Q. Please state your name, business address and position with PacifiCorp dba Rocky Mountain Power.

A. My name is Darrell T. Gerrard. My business address is 825 N.E. Multnomah, Suite 1600, Portland, Oregon. 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 (Power Systems Major) at 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 planned 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 strategy ("Energy Gateway").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide additional details and technical information on the Company's decision to build the double-circuit 345kv Populus to Terminal transmission line (Phase I and II), which is part of Segment B of the Energy Gateway Project (see Exhibit RMP___(JAC-1)).

Overview of Transmission Project

Q. Please describe the scale and size of the Populus to Terminal transmission segment.

A. Populus to Terminal will add 135 miles of new transmission line, over 8,600,000 linear feet of conductor and approximately 900 poles will be installed on new foundations. The Ben Lomond to Terminal section specifically, is approximately 47 miles and includes 3,010,000 linear feet of conductor and over 260 poles. At the time of this filing, the overall Populus to Terminal segment is on schedule with a total of 833 transmission structure foundations installed, 871 access roads constructed, 755 poles set and 6,375,000 linear feet of conductor pulled. For Ben Lomond to Terminal (Phase 1), 265 foundations are installed, 260 poles set and 2,941,000 linear feet of conductor pulled. The large majority of work remaining before the June 2010 completion date is substation work at Ben Lomond and Terminal. Exhibit RMP___(DTG-1) contains photos of assets in place for Ben Lomond to Terminal and Populus to Ben Lomond.

Q. Please describe the transmission investment included in this rate case.

A. In this Docket, the Company is seeking cost recovery for the Ben Lomond to Terminal section ("Phase I") of the Populus to Terminal transmission segment B of Energy Gateway, described in more detail in the direct testimony of Mr. John A. Cupparo. A map showing the entire route of the Populus to Terminal segment is shown in Exhibit RMP___(JAC-2). Phase I is an integral part of the overall Populus to Terminal transmission segment and is the first section to be constructed and completed. The Ben Lomond Substation and Terminal Substation will be expanded to accommodate the new 345 kV transmission lines and termination points. The Company expects the total investment in the Ben Lomond to Terminal section (Phase I) to be $268 million, based on project costs estimates detailed in Exhibit RMP___(DTG-2) and expects the line to be fully in-service by June 30, 2010, and used and useful to customers at that time.

Q. What is the purpose of the Populus to Terminal transmission segment?

A. In addition to the project benefits described in the testimony of Mr. Cupparo, the purpose of the Populus to Terminal line project is to:

- Increase the overall transmission capacity in the existing transmission corridor between Southeast Idaho and Northern Utah where the existing system has limited capacity and has demonstrated operational limitations;
- Meet the immediate need to improve system reliability in the area by installing transmission capacity to ensure the system can sustain transmission outages north of Terminal Substation without curtailing loads, generation or impacting the PacifiCorp East Control Area and

neighboring transmission balancing authority areas. Currently between Terminal Substation and Ben Lomond Substation, there is only one double 345 kV circuit and one single 230 kV circuit. Loss of the existing double 345 kV circuit has potentially serious operational consequences as the remaining system overloads;

- Improve the Company's ability to perform maintenance on transmission facilities between Populus and Terminal by having alternative transmission paths that allow facilities to be taken off-line and maintained;
- Integrate with future Energy Gateway segments to increase transfer capability between PacifiCorp's east and west control areas in order to balance generating resources and loads, enable commercial energy purchases or sales while allowing integration of new renewable generation resources;
- Provide PacifiCorp with options and greater flexibility when considering future planned resources to meet customers' growing demands for energy service requirements while meeting current and future energy requirements that may be mandated by state and federal regulation;
- Facilitate the integration of potential new energy resources in Wyoming, Utah and Idaho, and help support economic development planned in those states; and
- In the long-term, provide an incremental increase in transmission capacity and reliability benefits for future Energy Gateway transmission segments planned between Wyoming, Idaho, Utah, Oregon and Washington, and

interconnecting the region in general.

