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

A. My name is Natalie L. Hocken. My business address is 825 NE Multnomah Street, Suite 1600, Portland, Oregon 97232. I am Senior Vice President of Transmission and System Operations for PacifiCorp.

Qualifications

Q. Please describe your education and business experience.

A. I have a law degree from the University of Oregon and am a graduate of the Willamette University Atkinson Graduate School of Management with a certificate in Utility Management. My experience spans over 19 years in the energy industry. Prior to joining PacifiCorp in 2002, I was an energy attorney specializing in federal and state regulatory and energy matters. I have held positions at PacifiCorp of vice president and general counsel of Pacific Power, assistant general counsel and senior counsel.

Q. What are your responsibilities as Senior Vice President of Transmission and System Operations?

A. As Senior Vice President of Transmission and System Operations, I am responsible for management of transmission services, transmission planning and system operations for PacifiCorp's two balancing authority areas. I am responsible for activities required to support PacifiCorp's existing and future bulk transmission system and to ensure a safe and reliable transmission system that provides economic service to our customers, including delivery of the Company's long-term Energy Gateway Transmission Expansion Plan ("Energy Gateway").

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the major test year costs associated with capital investments in the Company's transmission system. The capital investments that will be placed into service during the test year in this case that represent individual project investments greater than $10.0 million include the following:

- the costs to plan and build the Sigurd-to-Red Butte 345 kilovolt transmission project ("Sigurd-to-Red Butte Project"),
- the costs to plan and build the Carbon Plant replacement,
- the costs to plan and build the 230 kilovolt Standpipe substation,
- the phase one costs to plan and build the Whetstone 230/115 kilovolt substation,
- the costs to plan and upgrade the Union Gap 230 kilovolt transmission substation, and
- the costs to plan and build the Lakeside 2 generating plant transmission service project.

My testimony will provide evidence showing that the Company was prudent in managing these costs, and that these investments will be used and useful during the test year and beneficial to our retail customers.

Q. Please summarize your testimony.

A. First, I will provide a detailed description of the Sigurd-to-Red Butte Project, including associated costs to plan and build. I will show that, given existing

limited capacity on the transmission system, the Sigurd-to-Red Butte Project is needed to support both short- and long-term energy demands. The project will strengthen the overall reliability of the existing transmission system, and the project is necessary to maintain the Company's compliance with mandated North American Electric Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC") reliability and performance standards. Our customers' demand for energy continues to increase and the need for the Sigurd-to-Red Butte Project at this time, which was demonstrated during the Certificate of Public Convenience and Necessity proceeding in Docket No. 12-035-97, has not changed.

Next, I will describe the completion of construction and placement into service of the Sigurd-to-Red Butte Project, including associated costs. I will show that the Company prudently managed the costs of the Sigurd-to-Red Butte Project by ensuring that it was built in an efficient and cost effective manner for the benefit of our customers.

Finally, I will discuss the other transmission capital investments included in the test year, and will demonstrate that these investments, as well as the Sigurd-to-Red Butte Project, will be used and useful for our customers.

Q. What are the projected costs associated with transmission investments included in rate base in this proceeding?

A. The projected costs associated with transmission investments included in rate base in this proceeding total $771.1 million for the period July 1, 2013, through June 30, 2015, as shown below:

Transmission Projects	Investment
Sigurd-to-Red Butte Project	363.7
Carbon Plant replacement project	46.5
Standpipe Substation construction project	26.9
Union Gap transmission substation project	19.1
Whetstone Substation project	17.7
Lake Side 2 generating plant transmission service project	11.8
Non-Main Grid Transmission Projects	194.7
Projects less than $10m / close out of previously approved projects	90.7
	771.1

Company witness Mr. Douglas N. Bennion addresses the non-main grid transmission projects in his direct testimony. Also refer to Mr. Steven R. McDougal's plant additions Exhibit RMP___(SRM-3).

