 5 days	$0.081603
13	Off-Peak Days ($/kW)	Line 11 / 7 days	$0.058288
	Non-Firm Hourly Rates:		
14	On-Peak Hours ($/MWh)	Line 12 / 16 hours * 1000	$5.100198
15	Off-Peak Hours ($/MWh)	Line 13 / 24 hours * 1000	$2.428666

PacifiCorp
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet
Beginning of Current Year

Line	Description	Reference	Transmission related	Plant related	Labor related	Total Transmission ADIT	
	(A)	(B)	(C)	(D)	(E)	(F)	
1	ADIT- 282	Sch. 282 Below	0	0	0		
2	ADIT-281	Sch. 281 Below	0	0	0		
3	ADIT-283	Sch. 283 Below	0	0	0		
4	ADIT-190	Sch. 190 Below	0	0	0		
5	**Subtotal ADIT**	Sum (Lines 1 to 4)	0	0	0		
6	Allocator (100% Transmission; Net Plant; Wages & Salary)	Appendix A	100.0000%	23.4395%	6.8551%		
7	**Sub-total Transmission Related ADIT**	Line 5 * Allocator	0	0	0		
8	**Total Transmission ADIT**	Sum Cols. (C), (D), (E)				0	Attachment 1a input

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-F and each separate ADIT item will be listed, dissimilar items with amounts exceeding $100,000 will be listed separately.

A		B	C	D	E	F	G
Schedule ADIT-190		**Total**	**Gas, Prod, Dist Or Other Related**	**Transmission Related**	**Plant Related**	**Labor Related**	**Justification**
Account 190							
Subtotal - p234		0	0	0	0	0	
Less FASB 109 Above if not separately removed							
Less FASB 106 Above if not separately removed							
Total		0	0	0	0	0	

Instructions for Account 190:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

PacifiCorp

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A		B	C	D	E	F	G
Schedule ADIT-281		**Total**	**Gas, Prod, Dist Or Other Related**	**Transmission Related**	**Plant Related**	**Labor Related**	**Justification**
Account 281							
Subtotal - p275		0	0	0	0	0	
Less FASB 109 Above if not separately removed							
Less FASB 106 Above if not separately removed							
Total		0	0	0	0	0	

Instructions for Account 282:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

PacifiCorp

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
Schedule ADIT-282	**Total**	**Gas, Prod, Dist Or Other Related**	**Transmission Related**	**Plant Related**	**Labor Related**	**Justification**
Account 282						
Subtotal - p275	0	0	0	0	0	
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed						
Total	0	0	0	0	0	

Instructions for Account 282:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

A

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
Schedule ADIT-283	**Total**	**Gas, Prod, Dist Or Other Related**	**Transmission Related**	**Plant Related**	**Labor Related**	**Justification**
Account 283						
Subtotal - p277	0	0	0	0	0	
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed						
Total	0	0	0	0	0	

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

PacifiCorp

Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet

End of Current Year for Projection and Average of Beginning and End of Current Year for True-up

Line	Description (A)	Reference (B)	Total Company	Gas, Prod., Dist., or Other	Transmission Related (C)	Plant Related (D)	Labor Related (E)	Total Transmission ADIT (F)
1	ADIT-282	Sch. 282 Below	(3,994,287,475)	(3,078,949,781)	(701,969,145)	26,992,729	(240,361,278)	
2	ADIT-281	Sch. 281 Below	(11,642,708)	(11,642,708)	0	0	0	
3	ADIT-283	Sch. 283 Below	(510,315,958)	(502,827,920)	0	(7,448,212)	(39,826)	
4	ADIT-190	Sch. 190 Below	557,626,580	535,442,034	2,136,751	0	20,047,795	
5	Subtotal ADIT	Sum (Lines 1 to 4)	(3,958,619,561)	(3,057,978,375)	(699,832,394)	19,544,517	(220,353,309)	
6	Allocator (100% Transmission; Net Plant; Wages & Salary)	Appendix A			100.0000%	23.4395%	6.8551%	
7	Sub-total Transmission Related ADIT	Line 5 * Allocator			(699,832,394)	4,581,144	(15,105,350)	
8	Total End of Year Transmission ADIT	Sum Cols. (C), (D), (E)						(710,356,600)
9	Beginning of Year Total (Attachment 1)				0	0	0	0
10	**Appendix A, line 33 input**	Line 8 for Projection and average of Lines 8 & 9 for True-Up						**(710,356,600)**

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-F and each separate ADIT item will be listed, dissimilar items with amounts exceeding $100,000 will be listed separately.

Schedule ADIT-190

Description			A Form 1 Reference	B Total Company	C Gas, Prod, Dist Or Other Related	D Transmission Related	E Plant Related	F Labor Related	G Justification
Account 190									
Employee Benefits									
287323	505.400	Bonus Liability - Electric - Cash Basis (2.5 months)		9,799	0	0	0	9,799	Book accruals recorded for incentive plan.
287324	720.200	Deferred Compensation Accrual - Cash Basis		3,736,452	0	0	0	3,736,452	Non-qualified deferred compensation plan.
287326	720.500	Severance Accrual - Cash Basis		10,305	0	0	0	10,305	Severance accruals related to regular employment downsizing.
287327	720.300	Pension / Retirement Accrual - Cash Basis		890,726	890,726	0	0	0	Accrued retiree payment obligations.
287332	505.600	Vacation Accrual - Cash Basis (2.5 months)		14,711,500	0	0	0	14,711,500	Book accruals recorded for unused vacation and sick leave due to employees in future periods or upon termination.
287413	720.550	Accrued CIC Severance		(9,805)	0	0	0	(9,805)	Change in control severance accruals.
287460	720.800	FAS 158 Pension Liability		73,571,917	73,571,917	0	0	0	Total unfunded pension liability as required under FAS 158.
287461	720.810	FAS 158 Post-Retirement Liability		72,988,785	72,988,785	0	0	0	Total unfunded Other Post-Employment Benefit Obligation liability as required under FAS 158.
287462	720.820	FAS 158 SERP Liability		21,204,912	21,204,912	0	0	0	Total Supplemental Executive Retirement Plan obligations, as required by FAS 158.
FAS 133 Derivatives:									
287336	730.120	FAS 133 Derivatives - noncurrent		148,039,717	148,039,717	0	0	0	Unrealized derivative gains and losses under FASB Statement No. 133 which requires that certain financial instruments be valued at FMV for book purposes.

Description		Form 1 Reference (A)	Total Company (B)	Gas, Prod, Dist Or Other Related (C)	Transmission Related (D)	Plant Related (E)	Labor Related (F)	Justification (G)
287434	730.110	FAS 133 Derivatives - Current	36,470,107	36,470,107	0	0	0	Unrealized derivative gains and losses under FASB Statement No. 133 which requires that certain financial instruments be valued at FMV for book purposes.
Regulatory Liabilities:								
287262	100.100	Regulatory Liability - FAS 109 ITC Amortization	6,782,550	6,782,550	0	0	0	Income tax gross-up on unamortized Investment Tax Credits pursuant to IRC Subsection 46(f)(2).
287267	415.704	Regulatory Liability - Tax Revenue Adjustment - UT	18,685	18,685	0	0	0	Regulatory liability related to state retail rates.
287272	705.337	Regulatory Liability - Sale of Renewable Energy Credits - WY	1,363,981	1,363,981	0	0	0	Regulatory liability related to state retail rates.
287274	705.261	Regulatory Liability - Sale of Renewable Energy Credit - OR	1,488,506	1,488,506	0	0	0	Regulatory liability related to state retail rates.
287277	605.101	Trojan Unrecovered Plant - WA	8,721	8,721	0	0	0	Regulatory liability related to state retail rates.
287278	605.102	Trojan Unrecovered Plant - OR	2,149	2,149	0	0	0	Regulatory liability related to state retail rates.
287284	610.147	Reg Liability - Other - Balance Reclass	77,996	77,996	0	0	0	Reclass of miscellaneous regulatory assets/liabilities that have flipped to debit/credit balances.
287291	705.300	Regulatory Liability - Deferred Benefit Arch Settlement	16,800	16,800	0	0	0	Regulatory liability related to state retail rates.
287292	705.305	Regulatory Liability-CA Gain on Sale of Asset	1,425	1,425	0	0	0	Regulatory liability related to state retail rates.
287299	705.265	Regulatory Liability - OR Energy Conservation Charge	887,670	887,670	0	0	0	Regulatory liability related to state retail rates.
287304	610.146	OR Reg Asset/Liability Consolidation Account	73,103	73,103	0	0	0	Regulatory liability related to state retail rates.
287309	705.200	Oregon Gain on Sale	27,913	27,913	0	0	0	Regulatory liability related to state retail rates.
287312	105.400c	ARO Regulatory Liabilities	3,018,089	3,018,089	0	0	0	Regulatory liability used to record the depreciation/accretion associated with FAS 143 asset retirement obligations.
287314	415.700	Regulatory liability BPA Oregon balancing account	1,205,000	1,205,000	0	0	0	Regulatory liability related to state retail rates.
287316	715.720	Regulatory liability BPA Washington balancing account	562,601	562,601	0	0	0	Regulatory liability related to state retail rates.
287320	910.560	SMUD Revenue Imputation	3,443,787	3,443,787	0	0	0	Regulatory liability related to state retail rates.
287374	100.105	FAS 109 Deferred Tax Liability - WA Flow-through	920,861	920,861	0	0	0	Regulatory liability related to state retail rates.
287389	610.145	Reg Liability - DSM Balance Reclass	2,730,357	2,730,357	0	0	0	Regulatory liability related to state retail rates.
287439	415.805	RTO Grid West Notes Receivable - WY	157,154	157,154	0	0	0	Regulatory liability related to state retail rates.
287440	415.806	RTO Grid West Notes Receivable - ID	41,232	41,232	0	0	0	Regulatory liability related to state retail rates.
287441	605.100	Trojan Unrecovered Plant & Decommissioning Costs	1,912,923	1,912,923	0	0	0	Regulatory liability related to state retail rates.

Description		Form 1 Reference (A)	Total Company (B)	Gas, Prod, Dist Or Other Related (C)	Transmission Related (D)	Plant Related (E)	Labor Related (F)	Justification (G)
287442	610.135	SB 1149 Costs	371,861	371,861	0	0	0	Regulatory liability related to state retail rates.
287445	610.142	Regulatory Liability - UT Home Energy Lifeline	77,179	77,179	0	0	0	Regulatory liability related to state retail rates.
287453	610.143	Regulatory Liability - WA Low Energy Program	78,199	78,199	0	0	0	Regulatory liability related to state retail rates.
287473	705.270	Regulatory Liability-Blue Sky Program OR	237,928	237,928	0	0	0	Regulatory liability related to state retail rates.
287474	705.271	Regulatory Liability-Blue Sky Program WA	18,381	18,381	0	0	0	Regulatory liability related to state retail rates.
287475	705.272	Regulatory Liability-Blue Sky Program CA	7,020	7,020	0	0	0	Regulatory liability related to state retail rates.
287476	705.273	Regulatory Liability-Blue Sky Program UT	349,416	349,416	0	0	0	Regulatory liability related to state retail rates.
287477	705.274	Regulatory Liability-Blue Sky Program ID	918	918	0	0	0	Regulatory liability related to state retail rates.
287478	705.275	Regulatory Liability-Blue Sky Program WY	20,867	20,867	0	0	0	Regulatory liability related to state retail rates.
Other Deferred Assets:								
287263	720.861	Reserve on Pension Boilermarker Trust	1,632,957	1,632,957	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.
287264	720.860	PMI Pension Liability - Boilermarker Trust	3,265,914	3,265,914	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.
287266	920.115	Bridger Coal Company Mine Reclamation Costs	(355,885)	(355,885)	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.
287269	- - - - -	Colorado Tax Credit Carryforward	188,180	188,180	0	0	0	Colorado state income tax credit carryforward.
287270	- - - - -	Valuation Allowance	(311,743)	(311,743)	0	0	0	Valuation allowance against state tax credits that may not be realized before they expire.
287275	- - - - -	Arizona Tax Credit Carryforward	347,619	347,619	0	0	0	Arizona state income tax credit carryforward.
287276	920.107	BCC Money Market Interest Income - PMI	768	768	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.
287280	- - - - -	Net Operating Loss - State Charitable Contribution	198,857	198,857	0	0	0	Charitable contribution carryforward for state income tax purposes.
287281	- - - - -	California AMT Tax Credit Carryforward	72,208	72,208	0	0	0	California state income tax credit carryforward.
287289	425.130	Rogue River - Habitat Enhancement Liability	22,640	22,640	0	0	0	Accrued liability associated with the acceptance of the Rogue River FERC license.
287290	425.150	Lewis River Settlement Agreement	186,876	186,876	0	0	0	Accrued liability associated with the acceptance of the Lewis River FERC license.
287297	505.155	Deferred Revenue - Citibank	8,728	8,728	0	0	0	Accrued liability associated with the use of corporate credit cards.
287302	610.114	PMI EITF04-06 Pre-Stripping Cost	549,240	549,240	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.

Description		Form 1 Reference	B Total Company	C Gas, Prod, Dist Or Other Related	D Transmission Related	E Plant Related	F Labor Related	G Justification
287321	100.100	Regulatory Liability - FAS 109 ITC Amortization	12,562,792	12,562,792	0	0	0	Unamortized Investment Tax Credits pursuant to IRC Subsection 46(f)(2).
287337	715.105	MCI Fiber Optic Ground Wire Lease	211,937	211,937	0	0	0	Accrued liability for paid, but unearned lease revenue.
287338	415.110	Def Regulatory Asset-Transmission Service Deposit	877,635	0	877,635	0	0	Accrued liability for refundable cash deposits received from customers who wish to reserve transmission line services.
287339	105.400a	FAS 143 ARO Liability	37,497,233	37,497,233	0	0	0	Asset Retirement Obligation liability accrued pursuant to FASB Statement No. 143.
287340	220.100	Bad Debts Allowance - Cash Basis	3,844,158	3,844,158	0	0	0	Accrued liability established to reserve for accounts receivable for which collection is not expected.
287341	910.530	Injuries and Damages Accrual - Cash Basis	3,225,456	3,225,456	0	0	0	Accrued liability established as a reserve for anticipated injury and damage expense.
287343	415.120	Def Regulatory Asset-Foote Creek Contract	215,433	0	215,433	0	0	Accrued prepayment for the use of transmission facilities.
287344	715.800	Redding Contract - Prepaid	1,043,683	0	1,043,683	0	0	Accrued prepayment for transmission services.
287345	145.030	Distribution O&M Amortization of Write-off	1,793,564	1,793,564	0	0	0	Accrued estimated liability for distribution projects that are estimated to not be recovered.
287349	505.100	Energy West Accrued Liabilities	444,611	444,611	0	0	0	Mining Related book-tax difference: Energy West Mining Company
287354	505.150	Misc. Current and Accrued Liability	2,413,233	2,413,233	0	0	0	Miscellaneous accrued liabilities related to PacifiCorp.
287357	425.200	Other Environmental Liabilities	3,563,273	3,563,273	0	0	0	Accrued liability for estimated reserves for environmental remediation related to certain operating facilities.
287370	425.215	Unearned Joint Use Pole Contact Revenue	1,276,235	1,276,235	0	0	0	Accrued liability for prepaid rents on company owned utility poles.
287373	910.580	Wasatch workers comp reserve	1,589,544		0	0	1,589,544	Accrued liability for the expected claims related to workers compensation.
287391	425.320	Umpqua Settlement Agreement	9,680,127	9,680,127	0	0	0	Accrued liability associated with the acceptance of the North Umpqua FERC license.
287392	425.120	Bear River Settlement Agreement	5,844,523	5,844,523	0	0	0	Accrued liability associated with the acceptance of the Bear River FERC license.
287393	425.110	Tenant Lease Allow - PSU Call Center	47,212	47,212	0	0	0	Accrued liability associated with deferred revenue for construction allowances provided by a landlord for a lease of 15 years.
287399	920.150	FAS 112 Book Reserve - Postemployment Benefits	7,708,082	0	0	0	7,708,082	Accrued liability for worker's compensation benefits pursuant to FASB Statement No. 112.

