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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	**CASE NO. PAC-E-11-12**
MOUNTAIN POWER FOR	)	
APPROVAL OF CHANGES TO ITS	)	**Direct Testimony of Darrell T. Gerrard**
ELECTRIC SERVICE SCHEDULES	)	
AND A PRICE INCREASE OF $32.7	)	
MILLION, OR APPROXIMATELY	)	
15.0 PERCENT	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-11-12

May 2011

Q. Please state your name, business address and present position with PacifiCorp dba Rocky Mountain Power (the "Company").

A. My name is Darrell T. Gerrard. My business address is 825 NE Multnomah, Suite 1600, Portland, Oregon 97232. I am Vice President of Transmission System Planning for the Company.

Qualifications

Q. Please describe your education and business experience.

A. I have a Bachelor of Science degree in Electrical Engineering (Electric Power Systems Major) from the University of Utah and Certificate of Completion with Honors in Electrical Technology from Utah Technical College at Salt Lake. My experience spans more than 30 years in the electric utility business and electric power industry in general. I have working experience and have had management responsibility for a number of functional organizations at PacifiCorp including: Area Engineering, Area Planning, Region Engineering, T&D Facilities Management, Transmission, Substation and Distribution Engineering, System Protection and Control, T&D Project Management and Delivery, Asset Management, Electronic Communications, Hydro System Engineering, Transmission Grid Operations, and most recently Transmission System Planning.

Q. What are your responsibilities as Vice President of Transmission System Planning?

A. I am responsible for transmission planning activities required to support PacifiCorp's existing and future bulk transmission system and to ensure a safe and reliable transmission system provides adequate service to our customers economically. I am also responsible for the conceptual and detailed system planning and architecture associated with the Company's long-term Energy Gateway Transmission Expansion Plan ("Energy Gateway").

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to:

- provide support for the Company's request for rate recovery of the portion of the Populus to Terminal project ("Project") not currently in rate base;
- discuss the "used and useful" standard in the context of industry planning practices and precedents, and system path rating requirements;
- describe the timing and key drivers requiring investment in new electric transmission infrastructure such as the Project; and
- request recovery of the additional transmission capital investments included in this Application.

Q. Please describe the major transmission investments that the Company is adding to rate base in this filing.

A. The Company is requesting that the remaining investment associated with the Populus to Terminal project, previously found by the Commission not to be "currently used and useful,"[1] be included in rate base. My testimony also discusses the addition of more than $150 million in other transmission capital investment for the test period January 1, 2011, to December 31, 2011, as provided in Exhibit No. 30, Transmission Major Plant Additions.

[1] IPUC Case No. PAC-E-10-07, Order No. 32196, February 28, 2011.

Populus to Terminal

Q. This Commission found that only 73 percent of the Project is currently used and useful. Is the Company providing new and additional information to the Commission in support of inclusion of 100 percent of the project in rate base?

A. Yes. In its reconsideration order in Case No. PAC-E-10-07 (the "2010 General Rate Case"), the Commission stated that the Company "will receive a full and fair return on the remainder of its investment if and when it presents evidentiary support for moving the balance of the investment (27 percent) into rate base."[2] I will provide additional evidence, in my testimony, about the Project and the integrated system to support the fact that 100 percent of the Project is presently used and useful.

Q. In your reading of the Commission's Order No. 32224, do you believe the issue for the Commission is one of timing and not of prudence of the Company's decision to build the line?

A. Yes. The Commission acknowledged this in its Order in regards to the Company's ability to ultimately recover the full investment in the Project.

> [the] Company does not lose out on the 27 percent of the investment in the Transmission Line that is currently slated for the PHFU account. If...Rocky Mountain is able to present sufficient evidence which confirms that 100 percent of the Transmission Line is "used and useful" this Commission will include that additional amount in Idaho rate base.[3]

Q. Did the Commission address the Project in any other proceedings prior to the Company's 2010 general rate case?

A. Yes, In Case No. PAC-E-08-03, the Commission approved the Company's

[2] Case No. PAC-E-10-07, IPUC Order No. 32224, page 12, April 18, 2011.
[3] Id.

Application for a Certificate of Public Convenience and Necessity to construct the Populus to Terminal project. Significantly, with regard to the certificate's need determination, the Commission noted in its Final Order:

> The Commission agrees with Staff's assertion that the proposed transmission project is an "integral part" of the Company's preferred resource portfolio of an additional 2,000 MWs of renewable resources by the end of 2013. The Commission also believes that the Project has the potential to upgrade the Company's overall transmission capacity and thereby improve the flexibility and reliability of electrical service for Idaho customers during peak demand times.[4]

In addition, in its September 15, 2009, Acceptance of Filing, the Commission formally acknowledged the Company's 2008 Integrated Resource Plan (IRP), which detailed the Project's initial and planned capacity ratings and included in its Action Plan (Chapter 9)[5] the construction of the Project in 2010 as configured. Commission Staff concluded:

> Staff believes that PacifiCorp has performed extensive analyses, given equivalent consideration of supply- and demand-side resources, provided acceptable opportunities for public input, and that the end result is representative of the Commission's directives toward integrated resource planning.[6]

Furthermore, in its findings, the Commission stated:

> We recognize and commend the Company for the Plan that it has presented and for the public process that it used to produce the Plan.[7]

Q. **Did the Company rely upon the Commission's final order approving a Certificate of Public Convenience and Necessity when it decided to proceed with the Project?**

A. Yes. The Company did rely heavily on the Commission's determination and final

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[4] Case No. PAC-E-08-03, IPUC Order No. 30657, pp. 5-6.
[5] PacifiCorp Integrated Resource Plans available at http://www.pacificorp.com/es/irp.html.
[6] Case No. PAC-E-09-06, Acceptance of Filing, p. 10.
[7] Id.

order that the Project was necessary and in the public interest. Had the Commission's final order made the determination that the Project was not necessary or not in the public interest, the Company would not have proceeded with the Project in its current configuration. In this event, the Company would have been forced to consider alternatives previously rejected based on cost to customers and/or their inability to meet the Project's requirements and need.