Sigurd-to-Red Butte Project

Description

Q. Please describe the Sigurd-to-Red Butte Project.

A. The Project is one component of the Company's Energy Gateway transmission plan, and consists of a single-circuit 345 kilovolt transmission line originating from the Sigurd substation in Sevier County located approximately six miles northeast of the town of Richfield, Utah extending southward approximately 170 miles to the Red Butte substation in Washington County, Utah west of State Route 18 and near Central, Utah, as more particularly depicted in the attached map, Exhibit RMP___(NLH-1).

Q. Please provide the details of the project cost.

A. The total cost of the project is $363.73 million, comprised of the following:

SIGURD-RED BUTTE PROJECT
Summary of Accounting Entries by Major Cost Category
Estimated Costs to be Booked in June, 2015

ROW	(All Rights of Way Obtained, Including Labor)	**$ 16,829,497**
EPC	(EPC Contracts)	**$ 252,950,467**
Property	(Land, Property Tax)	**$ 5,965,783**
Permitting	(EIS, POD, CUP's, CPCN, Community Outreach)	**$ 19,432,745**
Engineering	(Engineering Support during Permitting and Construction, EPC RFP)	**$ 20,762,716**
PMO	(Project Management, Project Controls, Vegetation Management, Inspection)	**$ 39,080,359**
Non-EPC	(Communications Equipment and Internal Construction Labor)	**$ 8,587,173**
	Estimated Spend Through June 30, 2015	**$ 363,608,740**
	Estimated Project Completion Percentage	97%

Q. What is the current status of the Sigurd-to-Red Butte Project and the expected in-service date?

A. Construction on the Sigurd-to-Red Butte Project began in May 2013. As of December 2013, construction access roads are in place for approximately 48 miles of the transmission line path. Over 321 foundations have been completed representing approximately 40 percent of the total foundations, and 254 of the single-circuit 345 kilovolt lattice towers have been erected representing approximately 32 percent of the total structures. The installation of ground grid and major equipment foundations began in the first quarter of 2014, with equipment scheduled for delivery beginning in the second quarter of 2014. The timing of these activities supports the projected June 2015 in-service date. This investment is being included in the test period for one month. Exhibit

RMP___(NLH-2), attached hereto, contains recent photos of construction progress on the Sigurd-to-Red Butte Project.

Q. What actions have been taken to ensure the Sigurd-to-Red Butte Project will be placed in service on time and at its current cost forecast?

A. The Company has in place a turnkey engineer, procure, and construct contract for the Sigurd-to-Red Butte Project similar to what it has done on prior segments of Energy Gateway. This approach establishes a lump sum cost for design and construction. The contract establishes monitoring and reporting controls to which the contractor must adhere in completing the Sigurd-to-Red Butte Project. These include providing monthly progress reports on engineering, procurement, status of construction to schedule, risks identified and cost expenditures. If the contractor feels it necessary to request changes to the Sigurd-to-Red Butte Project that would affect the contract schedule or cost, the Company requires a review process for the requested change. The contractor is not allowed to proceed with the requested change until the Company approves the change.

Project Need and Justification

Q. Was the Sigurd-to-Red Butte Project included in the Company's most recent IRP?

A. Yes. The Company's 2013 IRP includes the Sigurd-to-Red Butte Project as part of the modeled transmission topology for the purpose of selecting the Company's preferred portfolio of future supply-side and demand-side resources. The 2013 IRP Action Plan, Chapter 9, consists of a number of actions needed to deliver the

plan, one of which is to "Complete project construction per plan for the Sigurd-to-Red Butte 345 kilovolt transmission line."