Description		A Form 1 Reference	B Total Company	C Gas, Prod, Dist Or Other Related	D Transmission Related	E Plant Related	F Labor Related	G Justification
287415	205.200	Inventory Reserve	1,336,611	1,336,611	0	0	0	Accrued liability for estimated obsolete or excess inventory that will be sold for scrap.
287417	605.710	Reverse Accrued Final Reclamation	4,340,938	4,340,938	0	0	0	Accrued liability for various reclamation costs for the site reclamation of the closed mines.
287429	425.225	Duke/Hermiston Contract Renegotiation	155,170	155,170	0	0	0	Accrued liability for deferred revenue related to a gas supply contract negotiation.
287430	505.125	Accrued Royalties	2,402	2,402	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.
287431	505.160	California Public Utility Commission Fee	9,108	9,108	0	0	0	Accrued liability for monthly fee collected through customer bills awaiting quarterly remittance.
287433	425.295	BPA Conservation Rate Credit	262,659	262,659	0	0	0	Accrued liability for a now suspended program whereby the company received monthly payments from Bonneville Power Administration (BPA) for conservation and renewable projects.
287435	105.154	Section 383 Capital Loss Carryforward	37,345	37,345	0	0	0	Capital loss carryforward for income tax purposes.
287437	- - - - -	Net Operating Loss - State	57,983,785	57,983,785	0	0	0	State net operating loss carryforward for income tax purposes.
287446	205.100	Coal Pile Inventory Adjustment	1,245,069	1,245,069	0	0	0	Mining Related book-tax difference
287447	720.830	Western Coal Carrier FAS 106 Accrual	2,989,051	0	0	0	2,989,051	Accrued post-retirement liabilities pursuant to FASB Statement No. 106.
287448	505.180	Accrued Insurance Premium Tax	140,006	140,006	0	0	0	Accrued estimated liability for insurance premium taxes.
287449	- - - - -	Net Operating Loss - State - (Federal Detriment)	(20,363,925)	(20,363,925)	0	0	0	Federal income benefit for the deduction state taxes associated with state net operating loss carryforward.
287479	105.221	Cholla Safe Harbor Lease (Tax Int. - Tax Rent)	36,873,792	36,873,792	0	0	0	Book-tax difference for the Cholla generation plant safe harbor lease agreement.
287480	105.241	Malin Safe Harbor Lease (Tax Int. - Tax Rent + Book Depreciation)	1,104,319	1,104,319	0	0	0	Book-tax difference for Malin-to-Midpoint transmission safe harbor lease agreement.
287482	205.025	PMI-Fuel Cost Adjustment	1,694,719	1,694,719	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.
287483	120.105	Willow Wind Account Receivable	37,066	37,066	0	0	0	Accrued liability related to a promissory note from a retail account.
287491	- - - - -	Oregon BETC Credit Carryforward	3,231,605	3,231,605	0	0	0	Oregon state income tax credit carryforward.
287494	- - - - -	Idaho ITC Carryforward	5,430,407	5,430,407	0	0	0	Idaho state income tax credit carryforward.

	A	B	C	D	E	F	G
Description	Form 1 Reference	Total Company	Gas, Prod, Dist Or Other Related	Transmission Related	Plant Related	Labor Related	Justification
287499 - - - - - PMI Reclass Deferred Tax Assets		3,101,809	3,101,809	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.
287681 920.110 Bridger Coal Company Extraction Taxes Payable - PMI		2,888,983	2,888,983	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.
287706 610.000 Coal Mine Development - PMI		1,833,054	1,833,054	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.
287719 910.910 Bridger Coal Company Section 471 Adjustment - PMI		(606,187)	(606,187)	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.
287720 610.100 PMI Development Cost Amortization		(2,595,360)	(2,595,360)	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.
287721 610.115 PMI Overburden Removal		209,388	209,388	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.
287722 505.510 Vacation Accrual - PMI		308,565	308,565	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.
287723 205.411 Sec. 263A Inventory Change - PMI		2,072,872	2,072,872	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.
287725 920.100 Bridger Coal Company Reclamation Trust Earnings - PMI		20,385,287	20,385,287	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.
287726 105.121 Book Depreciation - PMI		47,545,746	47,545,746	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.
287726 105.126 Tax Depreciation - PMI		(79,962,763)	(79,962,763)	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.
287735 910.905 Bridger Coal Company Underground Mine Cost Depletion		(274,384)	(274,384)	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.
Rounding		2	2	0	0	0	
Subtotal - p234		588,589,916	555,708,237	2,136,751	0	30,744,928	
Less FASB 109 Above if not separately removed		20,266,203	20,266,203	0	0	0	
Less FASB 106 Above if not separately removed		10,697,133	0	0	0	10,697,133	
Total		557,626,580	535,442,034	2,136,751	0	20,047,795	

Instructions for Account 190:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula,

Description	Form 1 Reference	B Total Company	C Gas, Prod, Dist Or Other Related	D Transmission Related	E Plant Related	F Labor Related	G Justification

PacifiCorp

Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet

Schedule ADIT-281

A		B Total	C Gas, Prod, Dist Or Other Related	D Transmission Related	E Plant Related	F Labor Related	G Justification
Account 281							
Electric:							
287960	- - - - - Accelerated Pollution Control Facilities Depreciation	(11,642,708)	(11,642,708)	0	0	0	Depreciation on pollution control facilities.
Rounding		0	0	0	0	0	
Subtotal - p275		(11,642,708)	(11,642,708)	0	0	0	
Less FASB 109 Above if not separately removed		0	0	0	0	0	
Less FASB 106 Above if not separately removed		0	0	0	0	0	
Total		(11,642,708)	(11,642,708)	0	0	0	

Instructions for Account 281:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula,

Description	Form 1 Reference	Total Company	Gas, Prod, Dist Or Other Related	Transmission Related	Plant Related	Labor Related	Justification
	A	B	C	D	E	F	G

PacifiCorp

Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet

Schedule ADIT-282

A	B Total	C Gas, Prod, Dist Or Other Related	D Transmission Related	E Plant Related	F Labor Related	G Justification
Account 282						
Electric:						
287313 105.450 Non-ARO Liability - Regulatory Liability	296,327,967	296,327,967	0	0	0	Regulatory liability related to removal costs.
287605 105.100 30% Capitalized Labor Costs	18,468,374	18,468,374	0	0	0	Book-tax basis difference that is generally allocable to all property, plant and equipment.
287605 105.115 Regulatory Adjustment: Depreciation Flow-Through	(90,342,493)	(90,342,493)	0	0	0	Accounting adjustment to record the amount of tax benefits associated with fixed assets that have previously been flowed through to customers and are probable of recovery as the temporary book-tax differences reverse and result in higher taxable income as compared to book income.
287605 105.120 Book Depreciation	1,349,717,391	1,349,717,391	0	0	0	Book-tax difference that is generally allocable to all property, plant and equipment.
287605 105.122 Repair Deduction	(134,281,605)	(134,281,605)	0	0	0	Book-tax basis difference that is generally allocable to all property, plant and equipment.
287605 105.123 Sec. 481a Adjustment - Repair Deduction	(204,239,439)	(204,239,439)	0	0	0	Book-tax basis difference that is generally allocable to all property, plant and equipment.
287605 105.125 Tax Depreciation	(3,947,537,592)	(3,947,537,592)	0	0	0	Book-tax difference that is generally allocable to all property, plant and equipment.
287605 105.130 CIAC	187,886,502	187,886,502	0	0	0	Book-tax basis difference that is generally allocable to all property, plant and equipment.
287605 105.137 Capitalized Depreciation	(12,089,303)	(12,089,303)	0	0	0	Book-tax basis difference that is generally allocable to all property, plant and equipment.
287605 105.140 Reimbursements	25,920,661	25,920,661	0	0	0	Book-tax basis difference that is generally allocable to all property, plant and equipment.
287605 105.141 AFUDC	(187,467,826)	(187,467,826)	0	0	0	Book-tax basis difference that is generally allocable to all property, plant and equipment.
287605 105.142 Avoided Costs	143,869,912	143,869,912	0	0	0	Book-tax basis difference that is generally allocable to all property, plant and equipment.
287605 105.146 Capitalization of Test Energy	1,457,691	1,457,691	0	0	0	Book-tax basis difference that is generally allocable to all property, plant and equipment.
287605 105.147 §1031 Exchange	(172,941)	(172,941)	0	0	0	Book-tax difference that is generally allocable to all property, plant and equipment.

Description		A Form 1 Reference	B Total Company	C Gas, Prod, Dist Or Other Related	D Transmission Related	E Plant Related	F Labor Related	G Justification
287605	105.148	Mine Safety Sec 179E Election ~PPW	(412,943)	(412,943)	0	0	0	Book-tax basis difference that is generally allocable to all property, plant and equipment.
287605	105.152	Gain / (Loss) on Prop. Disposition	(68,239,822)	(68,239,822)	0	0	0	Book-tax difference that is generally allocable to all property, plant and equipment.
287605	105.165	Coal Mine Development	(4,647,554)	(4,647,554)	0	0	0	Book-tax basis difference that is generally allocable to all property, plant and equipment.
287605	105.170	Coal Mine Extension	(3,585,170)	(3,585,170)	0	0	0	Book-tax basis difference that is generally allocable to all property, plant and equipment.
287605	105.175	Removal Costs	(123,657,508)	(123,657,508)	0	0	0	Book-tax difference that is generally allocable to all property, plant and equipment.
287605	105.185	ADR Repair Allowance	2,163,207	2,163,207	0	0	0	Book-tax basis difference that is generally allocable to all property, plant and equipment.
287605	105.470	Book Gain/Loss on Land Sales	887,533	887,533	0	0	0	Book-tax difference that is generally allocable to all property, plant and equipment.
287605	320.210	R & E - Sec.174 Deduction	(11,524,824)	(11,524,824)	0	0	0	Book-tax difference that is generally allocable to all property, plant and equipment.
287605	- - - - -	Reclass to Pollution Control Facilities Depreciation	11,642,708	11,642,708	0	0	0	Reclassification of pollution controls facilities depreciation from FERC account 282 to FERC account 281.
287605		Direct Assignment: Transmission Fixed Assets	(701,969,145)		(701,969,145)	0	0	PowerTax Report #257: Transmission Book Allocation Group
287605		Direct Assignment: Intangible Fixed Assets	(59,411,315)		0	0	(59,411,315)	PowerTax Report #257: Intangible Book Allocation Group X Wage & Salary Allocator
287605		Direct Assignment: General Fixed Assets	(180,949,963)		0	0	(180,949,963)	PowerTax Report #257: General Book Allocation Group X Wage & Salary Allocator
287608	105.220b	Cholla Safe Harbor Lease (Amortization of SHL Gain)	(6,774,464)	0	0	(6,774,464)	0	Book-tax difference for the Cholla generation plant safe harbor lease agreement.
287608	105.220c	Cholla Safe Harbor Lease NOPA (Lease Amortization)	1,575,977	0	0	1,575,977	0	Book-tax difference for the Cholla generation plant safe harbor lease agreement.
287610	105.460	Non ARO - reclass to regulatory assets/liabilities	(296,327,967)	(296,327,967)	0	0	0	Regulatory liability related to removal costs.
287610	105.400d	ARO - reclass to ARO liabilities	(27,507,634)	(27,507,634)	0	0	0	Book-tax difference related to Asset Retirement Obligations recorded for book purposes pursuant to FASB Statement No. 143.
287704	105.143	Basis Intangible Difference	(1,111)	0	0	(1,111)	0	Book-tax basis difference for the capitalization of interest for income tax purposes specifically related to hydro-relicensing costs transferred to plant-in-service.
287740	110.200	Tax Percentage Depletion - Deduction	415,802	415,802	0	0	0	Mining Related book-tax difference.

Description		Form 1 Reference	B Total Company	C Gas, Prod, Dist Or Other Related	D Transmission Related	E Plant Related	F Labor Related	G Justification
287753	110.100	Book Cost Depletion - Addback	(6,538,228)	(6,538,228)	0	0	0	Mining Related book-tax difference.
287766	610.100N	Amortization NOPAs 99-00 RAR	285,939	285,939	0	0	0	Book-tax difference for the capitalization and depreciation of legal fees associated with the re-licensing of specific hyrdo generation facilities.
287771	110.205	Tax Depletion-SRC	579,379	579,379	0	0	0	Mining Related book-tax difference.
287962	105.129	Fixed Assets - State Modification	49,526,656	0	0	49,526,656	0	Tax adjustment to account for the difference between federal and state depreciation methodologies; primarily resulting from states that have not adopted bonus depreciation.
287963	105.129	Fixed Assets - State Modification (Federal Detriment)	(17,334,329)	0	0	(17,334,329)	0	Federal income tax benefit of the state tax adjustment made to account for the difference between federal and state depreciation methodologies; primarily resulting from states that have not adopted bonus depreciation.
287648	100.120	FAS 109 Deferred Tax Asset	(278,277,839)	(278,277,839)	0	0	0	Accounting adjustment to record the amount of tax benefits associated with fixed assets that have previously been flowed through to customers and are probable of recovery as the temporary book-tax differences reverse and result in higher taxable income as compared to book income.
Rounding			2	2	0	0	0	
Subtotal - p275			(4,272,565,314)	(3,357,227,620)	(701,969,145)	26,992,729	(240,361,278)	
Less FASB 109 Above if not separately removed			(278,277,839)	(278,277,839)	0	0	0	
Less FASB 106 Above if not separately removed			0	0	0	0	0	
Total			(3,994,287,475)	(3,078,949,781)	(701,969,145)	26,992,729	(240,361,278)	

Instructions for Account 282:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula,

Description	Form 1 Reference	B Total Company	C Gas, Prod, Dist Or Other Related	D Transmission Related	E Plant Related	F Labor Related	G Justification

PacifiCorp

Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet

Schedule ADIT-283

A	B Total	C Gas, Prod, Dist Or Other Related	D Transmission Related	E Plant Related	F Labor Related	G Justification
Account 283						
Regulatory Assets:						
287571 415.702 Regulatory Asset - Lake Side Liq.	(381,444)	(381,444)	0	0	0	Regulatory asset related to state retail rates.
287573 415.873 Deferred Excess Net Power Costs - WA Hydro	(1,013,298)	(1,013,298)	0	0	0	Regulatory asset related to state retail rates.
287576 430.110 Regulatory Asset Balance Reclass	(2,730,357)	(2,730,357)	0	0	0	Reclass of miscellaneous regulatory assets/liabilities that have flipped to debit/credit balances.
287577 415.820 Contra Pension Regulatory Asset MMT & CTG _OR	3,080,509	3,080,509	0	0	0	Regulatory asset related to state retail rates.
287578 415.821 Contra Pension Regulatory Asset MMT & CTG _WY	631,472	631,472	0	0	0	Regulatory asset related to state retail rates.
287579 415.822 Regulatory Asset _ Pension MMT -UT	(752,277)	(752,277)	0	0	0	Regulatory asset related to state retail rates.
287580 415.823 Contra Pension Regulatory Asset CTG - UT	2,258,576	2,258,576	0	0	0	Regulatory asset related to state retail rates.
287581 415.824 Contra Pension Regulatory Asset MMT & CTG _CA	275,307	275,307	0	0	0	Regulatory asset related to state retail rates.
287582 415.825 Contra Pension Regulatory Asset CTG - WA	772,654	772,654	0	0	0	Regulatory asset related to state retail rates.
287584 415.827 Regulatory Asset - Post -Ret MMT -OR	(586,069)	(586,069)	0	0	0	Regulatory asset related to state retail rates.
287585 415.828 Regulatory Asset - Post -Ret MMT -WY	(117,133)	(117,133)	0	0	0	Regulatory asset related to state retail rates.
287586 415.829 Regulatory Asset - Post - Ret MMT -UT	(740,248)	(740,248)	0	0	0	Regulatory asset related to state retail rates.
287588 415.831 Regulatory Asset - Post - Ret MMT -CA	(52,328)	(52,328)	0	0	0	Regulatory asset related to state retail rates.
287590 415.840 Regulatory Asset-Deferred OR Independent Evaluator Fees	(204,751)	(204,751)	0	0	0	Regulatory asset related to state retail rates.
287591 415.301 Environmental Costs - WA	246,726	246,726	0	0	0	Regulatory asset related to state retail rates.
287593 415.874 Deferred Excess Net Power Costs - WY	(6,106,109)	(6,106,109)	0	0	0	Regulatory asset related to state retail rates.
287596 415.892 Deferred Excess Net Power Costs - ID	(4,917,284)	(4,917,284)	0	0	0	Regulatory asset related to state retail rates.