Q. Do you agree with the finding of the Commission that 27 percent of the Project investment was not presently used and useful?

A. No. I do not agree with the Commission's conclusion that 27 percent of the project investment is not presently used and useful and is contingent on the construction of the remainder of Energy Gateway.[8] This conclusion is not based on any accepted utility industry practice, standard, rule or regulation of which I am aware.

Q. Have any other utility commissions disallowed or deferred recovery of a portion of the Project investment?

A. No. The Company has been granted full recovery in rates for the Project investment in each of the states in which recovery has been sought, including Utah, Oregon, California and Wyoming.[9]

Q. If a new transmission or generation system addition is not operating at full capacity at the time it is placed into service, does that mean it is not fully "used and useful"?

A. No. When a transmission project or generation plant is energized and placed into

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[8] Case No. PAC-E-10-07, IPUC Order No. 32196, page 38, February 28, 2011.

[9] The Ben Lomond to Terminal segment of the Project was included in the Company's last Wyoming general rate case (Docket No. 20000-352-ER-09), in which recovery for this investment was granted. The remaining Project segment investment is included in the Company's current Wyoming rate proceeding (Docket No. 20000-384-ER-10), which, as of the time of this filing, is currently underway.

service, all elements of the project are part of the interconnected system. These elements are fully used and useful in providing transmission or generation service on the system. Transmission and generation infrastructure additions inherently have some ability to provide future capacity after being placed in service. This results from using industry standard voltages and design criteria, and reliability requirements necessary for system operation and maintenance.

Q. You indicate that when a new transmission line is added, it becomes a part of the integrated system as a whole. Please explain.

A. Electrical transmission systems are made up of numerous electrical elements, including lines, substations, generation plants and control systems that operate as a fully integrated network. All elements of the network are electrically dependent upon each other for the purpose of producing and transmitting energy instantaneously to customers on demand. New transmission capacity, when added to an existing system, is installed in increments based on standard system voltages, line conductors, equipment and apparatus that are available in the utility industry. Electrical power flows across the entire system, and on any individual line or station, is a function of the physics of the entire interconnected network and the level of generation and load present and any given instant in time. As a result, when a new line or substation is added, it immediately carries its full share of the total energy being transmitted by the system. Whenever a new line or substation is added to the transmission system, electrical capacity on the network is increased. The incremental capacity increase added to the network is based on both the capacity of the new facility and on the new facility's electrical interaction with all other facilities to which it is interconnected.

Therefore a new project, when added to an existing transmission system, may not operate at its full planned capacity (1,400MW for this Project) due to those interactions with other facilities and limits existing at the time it is placed in-service. Any future capacity increase on an existing system made possible by future construction of system facilities is attributable to those future system additions. These basic principles are discussed in further detail in a paper titled *A Transmission Tutorial for Non-Technical Readers*, available on the Western Electricity Coordinating Council's (WECC) Regional Transmission Expansion Planning (RTEP) document portal on its website.[10]

Q. Is the Commission's determination that 27 percent of the Project is not presently used and useful a reasonable basis for deferring cost recovery of 27 percent of the investment?

A. Respectfully, no. The Commission notes in its Order that the 73 percent used and useful portion of the Project "represents 1,022 MW of the total 1,400 MW that Populus to Terminal can ultimately provide."[11] There is no one-for-one correlation between megawatt capacity and construction costs. It is not possible to size transmission in discrete increments to meet any specific capacity at the time it is needed. There was no alternative available that met all the Project requirements at 73 percent of its capacity and at 73 percent of the cost.

Q. What percent of the Project is currently energized?

A. 100 percent. Since the Project went into service in November 2010, 100 percent

[10] http://www.wecc.biz/Planning/TransmissionExpansion/RTEP/Transmission percent20Planning/Transmission percent20Tutorial.pdf.
[11] Case No. PAC-E-10-07, IPUC Order No. 32196, page 38, February 28, 2011.

of its elements were energized and being used to provide transmission service.

Q. **What percent of the Project's right of way, its 900 poles and foundations, its permits and 135-mile length is currently being used?**

A. 100 percent. It simply would not be viable to construct the Project with anything less than 100 percent of each of these major project components and all of these components are fully used and useful.

Q. **Did the Company analyze a phased capacity approach for the Project to coincide with future segments of Energy Gateway?**

A. Yes. The Company performed a theoretical analysis using a configuration where the Project would be constructed as designed but the second set of conductors would not be installed until a later date to coincide with the addition of future Energy Gateway segments. This design provided a project rated at 50 percent capacity and reduced reliability; however, if built at the 50 percent level, the project costs would be reduced by only nine percent of the total investment. I have attached Exhibit No. 31, Savings Estimate if Second Circuit Deferred, which presents this analysis.

Q. **Is the Project the most economic to meet system requirements?**

A. Yes. The Company evaluated multiple configurations for the Project where new transmission line corridors are scarce due to geographic constraints and heavily developed urban areas, and determined the Project as constructed is the most cost effective. Alternatives considered are discussed in Confidential Exhibit No. 32, September 2008 Analysis of Populus-Terminal. Had the Company built a lower capacity, single circuit 345 kV line in the new project corridor, the only viable option under this alternative for gaining the required future transmission capacity would be to remove the line and replace it with a higher capacity line. The Company estimates that, if it had pursued this option and replaced a single circuit 345 kV line with a double circuit 345 kV line in the future, the cost to customers would be approximately $1.24 billion (see Exhibit No. 33, Single Circuit Construction Replaced with Double Circuit). This incremental approach would have resulted in a nearly 50 percent higher total cost for the Project than the option elected by the Company.

Q. Are there other problems with this theoretical incremental capacity option?

A. Yes. This option would also require extensive and costly transmission line outages during construction, assuming these outages could be scheduled at all, and would reduce Path C capacity back to pre-Project levels or lower during the lengthy reconstruction period.

Q. If the Company decided not to build the remaining Energy Gateway segments, would the Project at its current rated capacity still be needed?