Q. Has the Sigurd-to-Red Butte Project been included in previous IRPs?

A. Yes. The 2008 Integrated Resource Plan ("IRP"), updated March 31, 2010, and 2008 IRP Update Errata dated June 16, 2010, include the Project as part of the modeled transmission topology for the purpose of selecting the Company's preferred portfolio of future supply-side and demand-side resources. The 2008 IRP describes what the Company calls the "Energy Gateway Transmission Expansion." (2008 IRP, at pages 60-66). The Sigurd-to-Red Butte Transmission Project is an integral part of the Energy Gateway Transmission Expansion. Energy Gateway is designed to use "a 'hub and spoke' concept to most efficiently integrate transmission lines and collection points with resources and loads centers aimed at serving the Company's customers while keeping in sight Regional and Sub Regional needs." (2008 IRP, at page 61). The "2008 IRP Action Plan Update" consisted of 21 Action Items, one of which was to "Permit and construct a 345 kilovolt line between Sigurd and Red Butte." (2008 IRP, Table 6.1, at pages 56 through 66; the Sigurd-to-Red Butte project is identified as item 12 on page 64). The Sigurd-to-Red Butte Project was evaluated for cost-effectiveness from an integrated system benefits perspective. Further the Project was incorporated as part of a transmission expansion option included in the 2007 IRP capacity expansion optimization model. This analysis helped support the decision to include the Project as part of the Company's preferred portfolio. (2007 IRP, page 231).

Q. Were alternatives to the Sigurd-to-Red Butte Project considered?

A. Yes. Long-term alternatives to constructing a new transmission line are limited; however, alternatives have been assessed by the Company during the IRP process. Alternatives considered included: (1) electric load and demand-side management and energy conservation as part of the Company's IRP; (2) the installation of new generation facilities; (3) additional capacity to existing transmission lines and alternative transmission technologies. As a result of the resource portfolio modeling conducted for the 2011 IRP, the Company concluded that none of these alternatives met the Company's needs and long-term requirements, and additional transmission transfer capability in Utah presented the lowest overall cost and was the best alternative to meet our customers' demand for electricity.

Q. Has the Sigurd-to-Red Butte Project's purpose and need been established and justified in Utah?

A. Yes. The Sigurd-to-Red Butte Project's purpose and need has been clearly established and justified through previous regulatory proceedings conducted in Utah. Detailed and credible evidence justifying the Sigurd-to-Red Butte Project was presented by the Company through its efforts to successfully obtain a Certificate of Public Convenience and Necessity ("CPCN").

Q. Did this Commission find that the Sigurd-to-Red Butte Project was needed, justified, and necessary in the interest of the public?

A. Yes. The Commission granted a CPCN for the transmission line and related facilities in its Report and Order issued March 15, 2013, in Docket No. 12-035-97.

Q. When placed in service will the Sigurd-to-Red Butte Project be used and useful?

A. Yes. When a transmission project is energized and placed into service, all elements of the project are part of the interconnected system as a whole. These elements are fully used and useful in providing transmission service on the system. Transmission 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, are a function of the physics of the entire interconnected network and the level of generation and load present at 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 new facility's capacity and its electrical interaction with all other facilities to which it is interconnected. While the Project provides benefits to the local areas wherein it is constructed, it also provides benefits to the wider interconnected transmission system.

Prudence of Sigurd-to-Red Butte Project Delivery

Q. How did the Company ensure that the costs expended to engineer, design, site, and build the Sigurd-to-Red Butte Project were the most cost effective for its customers?

A. From a planning perspective, the Company applied prudent industry standards to identify the best transmission route and substation locations in order to balance engineering requirements, environmental impacts, project costs, and impacts to communities during the siting process, while ensuring that the siting criteria requirements were met. This included the completion of project siting and routing feasibility studies by the Company between 2005 to 2008 and the completion of the National Environmental Policy Act ("NEPA") Environmental Impact Statement ("EIS") process between December 2008 and December 2012, resulting in issuance of Records of Decision by the United States Forest Service and the Bureau of Land Management granting PacifiCorp right-of-way across public lands. This process determined the final preferred transmission line route and substation locations, which were then incorporated into the Company's competitive bidding process for construction.

Q. Please describe the Company's competitive bidding process.

A. The Company initiated a competitive bidding process to receive blind-sealed bids for the project to be delivered on a turnkey, fixed price, guaranteed completion date basis using an engineer, procure, and construct ("EPC") contract. The Company utilized this process for the substation build part of the project and separately for the transmission line build part of the project. The competitive bid process resulted in the Company obtaining the lowest risk evaluated cost for delivery of the Sigurd-to-Red Butte Project.

