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 PacifiCorp.

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 explain and support a portion of the transmission capital expenditures included in the Company's application for a general rate increase. Specifically, my testimony identifies the major capital investments in the Company's main transmission grid that will be placed into service between June 30, 2010 (the end of the base year in this case) and June 30, 2012 (the end of the test period in this case), explains the primary driver(s) creating the need for these projects and resulting investment, and describes the benefits to customers and the electrical system overall.

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 to determine the investments are needed now?

A. PacifiCorp's Open Access Transmission Tariff ("OATT"), [1] approved by the Federal Energy Regulatory Commission ("FERC") details the Company's requirements and obligations to provide transmission service. Section 28.2 defines PacifiCorp's responsibilities, which include the requirement to "plan, construct, operate and maintain the system in accordance with good utility practice." Section 31.6 defines the requirement for network customers to supply annual load and

[1] http://www.oasis.pacificorp.com/oasis/ppw/OATTVol11Baseline_20100908.pdf

resource updates for inclusion in planning studies. The Company solicits this data annually in order to determine future load and resource requirements for all transmission network customers. The Company's retail loads comprise the bulk of the transmission network customer needs, including those in Utah. Section 28.3 includes the requirement for PacifiCorp to provide "firm service over the system so that designated resources can be delivered to designated loads." The project investments included in this proceeding are necessary to meet these requirements and customer demand.

The customer load demands from 2010 network customer loads and resource submittals indicates demand in the Wasatch Front of Utah alone is anticipated to grow from a peak of 4800 MW in 2011 to 6,211 MW in 2019. The Wasatch Front area of Utah comprises more than 80 percent of the electrical demand in the state of Utah.

Q. Do you believe that such customer load demand forecasts reflect the economic conditions in Utah 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. The 2010 customer demand forecasts for the Wasatch Front, for example, showed a reduction in forecasted customer demand for the year 2018 of nearly 375 MW compared to the 2018 forecasts received in 2009. Despite this reduction, the overall demand forecast for the Wasatch Front is still expected to grow to 6,211 MW by 2019.

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 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 $16 million Pinto 345 kV Series Capacitor project was delayed one year from 2009 to 2010 based on reduced risk due to lower customer demand as well as construction schedules;
- The Red Butte Static VAR Compensator project was delayed early in its project life cycle from 2009 to 2011, again 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 $44 million of remaining investment by two years; and
- 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. Which customers provided load data for PacifiCorp's 2010 annual load and resource forecast?

A. All PacifiCorp network load customers provided their annual load and resource forecast in 2010. These customers include: PacifiCorp Commercial and Trading, Utah Associated Municipal Power Systems, Utah Municipal Power Agency, Deseret Power Electric Cooperative, Bonneville Power Administration, Basin Electric Power Cooperative, and Moon Lake Electric Association.

Q. Are there other transmission performance requirements, besides growing customer energy demand, 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 the Western Electricity Coordinating Council ("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 Utah. The projects and related investments discussed herein 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 and drive their timing to completion?

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 federal law stated 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 to which the Company must comply. The project investments and their respective in-service date timing are required to maintain compliance with the following:

- NERC TPL-001 System Performance Under Normal Conditions[2]
- NERC TPL-002 System Performance Following Loss of a Single BES Element[3]
- NERC TPL-003 System Performance Following Loss of Two or More BES Elements[4]
- NERC TPL-004 System Performance Following Extreme BES Events[5]
- TPL 001-WECC-1-CR System Performance Criteria Normal Conditions[6]
- 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

[2] NERC TPL-001 can be found at: http://www.nerc.com/files/TPL-001-0.pdf

[3] NERC TPL-002 can be found at: http://www.nerc.com/files/TPL-002-0.pdf

[4] NERC TPL-003 can be found at: http://www.nerc.com/files/TPL-003-0.pdf

[5] NERC TPL-004 can be found at: http://www.nerc.com/files/TPL-004-0.pdf

[6] TPL 001-WECC-1-CR – TPL 004-WECC -1-CR can be found at: http://www.wecc.biz/Standards/WECC%20Criteria/TPL-001%20thru%20004-WECC-1-CR%20-%20System%20Performance%20Criteria.pdf

- TPL 003-WECC-1-CR System Performance Criteria Following Extreme BES Events
- NERC TOP-002 Normal Operations Planning[7]
- NERC TOP-004 Transmission Operations[8]
- NERC TOP-007 Reporting SOL and IROL Violations[9]

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 you discuss in this filing.