A. Yes. The Project—as designed and constructed—is needed to relieve existing system capacity constraints, address known reliability concerns, and provide an immediate increase in capacity necessary to meet existing and ongoing customer load service and reserve obligations as demonstrated below. Please refer to Confidential Exhibit No. 32, September 2008 Analysis of Populus-Terminal. Specifically, page 8 of the analysis notes:

> Path C needs to be upgraded to support reliability and peak loads, even without other planned transmission - Energy Gateway West and Energy Gateway South. The investment is justified independent of the remaining Energy Gateway segments.

Used and Useful Considerations

Q. If a new transmission system addition is not operating at full capacity at the time it is placed into service, does that mean it is not fully "used and useful"?

A. No. When a transmission project is energized and placed into service, all elements of the project are used and useful in providing transmission service on the system. Transmission infrastructure additions installed and operated as part of an interconnected electric system inherently have some ability to provide future capacity after being placed in service. This fact is a result of using industry standard voltages, standardized manufacturing of components, design criteria and reliability requirements necessary for system operation and maintenance.

Q. Is Path C fully subscribed for firm transmission service at this time?

A. Yes. Path C, which includes multiple lines including the Populus to Terminal lines, is fully subscribed for firm (non-recallable) transmission services, both for network and point-to-point service in the southbound direction. A single-circuit configuration would not be capable of providing the level of incremental capacity additions, or reliability benefits to Path C being provided by the Project as constructed, and therefore would not be fully capable of meeting even today's customer demand.

Q. Do you have requests for additional firm capacity on Path C that cannot currently be met because the capacity is fully subscribed?

A. Yes. A list of pending requests for additional capacity is set forth in Exhibit No. 34, Path C Firm Transmission Reservation.

Q. Is 27 percent of the Project currently unused, as previously determined by the Commission?

A. No. Both circuits of the Project are energized and are providing the system reliability benefits and increased transfer capacity the Project was designed to provide. The Project was fully used and useful from the time it was placed into service in November 2010.

Furthermore, the Project is operating at 100 percent of its intended nominal design voltage of 345 kV, not 73 percent or some other number. The Company's current customers' electrical demand is served by power flow across 100 percent of the entire Project elements, not 73 percent or some other portion of the Project elements. Our future customer demand, as it increases, will be met using 100 percent of all the Project elements.

Additionally, each circuit of the Project, its associated conductors and substation terminal apparatus has the capability to operate at 100 percent of its planned design. As the Project is configured, one of its lines can be taken out of service, whether planned or unplanned, without impacting Path C's total transfer capability since the second line is there to provide 100 percent backup capability.

Lastly, the transmission corridor, access roads, steel transmission towers, footings and foundations, conductors, and property rights obtained for the lines and stations and all the labor and expense that made the Project possible are currently fully utilized, not 73 percent or some other percentage. Path C is operational at 100 percent of its rated capacity approved by WECC in order to reliably operate as an interconnected transmission system within the western grid, and 100 percent of this project is in use today and is useful.

Key Drivers for Transmission Investment and Timing

Q. Customer load growth information is an important factor in determining the need and the timing of transmission projects. What load information was used to determine project need and the investments necessary to meet that need?

A. The need and timing for the Project was largely based on PacifiCorp's 2007 Integrated Resource Plan (IRP). The 2007 IRP showed system-wide coincidental peak load growth forecasted at an average of 2.6 percent per year through 2016 and an annual peak demand growth forecast of 1.2 percent for the state of Idaho for the same period.[12] In addition, the Project is required to support the Company's recently released 2011 IRP which shows system-wide coincidental peak load growth forecasted at an average of 2.1 percent per year through 2020, with Idaho's growth increasing by 2.7 percent on average per year.[13]

Q. Does the Company's Open Access Transmission Tariff ("OATT") also require planning for and construction of transmission resources necessary for future needs?

A. Yes. PacifiCorp's OATT,[14] approved by the Federal Energy Regulatory Commission ("FERC"), details the Company's requirements and responsibilities, which include the requirement to "plan, construct, operate and maintain its transmission system in accordance with good utility practice…" (Section 28.2),

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[12] PacifiCorp 2007 IRP, Table 4.3, available at http://www.pacificorp.com/es/irp.html.
[13] The Idaho average annual peak load growth rate excludes growth forecasted for the Bonneville Power Administration's southeast Idaho loads that PacifiCorp serves under its BPA power exchange contract. Source: PacifiCorp 2011 IRP, Volume 2 Table A.10, available at http://www.pacificorp.com/es/irp.html.
[14] http://www.oasis.pacificorp.com/oasis/ppw/OATTVol11Baseline_20100908.pdf.

and to provide network customers "firm transmission service…for the delivery of capacity and energy from its designated Network Resources to serve its Network Loads…" (Section 28.3). Section 31.6 defines the network customers' requirement to supply annual load and resource updates, which enable the Company to determine future load and resource requirements for all transmission network customers. The project investments included in this proceeding are necessary to meet these requirements and customer demand.

Q. **Do you believe that these customer load demand forecasts reflect the economic conditions in Idaho and impacts on customer demand?**

A. Yes. While I'm not an expert on the economy, I can attest to the fact that reductions in customer energy demand forecasts have coincided with the economic downturn. As stated above, the company requests and reviews all of its forecasted energy demand and resource submittals annually. While the Company's last four IRPs (filed in 2005, 2007, 2009 and 2011)[15] have shown declining 10-year system-wide coincidental peak load growth forecasts (3.0 percent, 2.6 percent, 2.4 percent and 2.1 percent, respectively), even the weakest growth forecast shows a need for an additional 2,158 MW in 10 years[16] to serve customer load growth, 79 percent of which is growth in the east side of PacifiCorp's system, including Idaho.

Q. **Can you provide examples of instances where the Company revised its investment timing as a result of reductions in forecasted demand?**

A. Yes. The Company uses its customer demand forecasts and best available

[15] PacifiCorp IRPs available at http://www.pacificorp.com/es/irp.html.
[16] PacifiCorp 2011 IRP, Table A.11.

information to determine project need and investment timing. Examples of projects in this filing which have been rescheduled and influenced by actual and forecast reductions in customer demand include:

- The Red Butte Static VAR Compensator project was delayed early in its project life cycle from 2009 to 2011 based on reduced risk due to lower customer demand. The Company delayed the full investment, to the benefit of customers, by installing only an initial $4 million portion of the device in 2010, delaying more than $40 million of remaining investment by two years; and
- A portion of the Mona to Oquirrh project, the second segment of Gateway Central, was delayed two years from 2011 to 2013 due to changing business requirements along with some reduced risk resulting from slower customer growth and reduced demand.