Description		A Form 1 Reference	B Total Company	C Gas, Prod, Dist Or Other Related	D Transmission Related	E Plant Related	F Labor Related	G Justification
287597	415.703	Goodnoe Hills Liquidation Damages - WY	(185,486)	(185,486)	0	0	0	Regulatory asset related to state retail rates.
287614	430.100	Demand Side Management Regulatory Assets	(2,432,945)	(2,432,945)	0	0	0	Regulatory asset related to state retail rates.
287634	415.300	Environmental Clean-up Accrual	(6,704,995)	(6,704,995)	0	0	0	Regulatory asset related to state retail rates.
287635	415.500	Cholla Plant Transaction Costs-APS Amortization	(2,804,313)	(2,804,313)	0	0	0	Regulatory asset related to state retail rates.
287639	415.510	WA Disallowed Colstrip #3-Write-off	(199,720)	(199,720)	0	0	0	Regulatory asset related to state retail rates.
287640	415.680	OR Deferred Intervenor Funding Grants	(14,073)	(14,073)	0	0	0	Regulatory asset related to state retail rates.
287642	105.400b	ARO Regulatory Assets	(13,007,690)	(13,007,690)	0	0	0	Regulatory asset used to record the depreciation/accretion associated with FAS 143 asset retirement obligations.
287647	425.100	ID Deferred Intervenor Funding	(16,622)	(16,622)	0	0	0	Regulatory asset related to state retail rates.
287649	730.170	Regulatory assets - FAS 133	(184,933,427)	(184,933,427)	0	0	0	Regulatory assets established to record the effects of the accounting pursuant to FASB Statement No. 133, which requires that certain financial instruments be valued at FMV for book purposes.
287685	425.380	BPA Idaho Balancing Account	(1,019,076)	(1,019,076)	0	0	0	Regulatory asset related to state retail rates.
287728	415.800	RTO Grid West N/R Allowance for Doubtful	429,499	429,499	0	0	0	Regulatory asset related to state retail rates.
287738	320.270	Regulatory Asset - FAS 158 Pension Liability Adj.	(169,500,551)	(169,500,551)	0	0	0	Regulatory asset established to track the recoverable expenses associated with pension liability.
287739	320.280	Regulatory Asset - FAS 158 Post Ret. Liability.	(61,700,653)	(61,700,653)	0	0	0	Regulatory asset established to track the recoverable expenses associated with post-retirement benefits liability.
287747	705.240	CA-(CARE) California Alternative Rate for Energy Program	(96,389)	(96,389)	0	0	0	Regulatory asset related to state retail rates.
287760	415.896	Chehalis Plant Revenue Requirement - WA	(5,692,650)	(5,692,650)	0	0	0	Regulatory asset related to state retail rates.
287779	415.850	Unrecovered Plant-Powerdale	(735,527)	(735,527)	0	0	0	Regulatory asset related to state retail rates.
287781	415.870	Deferred Excess Net Power Costs-CA	(724,729)	(724,729)	0	0	0	Regulatory asset related to state retail rates.
287783	415.880	Deferred UT Independent Evaluation Fee	6,262	6,262	0	0	0	Regulatory asset related to state retail rates.

Description		Form 1 Reference	B Total Company	C Gas, Prod, Dist Or Other Related	D Transmission Related	E Plant Related	F Labor Related	G Justification
287784	415.900	OR SB 408 Recovery	(415,770)	(415,770)	0	0	0	Regulatory asset related to state retail rates.
287787	415.895	OR _RCAC Sep-Dec 07 Deferred	(239,074)	(239,074)	0	0	0	Regulatory asset related to state retail rates.
287789	415.804	RTO Grid West Notes Receivable - OR	27,395	27,395	0	0	0	Regulatory asset related to state retail rates.
287860	415.855	CA - January 2010 Storm Costs	(466,797)	(466,797)	0	0	0	Regulatory asset related to state retail rates.
287861	415.857	ID - Deferred Overburden Costs	(94,535)	(94,535)	0	0	0	Regulatory asset related to state retail rates.
287862	415.893	OR - MEHC Transition Service Costs	(1,126,863)	(1,126,863)	0	0	0	Regulatory asset related to state retail rates.
287864	415.852	Powerdale Decommissioning Reg Asset - ID	(115,662)	(115,662)	0	0	0	Regulatory asset related to state retail rates.
287865	415.853	Powerdale Decommissioning Reg Asset - OR	(187,105)	(187,105)	0	0	0	Regulatory asset related to state retail rates.
287866	415.854	Powerdale Decommissioning Reg Asset - WA	(323,262)	(323,262)	0	0	0	Regulatory asset related to state retail rates.
287867	415.856	Powerdale Decommissioning Reg Asset - WY	(13,052)	(13,052)	0	0	0	Regulatory asset related to state retail rates.
287868	415.858	WY - Deferred Overburden Costs	(252,712)	(252,712)	0	0	0	Regulatory asset related to state retail rates.
287869	415.859	WY Deferred Advertising Costs	(19,810)	(19,810)	0	0	0	Regulatory asset related to state retail rates.
287870	415.865	Reg Asset - Utah Major Plant Additions	(5,967,613)	(5,967,613)	0	0	0	Regulatory asset related to state retail rates.
287871	415.866	Reg Asset - OR Solar Feed-In Tariff	(86,005)	(86,005)	0	0	0	Regulatory asset related to state retail rates.
287872	720.841	Tax Adj on Post-Retirement Benefits CA	(145,516)	(145,516)	0	0	0	Regulatory asset related to state retail rates.
287873	720.842	Tax Adj on Post-Retirement Benefits ID	(311,193)	(311,193)	0	0	0	Regulatory asset related to state retail rates.
287874	720.843	Tax Adj on Post-Retirement Benefits OR	(1,697,033)	(1,697,033)	0	0	0	Regulatory asset related to state retail rates.
287875	720.844	Tax Adj on Post-Retirement Benefits UT	(2,235,788)	(2,235,788)	0	0	0	Regulatory asset related to state retail rates.
287876	720.845	Tax Adj on Post-Retirement Benefits WA	(427,553)	(427,553)	0	0	0	Regulatory asset related to state retail rates.
287877	720.846	Tax Adj on Post-Retirement Benefits WY	(814,639)	(814,639)	0	0	0	Regulatory asset related to state retail rates.
287879	415.898	Deferred Coal Costs - Naughton Contract Settlement	(3,133,585)	(3,133,585)	0	0	0	Regulatory asset related to state retail rates.
287880	415.897	Reg Asset MEHC Transition Service Costs - CA	(84,544)	(84,544)	0	0	0	Regulatory asset related to state retail rates.

Description		Form 1 Reference	Total Company (B)	Gas, Prod, Dist Or Other Related (C)	Transmission Related (D)	Plant Related (E)	Labor Related (F)	Justification (G)
287881	415.705	Reg Asset - Tax Rev Req Adj - WY	(37,934)	(37,934)	0	0	0	Regulatory asset related to state retail rates.
287882	415.876	Deferred Excess Net Power Costs - OR	(1,338,184)	(1,338,184)	0	0	0	Regulatory asset related to state retail rates.
287942	430.112	Reg Asset - Other - Balance Reclass	(77,996)	(77,996)	0	0	0	Reclass of miscellaneous regulatory assets/liabilities that have flipped to debit/credit balances.
287944	430.114	Reg Asset Federal Interest Expense~UT	(548,357)	(548,357)	0	0	0	Regulatory asset related to state retail rates.
287945	720.840	Reg Asset Tax Adj on Post Retirement Benefits - Gross	9,578	9,578	0	0	0	Regulatory asset related to state retail rates.
287947	415.501	Cholla Plant Transaction Costs - APS Amortization - ID	82,382	82,382	0	0	0	Regulatory asset related to state retail rates.
287948	415.502	Cholla Plant Transaction Costs - APS Amortization - OR	134,449	134,449	0	0	0	Regulatory asset related to state retail rates.
287949	415.503	Cholla Plant Transaction Costs - APS Amortization - WA	242,364	242,364	0	0	0	Regulatory asset related to state retail rates.
287961	430.115	Reg Asset Federal Interest Expense~WY	(141,228)	(141,228)	0	0	0	Regulatory asset related to state retail rates.
287964	100.120	FAS 109 Deferred Tax Asset	(170,202,940)	(170,202,940)	0	0	0	Deferred income tax associated with the regulatory asset related to tax benefits associated with fixed assets that have previously been flowed through to customers and are probable of recovery as the temporary book-tax differences reverse and result in higher taxable income as compared to book income.
Other:								
287575	425.125	Deferred Coal Cost - Arch Settlement	(23,919)	(23,919)	0	0	0	Mining Related book-tax difference.
287653	425.250	TGS Buyout	(53,341)	(53,341)	0	0	0	Asset accrued for a deferred expense related to costs incurred for the termination of a power purchase agreement.
287656	425.280	Joseph Settlement	(369,306)	(369,306)	0	0	0	Asset accrued for a deferred expense related to costs incurred for the termination of a power purchase agreement.
287661	425.360	Hermiston Swap	(1,666,992)	(1,666,992)	0	0	0	Asset accrued for a deferred expense related to a termination fee related to the acquisition of an interest in a generating plant.

Description		A Form 1 Reference	B Total Company	C Gas, Prod, Dist Or Other Related	D Transmission Related	E Plant Related	F Labor Related	G Justification
287662	210.100	Prepaid Taxes - OR PUC	(169,910)	(169,910)	0	0	0	Asset accrued for prepaid commission fee, amortized for book purposes over a period of 12 months or less.
287664	210.120	Prepaid Taxes - UT PUC	(637,551)	(637,551)	0	0	0	Asset accrued for prepaid commission fee, amortized for book purposes over a period of 12 months or less.
287665	210.130	Prepaid Taxes - ID PUC	(72,093)	(72,093)	0	0	0	Asset accrued for prepaid commission fee, amortized for book purposes over a period of 12 months or less.
287669	210.180	Prepaid Membership Fees	(1,431,721)	(1,431,721)	0	0	0	Asset accrued for prepaid membership fees, amortized for book purposes over a period of 12 months or less.
287675	740.100	Post Merger Loss-Reacquisition Debt - Addback	(4,344,154)	(4,344,154)	0	0	0	Asset accrued for reacquired debt, amortized for book purposes over the remaining life of the original issuance, or over the life of the new issuance if the original issuance was refinanced.
287708	210.200	Prepaid Taxes - Property Taxes	(7,448,212)	0	0	(7,448,212)	0	Book-tax difference associated with the timing of deductibility of property taxes.
287737	415.803	RTO Grid West Note Receivable - w/o - WA	(8,907)	(8,907)	0	0	0	Asset established for the recovery of costs incurred to explore the organization Grid West, an RTO (regional transmission organization).
287750	425.310	N. Umpqua Settlement Agreement	(10,226,891)	(10,226,891)	0	0	0	Intangible asset for hydroelectric obligations associated with the acceptance of FERC licenses.
287770	120.205	Trapper Mining Stock Basis	(1,272,609)	(1,272,609)	0	0	0	Mining Related book-tax difference: Trapper Mine
287772	505.800	State Tax Deduction on Fed TR	(322)	(322)	0	0	0	Book-tax difference associated with the timing of deductible state income taxes.
287859	910.935	Unrealized Gain/Loss from Trading Securities	(39,826)		0	0	(39,826)	Book-tax difference for unrealized gains and losses on deferred compensation plan investments.
287921	505.501	Federal Benefit of Federal Interest - IRHI	(675,512)	(675,512)	0	0	0	Book-tax difference associated with interest and taxes that will be incurred when cash settlement of prior exam cycles occurs.

	A	B	C	D	E	F	G
Description	Form 1 Reference	Total Company	Gas, Prod, Dist Or Other Related	Transmission Related	Plant Related	Labor Related	Justification
287922	505.502 Federal Benefit of State Interest - IRHI	19,055	19,055	0	0	0	Book-tax difference associated with interest and taxes that will be incurred when cash settlement of prior exam cycles occurs.
287923	505.805 Federal Benefit of State Tax - IRHI	(507,701)	(507,701)	0	0	0	Book-tax difference associated with interest and taxes that will be incurred when cash settlement of prior exam cycles occurs.
287924	505.503 State Benefit of Federal Interest - IRHI	(87,621)	(87,621)	0	0	0	Book-tax difference associated with interest and taxes that will be incurred when cash settlement of prior exam cycles occurs.
287925	505.504 State Benefit of State Interest - IRHI	2,469	2,469	0	0	0	Book-tax difference associated with interest and taxes that will be incurred when cash settlement of prior exam cycles occurs.
287926	505.810 Rate Diff - Federal Benefit of State Tax - IRHI	1,275,683	1,275,683	0	0	0	Book-tax difference associated with interest and taxes that will be incurred when cash settlement of prior exam cycles occurs.
287990	- - - - - PMI Deferred Tax Reclass to DTA	(3,101,809)	(3,101,809)	0	0	0	Mining Related book-tax difference: Pacific Minerals, Inc.
Rounding		13	13	0	0	0	
Subtotal - p277		(680,518,898)	(673,030,860)	0	(7,448,212)	(39,826)	
Less FASB 109 Above if not separately removed		(170,202,940)	(170,202,940)	0	0	0	
Less FASB 106 Above if not separately removed		0	0	0	0	0	
Total		(510,315,958)	(502,827,920)	0	(7,448,212)	(39,826)	

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula,

PacifiCorp
Attachment 2 - Taxes Other Than Income Worksheet

	Other Taxes	Page 263, Col (i)	Allocator	Allocated Amount
	Plant Related		Net Plant Allocator	
	Real Property	100,004,029		
	Possessory taxes	357,411		
1	**Total Plant Related**	100,361,440	23.4395%	23,524,256
	Labor Related		Wages & Salary Allocator	
	Federal FICA	0		
	Federal Unemployment	0		
	State Unemployment	0		
2	**Total Labor Related**	0	6.8551%	0
	Other Included		Net Plant Allocator	
	Annual Report	93,853		
3	**Total Other Included**	93,853	23.4395%	21,999
4	**Appendix A input: Total Included Taxes (Lines 1 + 2 + 3)**	100,455,293		**23,546,254**
	Currently Excluded			
	Local Franchise	1,150,173		
	Energy License	269,226		
	Wholesale Energy	191,815		
	KWh	26,822		
	Department of Energy	722,590		
	Franchise	23,869,222		
	Public Utility	9,832,285		
	Other (Navajo Nation, Business & Occupation, Land Use, Other)	32,198		
5	**Subtotal Excluded Taxes**	36,094,331		
6	**Total Other Taxes Included and Excluded (Line 4 + Line 5)**	136,549,624		
	Total Other Taxes			
7	114.14c	136,550,272		
8	Difference (Line 6 - Line 7)	(648)		

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant, including transmission plant, will be allocated based on the Net Plant Allocator. If the taxes are 100% recovered at retail, they shall not be included.

B Other taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. If the taxes are 100% recovered at retail, they shall not be included.

C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator.

D Other taxes, except as provided for in A, B and C above, which are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service, will be allocated based on the Net Plant Allocator; provided, however, that overheads shall be treated, as described in footnote B above.

E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year.

PacifiCorp
Attachment 3 - Revenue Credit Worksheet

Line	Description	Notes	Reference	Value
	Account 454 - Rent from Electric Property			
1	Rent from Electric Property - Transmission Related			3,551,521
2	Pole Attachments - Transmission Related			432,933
3	Distribution Underbuild - Transmission Related		*detail below*	562,077
4	Various Rents - Transmission Related			803,778
5	Miscellaneous General Revenues		*detail below*	205,419
6	**Account 454 subtotal**		(Sum Lines 1-5)	**5,555,728**
	Account 456 - Other Electric Revenues (Note 1)			
7	Transmission for Others	Note 3	Attachment 13	29,577,461
8	Net revenues associated with Network Integration Transmission Service (NITS) for which the load is not included in the divisor	Note 3		0
9	Short-term firm and non-firm service revenues for which the load is not included in the divisor received by Transmission Owner		Attachment 13	82,673,356
10	Facilities Charges including Interconnection Agreements	Note 2		0
11	Transmission maintenance revenue		Account 456.2	494,787
12	**Account 456 subtotal**		(Sum Lines 7-11)	**112,745,603**
13	Appendix A input: **Gross Revenue Credits**		(Sum Lines 6 &12)	**118,301,331**

Detail for selected items above

Miscellaneous General Revenues		
Rents - general		81,527
One Utah Center and North Temple Office leases		2,880,701
Rent revenue - CSS		34,369
Total Miscellaneous General Revenue		2,996,597
Wages & Salary Allocator		6.86%
Total Allocated Miscellaneous General Revenue		**205,419**
Distribution Underbuild		
Third party attachments		6,309
Common pole location fixed annual revenue credit	fixed	555,768
Distribution Underbuild - Transmission related		**562,077**

Notes

Note 1 All revenues related to transmission that are received as a transmission owner (i.e., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this Attachment or elsewhere in the formula, will be included as a revenue credit or included in the peak on line 170 of Appendix A.

Note 2 If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.

Note 3 If the facilities associated with the revenues are not included in the formula, the revenue is shown here, but not included in the total above and explained in the Cost Support, (e.g., revenues associated with distribution facilities).