Q. Please describe the timing and competitive bid process for the substation build part of the project.

A. The competitive bid process for the substation build part of the project began in May 2011. Six bid responses were received in September 2011. Two addenda were subsequently issued and final bids were received in June 2012. After extensive evaluations of bidder proposals and review of exceptions to work scope and base terms and conditions from each bid proposal, the most qualified bidder was identified. Final negotiations with the qualified bidder began in August 2012 with the Company issuing the final contract in September 2012.

Q. Please describe the timing and competitive bid process for the transmission line build part of the project.

A. The competitive bidding process began in June 2011 and provided two separate blind-sealed bidding opportunities. All bid responses were due in December 2011 and again in August 2012 after additional information was provided to bidders allowing a refinement of previously submitted design solutions and terms and

conditions, including price. Five qualified bids were received in August 2012. After extensive evaluations of bidder proposals and review of exceptions to work scope and base terms and conditions from each bid proposal, the final most qualified bidder was identified. Final negotiations with the most qualified bidder were held in November 2012. That same month, the Company awarded the contract and issued a notice of intent, with a notice to proceed issued in March 2013.

Q. With respect to the construction of the Sigurd-to-Red Butte Project, how did the Company ensure that the costs to build the project were controlled for the benefit of customers?

A. EPC contracts are regarded in the industry as a prudent approach to control costs and manage design, procurement, and construction risks. EPC contracts provide schedule and cost certainty to the benefit of customers and, where possible, cap potential cost escalations upon the occurrence of defined risks. EPC contracts also ensure more timely delivery of needed testing, commissioning, and in-service dates to support system needs and help ensure ongoing transmission system reliability.

The fixed-price EPC contracts for the Sigurd-to-Red Butte Project have strong provisions to control cost and schedule variances. Where cost and schedule variances were not included in the fixed price for certain contingent aspects of the work scope, these items were identified as risk items and a contingent capped price and schedule allowance were agreed to before contract execution.

Contingent risk items were limited to defined occurrences such as weather delays and environmental impacts.

Benefits of the Project

Q. How will the Sigurd-to-Red Butte Project benefit the Company's customers?

A. The Project is necessary to provide safe and reliable service to customers and to meet expected and forecasted customer energy demand. In addition, the Sigurd-to-Red Butte Project is a key component required for executing the Company's current and future integrated resource plans, which require reliable transport of designated network resources to network loads consistent with PacifiCorp's federal Open Access Transmission Tariff ("OATT"). This is necessary to ensure an adequate, reliable, and low cost supply of energy is available for the benefit of our customers. Having adequate long-term transmission system capacity is fundamental in developing and executing those integrated plans and meeting our OATT obligations.

Q. What specific reliability standards and criteria require the Project and its in-service date?

A. PacifiCorp plans, designs, and operates its transmission system to meet NERC reliability standards for Bulk Electric Systems and WECC Regional standards and criteria. The NERC reliability standards are federal law as set forth 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 reliability standards. There are currently more than 100 approved NERC standards with which the Company must comply. The Project and its

respective in-service date timing are required to maintain the Company's compliance with these standards.

Carbon Plant Replacement Project

Q. Please describe the additional plant investments for the Carbon Plant replacement project.

A. The plant investments associated with the Carbon Plant replacement project consist of installation of capacitor banks and installation of a static var compensator at the Mathington Substation; the upgrade of communications and the modifying of the protection and control equipment at multiple locations; and the installation of one substation control building, one phase shifting transformer, the relocation of a series reactor from Spanish Fork Substation, six circuit breakers with associated voltage transformers, and switches at the Upalco Substation.

