Attachment D

Exhibit No. PAC-1

Exhibit No. PAC-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp	**)**	**Docket No. ER11-___-000**

TESTIMONY OF

KENNETH T. HOUSTON
ON BEHALF OF PACIFICORP

May 24, 2011

TABLE OF CONTENTS

I INTRODUCTION AND EXPERIENCE 1

II. OTHER TESTIMONY 3

III. DESCRIPTION OF PACIFICORP 4

IV. PURPOSE OF FORMULA RATE FILING 6

V. TRANSMISSION PLANNING 11

VI. PACIFICORP'S TRANSMISSION SYSTEM INVESTMENTS 12

A. Total Transmission Investment 12

B. Energy Gateway Project 14

1. Description of Project 14

2. Incentive Rate Proceeding 15

3. Current Status of Project 19

C. Other Future Investments 21

VII. DESCRIPTION OF FILING 22

LIST OF EXHIBITS

Exhibit No.	**Description**
PAC-2	Map of PacifiCorp Transmission System
PAC-3	Map of Energy Gateway Project

I. INTRODUCTION AND EXPERIENCE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My Name is Kenneth T. Houston. My business address is 825 NE Multnomah Street, Portland, Oregon 97232.

Q. IN WHAT POSITION ARE YOU CURRENTLY EMPLOYED?

A. I am the Vice President, Transmission Services for PacifiCorp (also hereinafter called the "Company"). I have been employed at PacifiCorp since 2003.

Q. PLEASE DESCRIBE YOUR EDUCATION AND BUSINESS EXPERIENCE.

A. I have a Bachelor of Science degree with Honors in Electrical Engineering from Saint Mary's University of San Antonio, Texas. I also have a Master's Degree in Management from Troy State University. I am registered as a professional engineer in Oregon, New Mexico, and Texas. My experience spans over 30 years in the energy industry, including engineering design, operations, and management positions in distribution and transmission for three different electric utilities. Since joining the Company in 2003, my responsibilities have included managing the following areas of PacifiCorp's transmission business: (i) Open Access Transmission Tariff ("OATT") and Open Access Same-Time Information System ("OASIS") administration; (ii) customer generator interconnection requests; (iii) customer transmission service requests; (iv) long-term transmission customer relations; (v) commercial transmission development opportunities; and (vi) regional transmission initiatives through the Western Electricity Coordinating Council ("WECC") and sub-regional planning groups.

Q. PLEASE SUMMARIZE THE BASIS OF YOUR KNOWLEDGE AND CONCLUSIONS CONCERNING THE ISSUES TO WHICH YOU ARE TESTIFYING IN THIS CASE.

A. The Company's last Federal Energy Regulatory Commission ("FERC" or the "Commission") transmission rate case was filed on October 2, 1995, as amended and supplemented on December 18, 1995 in Docket No. ER96-8-000, *et al*. As a result of that rate case and subsequent filings, the Company established an annual transmission revenue requirement ("ATRR") of $242.3 million and a firm point-to-point transmission rate of $2.025/kW-month. Since these rates were put into effect on January 1, 1996, the Company has significantly expanded its transmission system (as described further below), and both its network demand and firm transmission usage have increased considerably. Further, as described below, PacifiCorp continues to invest in transmission infrastructure in order to meet current needs and customers' projected load growth over the coming years. The Company needs updated transmission rates in order to be appropriately compensated for the costs incurred in providing reliable transmission service to its customers and making additional capital expenditures in transmission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide an overview of this filing, including the following: (1) PacifiCorp's proposed formula rate methodology; (2) the purpose of (and need for) the Company's proposed formula rate; (3) the proposed changes to PacifiCorp's Ancillary Services rates, including the addition of a new Schedule 3A to cover Generator Regulation and Frequency Response Service; and (4) PacifiCorp's transmission system investment initiatives, including the Company's Energy Gateway transmission expansion

project ("Energy Gateway Project" or the "Project") for which the Commission has authorized incentive rate treatment. My testimony also describes the proposed changes to PacifiCorp's OATT and the other testimony supporting this filing.

II. OTHER TESTIMONY

Q. ARE ANY OTHER INDIVIDUALS FILING TESTIMONY ON BEHALF OF PACIFICORP IN THIS PROCEEDING?

A. Yes. The following individuals are providing testimony on behalf of PacifiCorp:

- Alan C. Heintz, Vice President of Brown, Williams, Morehead, and Quinn, Inc., has prepared testimony supporting PacifiCorp's proposed formula rate methodology. Mr. Heintz's testimony also supports the rate methodologies employed for PacifiCorp's proposed Ancillary Services charges for Schedules 1, 2, 3, 3A, 5 and 6 of PacifiCorp's OATT. In addition, Mr. Heintz will be sponsoring Statement BG (Revenue Data to Reflect Changed Rates), which provides revenue data reflected in the proposed transmission rates, and Statement BH (Revenue Data to Reflect Present Rates), which provides revenue data reflected in the current transmission rates (*See* Exhibit Nos. PAC-4 through PAC-8);
- Gregory N. Duvall, Director of Net Power Costs for PacifiCorp, has prepared testimony supporting the amount of reserves that are needed by PacifiCorp to provide service under PacifiCorp's revised Schedules 3, 5, and 6 and proposed Schedule 3A of PacifiCorp's OATT (*See* Exhibit No. PAC-9);
- Dr. William E. Avera, President of FINCAP, Inc., has prepared testimony supporting PacifiCorp's proposed 10.9% base return on equity ("ROE") for the Company (*See* Exhibit Nos. PAC-10 through PAC-20); and

- Paul M. Normand, a principal at Management Applications Consulting, Inc., has prepared testimony supporting PacifiCorp's proposal for a revised transmission real power loss factor, which is reflected in the revised Schedule 10 of PacifiCorp's OATT included with this filing (*See* Exhibit Nos. PAC-21 through PAC-24).

III. DESCRIPTION OF PACIFICORP

Q. PLEASE PROVIDE A DESCRIPTION OF PACIFICORP.

A. PacifiCorp is an indirect, wholly-owned subsidiary of MidAmerican Energy Holdings Company. PacifiCorp provides delivery of electric power and energy to approximately 1.7 million retail electric customers in six western states. PacifiCorp consists of three core business units: (1) PacifiCorp Energy manages the electric generation, commercial and trading, and coal mining operations of the Company; (2) Pacific Power delivers electricity to retail customers in Oregon, Washington and California; and (3) Rocky Mountain Power delivers electricity to retail customers in Utah, Wyoming and Idaho. PacifiCorp's transmission operations and management personnel are headquartered in Portland, Oregon.

Under its OATT, PacifiCorp provides Long-Term Firm Point-to-Point ("PTP") Transmission Service to 10 transmission customers, Short-Term Firm and Non-Firm PTP Transmission Service to over 140 transmission customers under umbrella agreements, and Network Integration Transmission ("NIT") Service to eight transmission customers, including PacifiCorp Energy. PacifiCorp also provides transmission service to certain "legacy" transmission customers under agreements pre-dating the OATT.