PacifiCorp
Attachment 4 - Calculation of 100 Basis Point Increase in ROE

	Return and Taxes with 100 Basis Point increase in ROE				
A	100 Basis Point increase in ROE and Income Taxes			Appendix A input: Line 127 + Line 137 from below	308,937,746
B	100 Basis Point increase in ROE				1.00%
Return Calculation					
			Notes	**Reference** (Appendix A Line or Source)	
117	Debt percent	Total Long Term Debt	(Notes Q & R)	(Line 90 / (Lines 90 + 110 +116))	48.13%
118	Preferred percent	Preferred Stock		(Line 110 / (Lines 90 + 110 +116))	0.31%
119	Common percent	Common Stock	(Notes Q & R)	(Line 116 / (Lines 90 + 110 +116))	51.56%
120	Debt Cost	Long Term Debt Cost = Long Term Debt Cost / Net Proceeds Long Term Debt		(Line 103 / Line 96)	5.85%
121	Preferred Cost	Preferred Stock cost = Preferred Dividends / Total Preferred Stock		(Line 111 / Line 110)	5.04%
122	Common Cost	Common Stock	(Note H)	Fixed plus 100 basis points	10.80%
123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 117 * Line 120)	2.82%
124	Weighted Cost of Preferred	Preferred Stock		(Line 118 * Line 121)	0.02%
125	Weighted Cost of Common	Common Stock		(Line 119 * Line 122)	5.57%
126	**Rate of Return on Rate Base (ROR)**			(Sum Lines 123 to 125)	**8.40%**
127	**Investment Return = Rate Base * Rate of Return**			**(Line 52 * Line 126)**	**220,155,404**
Composite Income Taxes					
	Income Tax Rates				
128	FIT = Federal Income Tax Rate				35.00%
129	SIT = State Income Tax Rate or Composite				4.54%
130	p = percent of federal income tax deductible for state purposes			Per state tax code	0.00%
131	T	T = 1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			37.95%
132	CIT = T / (1-T)				61.16%
133	1 / (1-T)				161.16%
	ITC Adjustment				
134	Amortized Investment Tax Credit			Attachment 5	(439,305)
135	**ITC Adjust. Allocated to Trans. - Grossed Up**			(Line 134 * (1 / (1 - Line 131)	**(707,996)**
136	**Income Tax Component =**	CIT = (T/1-T) * Investment Return * (1-(WCLTD/R)) =			89,490,338
137	**Total Income Taxes**				**88,782,342**

PacifiCorp

Attachment 5 - Cost Support

Plant in Service Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions							Detail/notes
		Calculation of Transmission Plant In Service	Source	Footnotes	Year	Balance	
	1	December	p206.58.b		2009		
	2	January	Monthly Balances		2010		
	3	February	Monthly Balances		2010		
	4	March	Monthly Balances		2010		
	5	April	Monthly Balances		2010		
	6	May	Monthly Balances		2010		
	7	June	Monthly Balances		2010		
	8	July	Monthly Balances		2010		
	9	August	Monthly Balances		2010		
	10	September	Monthly Balances		2010		
	11	October	Monthly Balances		2010		
	12	November	Monthly Balances		2010		
	13	December	p207.58.g		2010	4,339,114,233	
15	14	**Transmission Plant In Service**	(line 13)	(Note M)	Projection	**4,339,114,233**	Appendix A input
		Calculation of Distribution Plant In Service	Source		Year	Balance	
	15	December	p206.75.b		2009		
	16	January	Monthly Balances		2010		
	17	February	Monthly Balances		2010		
	18	March	Monthly Balances		2010		
	19	April	Monthly Balances		2010		
	20	May	Monthly Balances		2010		
	21	June	Monthly Balances		2010		
	22	July	Monthly Balances		2010		
	23	August	Monthly Balances		2010		
	24	September	Monthly Balances		2010		
	25	October	Monthly Balances		2010		
	26	November	Monthly Balances		2010		
	27	December	p207.75.g		2010	5,487,299,014	
	28	**Distribution Plant In Service**	(line 27)		Projection	5,487,299,014	
		Calculation of Intangible Plant In Service	Source		Year	Balance	
	29	December	p204.5.b		2009		
	30	December	p205.5.g		2010	847,651,696	
19	31	**Intangible Plant In Service**	(line 30)	(Note N)	Projection	**847,651,696**	Appendix A input
		Calculation of General Plant In Service	Source		Year	Balance	
	32	December	p206.99.b		2009		
	33	December	p207.99.g		2010	1,213,647,890	
18	34	**General Plant In Service**	(line 33)	(Note N)	Projection	**1,213,647,890**	Appendix A input
		Calculation of Production Plant In Service	Source		Year	Balance	
	35	December	p204.46b		2009		
	36	January	Monthly Balances		2010		
	37	February	Monthly Balances		2010		
	38	March	Monthly Balances		2010		
	39	April	Monthly Balances		2010		
	40	May	Monthly Balances		2010		
	41	March	Monthly Balances		2010		
	42	April	Monthly Balances		2010		
	43	August	Monthly Balances		2010		
	44	September	Monthly Balances		2010		
	45	October	Monthly Balances		2010		
	46	November	Monthly Balances		2010		
	47	December	p205.46.g		2010	9,892,359,008	
	48	**Production Plant In Service**	(line 47)		Projection	9,892,359,008	
	49	Electric Plant Sold	p207.102.g			(4,484,801)	
6	50	**Total Plant In Service**	(sum lines 14, 28, 31, 34, 48, & 49)	(Note M)	Projection	**21,775,587,040**	Appendix A input

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Attachment 5 - Cost Support

Accumulated Depreciation Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions							Notes
		Calculation of Transmission Accumulated Depreciation	Source		Year	Balance	
	51	December	Prior year p219.25		2009		
	52	January	Monthly Balances		2010		
	53	February	Monthly Balances		2010		
	54	March	Monthly Balances		2010		
	55	April	Monthly Balances		2010		
	56	May	Monthly Balances		2010		
	57	June	Monthly Balances		2010		
	58	July	Monthly Balances		2010		
	59	August	Monthly Balances		2010		
	60	September	Monthly Balances		2010		
	61	October	Monthly Balances		2010		
	62	November	Monthly Balances		2010		
	63	December	p219.25		2010	1,172,814,664	
25	64	**Transmission Accumulated Depreciation**	(line 63)	(Note M)	Projection	**1,172,814,664**	Appendix A input
		Calculation of Distribution Accumulated Depreciation	Source		Year	Balance	
	65	December	Prior year p219.26		2009		
	66	January	Monthly Balances		2010		
	67	February	Monthly Balances		2010		
	68	March	Monthly Balances		2010		
	69	April	Monthly Balances		2010		
	70	May	Monthly Balances		2010		
	71	June	Monthly Balances		2010		
	72	July	Monthly Balances		2010		
	73	August	Monthly Balances		2010		
	74	September	Monthly Balances		2010		
	75	October	Monthly Balances		2010		
	76	November	Monthly Balances		2010		
	77	December	p219.26		2010	2,072,617,011	
	78	**Distribution Accumulated Depreciation**	(line 77)		Projection	2,072,617,011	
		Calculation of Intangible Accumulated Depreciation	Source		Year	Balance	
	79	December	Prior year p200.21.c		2009		
	80	December	p200.21c		2010	471,575,613	
8	81	**Accumulated Intangible Depreciation**	(line 80)	(Note N)	Projection	**471,575,613**	Appendix A input
		Calculation of General Accumulated Depreciation	Source		Year	Balance	
	82	December	Prior year p219.28		2009		
	83	December	p219.28		2010	446,986,081	
26	84	**Accumulated General Depreciation**	(line 83)	(Note N)	Projection	**446,986,081**	Appendix A input
		Calculation of Production Accumulated Depreciation	Source		Year	Balance	
	85	December	Prior year p219		2009		
	86	January	Monthly Balances		2010		
	87	February	Monthly Balances		2010		
	88	March	Monthly Balances		2010		
	89	April	Monthly Balances		2010		
	90	May	Monthly Balances		2010		
	91	June	Monthly Balances		2010		
	92	July	Monthly Balances		2010		
	93	August	Monthly Balances		2010		
	94	September	Monthly Balances		2010		
	95	October	Monthly Balances		2010		
	96	November	Monthly Balances		2010		
	97	December	p219.20 through 219.24		2010	3,201,246,949	
	98	**Production Accumulated Depreciation**	(line 97)		Projection	3,201,246,949	
7	99	**Accumulated Depreciation (Total Electric Plant)**	(sum lines 64, 78, 84, & 98)	(Note M)	Projection	**6,893,664,705**	Appendix A input
	100	**Total Accumulated Depreciation**	(sum lines 64, 78, 81, 84, & 98)		Projection	7,365,240,318	

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Attachment 5 - Cost Support

Materials & Supplies

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions					Form No. 1 Amount	
	Undistributed Stores Expense		Prior Year	227.16c	0	
			Current Year	227.16c	0	
39		(Note N)	**Appendix A input**	Projection	**0**	current end-of-year balance
	Construction Materials & Supplies		Prior Year	227.5c	69,236,794	
			Current Year	227.5c	71,053,270	
42		(Note N)	**Appendix A input**	Projection	**71,053,270**	current end-of-year balance
	Transmission Materials & Supplies		Prior Year	227.8c	838,582	
			Current Year	227.8c	718,031	
45		(Note N)	**Appendix A input**	Projection	**718,031**	current end-of-year balance

ITC Adjustment

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				Form No. 1 Amount	Transmission related portion	**Appendix A input**	Details
	Amortized Investment Tax Credit				Net Plant Allocator		
133	Utility Investment Tax Credit Adj. - Net (411.4)		114.19c	(1,874,204)	23.44%	**(439,305)**	
	Rate Base Adjustment						
	Internal Revenue Code (IRC) 46(f)(1) adjustment to rate base						
		Current beg of year balance	266.6b	7,294,222			
		Current end of year balance	266.6h	5,669,770			
35	Internal Revenue Code (IRC) 46(f)(1) adjustment to rate base		Average	6,481,996	23.44%	**1,519,350**	(enter negative in Appendix A)

Transmission / Non-transmission Cost Support

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions					Form No. 1 Amount	Transmission Related	Non-transmission Related	Details
	Land Held for Future Use							
			Prior Year	214.47d	13,674,549	**0**	13,674,549	Detail for transmission-related value on Attachment 12
			Current Year	214.47d	17,678,149	**721,048**	16,957,101	Detail for transmission-related value on Attachment 12
23		(Notes B & L)	**Appendix A input**	Projection		**721,048**		current end-of-year balance

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Attachment 5 - Cost Support

Adjustments to A & G Expense

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				Adjusted Total	Details
	Excluded Membership Dues Expense				
	Electric Power Research Institute		353.f	547,651	
	National Electric Energy Testing Research and Application Center		353.f	23,750	
	Solar Electric Power Association		353.f	7,000	
	National Coal Transportation Association		component of 335b	1,250	
63	Total	(Note C)	**Appendix A Input**	**579,651**	
	PBOP				
	Fixed PBOP expense		FERC Authorized	15,236,246	
	Actual PBOP expense		Attachment 17	15,236,246	
58	Adjusted total (Current year actual)		**Appendix A Input**	**0**	Authorized minus Att 17 = Current year actual PBOP expense
	Property Insurance				
	Property Insurance Account 924		323.185b	23,341,430	
70		(Note F)	**Appendix A Input**	**23,341,430**	

Regulatory Expense Related to Transmission Cost Support

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount	Transmission Related **Appendix A input**	Non-transmission Related	Details
	Directly Assigned A&G					
	Specific Transmission related Regulatory Expenses					
	Federal Energy Regulatory Commission:					
	Annual Fee	350.30d	1,917,327	1,917,327		
	Annual Land Use Fee (hydro)	350.31d	596,587		596,587	
	Transmission Rate Case	350.32d	762,536	762,536		
67	**Total**	sum	3,276,450	**2,679,863**	596,587	

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Attachment 5 - Cost Support

Safety Related Advertising Cost Support

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount	Safety Related **Appendix A Input**	Non-safety Related	Details
	Directly Assigned A&G					
68	General Advertising Exp Account 930.1 - Safety-related Advertising	323.191b	20,382	**0**	20,382	Based on FERC 930.1 download

Education and Out Reach Cost Support

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount	Education & Outreach **Appendix A Input**	Other	Details
	Directly Assigned A&G					
71	General Advertising Exp Account 930.1 - Education and Outreach	323.191b	20,382	**0**	20,382	Based on FERC 930.1 download

Multistate worksheet

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				Details
	Income Tax Rates			
129	SIT = State Income Tax Rate or Composite	(Note G)	4.54%	Enter Average State Income Tax Rate

Adjustments to Transmission O&M

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Total	Plus adjustments	Transmission Related **Appendix A input**	Details
53	**Transmission O&M**	321.112b	195,628,269	0	**195,628,269**	
	Adjustment for Ancillary Services Accounts 561-561.5					
	(561) Load Dispatching	321.84b	650,305			
	(561.1) Load Dispatch-Reliability	321.85b	0			
	(561.2) Load Dispatch-Monitor and Operate Transmission System	321.86b	7,847,328			
	(561.3) Load Dispatch-Transmission Service and Scheduling	321.87b	0			
	(561.4) Scheduling, System Control and Dispatch Services	321.88b	0			
	(561.5) Reliability, Planning and Standards Development	321.89b	816,883			
54	**Less: Cost of Providing Ancillary Services Accounts 561.0-5**	sum	9,314,516	0	**9,314,516**	Adjustment for Ancillary Services Accounts 561-561.5
55	**Less: Account 565**	321.96b	136,854,649	0	**136,854,649**	

Facility Credits under Section 30.9 of the OATT

Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Amount	Description & Documentation
	Net Revenue Requirement		
166	Facility Credits under Section 30.9 of the OATT	**0**	Appendix A Input
168	Interest on Network Upgrade Facilities	**1,916,565**	Appendix A Input

Other adjustments to rate base

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions					Amount	
	Network Upgrade Balance					
			Prior Year	Enter negative	0	
			Current Year	Enter negative	(56,747,138)	
50	Network Upgrade Balance	(Note N)	Appendix A input	Projection	**(56,747,138)**	current end-of-year balance

PacifiCorp

Attachment 5 - Cost Support

Depreciation Expense

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				Total	
	Transmission Plant				
	Depreciation expense (403)	(Note H)	336.7b	71,678,696	
	Amortization of limited term electric plant (404)	(Note H)	336.7d	0	
76	**Transmission Depreciation Expense Including Amortization of Limited Term Plant**	(Note H)	sum	**71,678,696**	Appendix A Input
	General Plant				
	Depreciation expense (403)	(Note H)	336.10b	34,325,996	
	Amortization of limited term electric plant (404)	(Note H)	336.10d	2,921,169	
77	**General Depreciation Expense Including Amortization of Limited Term Plant**	(Note H)	sum	**37,247,165**	Appendix A Input
	Intangible plant				
	Amortization of limited term electric plant (404)	(Note H)	336.1d	31,747,938	
	Amortization of other electric plant (405)	(Note H)	336.1e	0	
78	**Total Intangible Amortization**	(Note H)	sum	**31,747,938**	Appendix A Input

Less Regulatory Asset Amortizations Account 930.2

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Amount	
	Transition Plan - OR	232.8e	2,289,365	
	Glenrock Mine Excluding Reclamation - UT (9)	232 19e	112,218	
	Goodnoe Hills Settlement - WY (24)	232.1 4e	21,250	
	Lake Side Settlement - WY (38)	232.1 5e	27,627	
61	Total	sum	**2,450,460**	Appendix A Input

PacifiCorp
Attachment 6 - Estimate and Reconciliation Worksheet

Instruction Summary

Step	Month	Year	Action
1	April	Year 2	TO populates the formula with Year 1 data from FERC Form No. 1 data for Year 1 (e.g., 2010)
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2011)
3	April	Year 2	TO adds weighted Cap Adds to plant in service in Formula
4	May	Year 2	Post results of Step 3
5	June	Year 2	Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2011 - May 31, 2012)
6	April	Year 3	TO populates the formula with Year 2 data from FERC Form No. 1 for Year 2 (e.g., 2011)
7	April	Year 3	Reconciliation - actual data
8	April	Year 3	TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2012)

Worksheet

Step	Month	Year	Action
1	April	Year 2	TO populates the formula with Year 1 data from FERC Form No. 1 data for Year 1 (e.g., 2010)

$ - Rev Req based on Year 1 data — Must run Appendix A to get this number (without inputs in lines 16 or 34 of Appendix A)

Step	Month	Year	Action
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2011) in projection and populates for actuals as inputs to Attachment 7 (but not Appendix A) for true up.