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

[7] NERC TOP-002 can be found at: http://www.nerc.com/files/TOP-002-2.pdf

[8] NERC TOP-004 can be found at: http://www.nerc.com/files/TOP-004-2.pdf

[9] NERC TOP-007 can be found at: http://www.nerc.com/files/TOP-007-0.pdf

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 ten) 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 conclusion, 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 and prudently act on all projects in that 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 for implementation.

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

A. As reflected by Mr. Steven McDougal's Exhibit RMP___(SRM-3), between June 30, 2010, and June 30, 2012, the Company will place into service over $1.1 billion of transmission investment. My testimony discusses major capital projects making up $929.9 million of total investment as follows: 1) completion of the first segment of Energy Gateway (Populus to Terminal); 2) transmission projects greater than $10 million; and 3) transmission projects less than $10 million and larger than $1 million. Exhibit RMP___(DTG-1) contains a list of these projects, including a short project description for each transmission investment and investment totals. Company witness Mr. Douglas N. Bennion addresses, separately, approximately $236.4 million of local transmission investments in his testimony.

Populus to Terminal

Q. Please describe the projects related to completion of the first segment of Energy Gateway (Populus to Terminal).

A. The Populus to Terminal project was fully energized and placed into service November 19, 2010. Exhibit RMP___(DTG-1) contains a list of transmission projects related to the Populus to Terminal segment of Energy Gateway that have been, or will be, placed into service after June 30, 2010, totaling approximately $575.5 million on a total company basis. The Ben Lomond to Terminal portion of the project was placed into service early in 2010 and the related costs are included in the unadjusted rate base balances in this case. Because the Populus to Ben Lomond portion of the project was completed in November 2010, the related costs are added to rate base as part of the capital addition adjustment in Mr. McDougal's revenue requirement calculations.

Q. Has the Commission already approved recovery of some of the Populus to Terminal transmission investments? If so, please explain why these investments are included in this case.

A. Yes. The Company included two segments of the Populus to Terminal project in its two major plant addition ("MPA") filings in Docket Nos. 10-035-13 and 10-035-89. In those dockets, the Company fully explained and justified the benefits of the Populus to Terminal project for Utah ratepayers. Effective January 1, 2011, the related revenue requirement is being collected from Utah customers through a surcharge in Schedule 40. In addition to the project costs included in the two MPA filings, this general rate case includes in rate base residual closing costs and the Borah Reconductor portion of the project, which amount to approximately three percent of the total project cost. As a result of this case all of the Populus to Terminal project investments will be included in base rates and Schedule 40 will be eliminated.

Transmission Projects Greater than $10 Million

Q. Please describe the other transmission investments that the Company is adding to rate base in this filing which are greater than $10 million.

A. Between June 30, 2010, and June 30, 2012, the Company will place into service approximately $294 million of transmission investment for projects over $10 million each. Exhibit RMP___(DTG-1) individually lists and breaks out these projects, as follows:

1. **Red Butte Static VAR Compensator and 345 kV Capacitor: $49 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.[10]

2. **90th South - Camp Williams 345 kV Double Circuit Line**: **$43 million** This project requires building a new double circuit 345 kV line 10.7 miles long in an existing corridor located between the Camp Williams and 90th South substations and modification of those facilities. Transmission operational transfer capability and reliability studies conducted northbound into the Wasatch Front area in Utah have demonstrated the need for the new double circuit 345 kV transmission line (10.7 miles). During periods of heavy customer demand along the Wasatch Front energy imports from the Company's generation facilities in the

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

southern part of the state must be limited for reliability reasons. The transmission path serving the Wasatch Front from Camp Williams cannot withstand a double line loss (loss of an existing corridor) and operate within mandatory WECC/NERC reliability criteria; such an event would overload the remaining transmission circuits in the area north of Camp Williams. This project and its resulting investment are necessary for ongoing reliable load service to existing customers and for future long term load growth forecasted in the area. The project is also required to maintain compliance with mandatory WECC transmission planning TPL-01 through 04 and transmission operating standards TOP-02, 04 and 07.