As of December 31, 2010, PacifiCorp's current total transmission plant in service is approximately $4.3 billion.[1] PacifiCorp is interconnected with more than 80 generation plants and 13 adjacent control areas at approximately 152 points of interconnection. PacifiCorp owns, or has an interest in, generation resources directly interconnected to its transmission system with a system peak capacity of approximately 16,343 MW.[2] This generation capacity includes a diverse mix of coal, hydro-electric, wind power, natural gas-fired combined cycles and combustion turbines, and geothermal resources.

Q. PLEASE DESCRIBE PACIFICORP'S TRANSMISSION SYSTEM.

A. PacifiCorp's bulk transmission network is designed to reliably transport electric energy from generation resources (owned generation or market purchases) to various load centers. The Company's transmission network is highly integrated with other transmission providers in the western United States. PacifiCorp owns and operates approximately 16,785 miles of transmission lines in 10 states.[3] Exhibit No. PAC-2 provides a high-level map of PacifiCorp's transmission system and service territory. A more detailed system one-line map can be found on PacifiCorp's OASIS site at the following link: http://www.oasis.pacificorp.com/oasis/ppw/pacificorp_oneline.pdf.

Q. WHICH STATE PUBLIC UTILITY COMMISSIONS REGULATE PACIFICORP'S RETAIL SERVICE OPERATIONS?

A. PacifiCorp is subject to the jurisdiction of the following six state public utility commissions: (1) California Public Utilities Commission; (2) Idaho Public Utilities

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1 PacifiCorp 2010 FERC Form No. 1 at 206-207 (Apr. 25, 2011).

2 PacifiCorp 2010 FERC Form No. 1 at 400 (Apr. 25, 2011).

3 PacifiCorp 2010 FERC Form No. 1 at 422 (Apr. 25, 2011).

Commission ("Idaho PUC"); (3) Oregon Public Utility Commission; (4) Public Service Commission of Utah; (5) Washington Utilities and Transportation Commission; and (6) Wyoming Public Service Commission.

IV. PURPOSE OF FORMULA RATE FILING

Q. PLEASE DESCRIBE PACIFICORP'S CURRENT OATT?

A. PacifiCorp provides PTP Transmission Service, NIT Service, and Ancillary Services under its current OATT, which is based on Order No. 890's *pro forma* OATT. In relevant part to this filing, Attachment H provides for the Company's current ATRR for NIT Service, which currently is approximately $242.3 million. Schedule 10 to PacifiCorp's OATT includes the Company's real power loss factors. The stated rates for PTP Transmission Service and NIT Service in PacifiCorp's current OATT were effective in 1996 and 2002, respectively, as a result of the Company's last transmission rate case filing and subsequent filings, as described further below.

Q. PLEASE PROVIDE A DESCRIPTION OF PACIFICORP'S LAST RATE CASE RESULTING IN THE CURRENT TRANSMISSION RATES.

A. PacifiCorp's last full transmission rate case proceeding was filed on October 2, 1995, as amended and supplemented on December 18, 1995, in Docket No. ER96-8-000, *et al*., when the Company made a filing to update its rates for transmission service and firm "requirements" electric service for several municipal customers.[4] PacifiCorp was not proposing to increase any rates. The proposed rates were designed to collect PacifiCorp's new revenue requirements as a result of billing demands, and were based on 1994 FERC Form No. 1 costs and information. A partial settlement agreement among PacifiCorp and

[4] *PacifiCorp*, Rate Filing, Docket No. ER96-8-000 (Oct. 2, 1995); *PacifiCorp*, Amendment to Rate Filing, Docket No. ER96-8-000 (Dec. 18, 1995).

various intervening parties was filed with the Commission on June 10, 1996. The ATRR for purposes of NIT Service was approximately $167.6 million under the settlement. The settlement charge for Firm PTP Transmission Service was based on an annual rate of $24.30/kW-year and a monthly rate of $2.025/kW-month. The effective date for the settlement rates was January 1, 1996. Because the settlement agreement contained "black box" settlement rates, it does not discuss the specific manner in which the rates were derived. The Commission approved the partial settlement as in the public interest. The rates submitted with the partial settlement were accepted for filing, subject to refund and revision.[5] On June 3, 2002, in Docket No. ER02-653-000, the Commission approved PacifiCorp's request to revise its ATRR from approximately $167.6 million to its current $242.3 million to reflect appropriate revenues.[6] The $24.30/kW-year rate was not modified. PacifiCorp's stated rates have not changed since this time.

Q. WHY IS PACIFICORP MAKING A FILING AT THIS TIME?

A. On November 21, 2007, in Docket No. EL07-84-000, *et al*., PacifiCorp, Pacific Gas and Electric Company, the California Independent System Operator Corporation, and several other parties filed an uncontested "Offer of Settlement and Stipulation" ("Offer of Settlement") providing for, among other things, the shared usage and coordinated operation, maintenance, and planning of certain assets making up a portion of the California-Oregon Intertie ("COI"). The Commission accepted the Offer of Settlement by order dated December 20, 2007.[7] The Offer of Settlement provided that, upon its

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[5] *PacifiCorp*, 83 FERC ¶ 61,059 (1998); *see also PacifiCorp*, 84 FERC ¶ 61,303 (1998), *aff'g*, 79 FERC ¶ 63,003 (1997) (accepting the transmission rates included in PacifiCorp's black box settlement subject to the outcome of the three litigated issues in Docket No. ER96-8-000, *et al.*, concerning the rate treatment of several of PacifiCorp's legacy contracts).

[6] *PacifiCorp*, 98 FERC ¶ 61,224 (1998), *reh'g granted in part and denied in part*, 99 FERC ¶ 61,259 (2002).

[7] *PacifiCorp, et al.*, 121 FERC ¶ 61,278 (2007).

acceptance, the Commission's investigation of PacifiCorp's transmission rates established in Docket No. EL07-84 shall be terminated. Section 8.2 of the Offer of Settlement also provided that PacifiCorp would file a general rate case for its system-wide transmission rates no later than June 1, 2011.[8]

Consistent with Section 8.2 of the Offer of Settlement, PacifiCorp is now proposing to update its transmission rates so that the charges recovered for providing transmission service more accurately (and more timely) reflect PacifiCorp's costs of providing transmission services, including PacifiCorp's substantial investment in new transmission infrastructure to support load growth in the Company's service area. PacifiCorp's load and firm transmission usage have also grown considerably since the last transmission rate case. By aggressively managing its costs and matching new investments to load growth since its 1995 rate case, PacifiCorp has avoided the need to request a change in its transmission rates. However, given PacifiCorp's recent and planned transmission investments, PacifiCorp believes that new OATT rates are necessary for the Company to appropriately recover capital, operating and maintenance ("O&M"), and other applicable costs.

Q. PLEASE PROVIDE AN OVERVIEW OF PACIFICORP'S PROPOSED FORMULA RATE.

A. PacifiCorp is proposing to employ a formula rate methodology to calculate its rates for PTP Transmission Service and NIT Service. The transmission rates will be adjusted annually, using the approved rate formula to calculate the Company's ATRR for each year based on actual cost inputs from PacifiCorp's FERC Form No. 1 data and other

[8] *Id.* at P 10.