Q. Please provide the details of the project cost.

A. The total cost of the project is $46.5 million, comprised of the following:

CARBON PLANT REPLACEMENT PROJECT
Summary of Estimated Spend by Cost Category

		Estimated
Labor	**(Internal Crews/Construction, Engineering, Project Management, etc.)**	**$ 2,332,286**
Material	**(Equipment)**	**$ 7,514,340**
	Capacitor Banks	
	Static Var Compensator	
	Phase Shifting Transformer	
	Circuit Breakers	
Purchase Services	**(External Crews/Construction)**	**$ 27,683,331**
Other		**$ 2,708,717**
	Land Purchase	
	Right of Way	
	Permitting	
Surcharge & AFUDC		**$ 6,274,849**
Total Estimate for Rate Period		**$ 46,513,523**

Q. Please explain why this additional plant investment is needed.

A. The plant investment for the Carbon Plant replacement project is needed because an interconnection customer (PacifiCorp Energy), requested to decommission the existing 172 MW Carbon thermal facility ("Carbon Plant") located in Carbon County, Utah. The requested completion date for the Project is April 2015. The northeastern to central Utah transmission system consists of the Vernal-Ashley-Upalco-Carbon 138 kilovolt line (owned by PacifiCorp) and the Bonanza-Mona 345 kilovolt line (owned by Deseret Generation and Transmission Cooperative). The balance of energy flow between the 138 and 345 kilovolt lines is critical to

maintaining the Bonanza West path rating granted by the WECC. With the 2015 decommissioning of the Carbon Plant the relay load level for tripping the Bonanza generation unit will be significantly lowered (more than 100 MW) to maintain the path rating when the Sunnyside generation plant (52 MW) is operating. The Sunnyside cogeneration plant is owned by Exelon Corporation and is located near the town of Sunnyside, Utah. For operating conditions with the Sunnyside generation off-line and high Bonanza West flows, the Bonanza West path rating will be reduced by 50 to 100 MW due to high flow on the Upalco-Carbon 138 kilovolt line, and Bonanza unit generation will have to be reduced more than 100 MW. Therefore, installation of the assets described above and included in the Carbon Plant replacement project are critical to maintain transmission system stability and current path ratings after the Carbon Plant is decommissioned.

Standpipe Substation

Q. Please describe the additional plant investment for the Standpipe Substation construction project.

A. The transmission capital investment costs in this proceeding include approximately $26.9 million for the Standpipe Substation construction project plant that will be placed into service in 2014. This plant investment consists of a new 230 kilovolt substation called Standpipe. The substation will be constructed as a 2-bay breaker and a half bus, with a partial build out of a third bay to connect a future synchronous condenser. Other additions include upgrades at the existing Platte and Latham Substations located near Rawlins, Wyoming, including bus

reconfigurations, and a shunt capacitor bank at Latham, and the associated controls, breakers, and protection. The synchronous condenser and associated equipment will be placed into service in June of 2016.

Q. Please provide the details of the project cost.

A. The total cost of the project is $26.9 million, comprised of the following:

STANDPIPE SUBSTATION CONSTRUCTION PROJECT
Summary of Estimated Spend by Cost Category

		Estimated $
Labor	**(Internal Crews/Construction, Engineering, Project Management, etc.)**	**$ 2,102,129**
Material	**(Equipment)**	**$ 4,990,883**
	Breakers & Bus Work at New Standpipe Substation	
	Bus Work at Platte Substation	
	Capacitor Bank at Latham Substation	
Purchase Services	**(External Crews/Construction)**	**$ 13,688,167**
Other		**$ 2,952,806**
	Right of Way	
	Surveying	
	Engineering Studies	
	Environmental Studies	
	Employee Expenses	
Surcharge & AFUDC		**$ 3,127,633**
Total Estimate for Rate Period		**$ 26,861,618**

Q. Please explain why this additional plant investment for the Standpipe Substation project is needed.

A. The plant investment for the Standpipe Substation construction project is needed because customers in the Platte area of the Wyoming system have been exposed to excessively high steady state voltages as well as a large number of transient

voltage excursions. Reported customer impacts following these high voltage conditions have been significant, and at this time, there are limited operational means of reducing voltage during these conditions. To mitigate system instability resulting from high voltage levels, installation of shunt reactors and capacitors in addition to a synchronous condenser at a new Standpipe substation will provide a means to mitigate these conditions and improve power quality and reliability in the region. Additionally, the installation of a synchronous condenser at Standpipe will increase the reactive support of the transmission system in the region, resulting in better voltage stability and attenuation of voltage swings during system operation.