Q. Beyond growing customer energy demand, are there other transmission performance requirements driving the need for these system investments?

A. Yes. In meeting the current and future customer energy needs described above, the Company must maintain a minimum level of system reliability to provide adequate transmission service. The North American Electric Reliability Corporation ("NERC") and WECC have recently enacted a significant number of standards and guidelines that specify in detail the levels of system performance that utilities must maintain during the planning, operation and ongoing maintenance of their bulk electric systems. NERC's reliability standards were approved by FERC and are mandatory for all FERC-jurisdictional entities. These reliability standards are targeted at improving the security and reliability of the nation's bulk electric system, including the system in Idaho. The projects and related investments discussed in my testimony are required for the Company to comply with these mandatory reliability standards and to provide safe, reliable and efficient transmission service to customers.

Q. What specific reliability performance standards and criteria require the project investments in this case?

A. PacifiCorp plans, designs and operates its transmission system to meet or exceed NERC Standards for Bulk Electric Systems and WECC Regional standards and criteria. The NERC standards are found in 18 CFR Part 40 (Mandatory Reliability Standards for Bulk-Power Systems). The WECC standards and criteria are deemed necessary for the WECC Region to meet or exceed NERC standards. There are currently more than 100 approved NERC standards with which the Company must comply. The project investments and their respective in-service dates are required to comply with the following standards:

- NERC TPL-001 System Performance Under Normal Conditions[17]
- NERC TPL-002 System Performance Following Loss of a Single BES Element[18]
- NERC TPL-003 System Performance Following Loss of Two or More BES Elements[19]
- NERC TPL-004 System Performance Following Extreme BES Events[20]

[17] NERC TPL-001 can be found at: http://www.nerc.com/files/TPL-001-0.pdf.
[18] NERC TPL-002 can be found at: http://www.nerc.com/files/TPL-002-0.pdf.
[19] NERC TPL-003 can be found at: http://www.nerc.com/files/TPL-003-0.pdf.

- TPL 001-WECC-1-CR System Performance Criteria Normal Conditions[21]
- TPL 002-WECC-1-CR System Performance Criteria Following Loss of a Single BES Element
- TPL 003-WECC-1-CR System Performance Criteria Following Loss of Two or More BES
- TPL 003-WECC-1-CR System Performance Criteria Following Extreme BES Events
- NERC TOP-002 Normal Operations Planning[22]
- NERC TOP-004 Transmission Operations[23]
- NERC TOP-007 Reporting SOL and IROL Violations[24]

The above-referenced standards dictate the minimum levels of transmission system reliability, redundancy and performance required for transmission facilities in this case.

Q. Please discuss further how these standards and criteria influence the timing of the transmission project investments in this case.

A. The above mandatory standards require the Company to have a forward-looking transmission plan to reliably serve current and anticipated customer demands under all expected operating conditions. These conditions include normal system operations (all system elements in service) and system contingencies (where elements of the transmission system are out of service), both planned or

[20] NERC TPL-004 can be found at: http://www.nerc.com/files/TPL-004-0.pdf.
[21] TPL 001-WECC-1-CR – TPL 004-WECC -1-CR can be found at: http://www.wecc.biz/Standards/WECC percent20Criteria/TPL-001 percent20thru percent20004-WECC-1-CR percent20- percent20System percent20Performance percent20Criteria.pdf.
[22] NERC TOP-002 can be found at: http://www.nerc.com/files/TOP-002-2.pdf.
[23] NERC TOP-004 can be found at: http://www.nerc.com/files/TOP-004-2.pdf.
[24] NERC TOP-007 can be found at: http://www.nerc.com/files/TOP-007-0.pdf.

otherwise. NERC Transmission Planning Standard TPL 002 states:

> **A. Introduction**
> **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that *meet specified performance requirements with sufficient lead time,* and continue to be modified or upgraded as *necessary to meet present and future system needs.*
>
> **B. Requirements**
> **R1.** The Planning Authority and Transmission Planner shall each demonstrate through valid assessment that its portion of the interconnected transmission *system is planned such that the Network can be operated to supply projected customer demands and projected Firm (nonrecallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions* as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:
>
> > **R1.1.** Be made annually.
> > **R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through 10) planning horizons.
>
> **R2.** When System simulations indicate an *inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1,* the Planning Authority and Transmission Planner shall each:
>
> > **R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
> > ***R2.1.1.*** *Including a schedule for implementation.*
> > ***R2.1.2.*** *Including a discussion of expected required in-service dates of facilities.*
> > ***R2.1.3.*** *Consider lead times necessary to implement plans.*

(Emphasis added)

In summary, the Company is required to have both short-term and long-term transmission plans to reliably meet all expected current and forecasted customer electrical demands. The requirement to have such a plan is not optional for the Company. The Company conducts annual load and resource forecasting analyses and revises its investment timing as a result of identified reductions in forecasted demand where appropriate. Most of the projects in this filing require multi-year planning, permitting and construction processes, and the Company must consider the lead times and schedules necessary in advance of customer demand.

Standard Industry Practice and Precedents

Q. Is it common and accepted industry practice for utilities to plan for both the current needs and to anticipate future system needs when planning, designing and constructing new transmission infrastructure projects?