Company records, as well as projected transmission plant additions. The rates will be updated based on formula rate implementation protocols, discussed further below. The formula will allow PacifiCorp to recover the costs of providing transmission service on a timely basis, which will support the addition of needed transmission facilities and help to ensure the reliability of PacifiCorp's transmission system. A formula rate provides PacifiCorp with the best mechanism to equitably allocate to transmission customers those costs attributable to the Company's transmission additions and upgrades on an annual basis. A formula rate ensures that transmission customers will be assessed a charge reflecting an accurate representation of the Company's transmission costs and the reliability benefits received. In addition, it is more efficient for all interested parties if PacifiCorp implements a formula rate methodology with an annual true-up mechanism, rather than submitting a separate transmission rate case filing on an annual basis. The testimony of Mr. Alan Heintz will provide a more detailed description of the proposed formula rate, its components, and how the formula is implemented.

Q. HOW HAVE PACIFICORP'S TRANSMISSION COSTS INCREASED SINCE THE LAST RATE CASE?

A. PacifiCorp's transmission costs have increased substantially since its last rate case was filed. The primary driver for this increase is PacifiCorp's substantial investment in transmission facilities since PacifiCorp's current rates went into effect on January 1, 1996, as PacifiCorp has increased its investment in net transmission plant from approximately $2.042 billion (for 1995)[9] to $4.3 billion (for 2010).[10] This represents an approximately 110% increase over the last 15 years.

[9] PacifiCorp 1995 FERC Form No. 1 at 206-207 (April 29, 1996).

[10] PacifiCorp 2010 FERC Form No. 1 at 206-207 (Apr. 25, 2011).

Q. PLEASE DESCRIBE PACIFICORP'S PROPOSED TRANSMISSION RATE.

A. PacifiCorp's proposed formula rate contains two components that will be incorporated into PacifiCorp's OATT. The first component is Attachment H-1 (including Attachments 1 through 8) which contains the formula to be used to determine PacifiCorp's annual rates for NIT Service and PTP Transmission Service. The second component is Attachment H-2, the Formula Rate Implementation Protocols (the "Protocols"). The Protocols describe how PacifiCorp will update the formula every year, the customer review procedures to be followed, how customer challenges will be resolved and how changes to the annual rate will be implemented. The testimony of Mr. Alan Heintz details these procedures.

Q. HOW HAS PACIFICORP PROPOSED TO TREAT LOSSES IN ITS FILING?

A. PacifiCorp proposes to modify the definition of "Reserved Capacity" in Section 1.45 and to modify Section 34.2 of the OATT to clarify that the maximum amount of capacity and energy that the Transmission Provider agrees to transmit for PTP Transmission Service or NIT Service customers will include transmission service attributable to losses. As explained below, PacifiCorp has calculated its proposed rates by also including losses in the divisor of each rate calculation.

Q. PLEASE DESCRIBE THE IMPACT OF THIS FILING ON PACIFICORP'S RATES.

A. PacifiCorp proposes to increase its ATRR from approximately $242.3 million, approved in 2002, to $ 367.1 million. This increase in ATRR will result in an average increase in rates to PacifiCorp's NIT Service customers for an average of 52%, generally reflecting the increase in the ATRR and including losses. When PacifiCorp's new ancillary

services rates are applied, the rate impact on NITS Customers is an average rate increase of 63%. PacifiCorp's Long-Term Firm PTP Service rates will increase from a yearly demand charge of $24.30/kW-year to $24.77/kW-year, which will result in an approximate 2% increase in rates for PacifiCorp's Long-Term Firm PTP Transmission Service customers. When losses are grossed-up and the new rate design is applied, the rate impact on the Customer is approximately 7%. When PacifiCorp's new ancillary services are applied, the rate impact on PTP Service Customers is a 15% to 41% increase in rates. Statement BG and Statement BH, sponsored through the testimony of Mr. Alan Heintz, include a detailed analysis of PacifiCorp's proposed rate increases (See Exhibit No. PAC-8).

Q. HOW WAS PACIFICORP'S INITIAL TRANSMISSION REVENUE REQUIREMENT DERIVED?

A. The testimony of Mr. Alan Heintz includes a populated version of the proposed formula to establish the initial ATRR. The formula produces a net ATRR that is the sum of the return on rate base, O&M expense, depreciation expense, taxes other than income taxes, income taxes, and revenue credits.

V. TRANSMISSION PLANNING

Q. HOW DOES PACIFICORP PLAN THE TRANSMISSION SYSTEM?

A. PacifiCorp performs an annual assessment of its transmission system and implements at least a ten-year planning forecast. The Company must maintain system reliability to provide adequate transmission service. In particular, PacifiCorp plans the system in accordance with North American Electric Reliability Corporation Reliability Standards, WECC regional Reliability Standards, and Company planning guidelines. PacifiCorp

also performs assessments and studies with other transmission providers consistent with regional planning criteria. In addition to planning its transmission system for reliability, the Company also plans to meet the needs of its transmission customers. Pursuant to Part III of PacifiCorp's OATT, NIT Service customers must provide PacifiCorp with annual updates of network load and network resources forecasts. Network service allocations are studied and adjusted based upon the NIT Service customers' load and resource forecast submittals. PacifiCorp assesses future load and resource developments to plan the evolution of an efficient transmission system, and to undertake reliability analysis and improvements. PacifiCorp's transmission planning process is performed in three distinct, yet coordinated, levels – on a local, sub-regional, and regional basis, as set forth in greater detail in Attachment K to PacifiCorp's OATT.

VI. PACIFICORP'S TRANSMISSION SYSTEM INVESTMENTS

A. Total Transmission Investment

Q. WHAT FACTORS ARE DRIVING THE COMPANY'S INCREASING CAPITAL REQUIREMENTS?

A. Transmission capacity on PacifiCorp's existing transmission system is at or near full utilization. In addition, forecasted annual load growth and annual coincidental peak load are both expected to grow over the next ten years. The Company has identified the need for significant investment in major new transmission facilities to meet customers' forecasted electricity usage and to help satisfy renewable portfolio standards throughout its service territory. Over the next few years, capital will be required in order to meet future load growth on the system, integrate new generation on the grid, accommodate transmission service requests, and maintain reliability.

Q. PLEASE DESCRIBE THE COMPANY'S TRANSMISSION SYSTEM INVESTMENT OVER THE PAST 15 YEARS.

A. In 1995, PacifiCorp's total transmission plant in service was approximately $2.042 billion.[11] In 2010, PacifiCorp's total transmission plant in service was $4.3 billion,[12] which represents an approximately 110% increase over the last 15 years. In particular, the total investment PacifiCorp made in its transmission system over the past five years is approximately $1.7 billion.[13] PacifiCorp made numerous transmission improvements between 1995 and 2010 in order to maintain adequate and reliable service. During this time, PacifiCorp has added approximately 652 miles of new transmission lines, including approximately 354 miles of 230/345 kV transmission. In addition, since 1995, PacifiCorp has constructed 12 new transmission substations.