Need for and Benefit of Additional Transmission

Q. What information has been used in determining the need and justification for this investment?

A. PacifiCorp's Open Access Transmission Tariff ("OATT"), approved by the Federal Energy Regulatory Commission ("FERC"), provides details regarding PacifiCorp'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 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 including PacifiCorp's network customers and customers of third parties under our FERC-approved OATT. 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." These future requirements and needs will be met via Energy Gateway and its segments, including the Populus to Terminal. Ben Lomond to Terminal is Phase I of that segment, all of which is an important part of PacifiCorp's overall transmission plan for Utah and the region.

Q. Are other transmission performance requirements besides growing customer energy demand driving the need for this system investment?

A. Yes**.** In meeting the current and future customer energy needs described above, the Company must maintain a level of system reliability in order to provide adequate transmission service. The North American Electric Reliability Corporation ("NERC") and the Western Electricity Coordinating Council ("WECC") have recently adopted and enacted a significant number of standards and guidelines that specify in detail the levels of system performance that entities like PacifiCorp must maintain during the planning, operation and ongoing maintenance of their bulk electric system. NERC's reliability standards have been 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 electric infrastructure and, specifically in our case, in the WECC region. Investments being made via this transmission project will help PacifiCorp meet reliability requirements. Further, the investment will provide reliability benefits to future planned high-voltage transmission additions interconnecting Wyoming, Utah and Idaho and the region.

Q Are there examples where these new reliability standards and guidelines have resulted in changes to the system and its operation? If so, how is that change driving investments required in transmission?

A. Yes. In early 2008, PacifiCorp performed an operational analysis of the transmission system north of Ben Lomond substation. As a result of this analysis and reflective of NERC and WECC standards and guidelines, the system firm transmission capacity was reduced from approximately 775MW to 430MW during heavy load hours and reduced from approximately 900MW to 620MW during light load hours. This reduction in firm capacity was a result of NERC and WECC standards and guidelines that require transmission capacity to be reduced due to potential outage risks associated with multiple transmission lines being located adjacent to each other in common corridors. The investment in the Populus to Terminal segment is required to improve the firm capacity in this part of the transmission system.

Q. How did the Company determine that additional transmission capacity was needed?

A. The Company utilizes the Integrated Resource Plan ("IRP") to review whether additional transmission capacity is needed. The IRP uses a public process to develop a framework for the prudent future actions required to ensure the Company continues to provide reliable and least-cost electric service to its customers, while striking an expected balance between cost and risk over the planning horizon and taking into consideration environmental issues and the energy policies of our states. As stated in the 2008 IRP, "PacifiCorp's IRP mandate is to assure, on a long-term basis, adequate and reliable electricity supply at a reasonable cost and in a manner consistent with the long-run public interest."

Q. Did the Company make any commitments to add transmission capacity?

A. Yes. During the MidAmerican Energy Holdings Company ("MEHC") acquisition of PacifiCorp in 2006, the Company committed to increase the transmission capacity by 300 MW from southeast Idaho to northern Utah. The objectives of the transaction commitment were to:

- Enhance the reliability of the only high use commercial path between Idaho and Utah;
- Provide for increased transfer capability between PacifiCorp's east and west control areas; and
- Facilitate the delivery of future power from wind projects in Wyoming and Idaho, and provide PacifiCorp with greater flexibility and the opportunity to consider additional options regarding future planned generation capacity additions.

Q. Describe how the Populus to Terminal transmission segment complies with the IRP and MEHC commitment.

A. The Populus to Terminal transmission line segment is designed to meet load growth, future customer energy service requirements and improve overall system reliability. Based on the Company's 2008 IRP forecasts, PacifiCorp's network load obligation is expected to grow during the next 10 to 20 years. In addition, operational reserve obligations required to balance and maintain system reliability will increase over time as they are a function of load served. The existing transmission capacity from southeastern Idaho into Utah is fully subscribed and no additional capacity can be made available without the addition of new transmission lines. The Populus to Terminal line will add significant new incremental transmission capacity (1,400MW planned) to this area of the system and will help integrate other future planned resources, market purchases and sales as necessary to help control energy costs. The investment also improves the system reliability as needed, which I discuss later in my testimony. All of the above support PacifiCorp's IRP and the commitments made by MEHC.