A. Yes. It is a common and accepted industry practice to plan, design and construct transmission systems while anticipating future needs. This has been a common and accepted practice for decades. Some of the oldest and most trusted utility system planning and design guides used in the industry address the need to consider, plan and design for the future. The <u>Westinghouse Transmission and Distribution Reference Book</u>,[25] which provides the electric power industry basic and essential information when planning and designing electric power systems, states:

> Choice of Voltage; *The voltage is sufficiently high for use as a sub transmission voltage if and when the territory develops and additional load is created. The likelihood of early growth of a load district is an important factor in selection of the higher voltage and larger conductor.*[26]

Further, the reference book states in Section 9:

> Choice of Conductors: *As an insurance against breakdown (line outages) important lines frequently are built with circuits in*

[25] Westinghouse Electric Corporation, 4th addition, Copyright 1964.
[26] Chapter 1, General Considerations of Transmission Lines, Section 8 page 8.

duplicate. In such cases the cost of conductors for two circuits should not be overlooked.[27]

Finally, the reference book states in Section 11:

> Choice of Supply Circuits; *The choice of the electrical layout of the proposed power station is based on the conditions prevailing locally. It should take into consideration the character of the load and the necessity for maintaining continuity of service. It should be as simple in arrangement as practicable to secure the desired flexibility in operation and to provide the proper facilities for inspection of the apparatus.*

The Company has balanced these industry design criteria in its planning, designing and construction of the Project. I believe it is prudent for the Company to follow these standards.

Q. What process did the Company follow in determining the Project's capacity contribution to Path C capacity ratings and why?

A. The Company was required to adhere to industry accepted rating policies and procedures in place today and administered by the WECC.[28] These policy and review procedures were followed and new ratings were approved by WECC for Path C capacity with the inclusion of the Project as a new path element. The Company requested, and WECC has approved, ratings for Path C operation both today and in the future when other segments of Energy Gateway are constructed and/or when additional generation is added north of Path C. Path C in-service operational ratings are reviewed and approved by WECC for each operating season and can change based on additional transmission and/or generation facilities installed or removed from the system. It is important to understand that

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[27] Id., Section 9.

[28] WECC Policies and Procedures for Regional Planning, Project Review, Project Rating Review and Progress Reporting Revised-April 2005.

the operational capacity ratings of WECC Paths, including Path C, can and do change. Through this WECC process and procedure, ratings are not established and approved for an individual transmission line or substation; they are established and approved based on the capability of the wider interconnected system. The Company cannot simply assign a capacity rating to a project and then go out and build and operate it as part of the wider interconnected electric system in the west. Rather, the Company must meet the governing standards and ratings.

Q. Why did the Company obtain approved ratings for Path C operation at some future date?

A. The Company obtained future Path C ratings to "lock in" for our existing and future customers the incremental Path C capacity attributable to planned transmission system additions, as that capacity could otherwise be claimed by another interconnected project, which may not benefit the Company's customers. The WECC policies and procedures recognize and are specifically crafted based on the reality that transmission projects are rarely built all at one time; their capacities come in large increments, and they are often staged and placed into service over a period of time. These policies reflect very practical economic, constructability and load growth considerations as well as the timing of new generation resources. The Company made a prudent decision not to build all Gateway segments simultaneously, as it would not have been feasible, practical, economic or in the best interest of our customers to do so.

Q. Given that the Commission deemed 73 percent of the Project used and useful based on its current incremental capacity addition to Path C, wouldn't it have been better for the Company only to seek ratings for the current system configuration?

A. No. Our customers would have been disadvantaged by a narrow and limited approach. Had the Company sought WECC ratings of Path C only under the current system configuration, with all else equal, the Commission presumably would have found the Project to be 100 percent used and useful since Path C is fully subscribed today. However, the Project was necessarily designed and built with the capability of serving both current and forecasted customer needs, and the Path C capacity additions attributable to future Energy Gateway segments are needed to serve growing customer needs. Had the Company opted only to secure ratings for today's system configuration, any capacity improvements to Path C attributable to another regional entity's project would potentially belong to that entity and not to the Company's customers. Therefore, under such a scenario, customers would not get the full benefit of the Project and further investment would be required to meet future customer needs. The future rating secures the incremental Path C capacity for maximum benefit to customers.

Q. Can you provide examples of transmission projects in the industry that have been placed into service at one capacity and, at a future date, operated at higher capacity?

A. Yes. There are many. The following are examples of transmission projects that were placed in service with an initial electrical capacity and, at future dates, have achieved or will achieve increased capacity due to the addition of: 1) more transmission elements; 2) more generation facilities; and/or 3) increased electrical load on the system.

- Pacific DC Intertie (WECC Path 65) was commissioned in 1970 with an initial capacity of +/- 1,440 MW. As load grew over time and transmission parallel and supporting elements were added to the system, the capacity of the original line has been incrementally increased to its present capacity of +/-3,100 MW.

- The Intermountain DC line (WECC Path 27) had a capacity of 1,920 MW when commissioned in 1986; however that capacity has recently been increased to 2,400 MW due to modifications to the converter, consideration of the addition of new generation resources, increased loads, and changes in the interconnected system associated with Path 27.

- PacifiCorp's 345 kV interconnection with Nevada Energy at Harry Allen (WECC Path TOT2C) will more than double from the existing rating of 300 MW in 2014 with the addition of the proposed Sigurd-Red Butte #2 345 kV line.

- The East of the Colorado River system (WECC Path 49) capacity was increased from 8,055 MW to 9,300 MW due to the addition of new generation resources, load growth and changes in the interconnected system connected to Path 49.

- The Bridger West system (WECC Path 19) has a present westbound capacity of 2,200 MW. Its joint owners, PacifiCorp and Idaho Power Company, plan to increase this capacity to 2,400 MW as a result of additional new generation resources, load growth and changes in the interconnected system connected to Path 19. This capacity increase is due, in part, to the new transmission capacity resulting from the Project.

- The Company's existing Craven Creek-Chapel Creek-Jonah 230 kV line has a capacity rating of 388 MW and presently serves approximately 175 MW of growing Upper Green River load. As the customer load increases the Company's plan is to construct a new 230 kV line from a point south of Atlantic City to Jonah Field. This will increase the reliability in the area by elimination of a single radial feed 230 kv line and it will simultaneously add southbound capability to the existing line and increase the overall transmission capability from central Wyoming to southwestern Wyoming. Clearly the line today is used and useful as a radial line serving customer load and its capacity will increase in the future as other facilities are interconnected.