Further, as explained below, in 2007, PacifiCorp announced its plan to construct the Energy Gateway Project, which PacifiCorp estimates will be a $6 billion "backbone" transmission infrastructure investment. PacifiCorp currently anticipates that the Project will include eight segments. The first segment – the Populus to Terminal transmission line – was placed in service in November 2010. This segment alone represents an $830 million investment. PacifiCorp began construction on the second segment of the Project – the Mona to Oquirrh line (at approximately $440 million) – in May 2011. Remaining segments will follow as permitting and construction efforts are completed.

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[11] PacifiCorp 1995 FERC Form No. 1 at 206-207 (April 29, 1996).

[12] PacifiCorp 2010 FERC Form No. 1 at 206-207 (Apr. 25, 2011).

[13] *Compare* PacifiCorp 2010 FERC Form No. 1 at 206-207 (Apr. 25, 2011), *with* PacifiCorp 2005 FERC Form No. 1 at 206-207 (Mar. 20, 2006) (identifying a total net transmission plant of approximately $2.6 billion).

B. Energy Gateway Project

1. Description of Project

Q. PLEASE DESCRIBE THE ENERGY GATEWAY PROJECT.

A. When completed, the Energy Gateway Project will traverse six states, numerous communities, and several areas of federally-administered lands. The Project is expected to add approximately 2,000 miles of new transmission lines and related improvements to the PacifiCorp transmission system. The table below lists each of the segments of the Energy Gateway Project and Exhibit No. PAC-3 provides a map of the Project and PacifiCorp's service territory.

Segment	Designation
Segment A: Wallula to McNary	No regional designation
Segment B: Populus to Terminal	Gateway Central
Segment C: Mona to Oquirrh and Oquirrh to Terminal	Gateway Central
Segment D: Windstar to Populus	Gateway West
Segment E: Populus to Hemingway	Gateway West
Segment F: Aeolus to Mona	Gateway South
Segment G: Sigurd to Red Butte	Gateway South
Segment H: Hemingway to Captain Jack	No regional designation

The Project will enhance reliability, reduce transmission congestion, and improve the flow of electricity throughout the region. The Project's 500 kV transmission lines will be the first such lines to be installed in the Project footprint (primarily Wyoming, Idaho, and Utah), and the Project will provide an essential reliability backbone that will contribute to the existing transmission network in the region. The Project will also connect areas rich in energy resources to load centers, enabling transmission customers' access to these areas with options for the development of new energy resources, including renewables.

2. Incentive Rate Proceeding

Q. PLEASE BRIEFLY DESCRIBE PACIFICORP'S PETITION REQUESTING INCENTIVE RATES FOR THE ENERGY GATEWAY PROJECT.

A. On July 3, 2008, in Docket No. EL08-75, PacifiCorp submitted a Petition for a Declaratory Order to FERC seeking incentive rate treatment for the Energy Gateway Project, pursuant to Federal Power Act ("FPA") Section 219 and the Commission's Order No. 679 (the "Petition"). In the Petition, the Company explained that the Energy Gateway Project qualified for rate incentives because of the scope and magnitude of the Project, as well as the significant risks and challenges in pursuing this Project at that time (*e.g.*, siting, construction, regulatory, financing, and technology). In the Petition, PacifiCorp explained that it will propose to include the Energy Gateway Project in retail rates. To the extent that recovery of all of the transmission investment is permitted in the Company's retail rate base, PacifiCorp will compensate its retail customers by crediting the transmission-related revenues, inclusive of any incentives granted by the Commission, against its retail revenue requirement.

Q. WHAT DID THE COMMISSION CONCLUDE CONCERNING THE ENERGY GATEWAY PROJECT'S ELIGIBILITY FOR INCENTIVE RATES?

A. In its Order of Petition for Declaratory Order,[14] the Commission found that PacifiCorp adequately demonstrated that Segments B through H of the Project will ensure reliability and reduce transmission congestion, and therefore satisfied the requirements of FPA Section 219 for incentive rate treatment. FERC determined, however, that Segment A

[14] *PacifiCorp*, 125 FERC ¶ 61,076 (2008) ("Incentive Rate Order").

should not receive incentives at the time.[15] FERC found that Segments B through H of the Project "would establish for the first time a backbone of 500 kV transmission lines in PacifiCorp's Wyoming, Idaho and Utah regions."[16] The Commission found that the Company faces significant risks and challenges in pursuing the Project related to the magnitude of the financial investment required and the regulatory risks involved, including significant siting issues because the individual segments must be approved by numerous states and several federal authorities.[17] With the exception of Segment A, FERC concluded that each segment of the Project improves PacifiCorp's transmission operations and increases transfer capability, thereby concluding that the Project as a whole satisfied the Commission's nexus requirement.[18]

Q. WHAT TRANSMISSION INCENTIVES DID THE COMMISSION AUTHORIZE FOR PACIFICORP'S ENERGY GATEWAY PROJECT?

A. The Commission granted the following incentive rate treatment for Segments B through H of the Project: (1) a 200 basis point adder to the base ROE and (2) recovery of prudently-incurred costs if the Project is cancelled or abandoned due to factors beyond the Company's control. The Commission found that a number of factors, including the Project's vast size, cost, extended period of time for completion, and the siting, regulatory, and financial risks, supported the Company's request for an incentive ROE adder to the base ROE to be determined in a future rate case.[19] The Commission also granted the requested incentive of recovery of prudently-incurred development and

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[15] *Id.* at P 40.

[16] *Id.* at P 39.

[17] *Id.* at P 44.

[18] *Id.* at P 46.

[19] *Id.* at P 51. The Commission's grant of a 200 basis point incentive ROE adder is bound by the upper end of the zone of reasonableness. *Id.* at P 53.

construction costs if the Project is cancelled or abandoned, in whole or in part, as a result of PacifiCorp's inability to obtain necessary approvals or as a result of action or inaction by any governmental or regulatory authority, for any reason determined to be outside of PacifiCorp's control.[20] FERC found that this incentive will serve as "an effective means to encourage the completion of the Project," in light of the Project's need for timely approvals from multiple jurisdictions and various federal approvals. FERC stated that "[d]ependence upon approval by multiple jurisdictions introduces a significant element of risk to this Project that is not faced by utilities building transmission facilities within a single jurisdiction."[21] The Commission concluded that multiple incentives are justified here in light of the demonstrable risks and challenges faced by the Project, and found that PacifiCorp demonstrated a nexus for the total package of incentives.[22]

The testimony of Mr. Alan Heintz and Dr. William Avera further address the ROE adder incentive for Project segments as part of PacifiCorp's formula rates. The testimony of Mr. Heintz explains how the formula mechanism applies the ROE adder incentive to the Project's facilities for approved segments and how abandoned plant costs would be incorporated into the formula to the extent that they are sought and approved for recovery pursuant to a future Section 205 filing. PacifiCorp is not seeking any abandoned plant costs associated with the Project at this time.

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[20] *Id.* at P 54.

[21] *Id.* at P 55.

[22] *Id.* at P 59.