Union Gap Transmission Substation Upgrade Project

Q. Please describe the additional plant investment for the Union Gap transmission substation upgrade project.

A. The transmission capital investment costs in this proceeding include approximately $19.0 million for the Union Gap upgrade transmission substation project. This plant investment includes relocating and upgrading the existing 230 kilovolt bus into a ring bus including the installation of six new 230 kilovolt breakers and the addition of a new 230/115 kilovolt, 250 Mega Volt Ampere transformer to be placed in service in March of 2015 and will be used and useful in supporting the transmission system. Final completion of the project that will be placed into service in June of 2016 includes a rebuild of the existing 115 kilovolt main transfer bus to a breaker and a half scheme, and fifteen new 115 kilovolt breakers on the 115 kilovolt bus.

Q. Please provide the details of the project cost.

A. The total cost of the project is $19.1 million, comprised of the following:

UNION GAP TRANSMISSION SUBSTATION UPGRADE
Summary of Estimated Spend by Cost Category

		Estimated $
Labor	**(Internal Crews/Construction, Engineering, Project Management, etc.)**	**$ 519,494**
Material	**(Equipment)**	**$ 2,961,114**
	230 kV Ring Bus and Breakers	
	230/115 kV Transformer	
Purchase Services	**(External Crews/Construction)**	**$ 12,467,847**
Other		**$ 727,291**
	Environmental Studies	
	Permitting	
	Right of Way	
	Labor Expense	
Surcharge & AFUDC		**$ 2,417,983**
Total Estimate for Rate Period		**$ 19,093,729**

Q. Please explain why this additional plant investment for the Union Gap transmission substation upgrade project is needed.

A. The plant investment for the Union Gap upgrade transmission substation project is needed to comply with NERC reliability standards. Specifically, the project is necessary to enable compliance with NERC Standard TPL-002 "System Performance Following Loss of a Single Bulk Electric System Element (Category B)" that requires bulk electric system elements, including transmission transformers, to be within thermal limits following the single contingency loss of a transmission system element. An outage of one of the two 230/115 kilovolt

transformers results in an overload of the remaining transformer of approximately 50 MW which can be maintained for a maximum of four hours. PacifiCorp's 2011 West System Assessment for TPL-002 Compliance Requirements notes that for the loss of a Union Gap 230/115 kilovolt transformer in heavy summer loading conditions, overload of the posted four hour emergency limit of the transformer will be experienced by 2016. To correct this system deficiency, the recommended plan of service is to install a third 230/115 kilovolt transformer at Union Gap.

Q. Are there other system limitations that this transmission investment will alleviate?

A. Yes. PacifiCorp's 2011 West System Assessment for TPL-003 Compliance Requirements notes nine outages involving 115 kilovolt, 230 kilovolt breaker and bus faults, with stuck breakers and protection systems failures at Union Gap that result in thermal and voltage performance deficiencies. Loss of both 230/115 kilovolt transformers results in 30 MW of load being shed (6,000 customers) for the initial outage. This will also result in the remaining transformers at Pomona Heights being overloaded by approximately 150 MW which would require corrective measures to remove the overloads from the transformers. To correct all aforementioned system limitations in a cost effective manner, this plan of service was selected to rebuild the 230 kilovolt and 115 kilovolt buses into a ring bus for the 230 kilovolt bus and breaker and a half configuration for the 115 kilovolt bus which will eliminate the TPL-003 system deficiencies at Union Gap.

Whetstone Substation Construction Project

Q. Please describe the additional plant investment for the Whetstone Substation construction project.

A. The transmission capital investment costs in this proceeding include approximately $17.7 million for the Whetstone Substation construction project. This plant investment consists of a new substation with one 150/200/250 Mega Volt Ampere, three phase, load tap changer autotransformer, four 115 kilovolt breakers and three 230 kilovolt breakers with associated switches. Other investments include a generator, a control house with a battery system, communication facilities, relay equipment, and a reconfiguration and reconductor of 3.8 miles of 115 kilovolt transmission line from the Scenic substation to the Whetstone substation.