- Midpoint-Valmy 345 kV line used to deliver Idaho's 50 percent share, 260 MW, of the Valmy generation to Idaho. A single circuit 345 kV line was constructed to deliver the power northbound to Idaho. 345 kV voltage was selected minimize transformation stations, to minimize energy losses and provide a reliable interconnection to NV Energy's northern system. It has a northbound WECC rating of 500 MW, but its only firm use is to deliver Idaho's 260 MW Valmy share. While it is capable of delivering more capacity on a firm basis, it is clearly used and useful and its capacity could increase as additional transmission facilities are added to the interconnected system.

- Fire hole-Little Mountain-Flaming Gorge 230 kV line with a planned rating of 405 MW went into service in 1964. However the line is presently limited to 250 MW by the transformer limits at Flaming Gorge. The line has been in-service and in rate base for decades. While it is capable of more than 250 MW it is fully used and useful at its present rating and could increase over time as additional facilities are interconnected or equipment is upgraded.

The above examples clearly show that transmission projects, when initially placed in service may not operate at their full individual rated capabilities and are limited to some lower capacity due to other limited elements in the wider interconnected system. This Project is no different and reflects the prudent and accepted utility industry practice when planning, designing, constructing and operating transmission infrastructure. I urge the Commission to consider the accepted industry practices as it considers the Project's current usefulness.

Q. **Are there examples of regulatory support for cost recovery of prudent investment in transmission facilities even though their full utilization depended on the future construction of additional facilities?**

A. Yes. The Jim Bridger system located in Wyoming transports all of its energy to Southeast Idaho via three 345 kV transmission lines built in 1973, 1975 and 1976. The four Jim Bridger generating units were constructed in 1974, 1975, 1976 and

1979. The transmission facilities had to be built with sufficient capacity to transfer all of the planned generation at Bridger (approximately 2,200 MW). Despite the fact that the transmission was built with excess or unused capacity, those projects went into rate base for PacifiCorp and Idaho Power at the time of in service.

When the Huntington and Hunter plants were planned, Utah Power built five 345 kV lines, one for each 400 MW planned generation unit, but each line had an incremental planned capacity of about 500 MW, because you can't build 4/5ths of a line. This extra 1/5 capacity installed at the time has always been acknowledged as used and useful and part of rate base. Customers have benefited from this infrastructure for years.

Q. **Can you provide examples of future planned projects that are similar to the Project and are expected to be placed in service with some excess capacity for future use by customers?**

A. Yes. There are a number of similar projects that are currently following the same industry accepted practices I have stated above, the WECC regional planning and review process, the WECC path rating policy and procedures, and the National Energy Policy Act (NEPA) process. The Company is following the above policies and requirements in the development, design and configuration of all Energy Gateway segments. Project examples include:

- McNary-John Day 500 kV
- Big Eddy-Knight 500 kV
- I-5 Corridor Reinforcement 500 kV

- Central Ferry-Lower Monumental 500 kV
- Boardman-Hemingway 500 kV

All the major projects listed above are in various planning or construction stages and are expected to be placed in service in the next one to five years. All of these projects when placed in service will be interconnected to the wider transmission system and will initially be operated at capacities estimated to be from 10 to 40 percent less than each individual projects planned capacity. All of these projects will be 100 percent used and useful when placed into service in the western interconnection.

Transmission Capital Investment Projects

Q. Please describe the other transmission investments in addition to the Populus to Terminal Project that the Company is requesting to add to rate base in this case.

A. Between January 1, 2011, and December 31, 2011, the Company will place into service approximately $151 million of transmission investment, Exhibit No. 30, Transmission Major Plant Additions, lists each of these projects as follows:

1. **Red Butte Static VAR Compensator and 345 kV Capacitor: $46.4 million.** Installation of a 300 MVAR Static VAR Compensator and 345 kV capacitor is required along with facility expansion at the Red Butte substation in southwest Utah. Studies of the southwestern Utah area have shown the need for additional reactive power support during normal steady-state operations and during system outage conditions. This project is required to ensure continued reliable service to existing and growing loads

in this area. This includes the customers of Rocky Mountain Power, UAMPS and Deseret. It is also needed to maintain the Company's existing firm point-to-point firm transmission service contract obligations on the WECC rated transmission Path TOT 2C, which connects the Company's transmission system to Nevada at Nevada Energy's Harry Allen substation. The project is also required to maintain compliance with mandatory NERC/WECC Transmission Planning Standards TPL-01 through 04 and Transmission Operating Procedures TOP 02, 04, and 07.[29]

2. **Dave Johnston - Casper 230 kV Rebuild - #1 Line: $6.1 million.** This project involves relocation of portions and rebuilding of all of the existing Dave Johnston – Casper 230 kV #1 line. Additionally the project requires installation of a new conductor on the existing Dave Johnston – Casper 230 kV #2 line. Without this project the WECC rated Path TOT4A operating capacity must be reduced by approximately 100 megawatts resulting in reductions of firm energy transfers from the Dave Johnston and Wyodak plants and wind generation in the area. This project is required to maintain existing transmission capacity to serve existing customer demand in Idaho and other states and to meet forecast future load growth and to maintain existing WECC Path TOT4A ratings. The project and resulting investment are also necessary to maintain compliance with NERC/WECC Transmission Planning Standards TPL-01 through 04 and Transmission Operating Standards TOP-02, 04, and 07.

[29] http://www.nerc.com/files/Reliability_Standards_Complete_Set.pdf.

3. **Malin Substation 500 kV Series Capacitor Replacement: $18.7 million**. This project required the replacement of the Company's existing 500 kV series capacitor located in Bonneville Power Administration's Malin substation near Klamath Falls, Oregon. There are currently three separate series capacitors installed on the California-Oregon AC Intertie 500 kV system, one of which is owned by the Company. The Company's series capacitor located at Malin is the smallest of the existing three capacitors and thereby is the limiting electrical elements in obtaining a higher operating transfer capacity on the Pacific AC Intertie, of which the Company is also part owner. Replacement of the series capacitor was agreed to as a necessary transmission system upgrade under FERC Docket Number ER07-822-000 Article VII.
4. **Harry Allen Sub Install Transformer: $15.1 million.** This project requires installation of a second 300 MVA 230/345 kV transformer at Nevada Energy's Harry Allen substation. This is a 230/345 kV transformer which electrically connects the Company's single Red Butte 345 kV line to Nevada. The existing transformer at Harry Allen is not capable of serving the existing or future forecasted network customer loads. Under certain expected operating conditions the Red Butte substation, which is served from the Harry Allen transformer, will become overloaded above its operating limits. The project and resulting investment are necessary to maintain compliance with NERC/WECC Transmission Planning Standards TPL-01 through 04 and Transmission Operating Standards TOP-02, 04, 07.