Q. HAS THE ENERGY GATEWAY PROJECT EXPERIENCED ANY REGULATORY OR OTHER RISKS?

A. Yes. In PacifiCorp's Petition, the Company recognized that, given the Project's scale and scope, the Project would face significant regulatory risks at the local, state, and federal levels – namely, the Project would require siting and permitting approval from multiple state and federal jurisdictions and encounter significant financial risks when the Company seeks retail rate recovery for its transmission investment in the Project from state regulators. PacifiCorp recognized the risks that it must apply for rate recovery in each of its retail jurisdictions and, in doing so, must show that any additions to rate base are prudently incurred and are "used and useful" for retail customers.[23] In a February 28, 2011 order, the Idaho PUC concluded that, rather than including in rate base 100% of the Company-requested costs attributable to the Populus to Terminal line, only a portion of the Company's investment is currently "used and useful", despite the fact that the facility is energized and fully integrated into the PacifiCorp transmission system.[24] In addition, as discussed in more detail below, the Project has experienced delays in the federal siting and permitting processes, particularly with the federal Bureau of Land Management's Environmental Impact Statement process for the Gateway West segments (*i.e.*, Segments D and E), which presents significant timing risks for delivering the Project. The Company anticipates that it will continue to face these types of risks throughout execution of the Project.

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[23] Petition at 35.

[24] *In the Matter of the Application of PacifiCorp d/b/a Rocky Mountain Power for Approval of Changes to its Electric Service Schedules*, Order No. 32196, Case No. PAC-E-10-07, at 38 (Feb. 28, 2011) ("Idaho PUC Order").

3. Current Status of Project

Q. WHAT IS THE CURRENT STATUS OF THE ENERGY GATEWAY PROJECT?

A. PacifiCorp is well underway in the rating, permitting, and construction of its expansive Energy Gateway Project transmission investment plan. In November 2010, the Company completed and placed into service the first major segment of Gateway Central – the 135-mile, double-circuit 345 kV Populus to Terminal line (Segment B) – on schedule.[25] Among other things, this line is needed to support long-term load growth and strengthen PacifiCorp's overall transmission system. The Populus to Terminal line will add significant new incremental transmission capacity (planned rating of 1,400 MW) to Northern Utah and help integrate other future planned resources, market purchases, and sales as necessary to help control energy costs. Further, the Populus to Terminal line, as part of Gateway Central, will be used to interconnect Gateway West (*i.e.*, Segments D and E) and Gateway South (*i.e.*, Segments F) and thus is critical for the overall successful integration of the Project in PacifiCorp's transmission system. Permitting and the specific routes for many of the other line segments remain subject to finalization. The Company continues to work with local, state, and federal entities as needed for this effort. Construction on the Mona to Oquirrh line (part of Segment C) began in May 2011, with an expected 2013 in-service date.

Q. HOW HAS THE TIMING OF THE ENERGY GATEWAY PROJECT CHANGED?

A. In the Petition, the Company indicated that it had prioritized the construction of the eight Project segments in order to ensure the most prudent approach to deliver completion of

[25] PacifiCorp's Petition included an estimated in-service date for Segment B of 2010. Petition at 11.

the Project. In addition to the completion of Segment B (the Populus to Terminal line), the Company has begun the preliminary permitting and construction work to get Segments A, C, and G on-line between 2012 and 2014. The Energy Gateway Project has experienced some delays in the federal siting and permitting processes, particularly for the Gateway West segments. These and other factors have required the Company to necessarily adapt and update the projected in-service dates from the initial estimated in-service dates, in order to allow for permitting delays while maintaining the urgency to complete the Project.

Q. HOW IS THE COMPANY'S INVESTMENT IN THE ENERGY GATEWAY PROJECT INCORPORATED IN THE PROPOSED FORMULA RATE?

A. Each of the segments of the Energy Gateway Project is reflected as a placeholder in the Company's proposed formula. While all of PacifiCorp's investment in the Project will eventually be recovered through the formula, only Segments B through H are subject to Order No. 679 rate incentives based on the Commission's Incentive Rate Order. Presently, PacifiCorp has incorporated the $830 million for its investment in the completed Populus to Terminal line and investment to date in the Mona to Oquirrh project in PacifiCorp's proposed transmission rates. The Testimony of Mr. Heintz details the formula rate's treatment of the Project.

C. Other Future Investments

Q. PLEASE DESCRIBE OTHER MAJOR TRANSMISSION INVESTMENTS PLANNED BY THE COMPANY WHICH ARE GREATER THAN TEN MILLION DOLLARS.

A. In addition to the Energy Gateway Project, PacifiCorp has plans for numerous other significant capital investments in the Company's transmission system. For example, the Company anticipates placing into service a significant number of projects, all exceeding $10 million, within the next one to two years. Examples of these projects and their associated investment are included below (the figures below are all approximate). These projects would be included in the formula rate as transmission plant in-service.

- **Red Butte Substation: $49 million.** Installation of a 300 MVAR Static VAR Compensator and 345 kV capacitor as part of a facility expansion at the Red Butte substation in southwest Utah;
- **Terminal Substation: $41 million.** Replacement of two 345/138 kV transformers at the Terminal substation and modification of existing facilities;
- **Dave Johnston-Casper 230 kV Transmission Lines and Substations: $31 million.** Relocation of portions and rebuilding the entirety of the existing Dave Johnston-Casper 230 kV #1 line, installation of a new conductor on the existing Dave Johnston-Casper 230 kV #2 line, and modification of facilities at the Casper and Dave Johnston substations; and
- **Shunt Capacitors in Wyoming: $18 million.** Installation of a Static VAR Controller for reactive power support and 230 kV voltage control in south/central Wyoming. The

project includes 230 kV equipment and control installations at several existing substations: Atlantic City, Midwest, Riverton and Platte.

VII. DESCRIPTION OF FILING

Q. HAS PACIFICORP PREPARED REVISED TARIFF SHEETS REFLECTING THE PROPOSED CHANGES IN TRANSMISSION RATES?

A. Yes. The Company has included as part of this filing both a clean version and a black-lined version of the revised OATT sheets.

Q. PLEASE DESCRIBE THE CHANGES MADE IN THE REVISED TARIFF SHEETS.

A. Changes to PacifiCorp's tariff sheets in this filing include:

- An updated Table of Contents;
- The addition of a definition of "Annual Transmission Revenue Requirement", modification of the definitions of "Control Area" and "Reserved Capacity," and removal of the definition of "Load Ratio Share," in OATT Section 1;
- The revision of OATT Parts I, II and III (*e.g.*, Sections 3, 30, 33, and 34) in order to reflect the revisions to other tariff provisions addressing the implementation of the formula rate, the changes to NIT Service, and the revised charges for Ancillary Services;
- The revision of OATT Schedule 1 to reflect a new formula rate for calculating charges for Scheduling, System Control, and Dispatch Service;
- The revision of OATT Schedule 2 to reflect the revised charges for providing Reactive Supply and Voltage Control from Generation or Other Sources Service;
- The revision of OATT Schedule 3 to reflect the revised charges for providing Regulation and Frequency Response Service;
- The addition of new OATT Schedule 3A, Generator Regulation and Frequency Response Service, to reflect PacifiCorp's obligation to offer Generator Regulation and Frequency Response Service and the rate at which the service will be provided;