Q. Has the Company performed other studies and analyses that demonstrate the need to improve the reliability of the transmission system in this area?

A. Yes, in addition to the long-term energy resource needs identified in PacifiCorp's IRP mentioned above, the Company performed specific analysis in late 2007 and 2008 addressing several system disturbance events that severely impacted generation, customers, and the operation of the transmission system affecting Wyoming, Utah and Idaho. These events also impacted other utilities interconnected to PacifiCorp's transmission system. It is evident from these disturbances and the resulting analysis that the transmission system in this area does not have the necessary capacity and reliability to meet all of the system operating conditions expected. NERC electric system reliability standards require that the system demonstrate adequate performance for all expected operating conditions expected including multiple contingencies. There have been five system disturbances since September 2007 for which the Populus to Terminal line directly mitigates the risk of reoccurrence. Three of these disturbances occurred on the system north of Ben Lomond substation and two occurred south in the Ben Lomond to Terminal section. These disturbances resulted in system overloads, curtailments of schedules, repeated curtailments of interruptible loads and generation reductions in Wyoming, Utah and other surrounding states. The three disturbances occurred on September 27, October 15 and October 21, 2007, during periods of heavy flow northbound from the Terminal Substation towards Ben

Lomond and into Idaho. As a result, over 1,450 customers were affected by the first outage, and Nucor and Monsanto loads were either interrupted and/or reduced during all three outages. Generation curtailments and adjustments of more than 1,000 MW had to be requested for all three incidents including reduced generation from Dave Johnston and Naughton plants in Wyoming. Details and analysis of the system performance during the events and transmission limitations are detailed in PacifiCorp System Disturbance Report dated November 11, 2007, and PacifiCorp's Abbreviated System Disturbance Report to WECC dated January 28, 2008.

On November 27 and November 30, 2007, two disturbances occurred on the Ben Lomond to Terminal section (refer to Exhibit RMP__JAC-2) of the system, causing overloads on three WECC designated and monitored transmission paths. The disturbances impacted more than 400 MW of PacifiCorp generation along with generation interconnected to three other utilities in surrounding states.

Based on the system performance, studies and analysis it is clear that the existing system requires new capacity to meet expected operating conditions and reliability requirements on both a short and long-term basis. The investment in the Ben Lomond to Terminal line is the first step in providing the needed capacity.

Q. What is the transmission capacity and limitations on this system today?

A. The existing transmission capacity in the area between Salt Lake City and Southeast Idaho is fully subscribed for firm service and has limited transfer capability between several key transmission substations (Terminal, Ben Lomond, and proposed Populus) connecting generation facilities in Idaho, Wyoming and

Utah. No new capacity will be available until new transmission facilities are constructed. The limitations and system performance deficiencies are discussed later in my testimony.

Q. Does the investment in the Ben Lomond to Terminal line provide reliability and capacity benefits to future planned transmission additions in the area?

A. Yes. The existing transmission in the corridor from Terminal to Southeastern Idaho has limitations. Without investment in the Populus to Terminal line, the full transfer capability on both of the Gateway West and Gateway South Segments would not be possible. To obtain the full capacity of the Gateway West and Gateway South segments, both segments must be electrically interconnected. This interconnection is achieved by building the Populus to Terminal transmission line as part of Gateway Central.

Q. What alternatives to the Populus to Terminal project did PacifiCorp consider?

A. The Company considered, but rejected four alternatives. The first alternative was to not build the line or to upgrade other existing paths or seek additional transmission corridors into Utah. The Company rejected this alternative because it did not improve existing system reliability, did not provide any new incremental transmission capacity required and precluded the ability of new resources to be delivered into Utah from Wyoming, Idaho, or the Northwest in general. New incremental transmission capacity is needed for both load service and for contingencies.