Q. Please provide the details of the project cost.

A. The total cost of the project is $17.7 million, comprised of the following:

WHETSTONE SUBSTATION CONSTRUCTION PROJECT
Summary of Estimated Spend by Cost Category

		Estimated $
Labor	**(Internal Crews/Construction, Engineering, Project Management, etc.)**	**$ 1,305,953**
Material	**(Equipment)**	**$ 3,967,146**
	230/115 kV Transformer	
	230 kV breakers	
	115 kV breakers	
	115 kV conductor	
Purchase Services	**(External Crews/Construction)**	**$ 6,158,504**
Other		**$ 2,978,746**
	Property/Permitting	
	Misc. labor	
Surcharge & AFUDC		**$ 3,335,923**
Total Estimate for		**$ 17,746,272**

Q. Please explain why this additional plant investment for the Whetstone Substation project is needed.

A. This plant investment for the Whetstone Substation construction project is needed because NERC Standard TPL-002 "System Performance Following Loss of a Single Bulk Electric System Element (Category B)" requires bulk electric system elements, including transmission transformers, to be within thermal limits following the single contingency loss of a transmission system element. The loss of one of the Lone Pine 230/115 kilovolt 250 Mega Volt Ampere transformers overloads the other transformer beyond the summer four hour emergency rating

and results in a system deficiency under TPL-002. After completing the new substation and reconfiguring the Medford system, the TPL-002 overload for loss of a Lone Pine 230/115 kilovolt transformer will be resolved. The reconductor of Line 74 must be completed to accommodate the loss of line 99 from Lone Pine to Brookhurst prior to Whetstone substation being placed in service.

Lake Side 2 Generating Plant Transmission Service Request Project

Q. Please describe the additional plant investments for the Lake Side 2 generating plant transmission service request project.

A. Transmission of energy from the Lake Side 2 generation facility to beyond the Steel Mill substation requires the installation of two new 345 kilovolt breakers and looping in of the Camp Williams - Emery 345 kilovolt line at Spanish Fork substation. A reconductoring of the ten mile Spanish Fork - Tanner 138 kilovolt line and communication fiber to Hale substation is also required. Equipment replacement, control modifications and communications upgrades will be required at the Spanish Fork, Tanner and Hale substations.

Q. Please provide the details of the project cost.

A. The total cost of the project is $11.8 million, comprised of the following:

LAKE SIDE 2 GENERATING PLANT TRANSMISSION SERVICE REQUEST
Summary of Estimated Spend by Cost Category

		Estimated $
Labor	**(Internal Crews/Construction, Engineering, Project Management, etc.)**	**$ 1,839,245**
Material	**(Equipment)**	**$ 3,396,652**
	345 kV Breakers	
	138 kV Conductor	
	Communications Equipment	
Purchase Services	**(External Crews/Construction)**	**$ 4,909,348**
Other		**$ 585,414**
	Right of way purchase	
	Labor expenses	
Surcharge & AFUDC		**$ 1,035,315**
Total Estimate for Rate Period		**$ 11,765,974**

Q. Please explain why these additional investments for the Lake Side 2 generating plant transmission service request project are necessary.

A. A transmission customer (PacifiCorp Energy) has requested transmission service to PacifiCorp's transmission network at the Lake Side 2 Generating facility near Vineyard, Utah under PacifiCorp's OATT. Under the OATT, PacifiCorp has completed the necessary studies and identified the additional network facilities necessary to provide transmission service for the Lake Side 2 project. PacifiCorp is required to provide transmission service per the terms and conditions of its OATT.

Conclusion and Recommendation

Q. What do you recommend?

A. I recommend that the Commission find the Company acted prudently in making the necessary investments and plant additions I have discussed in this testimony and that the Commission issue an order allowing full recovery of these costs.

Based on the evidence I have provided, I further recommend that the Commission find the Company has prudently selected the lowest cost project alternatives and managed costs and delivery risks for the transmission projects included within this case, and that the Commission find such projects provide significant benefits to our customers.

Q. Does this conclude your direct testimony?

A. Yes.