Plant In Service / CWIP

	(A) Monthly Additions Other Transmission PIS (EXCLUDING GATEWAY)	(B) Monthly Additions Energy Gateway	(C) Monthly Additions Energy Gateway Segment B	(D) Monthly Additions Energy Gateway Segment C	(E) Monthly Additions Energy Gateway Segment D	(F) Monthly Additions Energy Gateway Segment E	(G) Monthly Additions Energy Gateway Segment F	(H) Monthly Additions Energy Gateway Segment G	(I) Monthly Additions Energy Gateway Segment H	(J) Monthly Additions Energy Gateway Total (Segments A-H)	CWIP (K) Monthly Additions Transmission CWIP (Gateway only)
CWIP Balance Dec (prior year)	-	-	-	-	-	-	-	-	-	-	-
Jan	15,291,338	-	1,570,431	-	-	-	-	-	-	1,570,431	-
Feb	25,815,107	-	12,271,755	-	-	-	-	-	-	12,271,755	-
Mar	9,563,054	-	902,830	-	-	-	-	-	-	902,830	-
Apr	3,286,742	-	3,094,354	-	-	-	-	-	-	3,094,354	-
May	49,183,135	-	1,291,810	8,362,000	-	-	-	-	-	9,653,810	-
Jun	33,055,814	-	490,845	-	-	-	-	-	-	490,845	-
Jul	10,469,496	-	52,116	-	-	-	-	-	-	52,116	-
Aug	8,654,159	-	3,254,265	-	-	-	-	-	-	3,254,265	-
Sep	3,569,853	-	2,916,187	-	-	-	-	-	-	2,916,187	-
Oct	14,319,454	-	-	-	-	-	-	-	-	-	-
Nov	4,380,840	-	-	-	-	-	-	-	-	-	-
Dec	40,841,187	-	-	-	-	-	-	-	-	-	-
Total	218,430,179	-	25,844,593	8,362,000	-	-	-	-	-	34,206,593	-

	(L) Weighting	Plant In Service (M) Other Transmission PIS Amount (A x L)	(N) Energy Gateway Amount (J x L)	(O) Other Transmission PIS (M / 13)	(P) Energy Gateway (N / 13)	CWIP (Q) Transmission CWIP Amount (K x L)	(R) Transmission CWIP (O / 13)	(S) Input/Total
CWIP Balance Dec (prior year)	13	-	-	-	-	-	-	
Jan	12	183,496,050	18,845,178	14,115,080.78	1,449,629	-	-	
Feb	11	283,966,178	134,989,302	21,843,552	10,383,792	-	-	
Mar	10	95,630,543	9,028,295	7,356,196	694,484	-	-	
Apr	9	29,580,682	27,849,190	2,275,437	2,142,245	-	-	
May	8	393,465,077	77,230,480	30,266,544	5,940,806	-	-	
Jun	7	231,390,700	3,435,915	17,799,285	264,301	-	-	
Jul	6	62,816,978	312,696	4,832,075	24,054	-	-	
Aug	5	43,270,794	16,271,325	3,328,523	1,251,640	-	-	
Sep	4	14,279,412	11,664,748	1,098,416	897,288	-	-	
Oct	3	42,958,361	-	3,304,489	-	-	-	
Nov	2	8,761,679	-	673,975	-	-	-	
Dec	1	40,841,187	-	3,141,630	-	-	-	
Total		1,430,457,641	299,627,129	110,035,203	23,048,241	-	-	
Input to Line 16 of Appendix A								**133,083,444**
Input to Line 34 of Appendix A								**-**

New Transmission Plant Additions and CWIP (weighted by months in service)

Estimated Life		58
Estimated Depreciation for Attachment 7		
Jan	11.5	25,948
Feb	10.5	185,134
Mar	9.5	12,323
Apr	8.5	37,790
May	7.5	104,028
Jun	6.5	4,584
Jul	5.5	412
Aug	4.5	21,041
Sep	3.5	14,665
Oct	2.5	-
Nov	1.5	-
Dec	0.5	-
Total Estimated Depreciation for Attachment 7		405,925

Step	Month	Year	Action
3	April	Year 2	TO adds weighted Cap Adds to plant in service in Formula

$ - — Must run Appendix A to get this number (with inputs in lines 16 and 34 of Appendix A)

Step	Month	Year	Action
4	May	Year 2	Post results of Step 3

$ - — Must run Appendix A to get this number (with inputs in lines 16 and 34 of Appendix A)

Step	Month	Year	Action
5	June	Year 2	Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2011 - May 31, 2012)

$ -

Step	Month	Year	Action
6	April	Year 3	TO populates the formula with Year 2 data from FERC Form No. 1 for Year 2 (e.g., 2011)

$ - Rev Req based on Prior Year data — Must run Appendix A to get this number (without inputs in lines 16 or 34 of Appendix A)

Step	Month	Year	Action
7	April	Year 3	Reconciliation - actual data

$ - Result of Formula for Reconciliation — Must run Appendix A to get this number (with inputs in lines 16 and 34 of Appendix A)

$ - Schedule 1 Reconciliation

PacifiCorp
Attachment 7 - Transmission Enhancement Charge Worksheet

Line					
1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if not Contributions in Aid of Construction (CIAC)**				
		Formula Line			
3	A	157	Net Plant Carrying Charge without Depreciation		11.5022%
4	B	164	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation		12.1621%
5	C		Line B less Line A		0.6599%
6	**FCR if CIAC**				
7	D	158	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		2.7986%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years
In the True-up, the actual depreciation expense will be used.
Columns and rows may be added to accommodate more projects

Line				Transmission CWIP (Energy Gateway only)	Transmission PIS Projection (Energy Gateway Segment B-H)	Transmission PIS Actuals (Energy Gateway Segment B-H)	
8	Useful life of the project	Life			58.00	58.00	
9	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	
10	Input the allowed increase in ROE	Increased ROE (basis points)		0	50	50	
11	From line 3 above if "No" on line 13 and from line 7 above if "Yes" on line 13	9.8% ROE		11.5022%	11.5022%	11.5022%	11.5022%
12	Line 14 plus (line 5 times line 13)/100	FCR for This Project		11.5022%	11.8321%	11.8321%	11.5022%
13	13 Month Net Plant or CWIP Balance	Investment		-	778,842,537	22,845,278	-
14	Actual or estimated depreciation expense	Annual Depreciation Expense		-	13,428,320	405,925	-

Line		Invest Yr	13 Month Net Plant or CWIP Balance	Depreciation	Revenue	13 Month Net Plant or CWIP Balance	Depreciation	Revenue	13 Month Net Plant or CWIP Balance	Depreciation	Revenue	13 Month Net Plant or CWIP Balance	Depreciation	Revenue	Total	Incentive Charged	Without Incentive	Transmission Incentive Credit (incentive minus without)
15	W 9.8 % ROE	2010	-	-	-	778,842,537	13,428,320	103,012,068	22,845,278	405,925	3,033,626	-	-	-	$ 106,045,694		$ 106,045,694	
16	W Increased ROE	2010	-	-	-	778,842,537	13,428,320	105,581,899	22,845,278	405,925	3,109,006	-	-	-	$ 108,690,905	$ 108,690,905		$ 2,645,210
17	W 9.8 % ROE	2011	-	-	-	772,128,377	13,428,320	102,239,794			-	-	-	-	$ 102,239,794		$ 102,239,794	
18	W Increased ROE	2011	-	-	-	772,128,377	13,428,320	104,787,472	-	-	-	-	-	-	$ 104,787,472	$ 104,787,472		$ 2,547,677
19	W 9.8 % ROE	2012	-	-	-	765,414,217	13,428,320	101,467,520	-	-	-	-	-	-	$ 101,467,520		$ 101,467,520	
20	W Increased ROE	2012	-	-	-	765,414,217	13,428,320	103,993,044	-	-	-	-	-	-	$ 103,993,044	$ 103,993,044		$ 2,525,524
21	W 9.8 % ROE	2013	-	-	-	758,700,058	13,428,320	100,695,247	-	-	-	-	-	-	$ 100,695,247		$ 100,695,247	
22	W Increased ROE	2013	-	-	-	758,700,058	13,428,320	103,198,617	-	-	-	-	-	-	$ 103,198,617	$ 103,198,617		$ 2,503,370
23	W 9.8 % ROE	2014	-	-	-	751,985,898	13,428,320	99,922,973	-	-	-	-	-	-	$ 99,922,973		$ 99,922,973	
24	W Increased ROE	2014	-	-	-	751,985,898	13,428,320	102,404,189	-	-	-	-	-	-	$ 102,404,189	$ 102,404,189		$ 2,481,216
25	W 9.8 % ROE	2015	-	-	-	745,271,738	13,428,320	99,150,699	-	-	-	-	-	-	$ 99,150,699		$ 99,150,699	
26	W Increased ROE	2015	-	-	-	745,271,738	13,428,320	101,609,762	-	-	-	-	-	-	$ 101,609,762	$ 101,609,762		$ 2,459,063
27	W 9.8 % ROE	2016	-	-	-	738,557,578	13,428,320	98,378,426	-	-	-	-	-	-	$ 98,378,426		$ 98,378,426	
28	W Increased ROE	2016	-	-	-	738,557,578	13,428,320	100,815,335	-	-	-	-	-	-	$ 100,815,335	$ 100,815,335		$ 2,436,909
29	W 9.8 % ROE	2017	-	-	-	731,843,418	13,428,320	97,606,152	-	-	-	-	-	-	$ 97,606,152		$ 97,606,152	
30	W Increased ROE	2017	-	-	-	731,843,418	13,428,320	100,020,907	-	-	-	-	-	-	$ 100,020,907	$ 100,020,907		$ 2,414,755
31	W 9.8 % ROE	2018	-	-	-	725,129,259	13,428,320	96,833,878	-	-	-	-	-	-	$ 96,833,878		$ 96,833,878	
32	W Increased ROE	2018	-	-	-	725,129,259	13,428,320	99,226,480	-	-	-	-	-	-	$ 99,226,480	$ 99,226,480		$ 2,392,601
33	W 9.8 % ROE	2019	-	-	-	718,415,099	13,428,320	96,061,605	-	-	-	-	-	-	$ 96,061,605		$ 96,061,605	
34	W Increased ROE	2019	-	-	-	718,415,099	13,428,320	98,432,052	-	-	-	-	-	-	$ 98,432,052	$ 98,432,052		$ 2,370,448
35	W 9.8 % ROE	2020	-	-	-	711,700,939	13,428,320	95,289,331	-	-	-	-	-	-	$ 95,289,331		$ 95,289,331	
36	W Increased ROE	2020	-	-	-	711,700,939	13,428,320	97,637,625	-	-	-	-	-	-	$ 97,637,625	$ 97,637,625		$ 2,348,294
37	W 9.8 % ROE	2021	-	-	-	704,986,779	13,428,320	94,517,057	-	-	-	-	-	-	$ 94,517,057		$ 94,517,057	
38	W Increased ROE	2021	-	-	-	704,986,779	13,428,320	96,843,197	-	-	-	-	-	-	$ 96,843,197	$ 96,843,197		$ 2,326,140
39	W 9.8 % ROE	2022	-	-	-	698,272,619	13,428,320	93,744,784	-	-	-	-	-	-	$ 93,744,784		$ 93,744,784	
40	W Increased ROE	2022	-	-	-	698,272,619	13,428,320	96,048,770	-	-	-	-	-	-	$ 96,048,770	$ 96,048,770		$ 2,303,987
41	W 9.8 % ROE	2023	-	-	-	691,558,460	13,428,320	92,972,510	-	-	-	-	-	-	$ 92,972,510		$ 92,972,510	
42	W Increased ROE	2023	-	-	-	691,558,460	13,428,320	95,254,343	-	-	-	-	-	-	$ 95,254,343	$ 95,254,343		$ 2,281,833
43	W 9.8 % ROE	2024	-	-	-	684,844,300	13,428,320	92,200,236	-	-	-	-	-	-	$ 92,200,236		$ 92,200,236	
44	W Increased ROE	2024	-	-	-	684,844,300	13,428,320	94,459,915	-	-	-	-	-	-	$ 94,459,915	$ 94,459,915		$ 2,259,679
45	W 9.8 % ROE	2025	-	-	-	678,130,140	13,428,320	91,427,962	-	-	-	-	-	-	$ 91,427,962		$ 91,427,962	
46	W Increased ROE	2025	-	-	-	678,130,140	13,428,320	93,665,488	-	-	-	-	-	-	$ 93,665,488	$ 93,665,488		$ 2,237,525
47	W 9.8 % ROE	2026	-	-	-	671,415,980	13,428,320	90,655,689	-	-	-	-	-	-	$ 90,655,689		$ 90,655,689	
48	W Increased ROE	2026	-	-	-	671,415,980	13,428,320	92,871,060	-	-	-	-	-	-	$ 92,871,060	$ 92,871,060		$ 2,215,372
49	W 9.8 % ROE	2027	-	-	-	664,701,820	13,428,320	89,883,415	-	-	-	-	-	-	$ 89,883,415		$ 89,883,415	
50	W Increased ROE	2027	-	-	-	664,701,820	13,428,320	92,076,633	-	-	-	-	-	-	$ 92,076,633	$ 92,076,633		$ 2,193,218
51	W 9.8 % ROE	2028	-	-	-	657,987,661	13,428,320	89,111,141	-	-	-	-	-	-	$ 89,111,141		$ 89,111,141	
52	W Increased ROE	2028	-	-	-	657,987,661	13,428,320	91,282,206	-	-	-	-	-	-	$ 91,282,206	$ 91,282,206		$ 2,171,064
53	W 9.8 % ROE	2029	-	-	-	651,273,501	13,428,320	88,338,868	-	-	-	-	-	-	$ 88,338,868		$ 88,338,868	
54	W Increased ROE	2029	-	-	-	651,273,501	13,428,320	90,487,778	-	-	-	-	-	-	$ 90,487,778	$ 90,487,778		$ 2,148,911
55		....				-	13,428,320		-	-	....	-	-				$ -	
56		....				-	.....		-	.....	....	-	.....			$ -		$ -

PacifiCorp

Attachment 8 - Depreciation Rates

Applied Depreciation Rates by State

			Oregon		Washington		California		Utah		Wyoming		AZ, CO, MT, NM		Idaho		Company
Row	A/C	Description	Balance	Rate	Balance	Rate	Balance	Rate	Balance	Rate	Balance	Rate	Balance	Rate	Balance	Rate	Rate
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	350.2	Land Rights															1.35%
2	352	Structures and Improvements															1.31%
3	353	Station Equipment															1.75%
4	353.7	Supervisory Equipment															3.78%
5	354	Towers and Fixtures															1.56%
6	355	Poles and Fixtures															2.63%
7	356	Overhead Conductors and Devices															2.25%
8	356.2	Clearing & Grading															1.40%
9	357	Underground Conduit															1.65%
10	358	Underground Conductors and Devices															1.64%
11	359	Roads & Trails															1.39%
12		Unclassified Transmission															2.03%
13	389.2	Land Rights	-	0.00%	-	0.00%	-	0.00%	35,298.05	2.32%	74,341.83	2.01%	-	0.00%	4,867.64	2.01%	
14	390	Structures and Improvements	63,568,643.81	2.21%	10,963,408.48	3.80%	1,502,337.27	2.38%	85,930,765.57	2.18%	6,210,354.43	3.03%	383,797.68	2.06%	11,222,877.61	2.12%	
15	390.3	Structures and Improvements - Office Panels															6.67%
16	391	Office Furniture and Equipment															5.00%
17	391.2	Office Furniture and Equipment - Personal Computers															20.00%
18	393	Store Equipment															4.00%
19	394	Tools, Shop and Garage Equipment															4.17%
20	395	Laboratory Equipment															5.00%
21	397	Communication Equipment	87,236,122.82	4.06%	13,592,592.82	5.24%	4,970,884.88	4.15%	89,965,861.69	4.09%	36,949,250.69	5.40%	4,946,946.65	3.18%	16,195,319.38	3.79%	
22	397.2	Communication Equipment - Mobile Radio Equipment															9.09%
23	398	Miscellaneous Equipment															5.00%
24		Unclassified General	132,297.61	4.37%	46,835.09	5.49%	2,405.41	5.15%	441,756.85	4.30%	249,747.58	5.46%	-	3.17%	161,122.79	3.81%	
25	302	Franchises and Consents															2.73%
26	303	Miscellaneous Intangible Plant															4.85%
27	390.1	Leasehold Improvements - Gen															7.13%

Notes:

1 Depreciation Rates shown in rows 1 through 24 were approved by each of the Company's respective state jurisdictions during the last depreciation study.