3. Terminal Substation - Replace two 345/138 kV Transformers: $41 million

This project requires removal of the two existing 345-138 kV 450 MVA transformers at the Terminal substation and necessarily replaces and modifies the existing facilities. Areas of the Salt Lake valley are currently served from six interconnected 345-138 kV transformers operating as a network. Two transformers are located at each of the 90th South, Mid Valley, and Terminal substations. Studies performed for the summer loading season including calendar years 2010 to 2013 showed that if one of these transformers were out of service (planned or unplanned) the remaining transformers would become overloaded beyond their operating limitations. The most severe overload would occur due to loss of one of the 450 MVA transformers at the Terminal substation. This project and its resulting investment is required to provide ongoing reliable service to existing customers and for future long term load growth forecasted for the area.

The project is also required to maintain compliance with mandatory WECC Transmission Planning Standards TPL-01 through 04.

4. Wallula - McNary 230 kV Single Circuit Line: $36 million

This project requires building a new 30 mile long 230 kV transmission line in a new right-of-way from the existing PacifiCorp Wallula substation in Washington to the existing Bonneville Power Administration McNary substation near Umatilla, Oregon. To date, the line route has been determined, initial line design has been completed and the majority of required permits have been acquired. The Wallula substation will be expanded within existing property bounds to accommodate the new line connection. PacifiCorp's transmission system in the Walla Walla area, including the existing lines between Walla Walla, Wallula and McNary, is currently fully subscribed. PacifiCorp has a signed contract, for firm point-to-point transmission service from Wallula to McNary, and is required under it's OATT to construct this project in order to meet the terms of these transmission service contracts. The project and it's investment is required to facilitate integration of new renewable energy sources being constructed in the Wallula area.

5. Dave Johnston - Casper 230 kV Rebuild - Casper Sub: $31 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. The project scope also includes modification of facilities at the Casper and Dave Johnston Substations. Without this project the WECC rated Path TOT4A operating capacity must be reduced by 100 megawatts resulting in curtailment of firm energy transfers from the Dave Johnston and Wyodak plants and reductions in firm and non-firm power sales across the path. This project is required to maintain existing transmission capacity to serve existing customer demand and to meet forecast future load growth in areas of Wyoming and to maintain existing WECC Path 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.

6. **Install Shunt Capacitors in Wyoming - Platte Sub SVC: $18 million**

This project requires 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. The industrial load growth in Wyoming is currently being added in large megawatt increments, which the current 230 kV system cannot support. This project is required to maintain existing transmission transfer capacity to continue to reliably serve existing customers and to meet forecast future load growth in areas of Wyoming while maintain existing WECC rating on Path TOT4A. This path is a critical interconnection to the wider transmission system connecting Utah, Idaho and Wyoming. The project and resulting investments are also necessary to maintain compliance with NERC/WECC Transmission Planning Standards TPL-01 through 04 and Transmission Operating Standards TOP-02, 04, 07.

7. Malin Substation 500 kV Series Capacitor Replacement: $17 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 element 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.

8. Pinto 345 kV Series Capacitor: $17 million

This project requires the installation of a new 345 kV series capacitor bank at the existing Pinto substation. The new equipment has been installed on existing Company-owned property to the east of the Pinto substation and required modification of the Pinto facility. The series capacitor is required to provide normal steady-state service to existing customers in the area and is required for long term future load growth. The project is also required to meet the Company's existing firm point-to-point transmission service contracts on the WECC rated Path 2A "Pinto to Four Corners." This path is a critical interconnection to the wider transmission system connecting Utah into the Four Corner states. The project and resulting investments are necessary to maintain compliance with NERC/WECC

Transmission Planning Standards TPL-01 through 04 and Transmission Operating Standards TOP-02, 04, 07.