The second alternative considered was to rebuild the majority of the existing 138 kV lines interconnecting Utah and Southeast Idaho and continue operation of these lines at 138 kV. This alternative would have provided only a small incremental increase of 300 MWs or less in transmission capacity across the currently constrained path between Southeast Idaho and Utah. It also would not have provided adequate interconnection capacity between the future Energy Gateway West and Energy Gateway South segments or offer any additional capacity for the future. In addition to the marginal increase in transmission capacity, this alternative had serious constructability issues as it required large segments of the path to be completely removed from service for extended periods, a year or more, as these existing 138 kV facilities were rebuilt. This would have placed significant reliability exposure on the transmission system serving the area to Rocky Mountain Power customers during construction. This alternative did not allow the Company to meet its current firm transmission obligations nor did it meet the long-range resource plans and network load service requirements.

The third option considered was to construct a new single circuit 345 kV transmission line from the future Populus Substation near Downey, Idaho to the Ben Lomond Substation in Utah, which would have provided some capacity increase from Idaho to Ben Lomond. The alternative included an upgrade of the existing 138 kV line between Ben Lomond and Terminal required to realize a minimum increase in capacity of 300 MW from Ben Lomond to Terminal substation. However, this alternative would not have provided the necessary future system capacity between Energy Gateway West and Energy Gateway South and would have failed to take advantage of maximizing transmission capacity installed in new corridor and our existing Ben Lomond to Terminal transmission corridor.

The fourth option considered was to build a new 500 kV line along the route. The Company rejected this option because of its high cost, its potential for significant siting and community impacts, its requirement for a completely new corridor between Populus and Terminal stations, and its failure to use existing vacant corridors and property rights that the Company previously obtained.

Q. Please explain any further considerations that the Company made in selecting the Populus to Terminal line.

A. The Company selected this transmission line project based on several factors:

- It meets short-term and immediate reliability needs while prudently planning for the future by adding significant long-term incremental transmission capacity (planned rating 1,400 MWs) across the currently constrained transmission system. There have been several transmission outages since 2007 along this corridor that could have been mitigated with additional transmission facilities. The risk of further unplanned disturbances is too great if the current facilities are not improved.
- It allows import of up to 1,400 MWs of forecast resource capacity from Wyoming and Southern Idaho. This new capacity is required based on long-term planning results.
- Construction benefits occur on a significant portion of the transmission project due to existing corridors that were acquired by Utah Power many years ago just for this purpose. The project optimizes use of limited and

scarce transmission corridor lands by maximizing installed transmission capacity in new corridors.

- Construction could occur with minimum planned outages on existing facilities remaining in service without increasing reliability exposure to the current system.
- The Company's ability to perform required maintenance will be improved without significant operational risk associated with taking existing lines out of service.

Bid Process

Q. Please describe the Company's typical procurement process used for major transmission projects

A. The Company uses a competitive blind-sealed bid process to contract for the development of each project unless certain defined conditions apply, such as a restriction in the supply of technology or design solutions that prevent an open competitive process. The form of contract tendered is a turnkey, fixed price, date certain basis for delivery referred to as an engineer, procure and construct approach. The Company identifies potential bidders that provide the capabilities required to deliver the work scope within a boundary of project specific technical specifications and commercial terms. The tender process includes a question and answer period to clarify any outstanding issues and provides anonymity to the requesting bidder and responses of a non-confidential nature are provided to all bidders. Upon receipt of tender documents, the technical proposals are separated from commercial proposals and a separate technical and commercial evaluation is performed on all qualified bids using pre-established evaluation criteria (see Exhibit RMP___(DTG-3) summary of bidder evaluation). The technical evaluation is assisted by external consulting firms who have been pre-contracted for such work based on their industry experience. Upon completion of technical and commercial evaluations a recommendation is made to enter post-tender negotiations to reach final terms, conditions and pricing to support contract execution.