5. **Mona - Limber - Oquirrh 500/345 kV line Phases I and II: $8.4 million.** The Mona to Oquirrh project is the second segment of Energy Gateway Central planned for completion in 2013. This initial investment related to this project is required for development and construction of the initial portion of the Mona to Oquirrh segment. The project requires "looping in" the Company's existing Camp Williams to Terminal 345 kV line into and out of the Company's existing Oquirrh 345 kV substation located in South Jordan, Utah. This project is required for increased reliability necessary to maintain reliable service to existing and future customers in the Wasatch Front of Utah and Southeast Idaho and to maintain system reliability during transmission line outages north of Camp Williams. The project and resulting investment are necessary to maintain compliance with NERC/WECC Transmission Planning Standards TPL-01 through 04 and Transmission Operating Standards TOP-02, 04, 07.

The Mona to Oquirrh project is necessary to remove existing transmission system limitations, reliably serve existing customers and serve forecasted long term load growth in the state of Idaho. It is also required to meet the Company's integrated resource plans and is necessary to deliver identified energy resources to load centers. The Mona to Oquirrh project has been issued a Certificate of Public Convenience and Necessity by the Utah Public Service Commission under Docket No. 09-035-54, dated June 16, 2010, and has been approved by the Utah Utility Facility Review Board under Docket No. 10-035-39, dated June 10, 2010.

6. **Populus-Terminal 345 kV line - Borah Reconductor: $13.4 million.** The Populus to Terminal Project scope of work included a replacement of line conductors on some portions of the Borah to Ben Lomond 345 kV line. This work was defined as an incremental piece of the Populus to Terminal Project, however the Borah to Ben Lomond 345 kV line could not be removed from service for system integrity and reliability reasons until the new Populus to Terminal double circuit line was completed and energized, as this new line provided capacity and reliability during extended outages of the Borah 345 kV line.
7. **Populus-Terminal: Double Circuit 345 kV Transmission Line – Transmission: $13.4 million.** This investment is related to residual Project closeout costs incurred after the Project was placed in service in November 2010. These investments include but are but not limited to land reclamation costs (seeding areas that were previously covered with snow); finalizing as-built drawings; owner's engineer charges; legal fees for condemnation activity; and installation of traveling wave line fault locators.
8. **Oquirrh – New 345-138 kV Substation Transformer: $6.8 million.** This project is required to meet existing and future customer energy demand. It is located in Salt Lake City, Utah. The addition of a new substation transformer is required in order provide reliable electric service to customers and to comply with mandatory NERC/WECC reliability and performance standards. This transformer will provide new capacity required to prevent overloads on six existing interconnected 345-138 kV

transformers connected to the transmission system in the area. Failure of existing transformers would cause service disruption of up to 87,500 customers under certain operating conditions. The project is necessary to comply with NERC performance standard TPL-001 and TPL-002 and TPL-003. The 345 kv lines connected to the Oquirrh substation are part of the bulk electric system serving Southeast Idaho.

9. **Idaho and Wyoming Clearance Issue Corrections: $6.6 million and $5 million, respectively.** The Idaho and Wyoming clearance issue correction projects were implemented to comply with both 1) The National Electric Safety Code (NESC) clearance requirements, and 2) a NERC Alert released in late 2010. Per the NESC requirement, recent surveys of select lines identified several spans which, if loaded to published capacity, would violate the allowable NESC clearance. Phase 1 of these projects is to correct these potential clearance issues. Per the NERC alert, in late 2010 NERC issued a reliability alert requiring utilities to verify that published line ratings met field conditions.

10. **California-Oregon Intertie Upgrade 4800MW Rating: $6.2 million.** This project requires installation of a series capacitor at the Bakeoven substation and shunt capacitors at the Captain Jack and Slatt substations, as well as reconductoring of one mile of line on each of the John Day Grizzly #1 and #2 500 kV lines. These additions and upgrades are the result of Bonneville Power Administration reliability studies on the 500 kilovolt AC California-Oregon Intertie to determine what infrastructure additions are

required to operate closer to the operational line rating of 4800 MW. The studies show that the facility modifications will allow an average 80 megawatt increase of operating transfer capability during summer months on the 500 kV AC California-Oregon Intertie. The Company is part owner in the 500 kV AC intertie and by contract is obligated to participate in Intertie upgrades to maintain reliability.

11. **Skypark: Build New 138-12.5 kV Substation: $5.1 million.** The Skypark substation project is necessary to prevent thermal overloading of 5 substations in the Woods Cross/North Salt Lake, Utah area. The new substation will allow for load transfers from the existing substations and defers additional substation projects in the area until 2020. The project will also reduce loading at the Woods Cross substation and on the 46 kV transmission systems in the area. This portion of the overall project is related only to the investment in transmission facilities and is required to serve existing and future customers energy demands and the project is necessary in order for the company to comply with NERC TPL-001 and TPL-002.

Conclusion

Q. Please summarize your testimony.

A. The Populus to Terminal Project is in-service and is 100 percent used and useful. It is capable of operating at 100 percent of its current WECC rated capacity as an integral part of the wider interconnected transmission system. The Company complied with mandatory standards and followed industry accepted practices and precedents in planning, designing, construction and subsequent operation of the Project. The Company could have sought a reduced rating for Path C based only on its current capacity and not taking into consideration the future impact of the Project, other Energy Gateway Segments or other generation. This option would have supported a finding from the Commission in the last case that the Project was fully used and useful, but it would have put at risk the Company's ability to reserve the future benefits of the Project for its customers.