- The revision of OATT Schedule 5 to reflect the revised charges for providing Spinning Reserve Service;
- The revision of OATT Schedule 6 to reflect the revised charges for providing Supplemental Reserve Service;
- The revision of OATT Schedule 7 to provide that the charges for Long-Term and Short-Term Firm PTP Transmission Service will be calculated from the formula in Attachment H-1;
- The revision of OATT Schedule 8 to provide that the charges for Non-Firm PTP Transmission Service will be calculated from the formula in Attachment H-1;
- The revision of OATT Schedule 10 to reflect a revised transmission loss factor and method for transmission customers to settle real power losses;
- The revision of OATT Attachment H, stating that the Company's charges for NIT Service will be calculated based on the Company's ATRR, derived from PacifiCorp's proposed formula rate, as well as the addition of (i) Attachment H-1, PacifiCorp's proposed formula to determine the rates for NIT Service and PTP Transmission Service, and (ii) Attachment H-2, PacifiCorp's Protocols;
- The revision of OATT Attachment M, concerning the Oregon Direct Access program, to reflect the changes to NIT Service; and
- The removal of the contents of Attachment R ("Load Ratio Share Specification Table").

Q. WOULD YOU DESCRIBE THE CHANGES TO THE METHODOLOGY USED BY PACIFICORP TO BILL NIT SERVICE CUSTOMERS?

A. PacifiCorp has traditionally billed its NIT Service customers using a traditional "load ratio share" methodology. PacifiCorp is proposing to charge its NIT Service customers using the ATRR, whereby network customers will pay a Monthly Demand Charge, which will be determined by multiplying the monthly transmission rate established in Attachment H-1 by the customer's Monthly Network Load (its hourly load coincident with the Transmission Provider's Monthly Transmission System Peak), as stated in

proposed revision to Section 34 of the OATT. This change in billing will benefit NIT Service customers because it will be based on current load data, is easily verifiable by NIT Service customers, and will increase the level of transparency in customers' billing determinants. This method also facilitates ease of tariff administration and has been accepted for other transmission providers.[26]

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED REVISIONS TO SCHEDULE 1 OF THE TARIFF?

A. Currently in OATT Schedule 1, PTP Transmission Service and NIT Service customers pay a charge of $0.00 for Scheduling, System Control, and Dispatch Service. PacifiCorp proposes a change to Schedule 1 requiring PTP Transmission Service and NIT Service customers to pay a charge based on the Annual Revenue Requirement calculated from a rate formula included in Schedule 1. This charge will be calculated on an annual basis and subject to the Protocols in Attachment H-2. The testimony of Mr. Alan Heintz provides a more detailed description of the proposed Schedule 1 rate, its components, and how it will operate.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED REVISIONS TO SCHEDULE 2 OF THE TARIFF?

A. Currently in OATT Schedule 2, PTP Transmission Service and NIT Service customers pay a charge of $0.00 for Reactive Supply and Voltage Control from Generation or Other Sources Service. PacifiCorp proposes a change to Schedule 2 to include a stated rate for PTP Transmission Service and NIT Service customers. This new charge reflects the

[26] *See e.g., Carolina Power & Light Co. and Florida Power Corp.*, unpublished letter order, Docket Nos. ER10-288-000, *et al.*, (Feb. 4, 2010) (accepting revisions to Section 34 of the OATT to reflect revisions to implement formula rate); *Kansas City Power & Light Co., et al.*, 130 FERC ¶ 61,009 (2010) (conditionally accepting revisions to Section 34 of the OATT to reflect revisions to implement formula rate).

Company's actual costs in providing Reactive Supply and Voltage Control from Generation Service for each transaction on the Company's transmission facilities. Mr. Alan Heintz's testimony further discusses the methodology by which the proposed rate for this Schedule 2 charge was derived.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED REVISIONS TO SCHEDULE 3 OF THE TARIFF?

A. Currently in OATT Schedule 3, transmission customers seeking to cover their Regulation and Frequency Response Requirements through the purchase of such services pay a charge of $0.16 MW/h multiplied by the sum of (1) the total amount of energy delivered to the Points of Delivery by PacifiCorp plus applicable Real Power Losses, and (2) any of the Network Customer's Network Load served from generation internal to the Network Customer's system. Proposed Schedule 3 now provides stated rates for yearly, monthly, weekly, daily, and hourly service. Transmission customers purchasing service under Schedule 3 must purchase an amount of reserved capacity equal to 4.24% of the customer's Reserved Capacity for PTP Transmission Service or 4.24% of the customer's Monthly Network Load for NIT Service. The increase in charges under Schedule 3 reflects the Company's actual costs in providing this service for the continuous balancing of resources and load and maintaining scheduled interconnection frequency. Mr. Alan Heintz's testimony further discusses the methodology by which the proposed rates and percentage obligation for this Schedule 3 charge were derived. The testimony of Mr. Greg Duvall further addresses the Company's methodology for calculating the amount of regulating reserves required to meet reliability requirements and for reliable operation of the transmission system.

Q. WHAT IS PACIFICORP'S JUSTIFICATION FOR A NEW SCHEDULE 3A?

A. PacifiCorp is proposing a new Schedule 3A, Generator Regulation and Frequency Response Service, to recover the costs associated with holding generation capacity on-line and available to mitigate the moment-to-moment variations in generation output. Schedule 3A will apply to all transmission customers delivering energy from all generators (both thermal and renewable) in PacifiCorp's balancing authority areas ("BAAs") exporting the energy out of the BAAs, and it will apply to the extent that such customers are not already subject to Regulation and Frequency Response charges under Schedule 3. In addition to seeking to recover the full costs of regulation reserves associated with balancing generation variability, PacifiCorp's proposed Schedule 3A is intended to address concerns raised by certain of the state commissions regulating PacifiCorp's operations that retail ratepayers continue to bear a disproportionate burden of the costs of capacity associated with the integration of variable generation into PacifiCorp's transmission system.

Q. WHY DOES PACIFICORP NEED SCHEDULE 3A FOR REGULATION RESERVES WHEN IT HAS SCHEDULE 3?

A. While OATT Schedule 3 allows transmission providers to recover the costs of regulation reserves associated with mitigating load variations within their BAA, it does not provide a mechanism for transmission providers to recover the costs of holding capacity in reserve for the provision of balancing the variations in generation whose output is delivered outside of the BAA. As such, proposed Schedule 3A is intended to address this existing cost recovery gap under the *pro forma* OATT.