Q. Was this typical procurement process applied to Populus to Terminal?

A. Yes. Specifically for the project, the Company adopted an open competitive tendering rather than a restrictive competitive tendering process where 75 vendors were identified and received an invitation to bid. The competitive tendering process began in October 2007 and provided two separate blind-sealed bidding opportunities. During the October 2007 to May 2008 bidding period, four communications were provided to bidders containing additional project-specific information to assist bidders to refine their submissions specifically to remove any bid qualifications associated with contingent and non-firm pricing. All bid responses were due for submittal in May 2008 and again in July 2008 after additional information was provided to bidders during May 2008 to July 2008 allowing a further refinement of previously submitted design solutions, terms and conditions, including price. Three qualified bids were received and evaluated resulting from the May 2008 proposal submissions. Two competing proposals were received in July 2008. During the separate technical and commercial evaluations, the Company and its consultants identified non-fixed price aspects of the bidder's proposals affecting cost and schedule. The Company consultant computed a cost associated with non-fixed price work scope submitted by each bidder, which was estimated to range from approximately $103 million to $429 million. The Company engaged in negotiations to remove or cap the cost of non-fixed priced work to mitigate post-contract award price escalation and schedule change. The Company awarded the contract in October 2008 for $584.6 million after post-tender negotiation that reduced the contractor's price.

Q. What process, if any, did the Company use to identify and implement cost savings opportunities during the procurement process?

A. During the tender evaluation process, bidders were requested to submit cost savings opportunities for consideration. Each item was reviewed to assess savings with respect to potential impact to operability, reliability and maintainability that were included in the final contract price. In addition, post tender negotiation included a reduction of $25 million in consideration of commodity price reductions, which occurred in the global market during the tender evaluation period.

Construction Process

Q. Please describe the construction process.

A. The construction process involves several major activities and numerous subordinate tasks in order to engineer, procure and construct transmission facilities. The high-level tasks are outlined below:

1.) Preconstruction:

a. Planning and engineering

b. Construction permitting

c. Establishment of lay down yards

d. Development of safety and construction plans

e. Staging of construction crews and materials

f. Negotiation of construction stipulation forms with landowners

g. Public notification of construction

2.) Construct Transmission Line:

a. Initial access road construction

b. Foundation installation

c. Tower installation

d. Install conductor and OPGW

3.) Construct Substation:

a. Access construction and substation grading

b. Civil construction

c. Steel erection and control building installation

d. Equipment installation

4.) Testing and commissioning

a. Individual line and equipment tests

b. Critical punch list resolution

Q. What is the current status of construction for the Ben Lomond – Terminal phase?

A. Transmission Line: The transmission line is built, with the exception of line crossovers, four poles and one foundation outside of Parrish Substation, and one pole outside Terminal Substation. Punch list completion, access road restoration, right-of-way restoration, and landowner closeout is ongoing.

Substation: At the Terminal and Ben Lomond Substations foundations, civil work and steel erection are primarily completed. Equipment is mostly installed and is being connected and tested.

Q. Please state why you believe the project will be completed and in service by June 30, 2010.

A. Weekly project management status reports and field verification confirm construction is on schedule and will be completed by June 30, 2010 barring unforeseen events at this point.

Conclusion

Q. Please summarize your testimony.

A. The existing transmission system capacity from southeastern Idaho into Utah is fully utilized, significant operational limitations exist on the system in this area, and no additional capacity can be made available without the addition of new transmission lines. The Ben Lomond to Terminal transmission line investment is prudent as it meets short-term reliability requirements and meets longer term customer needs by adding significant incremental transmission capacity between Southeast Idaho and Northern Utah

Further the investment facilitates a stronger interconnection to systems in Idaho, Utah, and Wyoming and to the Northwest in general. The Ben Lomond to Terminal transmission line, especially when integrated with the other proposed Energy Gateway Segments, is fundamental to the development of new renewable and other generation sources in Utah, Idaho and Wyoming. The completion of the project will be an important step in strengthening the Western Grid's transmission infrastructure, which is necessary based upon the projected future energy service requirements of our customers including those in Wyoming.

The project was bid out through a competitive bid process followed by negotiations with the best bidders that resulted in a total contract price of $584.6 million. The project is on schedule for completion and going into service by June 30, 2010.

Q. Does this conclude your testimony?

A. Yes.