9. Harry Allen Sub Install Transformer: $15 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 customer loads in southwest Utah. Under certain expected operating conditions at Red Butte the existing 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.

10. Union Gap - Add 230 - 115kV Capacity: $15 million

This project requires installation of a third 150 MVA 230/115 kV transformer and expansion of both the 230 kV and 115 kV facilities at the existing Union Gap substation in Yakima, Washington, which is one of two main 230/115 kV source substations serving the Upper Yakima Valley of Washington. Failure of one of the existing transformers would result in unacceptable overload of the remaining transformer. This project and resulting investment is required to reliably meet existing customer load service and to meet the load growth demands forecasted for the future. This project and resulting investments are also necessary to maintain compliance with NERC/WECC Transmission Planning Standards TPL-01 through 04 and Transmission Operating Standards TOP-02, 04, 07.

11. Mona - Limber - Oquirrh 500/345 kV line Phases 0, I, II: $13.7 million

The Mona to Oquirrh project is the second segment of Energy Gateway Central. This plant addition is the total of three investments required for development and construction of the initial portion of the Mona to Oquirrh segment. The first project $8.4M requires "looping in" the Company's existing Camp Williams to Terminal 345kV line into and out of the Company's existing Oquirrh 345kV 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 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 second and third investments as part of this plant addition are necessary plant held for future use which the Company has included to allow for recovery of these costs. The Company has contracted to purchase the real property for the future Clover substation, near Mona Utah for $3.3 million, and for the future Limber substation in Tooele County for $2.0 million. These future substations are required in order to provide 345/138kv transmission service to customers in the Mona and Cedar City area and to customers in Tooele County respectively. In addition the property needed for both of these substations are part of the Company's Gateway Central plans. Securing substation property for both stations is required in 2011 in order for the Company to effectively complete substation physical layouts, perform geotechnical studies, engineering and designs, and to establish necessary transmission line entrances and exits and to avoid line crossings and conflicts and prepare complete bid packages .

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. 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. 9-035-54, 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.

Transmission Projects under $10 Million

Q. Please describe the major transmission investments that the Company is adding to rate base in this filing which are under $10 million and greater than $1 million.

A. Exhibit RMP___(DTG-1) individually lists projects that are less than $10 million and greater than $1 million each. These projects total $60.5 million dollars and are required to meet requirements and obligations under the Company's retail tariffs and FERC-approved Open Access Transmission Tariff ("OATT") and to maintain compliance with mandatory reliability and operational standards. These projects include: upgrading transmission facilities necessary to provide adequate and reliable service benefiting our existing customers and meeting their energy demands forecasted in the future, meeting transmission service requests and generator interconnection requests and third party customer transmission service contracts required by FERC under the Company's OATT, and maintaining the system in compliance with NERC/WECC reliability standards.

Q. Please summarize your testimony.

A. The major transmission capital expenditures included in my testimony are all essential to meet customers' needs, both current and future, while providing safe, adequate, reliable and efficient electric transmission service. The major portion of the transmission investment associated with plant additions in this case are a result of the Populus to Terminal project, which has already been scrutinized by parties through the regulatory process where the Company demonstrated prudence, purpose and need and that the project is used and useful. As a result of this filing, Populous to Terminal will be rolled into base rates and the current surcharge will be eliminated. The other transmission plant additions in this case will provide transmission service benefits to all of the Company's customers, including those in Utah, by providing access to low cost resources, increasing system reliability required for transport of energy to load centers while helping to control delivered energy costs.

Q. Are the Transmission capital investments included in this case in the public interest and do you recommend that the Commission include them in the Company's rate base?

A. Yes. The transmission capital investments included in this case are in the public interest for the reasons I discuss throughout my testimony, including serving the public with safe, adequate and reliable service. For these reasons, I recommend that the Commission approve these investments for inclusion in the Company's rate base.

Q. Does this complete your testimony?

A. Yes.