Further, in Order No. 890-A, the Commission allowed transmission providers to propose to assess regulation charges both to generators selling in the BAA and those selling outside their BAA. The Commission stated that it would consider such proposals on a case-by-case basis.[27] The Commission has approved transmission provider proposals to recover the costs of capacity associated with the provision of generator balancing service through a proposed schedule seeking charges for providing generator regulation and frequency response service.[28] Moreover, the Company's proposed Schedule 3A is consistent with the Commission's November 18, 2010 Notice of Proposed Rulemaking ("NOPR") on the integration of Variable Energy Resources ("VERs"), in which FERC proposed a generic rate schedule for the rates, terms, and conditions that apply to providing Generator Regulation and Frequency Response Service.[29] PacifiCorp's new Schedule 3A allows PacifiCorp to close the cost recovery gap with the type of ancillary service that FERC has contemplated and accepted in the past for other public utilities. A transmission customer subject to Schedule 3A must either (1) take Generator Regulation and Frequency Response Service from PacifiCorp or (2) demonstrate that it has satisfied its regulation service obligation.

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[27] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 (2007), *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 313 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[28] *See, e.g.*, *Sierra Pac. Res. Operating Cos.*, 125 FERC ¶ 61,026 (2008) (accepting revisions to OATTs proposing a new schedule for Regulation and Frequency Charges for Generators Selling Out of Control Area)*; Entergy Servs., Inc.*, 120 FERC ¶ 61,042 (2007) (accepting proposal to retain a *pro forma* Generator Imbalance Agreement containing graduated Generator Regulation Service charges); *Florida Power Corp.*, 89 FERC ¶ 61,263 (1999) (approving a proposal for a Generator Regulation Service charge assessed against transmission customers); *Westar Energy, Inc.*, 130 FERC ¶ 61,215 (2010) (accepting proposal for a new schedule for Generator Regulation and Frequency Response Service, allowing utility to provide and charge for this service to generators located within its balancing authority area whose output is delivered outside of the balancing authority area or to the Southwest Power Pool energy imbalance market).

[29] *Integration of Variable Energy Resources*, 133 FERC ¶ 61,149 (2010) ("VER NOPR").

Q. WILL A CHARGE ASSESSED UNDER SCHEDULE 3A RESULT IN DOUBLE RECOVERY OF A CHARGE ASSESSED UNDER SCHEDULES 3?

No. Transmission customers subject to charges for regulating reserves will be assessed charges under either Schedule 3 or Schedule 3A, but not both. In other words, PacifiCorp will not charge transmission customers for service under both Schedules 3 and 3A for the same transaction. PacifiCorp's Schedule 3A rate will be the same as PacifiCorp's proposed Schedule 3 rate. Rates for Schedules 3 and 3A are derived from the same revenue requirement and apply the same demand for purposes of calculating the resulting rate. As such, Schedules 3 and 3A will not double recover from any transmission customer.[30]

Q. WHAT IS THE DIFFERENCE BETWEEN CHARGES UNDER SCHEDULE 3A FOR GENERATOR REGULATION AND FREQUENCY RESPONSE SERVICE AND CHARGES UNDER SCHEDULE 9 FOR GENERATOR IMBALANCE SERVICE?

A. Schedule 3A recovers the costs associated with holding generation capacity on-line and available to mitigate the moment-to-moment variations in generation output on an intra-hour basis. Schedule 9 recovers the cost of imbalance energy the Company must provide or accommodate when a difference occurs between the output of a generator located in the BAA and a delivery schedule from that generator based on output and schedule changes at the beginning of the scheduling hour and the end of the scheduling hour. In sum, Schedule 3A is a capacity-based charge and Schedule 9 is an energy-based charge,

[30] Order No. 890 at P 690 (requiring transmission providers to demonstrate that any proposals to recover capacity costs associated with Generator Imbalance Service do not lead to double recovery); *see, e.g., Entergy Services, Inc.* 120 FERC at P 64-66; VER NOPR at P 88.

including a penalty to encourage accurate scheduling practices, consistent with Commission precedent acknowledging the difference between these charges.[31]

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED REVISIONS TO SCHEDULE 5 OF THE TARIFF?

A. Currently in OATT Schedule 5, transmission customers seeking to provide for their Spinning Reserve Requirements through the purchase of such services shall pay a charge of $0.266 MW/h multiplied by the amount of hydro-electric generated energy delivered to PacifiCorp at the generation interconnection and an amount equal to $0.373 MW/h multiplied by the amount of non-hydro generated energy delivered to PacifiCorp at the generation interconnection. PacifiCorp proposes to eliminate the two-tiered charge and instead substitute it with stated rates for yearly, monthly, weekly, daily, and hourly service. Transmission customers purchasing service under Schedule 5 must purchase an amount of reserved capacity equal to 1.75% of the customer's Reserved Capacity for PTP Transmission Service or 1.75% of the customer's Monthly Network Load for NIT Service. This increase in charges reflects the Company's actual costs in providing Spinning Reserve Service. Consistent with FERC policy, PacifiCorp will assess its Schedule 5 rate (with no mark-up) to unauthorized use of its transmission system in accordance with OATT Schedule 11. Mr. Alan Heintz's testimony will further discuss the methodology by which the proposed rates and percentage obligation for this Schedule 5 charge were derived.

[31] *See supra* note 28.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED REVISIONS TO SCHEDULE 6 OF THE TARIFF?

A. Currently in OATT Schedule 6, transmission customers seeking to cover their Supplemental Reserve Requirements through the purchase of such services shall pay a charge of $0.266 MW/h multiplied by the amount of hydro-electric generated energy delivered to PacifiCorp at the generation interconnection and an amount of $0.373 MW/h multiplied by the amount of non-hydro generated energy delivered to PacifiCorp at the generation interconnection. PacifiCorp proposes to eliminate the two-tiered charge and instead substitute it with stated rates for yearly, monthly, weekly, daily, and hourly service. Transmission customers purchasing service under Schedule 6 must purchase an amount of reserved capacity equal to 1.75% of the customer's Reserved Capacity for PTP Transmission Service or 1.75% of the customer's Monthly Network Load for NIT Service. This increase in charges reflects the Company's actual costs in providing Supplemental Reserve Service. Consistent with FERC policy, PacifiCorp will assess its Schedule 6 rate (with no mark-up) to unauthorized use of its transmission system in accordance with OATT Schedule 11. Mr. Alan Heintz's testimony will further discuss the methodology by which the proposed rates and percentage obligation for this Schedule 6 charge were derived.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED REVISIONS TO SCHEDULE 7 OF THE TARIFF?

A. Revisions to OATT Schedule 7 reflect that the charges for yearly, monthly, weekly, daily, and hourly Long-Term and Short-Term Firm PTP Transmission Service will be derived from the formula rate set forth in Attachment H-1. The Schedule 7 rates shall be

updated annually for the rate year (June 1 - May 31 of the following year) in accordance with the Protocols in Attachment H-2.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED REVISIONS TO SCHEDULE 8 OF THE TARIFF?

A. Revisions to OATT Schedule 8 reflect that the charges for monthly, weekly, daily, and hourly Non-Firm PTP Transmission Service will be derived from the formula rate set forth in Attachment H-1. The Schedule 8 rates shall be updated annually for the rate year (June 1 - May 31 of the following year) in accordance with the Protocols in Attachment H-2.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED REVISIONS TO SCHEDULE 10 OF THE TARIFF?