2 The columns labeled "Balance" are the amount of investment physically located in each state.

3 The plant balance is updated each month as new plant is added.

4 The balances to be reported in the columns labeled "Balances" in any update are the weighted 13-month average balances for the rate year.

5 "Company Rate" shows the depreciation rate approved by all of the jurisdictions on a total company basis.

6 Unclassified Transmission represents the transmission additions placed in service but not yet classified to a FERC level account. Monthly depreciation is calculated by multiplying the month's beginning unclassified balance by the monthly transmission composite depreciation rate.

7 Unclassified General represents the general plant additions placed in service but not yet classified to a FERC level account. Monthly depreciation is calculated by multiplying the month's beginning unclassified balance by the monthly state general plant composite depreciation rate.

8 Transfers into the General amortized accounts (rows 15 through 20, 22, and 23) are depreciated over the remaining life based on the account life.

9 Depreciation expense for General plant is decreased by the amount that is billed to joint owners for computer hardware.

10 Intangible and Leasehold Improvements (rows 25 through 27) are composite rates based on the 13 month average balance divided into the 2010 amortization expense for each account.

11 Amortization expense for Intangible is decreased by the amount that is billed to joint owners for computer software.

12 If the depreciation rates shown differ from the depreciation rates used to calculate the depreciation expense reported in FERC Form 1, then PacifiCorp is required to file under Section 205 for a modification of this Attachment or the calculation of depreciation expense and accumulated depreciation under this formula

PacifiCorp

Attachment 9a - Load Divisor for Projection

Average of current year and prior two years

OATT (Part III - Network Service)

Column	e	f1	f2	f3	f4	f5	f6	f7	f8	f9	f10	f11	f12	f
Customer Class RS / SA	PacifiCorp NFS	BPA Yakama NFO SA 328	BPA Gazley NFO SA 229	BPA Clarke PUD NFO SA 370	BPA: Benton REA NFO SA 539	BPA Oregon Wind NFO SA 538	Tri-State NFO SA 628	Noble Americas/ (Sempra) NFO SA 299	Basin Electric NFO SA 505	Basin Electric Sheridan NFO Terminated	Black Hills NFO SA 347	USBR NFO SA 506	WAPA NFO SA 175	Total NFO
Jan	8,533	6.59	3.38	28.37	0.34	0.10	-	12.90	14.76	7.53	35.80	-	0.00	110
Feb	8,153	5.21	2.99	26.77	0.67	0.11	-	13.26	13.77	3.67	29.67	-	-	96
March	7,750	5.72	3.05	25.81	0.25	0.10	-	13.24	14.08	3.67	29.12	-	0.00	95
April	7,415	5.51	2.93	23.93	0.95	-	-	13.03	15.78	3.33	25.24	0.08	0.00	91
May	7,810	4.58	2.98	14.78	0.22	-	-	15.17	9.39	3.33	25.53	0.52	2.89	79
Jun	8,845	5.71	3.02	9.44	0.11	-	-	14.97	12.08	3.33	30.88	0.51	2.11	82
Jul	9,440	6.03	3.37	12.71	0.12	-	0.01	15.49	13.84	3.33	28.31	0.56	2.70	86
Aug	9,269	5.95	3.45	13.39	0.11	0.10	-	16.70	13.74	3.33	28.67	0.54	2.71	89
Sept	8,240	5.51	3.17	11.09	0.12	0.12	0.01	14.19	13.25	3.33	26.21	0.46	2.65	80
Oct	7,475	5.65	2.96	13.46	0.09	0.10	0.00	13.42	12.40	3.33	24.55	0.10	0.65	77
Nov	8,149	5.73	3.10	24.22	0.75	0.01	4.65	11.76	12.91	3.33	30.67	-	0.00	97
Dec	8,970	5.70	3.42	32.26	1.55	-	4.65	11.57	8.09	3.67	34.60	-	0.00	106
Total	100,050	68	38	236	5	1	9	166	154	45	349	3	14	1,088
Ave 12CP	8,337	5.66	3	20	0	0	1	14	13	4	29	0	1	90.66

Other Service

Column	j1	j2	j3	j4	j5	j
Customer Class RS / SA	UAMPS OS RS 297	UMPA OS RS 637	Deseret OS RS 280	Western Area Power Administration OS RS 262/RS 263	APS OS RS 436	Total OS
Jan	300	100	119	282	-	800
Feb	324	108	124	243	-	798
March	262	94	114	250	-	720
April	305	56	86	203	-	649
May	354	73	80	226	-	733
Jun	445	114	114	271	-	944
Jul	473	138	115	268	-	993
Aug	488	129	114	276	-	1,007
Sept	421	105	100	271	-	897
Oct	334	91	91	217	-	732
Nov	308	71	72	268	-	720
Dec	342	90	81	294	-	807
Total	4,357	1,169	1,208	3,067	-	9,801
Ave 12CP	363	97	101	256	-	816.75

OATT Part II Long-Term Firm Point-to-Point Transmission Service 2011

Column	g1	g2	g3	g4	g5	g6	g7	g8	g9	g10	g12	g13	g13	g
Customer Class RS / SA	PacifiCorp LTP Various	Black Hills, Inc. LTP SA 67	BPA LTP SA 179	BPA LTP SA 656	Columbia Energy Partners LTP SA 662	Idaho Power LTP SA 212	Iberdrola LTP SA 279	Raser-Intermountain: SA 509 LTP SA 509	Powerex: SA 169 LTP SA 169	Seattle City Light LTP SA 80,105,289	NextEra: Capacity assignment LTP SA 426	State of SD LTP SA 170	Losses LTP	Total LTP
Jan	4,645	50	18	56		-	30	11	80	25	80	4	212	5,211
Feb	4,645	50	18	56		-	30	11	80	25	80	4	212	5,211
March	4,645	50	18	56		-	30	11	80	25	80	4	212	5,211
April	4,645	50	18	56		-	30	11	80	25	80	4	212	5,211
May	4,805	50	18	56		-	30	11	80	25	80	4	219	5,378
Jun	5,096	50	18	56	100	75	30	11	80	25	55	4	238	5,838
Jul	5,096	50	18	56	100	75	30	11	80	25	55	4	238	5,838
Aug	5,096	50	18	56	100	75	30	11	80	25	55	4	238	5,838
Sept	4,512	50	18	56	100	75	30	11	80	25	55	4	213	5,229
Oct	4,832	50	18	56	100	75	30	11	80	25	55	4	227	5,563
Nov	4,372	50	18	56		-	30	11	80	25	80	4	201	4,927
Dec	4,372	50	18	56		-	30	11	80	25	80	4	201	4,927
Total	56,761	600	216	672	500	375	360	132	960	300	835	48	2,625	64,384
Ave 12CP	4,730	50	18	56	42	31	30	11	80	25	70	4	219	5,365

	Total Network & OS	1% Growth	Behind-the Meter	Total Network Load
Jan	9,443	9,538	163	9,701
Feb	9,048	9,138	163	9,301
March	8,565	8,650	163	8,813
April	8,155	8,237	163	8,400
May	8,622	8,709	163	8,872
Jun	9,872	9,970	163	10,133
Jul	10,520	10,625	163	10,788
Aug	10,365	10,468	163	10,631
Sept	9,217	9,309	163	9,472
Oct	8,284	8,367	163	8,530
Nov	8,965	9,055	163	9,218
Dec	9,883	9,982	163	10,145
Total	110,939	112,048	1,956	114,004
Ave 12CP	9,245	9,337	163	9,500

	Divisor **Network + OS + LTP**
Jan	14,912
Feb	14,512
March	14,024
April	13,611
May	14,250
Jun	15,971
Jul	16,626
Aug	16,469
Sept	14,701
Oct	14,093
Nov	14,145
Dec	15,072
Total	178,388
Ave 12CP	**14,866**

PacifiCorp

Attachment 9a1 - Load (Current Year)

2010

			OATT (Part III - Network Service)													
Column			e	f1	f2	f3	f4	f5	f6	f7	f8	f9	f10	f11	f12	f
Customer Class RS / SA	Day	Time	PacifiCorp NFS	BPA Yakama NFO SA 328	BPA Gazley NFO SA 229	BPA Clarke PUD NFO SA 370	BPA: Benton REA NFO SA 539	BPA Oregon Wind NFO SA 538	Tri-State NFO SA 628	Noble Americas/ (Sempra) NFO SA 299	Basin Electric NFO SA 505	Basin Electric Sheridan NFO Terminated	Black Hills NFO SA 347	USBR NFO SA 506	WAPA NFO SA 175	Total NFO
Jan	7	18	8,152	5.77	3.15	24.11	1.03	0.31	-	17.70	1.28	10.59	54.41	-	0.01	118
Feb	22	8	8,002	6.63	2.97	26.32	1.00	0.34	-	17.78	0.32	-	46.01	-	-	101
March	9	19	7,574	4.15	3.14	21.42	0.74	0.29	-	18.72	0.23	-	39.36	-	0.01	88
April	1	8	7,248	4.52	2.80	20.80	0.86	-	-	18.10	1.34	-	36.71	0.24	0.01	85
May	6	8	7,092	4.73	2.94	21.35	0.67	-	-	17.52	1.18	-	37.59	0.55	1.66	88
Jun	28	17	8,824	5.14	3.05	7.33	0.32	-	-	16.90	1.23	-	46.64	0.54	3.32	84
Jul	27	16	9,398	6.08	3.10	11.14	0.36	-	0.04	16.48	0.53	-	46.94	0.69	3.11	88
Aug	17	16	9,382	5.84	3.34	14.17	0.33	0.31	-	20.10	1.22	-	49.00	0.62	3.12	98
Sept	3	17	8,169	5.54	3.51	12.27	0.37	0.37	0.03	14.58	0.76	-	33.63	0.38	2.95	74
Oct	1	16	7,426	3.95	2.88	9.39	0.28	0.29	0.01	17.27	0.20	-	33.65	0.29	0.94	69
Nov	23	18	8,592	5.20	3.29	31.67	1.26	0.03	13.94	12.27	0.73	-	53.00	-	0.01	121
Dec	29	18	8,402	5.11	3.26	25.77	1.64	-	13.96	12.71	0.27	-	46.80	-	0.01	110
Total			98,261	63	37	226	9	2	28	200	9	11	524	3	15	1,127

			Other Service					
Column			j1	j2	j3	j4	j5	j
Customer Class RS / SA	Day	Time	UAMPS OS RS 297	UMPA OS RS 637	Deseret OS RS 280	Western Area Power Administration OS RS 262/RS 263	APS OS RS 436	Total OS
Jan	7	18	352	88	59	255	-	753
Feb	22	8	297	69	71	249	-	686
March	9	19	316	71	59	253	-	698
April	1	8	305	45	100	205	-	656
May	6	8	311	69	63	154	-	596
Jun	28	17	452	124	107	284	-	967
Jul	27	16	461	149	96	291	-	997
Aug	17	16	555	153	104	248	-	1,060
Sept	3	17	444	112	90	282	-	929
Oct	1	16	419	103	76	226	-	824
Nov	23	18	324	83	72	264	-	743
Dec	29	18	331	82	72	313	-	798
Total			4,566	1,148	970	3,024	-	9,708

PacifiCorp
Attachment 9a1 - Load (One Year Prior)
2009

			OATT (Part III - Network Service)													
Column			e	f1	f2	f3	f4	f5	f6	f7	f8	f9	f10	f11	f12	f
Customer Class RS / SA	Day	Time	PacifiCorp NFS	BPA Yakama NFO SA 328	BPA Gazley NFO SA 229	BPA Clarke PUD NFO SA 370	BPA: Benton REA NFO SA 539	BPA Oregon Wind NFO SA 538	Tri-State NFO SA 628	Noble Americas/ (Sempra) NFO SA 299	Basin Electric NFO SA 505	Basin Electric Sheridan NFO SA 233	Black Hills NFO SA 347	USBR NFO SA 506	WAPA NFO SA 175	Total NFO
Jan	27	8	8,524	7.00	4.00	29.00	-	-	-	9.00	22.00	12.00	53.00	-	-	136
Feb	10	19	8,187	5.00	3.00	27.00	1.00	-	-	10.00	20.00	11.00	43.00	-	-	120
March	11	8	7,828	7.00	3.00	29.00	-	-	-	9.00	22.00	11.00	48.00	-	-	129
April	1	9	7,213	6.00	3.00	23.00	2.00	-	-	9.00	23.00	10.00	39.00	-	-	115
May	29	16	7,912	4.00	3.00	12.00	-	-	-	12.00	14.00	10.00	39.00	1.00	4.00	99
Jun	29	17	8,340	5.00	3.00	9.00	-	-	-	12.00	17.00	10.00	46.00	1.00	3.00	106
Jul	27	17	9,420	6.00	4.00	14.00	-	-	-	13.00	18.00	10.00	38.00	1.00	2.00	106
Aug	20	17	9,030	6.00	4.00	11.00	-	-	-	13.00	18.00	10.00	37.00	1.00	2.00	102
Sept	2	17	8,470	6.00	3.00	9.00	-	-	-	12.00	21.00	10.00	45.00	1.00	3.00	110
Oct	28	8	7,412	7.00	3.00	22.00	-	-	-	9.00	18.00	10.00	40.00	-	-	109
Nov	30	18	8,015	6.00	3.00	21.00	1.00	-	-	10.00	19.00	10.00	39.00	-	-	109
Dec	8	19	9,332	6.00	4.00	35.00	2.00	-	-	10.00	1.00	11.00	57.00	-	-	126
Total			99,683	71	40	241	6	-	-	128	213	125	524	5	14	1,367

			Other Service					
Column			j1	j2	j3	j4	j5	j
Customer Class RS / SA	Day	Time	UAMPS OS RS 297	UMPA OS RS 637	Deseret OS RS 280	Western Area Power Administration OS RS 262/RS 263	APS OS RS 436	Total OS
Jan	27	8	272	57	87	272	-	688
Feb	10	19	326	77	81	223	-	707
March	11	8	192	66	83	249	-	590
April	1	9	274	53	110	220	-	657
May	29	16	331	69	107	263	-	770
Jun	29	17	387	98	144	272	-	901
Jul	27	17	438	136	154	256	-	984
Aug	20	17	434	109	148	286	-	977
Sept	2	17	382	116	140	290	-	928
Oct	28	8	196	65	124	220	-	605
Nov	30	18	287	61	89	298	-	735
Dec	8	19	301	94	101	313	-	809
Total			3,820	1,001	1,368	3,162	-	9,351

PacifiCorp
Attachment 9a1 - Load (Two Years Prior)
2008

Column			OATT (Part III - Network Service)													
			e	f1	f2	f3	f4	f5	f6	f7	f8	f9	f10	f11	f12	f
Customer Class RS / SA	Day	Time	PacifiCorp NFS	BPA Yakama NFO SA 328	BPA Gazley NFO SA 229	BPA Clarke PUD NFO SA 370	BPA: Benton REA NFO SA 539	BPA Oregon Wind NFO SA 538	Tri-State NFO SA 628	Noble Americas/ (Sempra) NFO SA 299	Basin Electric NFO SA 505	Basin Electric Sheridan NFO SA 233	Black Hills NFO SA 347	USBR NFO SA 506	WAPA NFO SA 175	Total NFO
Jan	23	8	8,924	7.00	3.00	32.00	-	-	-	12.00	21.00	-	-	-	-	75
Feb	4	19	8,270	4.00	3.00	27.00	-	-	-	12.00	21.00	-	-	-	-	67
March	5	8	7,848	6.00	3.00	27.00	-	-	-	12.00	20.00	-	-	-	-	68
April	1	8	7,785	6.00	3.00	28.00	-	-	-	12.00	23.00	-	-	-	-	72
May	19	16	8,427	5.00	3.00	11.00	-	-	-	16.00	13.00	-	-	-	3.00	51
Jun	30	14	9,371	7.00	3.00	12.00	-	-	-	16.00	18.00	-	-	-	-	56
Jul	9	17	9,501	6.00	3.00	13.00	-	-	-	17.00	23.00	-	-	-	3.00	65
Aug	14	17	9,396	6.00	3.00	15.00	-	-	-	17.00	22.00	-	-	-	3.00	66
Sept	8	17	8,080	5.00	3.00	12.00	-	-	-	16.00	18.00	-	-	-	2.00	56
Oct	1	16	7,588	6.00	3.00	9.00	-	-	-	14.00	19.00	-	-	-	1.00	52
Nov	5	18	7,839	6.00	3.00	20.00	-	-	-	13.00	19.00	-	-	-	-	61
Dec	15	18	9,176	6.00	3.00	36.00	1	-	-	12.00	23.00	-	-	-	-	81
Total			102,205	70	36.00	242	1	-	-	169	240	-	-	-	12	770