I respectfully request that the portion of the Project investment not currently in rate base be included in this case. Additionally, the major transmission capital expenditures included in my testimony are all essential and are required to meet customers' needs, including those customers in Idaho, both current and future, while providing safe, adequate, reliable and efficient electric transmission service. These investments are required in order for the Company to comply with its statutory obligations to serve customers under its FERC approved OATT and to comply with FERC/NERC/WECC mandatory reliability standards for bulk electric systems.

Lastly, the transmission capital investments included in this case are in the public interest for the reasons I discuss throughout my testimony, including serving Idaho with an ongoing supply of safe, adequate and reliable electric energy, capacity and service. For these reasons, I urge the Commission to approve these investments and thereby include them in the Company's rate base.

Q. **Does this complete your direct testimony?**

A. Yes.

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Case No. PAC-E-11-12
Exhibit No. 30
Witness: Darrell T. Gerrard

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Darrell T. Gerrard

Transmission Major Plant Additions

May 2011

Rocky Mountain Power
Results of Operations - December 2010
Major Plant Addition Detail - January to December 2011

Project Description	In-Service Date	Jan11 to Dec11 Plant Additions
Transmission		
Red Butte Static Var Compensator and 345 kV Shunt Capacitor	May-11	46,434,990
Malin 500 kV series cap replacement	Feb-11	18,700,000
Harry Allen Sub Install Transformer	Jun-11	15,100,000
Populus-Terminal: Dbl Ckt 345 kV TransLn - Transmission	Nov-10	13,409,213
Populus - Terminal 345 kV line - Borah Reconductor	Feb-11	13,400,000
Mona - Limber - Oquirrh 500/345 kV line Phases I and II	Apr.11/May11	8,362,700
Oquirrh New 345-138kV Substation	Jan-11	6,804,918
Idaho Clearance Issue Corrections	Jun-11	6,616,683
Dave Johnston - Casper 230 kV Rebuild - #1 Line	Jan-11	6,127,474
California-Oregon Intertie Upgrade 4800MW Rating	Jul-11	6,157,000
Skypark: Build New 138-12.5 kV Substation	Oct-11	5,070,679
Wyoming Clearance Issue Corrections	Dec-11	5,017,130
Transmission Total		**151,200,786**

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Darrell T. Gerrard

Savings Estimate if Second Circuit Deferred

May 2011

Populus - Terminal 2010 Construction Costs One 345 kV Circuit and Two Substation Bays				
	Unit	QTY	$/Unit	2010 Cost
1272 Aluminum Conductor	LF	4,322,578	$ 4	$ 16,641,925
345kV Bundled V String	EA	780	$ 10,504	$ 8,193,385
345kV Bundled Angle	EA	75	$ 13,268	$ 995,126
345kV Bundled D.E	EA	55	$ 52,250	$ 2,873,763
Dampers	EA	5,450	$ 63	$ 342,424
Single 345kV Bay: Terminal	LS	1	$ 5,475,000	$ 5,475,000
Single 345kV Bay: Ben Lomond	LS	1	$ 4,725,000	$ 4,725,000
Access Road/Restoration	LS	1	$ 2,000,000	$ 2,000,000
Mobilization/Demobiliation	LS	1	$ 500,000	$ 500,000
Sales Tax	%	6.70%		$ 2,797,024
Construction Labor				$ 17,674,750
Construction Management				$ 6,212,003
Bonds/Insurance				$ 580,337
Owners Engineer Support				$ 1,888,184
Rocky Mountain Power Staff				$ 287,235
Permits				$ 365,000
Total - Direct Capital Costs[1]				$ 71,551,156

1) Costs do not include capital surcharge or allowance for funds used during construction

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September 2008 Analysis of Populus-Terminal

May 2011

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Single Circuit Construction Replaced with Double Ciruit

May 2011

Populus - Terminal 345 kV Single Circuit Estimate + Removal + Double Circuit Construction Forecast

Construction 345 kV Single Circuit Based on Block Estimates:								
Construction 345 kV Single Circuit	Description	Transmission build per unit	ROW cost per mile	Sub-Total	Units	Sub-Total	Related project costs @ 25%	Total
Transmission Line	345kV Single Circuit Steel H w/Doubled bundled 1272 ACSR	$718,561	$601,980	$1,320,541	135 miles	$178,273,035	$44,568,259	$222,841,294
Substation	345kV Single Circuit Substation	$44,634,838		$44,634,838	3 subs	$133,904,514	$33,476,129	$167,380,643
	Total					$312,177,549	$78,044,387	$390,221,936

Removal of 345 kV Single Circuit Line and Substation Facilities Based on Block Estimates:								
Removal 345 kV Single Circuit	Description	Transmission build per unit	ROW cost per mile	Sub-Total	Units	Sub-Total	Related project costs @ 25%	Total
Transmission removal per mile	345kV Single Circuit Steel H w/Doubled bundled 1272 ACSR	$289,913	0	$289,913	135 miles	$39,138,309	$9,784,577	$48,922,886
Substation removal per site	345kV Single Circuit Substation	$17,899,661	0	$17,899,661	3 subs	$53,698,983	$13,424,746	$67,123,728
	Total					$92,837,292	$23,209,323	$116,046,614

Actual Construction Cost of Populus - Terminal 345 kV Double Circuit Line and Substations:							
October 2010 Forecast							$832,219,636

Total Cost of Build/Remove Single Circuit 345 kV & Build 345 kV Double Circuit Line and Substations:								
Build/Remove Single Circuit 345 kV & Build 345 kV Double Circuit Line and Substations								$1,338,488,187
Remove Duplicate ROW Cost in Estimate								-$101,584,125
	Net Cost							$1,236,904,062

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Path C Firm Transmission Reservation

May 2011

Path C Southbound Firm Transmission Service Reservation (Megawatts)			
Network Load Service	PAC	1146	
Network Other	Other	100	Future
Sub-total Network Service		1246	
Point to Point Service	PAC	523	
Point to Point Service Other	Other	99	Future
Sub-total		622	
Total		**1868**	