A. OATT Schedule 10 is being revised to reflect the Company's updated transmission loss study, as described in Mr. Paul Normand's testimony. The current loss factor for use of any portion of PacifiCorp's transmission system is 4.48%; the current loss factor for use of any portion of PacifiCorp's distribution system is 3.56%; and the current loss factor for use of a combination of the Company's transmission and distribution systems is 8.04% (a sum of the transmission and distribution loss factors). PacifiCorp is proposing an increase in its transmission loss factor to 5.00%, based on the results of the transmission loss study performed by Mr. Paul Normand. The loss study is fully described in Mr. Normand's testimony and exhibits. As such, the proposed combination loss factor is 8.56%, because PacifiCorp proposes no changes in the distribution loss factor. Schedule 10 also now includes a section providing for the means by which PTP

Transmission Service customers shall settle Real Power Losses with PacifiCorp, which currently is set forth in Schedules 7 and 8.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED REVISIONS TO ATTACHMENT H OF THE TARIFF?

A. The proposed revisions to Attachment H provide that the charges for NIT Service shall be calculated on an annual basis using the ATRR, which is derived from the results of PacifiCorp's formula rate. The $/MW–year charge (designated as the "Network Service rate"), divided by 12, will be assessed each month to the NIT Service customer's Monthly Network Load. Attachment H also has two appendices: (i) Attachment H-1 is PacifiCorp's proposed formula rate, and (ii) Attachment H-2 is PacifiCorp's Protocols.

Q. WOULD YOU PLEASE DESCRIBE THE CLARIFYING REVISIONS TO THE DEFINITIONS SECTION OF THE OATT?

A. PacifiCorp has proposed the following revisions to the Definitions section of the OATT:

- The addition of the definition of "Annual Transmission Revenue Requirement" as "[t]he transmission revenue requirement calculated annually using the formula rate set forth in Attachment H-1";
- The modification of the definition of "Control Area" to clarify that "[t]he 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"; and
- The removal of the definition of "Load Ratio Share" in light of the changes in billing NIT Service customers described above.

Q. PLEASE DESCRIBE PACIFICORP'S EFFORTS TO INFORM ITS CUSTOMERS OF THE PROPOSED RATE INCREASE IN ANTICIPATION OF THIS FILING.

A. PacifiCorp has discussed its need and justifications for the proposed rate increase with its affected transmission customers prior to making this rate filing. PacifiCorp has held various public customer meetings in Portland and Salt Lake City to provide information and details about this rate case filing. Presentation materials and meeting minutes were posted on OASIS, including a formula rate model populated with inputs that produce PacifiCorp's proposed revenue requirement and rate. In addition, the Company created a "transmission rate case" email address and received questions from the participating customers and posted responses on its OASIS site. Questions and responses concerned such issues as the Protocols, calculation of the projected rate, and the mechanics of the annual rate restatement.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS CASE?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp	)	**Docket No. ER11-____-000**

VERIFICATION

STATE OF OREGON)
)
COUNTY OF MULTNOMAH)

I, Kenneth T. Houston, being first duly sworn, deposes and states that he is the witness identified in the foregoing prepared testimony, and that the statements of fact in the testimony and supporting exhibits are true and correct to the best of his knowledge, information and belief.

Kenneth T. Houston

SUBSCRIBED AND SWORN before me
the 24th day of May, 2011

Notary Public

My commission expires on: 4-18-15

OFFICIAL SEAL
PATRICIA ANN DEAS
NOTARY PUBLIC-OREGON
COMMISSION NO. 457250
MY COMMISSION EXPIRES APRIL 18, 2015

Exhibit No. PAC-2

CANADA

PACIFIC OCEAN

WASHINGTON

CHEHALIS
ASTORIA
LEWIS RIVER PROJECT
SEASIDE
YAKIMA
TOPPENISH
SUNNYSIDE
MARENGO
MARENGO II
DAYTON
GOODNOE HILLS
WALLA WALLA
PORTLAND
HOOD RIVER
HERMISTON
PENDLETON
LEANING JUNIPER I
ENTERPRISE
LINCOLN CITY
DALLAS
INDEPENDENCE
ALBANY
CORVALLIS
STAYTON
LEBANON
SWEET HOME
MADRAS
JUNCTION CITY
REDMOND
PRINEVILLE
BEND
CRESWELL
COTTAGE GROVE
COOS BAY/NORTH BEND
COQUILLE
ROSEBURG
NORTH UMPQUA PROJECT
MYRTLE CREEK
ROGUE RIVER PROJECT
GRANTS PASS
ROGUE RIVER
EAGLE POINT
CENTRAL POINT
CAVE JUNCTION
MEDFORD
KLAMATH FALLS
CRESCENT CITY
KLAMATH RIVER PROJECT
LAKEVIEW
YREKA
MT. SHASTA

OREGON

CALIFORNIA

NEVADA

IDAHO

MONTANA

COLSTRIP

ARCO
REXBURG
RIGBY
SHELLEY
BEAR RIVER PROJECT
MALAD CITY
PRESTON
SMITHFIELD
TREMONTON
LITTLE MOUNTAIN
OGDEN
LAYTON
GADSBY
SALT LAKE CITY
WEST VALLEY CITY
PARK CITY
TOOELE
MIDVALE
LAKE SIDE
DRAPER
AMERICAN FORK
PLEASANT GROVE
OREM
SANTAQUIN
CURRANT CREEK
MORONI
DELTA
GUNNISON
SALINA
RICHFIELD
BLUNDELL
MILFORD
PANGUITCH
CEDAR CITY
IVINS
LA VERKIN
BLANDING
MOAB
UTAH

LOVELL
CODY
BUFFALO
WYODAK
WORLAND
THERMOPOLIS
GLENROCK
ROLLING HILLS
GLENROCK III
WYOMING
RIVERTON
CASPER
DAVE JOHNSTON
DOUGLAS
PINEDALE
LANDER
LAVA HOT SPRINGS
BIG PINEY
MONTPELIER
DUNLAP I
SEVEN MILE HILL
SEVEN MILE HILL II
LAKETOWN
KEMMERER
JIM BRIDGER
RAWLINS
HIGH PLAINS
MCFADDEN RIDGE I
NAUGHTON
ROCK SPRINGS
GREEN RIVER
FOOTE CREEK I
LARAMIE
EVANSTON
VERNAL
CRAIG
HAYDEN
CARBON
PRICE
HUNTINGTON
CASTLE DALE
HUNTER

COLORADO

CHOLLA NO. 4

ARIZONA

NEW MEXICO

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

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Greg Abel

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En Español: 1-888-225-2611

Outage reporting:
1-877-508-5088

Location service (call before you dig):
811 or 1-888-221-7070

Free electric safety materials or presentations: 1-800-375-7085

- Pacific Power service area
- Rocky Mountain Power service area
- Thermal plants
- Gas-fueled thermal plants
- Wind projects
- Geothermal plants
- Mining
- Hydro systems
- Principal communities served
- Company-owned transmission lines
- Transmission access
- Other transmission

Exhibit No. PAC-3

Energy Gateway Transmission Investment

This map is for general reference only and reflects current plans.
It may not reflect the final routes, construction sequence or exact line configuration.

November 2010