Column			Other Service					
			j1	j2	j3	j4	j5	j
Customer Class RS / SA	Day	Time	UAMPS OS RS 297	UMPA OS RS 637	Deseret OS RS 280	Western Area Power Administration OS RS 262RS 263	APS OS RS 436	Total OS
Jan	23	8	276	156	210	318	-	960
Feb	4	19	349	178	219	256	-	1,002
March	5	8	279	146	199	247	-	871
April	1	8	335	69	47	183	-	634
May	19	16	421	82	69	260	-	832
Jun	30	14	497	120	91	257	-	965
Jul	9	17	521	128	94	256	-	999
Aug	14	17	474	124	91	294	-	983
Sept	8	17	436	87	71	240	-	834
Oct	1	16	387	104	73	204	-	768
Nov	5	18	314	70	54	243	-	681
Dec	15	18	395	94	69	257	-	815
Total			4,684	1,358	1,287	3,015	-	10,344

PacifiCorp
Attachment 9b - Load Divisor for True up

	OATT (Part III - Network Service)													
Column	e	f1	f2	f3	f4	f5	f6	f7	f8	f9	f10	f11	f12	f
Customer	PacifiCorp	BPA Yakama	BPA Gazley	BPA Clarke PUD	BPA: Benton REA	BPA Oregon Wind	Tri-State	Noble Americas/ (Sempra)	Basin Electric	Basin Electric Sheridan	Black Hills	USBR	WAPA	
Class	NFS	NFO	NFO	NFO	NFO	NFO	NFO	NFO	NFO	NFO	NFO	NFO	NFO	Total NFO
RS / SA	(see note)	SA 328	SA 229	SA 370	SA 539	SA 538	SA 628	SA 299	SA 505	Terminated	SA 347	SA 506	SA 175	
Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sept	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ave 12CP	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Other Service					
j1	j2	j3	j4	j5	j
UAMPS	UMPA	Deseret	Western Area Power Administration	APS	
OS	OS	OS	OS	OS	Total OS
RS 297	RS 637	RS 280	RS 262/RS 263	RS 436	
-	-	-	-	-	-
-	-	-	-	-	-
-	-	-	-	-	-
-	-	-	-	-	-
-	-	-	-	-	-
-	-	-	-	-	-
-	-	-	-	-	-
-	-	-	-	-	-
-	-	-	-	-	-
-	-	-	-	-	-
-	-	-	-	-	-
-	-	-	-	-	-
-	-	-	-	-	-
-	-	-	-	-	-

	OATT Part II Long-Term Firm Point-to-Point Transmission Service															
Column	g1	g2	g3	g4	g5	g6	g7	g8	g19	g10	g11	g12	g13	g14	g15	g
Customer	PacifiCorp	Black Hills, Inc.	BPA	BPA	Idaho Power	Iberdrola	Raser-Intermountain	Powerex	Seattle City Light	NextEra: Capacity assignment	State of SD	Losses	Powerex	Powerex	Powerex	
Class	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	Total LTP
RS / SA	Various	SA 67	SA 179	SA 656	SA 212	SA 279	SA 509	SA 169	SA 80,105,289	SA 426	SA 170		SA 701	SA 702	SA 703	
Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sept	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ave 12CP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Total Network & OS	Behind-the Meter	Total Network Load
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-
-	-	-

Divisor
Network + OS + LTP
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PacifiCorp
Attachment 10 - Accumulated Amortization of Plant in Service

Plant in Service - Accumulated Amortization Detail

FERC Account	Account Number	Description	Balance
1110000	146140	A/Amort-Soft Dev	(375,090,423)
	146200	A/Amort-Oth Intang	(50,748,284)
	146210	A/Amort-Oth Lic/Hydr	(7,372,774)
	146230	A/Amort-LsHld Imprmt	(30,224,398)
	146450	A/Amort-Capital Leas	(5,941,217)
1119000	146459	Cap Leases - Acc Am	(2,198,517)
		Attachment 5 input: **Total Accumulated Amortization**	**(471,575,613)**

PacifiCorp
Attachment 11 - Prepayments

Prepayments Detail

FERC Account	Account Number	Account Description	Category	Prior Year-end Balance	Current Year-end Balance	BoY-EoY Average	Other	100% Transmission	Plant-related	Labor-related
1651000	132008	Prep Ins-Publ Liab & Prop Dam	Plant-related	$ 1,846,337	$ 1,425,376	$ 1,635,857			$ 1,635,857	
	132012	Prep Ins-All Purpose Insurance	Plant-related	$ 7,638,779	$ 7,067,036	$ 7,352,908			$ 7,352,908	
	132013	Prep Ins-D&O Liability	Labor-related	$ 701,362	$ 389,645	$ 545,504				$ 545,504
	132016	Prep Ins-Minority Owned Plants	Other	$ 329,994	$ 145,770	$ 237,882	$ 237,882			
	132045	Prepaid Workers Compensation	Labor-related	$ 350,350	$ 263,750	$ 307,050				$ 307,050
	132055	Prepaid Employee Benefit Costs	Labor-related	$ 1,991,250	$ 1,374,878	$ 1,683,064				$ 1,683,064
	132722	I/C Prepaid Captive Prop Insur - MEHC	Plant-related	$ 1,195,867	$ 1,195,867	$ 1,195,867			$ 1,195,867	
	132723	I/C Prepaid Captive Liab Insur - MEHC	Plant-related	$ 340,311	$ 340,311	$ 340,311			$ 340,311	
1652000	132101	OR-Prepaid Property Tax	Plant-related	$ 9,620,711	$ 10,743,370	$ 10,182,040			$ 10,182,040	
	132200	Prepaid Taxes (Federal, State, Local)	Other	$ -	$ (3,514)	$ (1,757)	$ (1,757)			
	132924	Other Prepayments - Oregon DOE Fee	Other	$ -	$ 365,145	$ 182,573	$ 182,573			
1652100	132095	Prepaid Emissions Permit Fees (UT)	Other	$ 632,766	$ 596,638	$ 614,702	$ 614,702			
	132310	Prepaid Rating Agency Fees	Plant-related	$ 49,506	$ 109,970	$ 79,738			$ 79,738	
	132603	Other Prepay-Ashton Plant Land	Other	$ 8,294	$ 7,257	$ 7,775	$ 7,775			
	132606	Other Prepay - Lease Commissions	Other	$ 27,319	$ 19,695	$ 23,507	$ 23,507			
	132620	Prepayments - Water Rights Lease	Other	$ 987,416	$ 805,359	$ 896,388	$ 896,388			
	132621	Prepayments - Water Rights (Ferron Canal)	Other	$ -	$ 223,038	$ 111,519	$ 111,519			
	132622	Prepayments - Water Rights (Hntngtn-Clev)	Other	$ -	$ 15,379	$ 7,689	$ 7,689			
	132630	Prepaid OR Renewal & Habitat Restoration	Other	$ -	$ 601,354	$ 300,677	$ 300,677			
	132650	Prepaid Dues	Other	$ 4,539,187	$ 3,626,781	$ 4,082,984	$ 4,082,984			
	132700	Prepaid Rent	Plant-related	$ 238,263	$ 240,007	$ 239,135			$ 239,135	
	132705	Prepaid Pole Contact Rental	Other	$ 323,910	$ 323,476	$ 323,693	$ 323,693			
	132740	Prepaid O&M - Wind	Other	$ 1,170,000	$ 1,352,239	$ 1,261,119	$ 1,261,119			
	132825	Prepaid LGIA Transmission	Other	$ 2,429,856	$ 872,256	$ 1,651,056	$ 1,651,056			
	132831	Prepaid BPA Transmission - Wine Country	Other	$ 863,304	$ 863,304	$ 863,304	$ 863,304			
	132900	Prepayments - Other	Labor-related	$ 419,507	$ 1,597,549	$ 1,008,528				$ 1,008,528
	132901	Prep Fees-Oregon Pub Util Commission	Other	$ 802,237	$ 447,709	$ 624,973	$ 624,973			
	132903	Prep Fees-Utah Public Service Commission	Other	$ 1,968,201	$ 1,679,933	$ 1,824,067	$ 1,824,067			
	132904	Prep Fees-Idaho Pub Util Commission	Other	$ 164,017	$ 189,963	$ 176,990	$ 176,990			
	132910	Prepayments - Hardware & Software	Labor-related	$ 4,631,208	$ 6,645,307	$ 5,638,257				$ 5,638,257
	132926	Prepaid Royalties	Other	$ 904,330	$ 832,457	$ 868,394	$ 868,394			
	132998	Prepayments - Insurance - Reclass to L-T	Plant-related	$ (389,645)	$ (77,929)	$ (233,787)			$ (233,787)	
	132999	Prepayments - Reclass to Long-Term	Plant-related	$ (1,512,484)	$ (1,707,081)	$ (1,609,783)			$ (1,609,783)	
	134000	Long-Term Prepayments - Reclass from Current	Plant-related	$ 1,902,129	$ 1,785,010	$ 1,843,570			$ 1,843,570	
1652200	116131	InterCo Federal Tax Rec - (Even Years) - MEHC	Other	$ 761,849	$ 352,792,765	$ 176,777,307	$ 176,777,307			
	116132	InterCo Federal Tax Rec - (Odd Years) - MEHC	Other	$ 243,042,394	$ (3)	$ 121,521,196	$ 121,521,196			
	116133	InterCo State Tax Rec - (Even Years) - MEHC	Other	$ 7,562,015	$ (8,165,286)	$ (301,636)	$ (301,636)			
	116134	InterCo State Tax Rec - (Odd Years) - MEHC	Other	$ (2,311,165)	$ 44,000	$ (1,133,582)	$ (1,133,582)			
1653000	132303	Prepaid Interest Company-Owned Life Ins	Other	$ 3,273,530	$ 2,767,772	$ 3,020,651	$ 3,020,651			
	132304	Prepaid Interest - SERP Life Insurance	Other	$ 177,187	$ 170,165	$ 173,676	$ 173,676			
1655000	132400	Prepaid Mining Costs	Other	$ 1,976,171	$ 1,021,364	$ 1,498,767	$ 1,498,767			
		Total Prepayments		$ 298,656,263	$ 392,988,080	$ 345,822,171	$ 315,613,913	$ -	$ 21,025,855	$ 9,182,403

		Other	100% Transmission	Plant-related	Labor-related
Allocator		0.000%	100.000%	23.440%	6.855%
Total Allocated to Transmission by Category		$ -	$ -	$ 4,928,363	$ 629,459
Appendix A input: **Total Allocated to Transmission**	**$ 5,557,822**				

PacifiCorp
Attachment 12 - Plant Held for Future Use

Plant/Land Held For Future Use - Assets associated with Transmission at December 31

	Prior year	Current year
Troutdale Substation		6,979
Hazelwood Substation		161,944
Harmony - W. Cedar ROW		156,105
Terminal - Oquirrh 138 Kv Line		396,020
Attachment 5 input: **Total - Transmission**		**721,048**

		Prior year	Current year
Total - PacifiCorp	214.47d	13,674,549	17,678,149

PacifiCorp
Attachment 13 - Revenue Credit Detail

Revenue Credit Detail

Other Service (OS) contracts

Description	Revenue	MW	**As Filed** 1=Revenue credit 0=Denominator Treatment
Arizona Public Service RS 436	n/a	0.0	0
BPA: Summer Lake RS 369	0	n/a	1
BPA: GTA West RS 237	4,583,217	n/a	1
BPA: Lost Creek RS 324	234,207	n/a	1
BPA Malin RS 368	269,394	n/a	1
BPA GTA S. Idaho RS 299	1,872,178	n/a	1
Cowlitz RS 234	112,055	n/a	1
Deseret RS 280	n/a	81.0	0
Deseret: CASA RS 590	119,915	n/a	1
Fall River RS 322	151,308	n/a	1
Foote Creek III, LLC SA 130	36,182	n/a	1
Idaho RS 427 - Goshen	0	n/a	1
Idaho RS 257 - Antelope Sub	73,824	n/a	1
Idaho RS 203 - Jim Bridger Pumps	16,284	n/a	1
Moon Lake RS 302	19,685	n/a	1
Pacific Gas and Electric RS 607	20,000,000	n/a	1
Pacific Gas and Electric RS 298	307,856	n/a	1
Sierra Pacific Power RS 267	68,919	n/a	1
Southern Cal Edison RS 298	307,856	n/a	1
Tri-State RS 123	125,750	n/a	1
USBR Crooked River RS 67	12,433	n/a	1
USBR Weber Basin RS 286	26,649	n/a	1
UAMPS RS 297	n/a	380.5	0
UMPA RS 637	n/a	95.7	0
Warm Springs RS 591	119,700	n/a	1
WAPA RS 262 ("2436")	n/a	252.0	0
WAPA RS 262-Fixed Fee	606,357	n/a	1
WAPA RS 263	46,865	n/a	1
WAPA RS 264	20,932	n/a	1
Additional OS Revenue Credit	445,897	n/a	1
Att 3 input: **Total OS contract revenue credits**	**29,577,461**	809.2	

Short-term revenue

Short-term firm	
PacifiCorp Commercial and Trading (C&T)	35,380,064
Third parties	1,175,745
Total short-term firm	36,555,809
Short-term non-firm	
PacifiCorp Commercial and Trading (C&T)	37,954,826
Third parties	8,162,720
Total short-term non-firm	46,117,547

Short term firm and non-firm

PacifiCorp Commercial and Trading (C&T)	73,334,891
Third parties	9,338,465
Att. 3 input: **Total short term-firm and non-firm revenue**	**82,673,356**

PacifiCorp
Attachment 14 - Cost of Capital Detail

					Prior Year (month end)	Current Year (month end)											
Appendix A Line	Operation to apply to monthly input columns at right	Appendix A input value (result of operation specified in column to left on monthly data)	Description (Account)	Reference	December	January	February	March	April	May	June	July	August	September	October	November	December
86	13-month average	6,368,973,308	Bonds (221)	Form 1, pg 112, ln 18 c,d	6,372,343,000	6,372,343,000	6,372,343,000	6,372,343,000	6,372,343,000	6,372,343,000	6,372,343,000	6,372,343,000	6,372,343,000	6,372,343,000	6,357,741,000	6,357,741,000	6,357,741,000
87	13-month average	0	Reacquired Bonds (222)	Form 1, pg 112, ln 19 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
88	13-month average	0	Advances from Associated Companies (223)	Form 1, pg 256, various ln, col a,b	0	0	0	0	0	0	0	0	0	0	0	0	0
89	13-month average	0	Other Long-Term Debt (224)	Form 1, pg 112, ln 21 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
91	13-month average	14,897,359	Unamortized Discount (226)	Form 1, pg 112, ln 23 c,d	15,413,483	15,327,462	15,241,442	15,155,421	15,069,400	14,983,379	14,897,359	14,811,337	14,725,317	14,639,296	14,553,276	14,467,255	14,381,234
92	13-month average	34,639,691	Unamortized Debt Expense (181)	Form 1, pg 111, ln 69 c,d	35,978,910	35,755,707	35,532,504	35,309,300	35,086,097	34,862,894	34,639,691	34,416,488	34,193,284	33,970,081	33,746,878	33,523,675	33,300,472
93	13-month average	12,567,578	Unamortized Loss On Reacquired Debt (189)	Form 1, pg 111, ln 81 c,d	13,778,067	13,572,771	13,367,474	13,164,038	12,960,603	12,757,168	12,553,732	12,350,297	12,146,861	11,943,426	11,742,641	11,594,693	11,446,745
94	13-month average	34,204	Unamortized Premium (225)	Form 1, pg 112, ln 22 c,d	35,563	35,336	35,110	34,883	34,657	34,430	34,204	33,977	33,751	33,524	33,298	33,071	32,845
95	13-month average	0	Unamortized Gain On Reacquired Debt (257)	Form 1, pg 113, ln 61 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
97	12-month sum	363,203,396	Interest on Long Term (427) and Associated Companies (430) **LONG TERM ONLY**	Form 1, pg 257, ln 33 i	30,469,388	30,322,459	30,323,888	30,377,571	30,346,076	30,389,035	30,250,904	30,233,142	30,268,037	30,243,915	30,110,390	30,134,878	30,203,101
98	12-month sum	0	Hedging Expense (as noted in Appendix A, Note R)	Company records	0	0	0	0	0	0	0	0	0	0	0	0	0
99	12-month sum	3,727,614	Amort Debt Discount and Expense (428)	Form 1, pg 117, ln 63 c (portion)	309,224	309,224	309,224	309,224	309,224	309,224	309,224	309,224	309,224	309,224	309,224	309,224	326,150
100	12-month sum	2,331,323	Amort Loss on Reacquired Debt (428.1)	Form 1, pg 117, ln 64 c (portion)	205,296	205,297	205,297	203,435	203,435	203,436	203,435	203,436	203,435	203,436	200,785	147,948	147,948
101	12-month sum	2,718	Amort Premium (429)	Form 1, pg 117, ln 65 c (portion)	227	227	227	226	226	226	227	227	227	226	226	226	227
102	12-month sum	0	Amort Gain on Reacquired Debt (429.1)	Form 1, pg 117, ln 66 c (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
104	13-month average	41,013,946	Preferred Stock Issued (204)	Form 1, pg 112, ln 3 c, d	41,463,300	41,463,300	41,463,300	41,463,300	41,463,300	40,733,100	40,733,100	40,733,100	40,733,100	40,733,100	40,733,100	40,733,100	40,733,100
105	13-month average	0	Reacquired Capital Stock (217) **PREFERRED ONLY**	Form 1, pg 112, ln 13 c, d (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
106	13-month average	0	Premium on Preferred Stock (207)	Form 1, pg 112, ln 6 c, d (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
107	13-month average	0	Other Paid-In Capital (207-208) **PREFERRED ONLY**	Form 1, pg 112, ln 7 c, d (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
108	13-month average	0	Discount on Capital Stock (213) **PREFERRED ONLY**	Form 1, pg 112, ln 9 c, d (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
109	13-month average	184,901	Capital Stock Expense (214) **PREFERRED ONLY**	Form 1, pg 112, ln 10 c, d (portion)	187,146	187,146	187,146	187,146	187,146	183,498	183,498	183,498	183,498	183,498	183,498	183,498	183,498
111	12-month sum (enter positive)	2,058,333	Preferred Dividend	Form 1, pg 118, ln 29 c	(520,947)			(520,947)			(512,462)			(512,462)			(512,462)
112	13-month average	6,993,016,380	Total proprietary Capital	Form 1, pg 112, ln 16 c,d	6,648,397,184	6,704,678,836	6,742,743,329	6,789,711,511	6,828,428,966	6,874,468,231	7,037,348,852	7,110,785,482	7,158,867,281	7,194,203,792	7,238,168,510	7,270,360,129	7,311,050,837
114	13-month average	132,098,350	Unappropriated Undistributed Subsidiary Earnings (216.1)	Form 1, pg 112, ln 12 c, d	127,151,426	124,728,882	126,967,322	127,771,181	127,299,785	129,755,102	129,904,901	132,319,878	134,095,204	137,480,209	137,717,917	139,682,570	142,404,172
115	13-month average (enter negative)	(2,374,513)	Accumulated Other Comprehensive Income (219)	Form 1, pg 112, ln 15 c, d	(5,819,577)	(5,412,666)	(3,764,101)	181,316	(350,948)	(1,647,174)	(799,541)	(1,165,907)	1,014,516	(47,681)	(2,082,002)	(4,013,007)	(6,961,899)
n/a	-	-	Common Stock Issued (201)	Company records	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896
n/a	-	-	Other Paid-In Capital (211)	Company records	1,002,063,956	1,002,063,956	1,002,063,956	1,002,063,956	1,002,063,956	1,002,229,981	1,102,229,981	1,102,229,981	1,102,229,981	1,102,229,981	1,102,229,981	1,102,229,981	1,102,229,981

Description		Total	Interest Locks	Other
Unamortized balance for gains and losses on hedges.	(Note R)	0	0	0
Annual amortization for gains and losses on hedges.	(Note R)	0	0	0

PacifiCorp
Attachment 15 - GSU and Associated Equipment

Asset Class 353.40 - GSU (generator step-up) and Associated Equipment &
Asset Class 345 - Accessory Electrical Equipment
(At December 31)

353.4 Class Assets	**Acquisition value**
AIRBREAK SWITCH	27,811
BREAKER	5,237,438
BUS	289,919
FIRE PROTECTION	611,795
FOUNDATION AND SUBSTRUCTURE	1,495,100
INSTALLATION LABOR AND OVERHEADS	176,195
INSULATOR	35,789
LIGHTNING ARRESTER	67,859
MISC	4,769,646
POWER TRANSFORMER BUSHING	56,489
RELAY AND CONTROL	2,082,701
STEEL STRUCTURE	206,879
STEP-UP TRANSFORMER	109,269,051
Total 353.4 Class Assets	**124,326,671**
Wind Generation Facilities	**79,784,607**
34.5 kV Facilities	**7,832,481**
Appendix A input: **Total Assets to Exclude**	**211,943,759**

PacifiCorp
Attachment 16 - Unfunded Reserves

Accounts with Unfunded Reserve Balances contributed by customers
(Dollar values in millions)

			Accrued Liability:		Charged to:		Prior year	Current Year	Projection		By Category				
Description	**Account Calculation**	**Reserve type**	**SAP Account**	**FERC Account**	**SAP Account**	**FERC Account**	**December** month end	**December** month end	**Beg-/End-of-Year Average**	**Category**	**100% Transmission**	**Plant**	**Labor**	**Other**	**Total Transmission-related Unfunded Reserves**
Regulatory Liability for Property Insurance	Known	Unfunded	288115	254	548050	924.1	(0.1)	0.0	(0.1)	Plant		(0.050)			
New Source Review Provision (EPA & DOJ)	Estimate by PE Legal	Unfunded	248070	242	545500	557	(1.0)	(1.0)	(1.0)	Other				(1.000)	
Kluver Litigation Reserve (Colstrip Settlement)	Estimate by PE Legal	Unfunded	248070	242	545500	506	0.0	(0.4)	(0.2)	Other				(0.216)	
BPA AC Intertie - Unreturned Losses	Estimate by C&T	Unfunded	248025	242	505211	555.67	(1.2)	(1.2)	(1.2)	Other				(1.200)	
Western Area Power Administration (WAPA) - Unreturned Losses	Estimate by C&T	Unfunded	248025	242	505214	555.63	(0.6)	0.0	(0.3)	Other				(0.300)	
Injuries & Damages Reserve (General and Motor Liabilities) Risk	Known	Unfunded	280311 - 280313	228.2	545050	925	(7.5)	(8.5)	(8.0)	Labor			(8.000)		
Questar Gas Co. Lake Side Lateral Contingency '07-'08 Settlement	Estimate by PE Legal	Unfunded	210680	232	515201	547.1	(0.5)	0.0	(0.3)	Other				(0.250)	
BPA Summer Storage Energy Rejections and Returns Issue #2	Estimate by C&T	Unfunded	248025	242	505206	555.25	0.0	(1.5)	(0.8)	Other				(0.750)	
Provision for Customer A/R (CSS)	Calculated and Known Items	Unfunded	118100	144	550750	904	(6.5)	(6.9)	(6.7)	Other				(6.696)	
Provision for Other A/R (OAR)	Calculated and Known Items	Unfunded	118150	144	550750	904	(0.0)	0.0	(0.0)	Other				(0.004)	
Bad Debt Reserve - Pole Contracts	Uncollectible pole contact revenue - customer specific.	Unfunded	118157	144	550776	904.2	(0.5)	(0.5)	(0.5)	Other				(0.515)	
Provision for Doubtful Debts - Other	Known	Unfunded	118168	144	550750	904	(0.0)	(0.0)	(0.0)	Other				(0.040)	
Inventory Reserve - Power Supply	Known - Calculated	Unfunded	120930	154.99	516400	557	(0.4)	(0.8)	(0.6)	Other				(0.558)	
Construction Work-in-Progress (CWIP) Reserve	Calculated	Unfunded	148001	107	554990	557 / 598	(1.9)	(4.7)	(3.3)	Other				(3.300)	
Uncollectible Weatherization Loans Reserve	Historical Trend Judgment	Unfunded	162010	124.9	550750	904	(0.1)	(0.1)	(0.1)	Other				(0.096)	
Provision for Unbilled Severance Tax Cap (Chevron Mining Co.)	Estimate by Mining	Unfunded	210649	232	515100	501.1	0.0	(1.5)	(0.8)	Other				(0.750)	
Accrual - Severance Payments	Known	Unfunded	235190	232	500700	920	(0.1)	(0.1)	(0.1)	Labor			(0.067)		
Accrual - Severance Payments	Known	Unfunded	235190	232	500700	921	(0.2)	(0.1)	(0.2)	Labor			(0.150)		
Annual Incentive Plan (AIP)	Calculated plus CEO Discretion	Unfunded	235510	232	500410	Follows Labor	0.0	0.0	0.0	Labor			0.000		
401(K) Discretionary 1% Company Match	Calculated plus CEO Discretion	Unfunded	215078	232	501250	Follows Labor	(0.1)	(1.8)	(0.9)	Labor			(0.911)		
BPA - Surprise Valley	Known	Unfunded	248025	242	505214	555.63	(0.8)	0.0	(0.4)	Other				(0.400)	
Accrued Settlement Provision (UT PSC Class action Peterson)	Estimate by Legal	Unfunded	248070	242	545500	930.2	(0.0)	0.0	(0.0)	Labor			(0.005)		
Accrued Settlement Provision (McConnell (Hoopa & Karuk Indian Tribes))	Known	Unfunded	248070	242	545500	535	(0.1)	0.0	(0.0)	Other				(0.035)	
FAS112 - Wasatch Workers Comp	Calculated - Actuary	Unfunded	280490	228.3	501160	920	(4.3)	(4.2)	(4.3)	Labor			(4.250)		
Citi Card Signing Bonus & Usage Bonus (Deferred Revenue)	Estimate by A/P	Prefunded	289000	253.99	550500	921	(0.0)	(0.0)	(0.0)	Labor			(0.023)		
Sick Leave Liability-Utah (Energy West Mining)	Calculated by Payroll	Unfunded	248107	242	500500	501.1	(0.9)	(0.9)	(0.9)	Labor			(0.872)		
Vacation Accrual IBEW 57	Calculated by Payroll	Unfunded	248181	242	500515	Follows Labor	(12.6)	(12.8)	(12.7)	Labor			(12.699)		
Vacation Accrual IBEW 125	Calculated by Payroll	Unfunded	248182	242	500517	Follows Labor	(2.1)	(2.2)	(2.1)	Labor			(2.111)		
Vacation Accrual IBEW 659	Calculated by Payroll	Unfunded	248183	242	500520	Follows Labor	(2.4)	(2.5)	(2.4)	Labor			(2.407)		
Personal Time Accrual IBEW 57 - Laramie	Calculated by Payroll	Unfunded	248186	242	500515	Follows Labor	(0.0)	(0.0)	(0.0)	Labor			(0.042)		
Personal Time Accrual UWUA 127	Calculated by Payroll	Unfunded	248187	242	500518	Follows Labor	(3.4)	(3.5)	(3.4)	Labor			(3.437)		
Personal Time Accrual UWUA 197	Calculated by Payroll	Unfunded	248188	242	500519	Follows Labor	(0.1)	(0.1)	(0.1)	Labor			(0.112)		
Personal Time Accrual Non-Union	Calculated by Payroll	Unfunded	248189	242	500516	Follows Labor	(14.6)	(15.2)	(14.9)	Labor			(14.880)		
Sick Leave Accrual IBEW 57	Calculated by Payroll	Unfunded	248195	242	500515	Follows Labor	(6.2)	(6.2)	(6.2)	Labor			(6.222)		
Pension - Local 57	Pension - Calculated - Actuary	Unfunded	280350	228.35	501105	Follows Labor	(1.2)	(1.8)	(1.5)	Labor			(1.500)		
FAS 158 SERP Liability	SERP - Calculated - Actuary	Unfunded	280465	228.35	501115	920	(54.7)	(55.9)	(55.3)	Labor			(55.303)		
FAS 158 SERP Accumulated Other Comprehensive Income	SERP - Calculated - Actuary	Accum OCI/partially offsetting unfunded SERP liability	299107	219			9.4	11.2	10.3	Labor			10.300		
FAS 112 Book Reserve	Post-Employ - Calculated - Actuary	Unfunded	280330	228.3	501160	920	(19.1)	(20.7)	(19.9)	Labor			(19.888)		
Wasatch Worker's Compensation Reserve	Post-Employ - Calculated - Actuary	Unfunded	280490	228.3	501160	920	(4.3)	(4.2)	(4.2)	Labor			(4.240)		
Totals							(138.0)	(148.0)	(143.0)		0.000	(0.050)	(126.818)	(16.110)	
										Allocators	100.000%	21.187%	6.855%	0.000%	
										Total ($ millions)	0.000	(0.011)	(8.693)	0.000	(8.704)
										Appendix A input					**(8,704,056)**

PacifiCorp
Attachment 17 - Post-Retirement Benefits Other Than Pensions (PBOP)

FERC Acct	Description	Expense
4265000	OTHER DEDUCTIONS	(6)
5000000	OPER SUPV & ENG	(17)
5020000	STEAM EXPENSES	7,534
5060000	MISC STEAM PWR EXP	3,863,898
5063000	MISC STEAM JVA CR	(465,652)
5140000	MAINT MISC STM PLN	22,000
5350000	OPER SUPERV & ENG	566,180
5480000	GENERATION EXP	64,967
5490000	MIS OTH PWR GEN EX	34,967
5530000	MNT GEN & ELEC PLT	31,917
5560000	SYS CTRL & LD DISP	15,994
5570000	OTHER EXPENSES	751,675
5600000	OPER SUPERV & ENG	415,685
5610000	LOAD DISPATCHING	20,112
5612000	LD - MONITOR & OPER	132,802
5615000	REL PLAN & STDS DEV	4,995
5650000	Tx by Others	0
5660000	MISC TRANS EXPENSE	160
5680000	MNT SUPERV & ENG	25,668
5700000	MAINT STATION EQIP	4,880
5710000	MAINT OVHD LINES	3,330
5800000	OPER SUPERV & ENG	612,786
5810000	LOAD DISPATCHING	279,996
5850000	STRT LGHT-SGNL SYS	9,000
5880000	MSC DISTR EXPENSES	165,760
5900000	MAINT SUPERV & ENG	256,954
5920000	MAINT STAT EQUIP	93,465
5930000	MAINT OVHD LINES	21,670
5950000	MAINT LINE TRNSFRM	43,000
5970000	MNT OF METERS	113,967
5980000	MNT MISC DIST PLNT	35,994
7071000	LBR CLR - RMP	3,135,862
7072000	LBR CLR - PACPWR	1,642,646
9010000	SUPRV (CUST ACCT)	70,950
9020000	METER READING EXP	812,238
9030000	CUST RCRD/COLL EXP	6,000
9031000	CUST RCRD/CUST SYS	60,000
9032000	CUST ACCTG/BILL	70,989
9033000	CUST ACCTG/COLL	131,010
9036000	CUST ACCTG/COMMON	385,011
9050000	MISC CUST ACCT EXP	3,006
9070000	SUPRV (CUST SERV)	6,000
9080000	CUST ASSIST EXP	44,994
9084000	DSM DIRECT	63,667
9086000	CUST SERV	168,989
9090000	INFOR/INSTRCT ADV	10,000
9200000	ADMIN & GEN SALARY	1,467,214
9350000	MAINT GENERAL PLNT	23,989
	Attachment 5 input: **Total PBOP**	**15,236,246**

Notes: Excludes Mining Companies
Net of Joint Venture Cutback

ATTACHMENT C

A Draft Commission Order Approving the Offer of Settlement

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

______________, 2013

OFFICE OF ENERGY MARKET REGULATION

PacifiCorp
Docket No. ER11-3643-000, -001

PacifiCorp
825 N.E. Multnomah
Suite 1800
Portland, OR 97232

Attention: Mark M. Rabuano, Esq.
Senior Counsel for PacifiCorp

Reference: Offer of Settlement

Dear Mr. Rabuano:

On _______, 2013, you filed a Settlement Agreement and Explanatory Statement in Support of Settlement Agreement on behalf of PacifiCorp, in the above-referenced dockets. Initial comments were due on __________, 2013. [Insert reference to any comments received]. No other comments were received. On [DATE], the Presiding Settlement Judge John P. Dring certified the uncontested Settlement Agreement to the Commission.

The subject Settlement Agreement is in the public interest and is hereby approved. The settlement resolves all issues set for hearing by the Commission in the above-captioned proceedings.

The Commission's approval of the Settlement Agreement does not constitute approval of, or precedent regarding, any principle or issue in this proceeding, except to the limited extent expressly provided in the Settlement Agreement.

Consistent with the Settlement Agreement, PacifiCorp is directed to make a compliance filing to incorporate the approved tariff sheets serving as appendices to the Settlement Agreement, within thirty (30) calendar days of this order, or by [DATE].

This letter order terminates Docket No. ER11-3643-000, -001.

By direction of the Commission.

Kimberly D. Bose
Secretary

cc: All parties