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IDAHO PUBLIC UTILITIES COMMISSION

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| IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES | ) | CASE NO. PAC-E-10-07 |

DIRECT TESTIMONY OF RANDY LOBB

IDAHO PUBLIC UTILITIES COMMISSION

OCTOBER 14, 2010

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Q. Please state your name and business address for the record.

A. My name is Randy Lobb and my business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed?

A. I am employed by the Idaho Public Utilities Commission as Utilities Division Administrator.

Q. What is your educational and professional background?

A. I received a Bachelor of Science Degree in Agricultural Engineering from the University of Idaho in 1980 and worked for the Idaho Department of Water Resources from June of 1980 to November of 1987. I received my Idaho license as a registered professional Civil Engineer in 1985 and began work at the Idaho Public Utilities Commission in December of 1987. My duties at the Commission currently include case management and oversight of all technical Staff assigned to Commission filings. I have conducted analysis of utility rate applications, rate design, proposed tariffs and customer petitions. I have testified in numerous proceedings before the Commission including cases dealing with rate structure, cost of service, power supply, line extensions, regulatory policy and facility acquisitions.

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

A. The purpose of my testimony is to summarize the Staff revenue requirement recommendation, introduce Staff witnesses and describe the issues that each will address. I will also discuss treatment of costs associated with the Irrigation Load Control program, rate base treatment of investment associated with the Populus to Terminal transmission line and recovery of costs associated with wind resource acquisition.

Q. Could you please summarize your testimony?

A. Yes. Staff will sponsor ten witnesses in this case to support its recommendation for an overall revenue increase of $14.8 million or 7.3% based on an Idaho jurisdictional rate base of $682.3 million. Staff proposes an overall rate of return of 8.025% and a return on equity of 10%.

I will show that the costs of the Irrigation Load Control program assigned to Idaho customers is inequitable when compared to the program benefits received. I will show that 50% or approximately $401 million of the $802 million cost incurred for the Populus to Terminal transmission line is not currently used and useful and should be placed in plant held for future use rather than included in rate base as proposed by the Company. Finally, I will discuss Staff's review of the Company's wind acquisition process and my recommendation to include the cost in rate base as proposed by the Company.

Q. How is your testimony organized?

A. My testimony is organized as follows:

I. Recommendation Summary

II. Introduction of Staff witnesses

III. Case Evaluation

IV. The Irrigation Load Control Program

V. The Populus to Terminal Transmission Line

VI. Wind Resource Acquisition

**Recommendation Summary**

Q. Could you please summarize Staff's recommendations in this case?

A. Yes, Staff recommends an Idaho jurisdictional revenue requirement increase of $14.8 million or 7.3% with an overall rate of return of 8.025% and a return on equity of 10% (Company proposed 10.6%). Staff accepts the Company's proposed historic test year of January 1, 2009 through December 31, 2009 with reasonable proforma adjustments through December 31, 2010.

Staff rate base adjustments include placing a portion of the Populus to Terminal transmission line and the Dunlap I wind project cost in plant held for future use on the basis that the facilities are not fully used and useful. Recommended expense adjustments include elimination of all salary increases and bonuses for 2009 and 2010, reductions in pension cost, reductions in annual power supply costs, removal of costs associated with wind integration and a variety of other smaller adjustments. Staff's recommended revenue requirement adjustments reduce the Company's annual request by $12.89 million.

Staff accepts the Company proposed jurisdictional allocation methodology with the exception of the proposed treatment of Idaho Irrigation Load Control program costs. Staff also accepts the Company proposed class cost of service methodology. Based on the Staff revenue requirement proposal, Staff recommends a class revenue spread that largely follows cost of service with revenue increases of 3.06% for irrigation customers, 4.78% increase for residential customers and a 12.94% increase for Monsanto. Staff does not separate Schedule 1 from Schedule 36 Residential customers for the purposes of class revenue spread.

Staff supports the Company's proposed two tiered commodity rate for Residential Schedule 1 customers but proposes seasonal block sizes and a limited increase in the customer charge. Staff recommends an increase in the rate components of other customer classes by the percentage increase in the overall class revenue requirement.

Staff recommends that Company DSM expenditures for 2008 and 2009 be found prudent and that the Commission consider a modification to the base rate/tariff rider method of DSM cost recovery. Staff recommends that costs associated with the Idaho Irrigation Load Control program be treated as system power supply expenses instead of being directly assigned to the Idaho Jurisdiction.

Finally, Staff recommends that the Company read electrical meters and disconnect when service at a customer location is discontinued to avoid the loss of revenue for unbilled electrical consumption.

**Introduction of Staff Witnesses**

Q. Could you please describe Staff's filing in this case?

A. Yes. Senior Staff Auditor Cecily Vaughn provides the summary exhibits reflecting Staff's case. She begins with actual audited PacifiCorp system data for the historical 12-month test period of January 1, 2009 through December 31, 2009 with known and measurable changes in and adjustments to investment and expense levels through December 31, 2010 (the Company case). Ms. Vaughn then shows Staff adjustments and allocates the system adjusted costs to the Idaho Jurisdiction. The resulting Idaho revenue requirement increase is $14.8 million or approximately 7.3%.

The revenue requirement proposal provided in

Ms. Vaughn's testimony is based on rate base adjustments, expense adjustments and jurisdictional allocation modifications that she recommends and that are provided to her by other Staff witnesses.

Senior Staff Auditor Joe Leckie reviewed a broad cross section of Company investments included in the test year and the Company's proposed plant additions through December 31, 2010. Mr. Leckie makes adjustments to proforma rate base additions, removes a portion of the Dunlop I wind project costs that are not used and useful, reduces the value of the Company's coal stockpile inventory and recommends an adjustment for the Bridger #2 overhaul. Mr. Leckie also makes an expense adjustment for wind project O&M expenses and supports tax adjustments proposed by the Company.

Senior Staff Auditor Donn English addresses revenue requirement adjustments for salaries, pensions, property taxes and office lease expense. He recommends that salaries be adjusted to January 1, 2009 levels to reflect appropriate cost control measures in a weak economy. He further recommends that all bonuses included in revenue requirement be removed. Mr. English recommends an adjustment in pension costs to reflect the appropriate amortization of contributions. Finally, he recommends adjustments to reflect a more appropriate accounting of property taxes and office lease revenues.

Deputy Administrator and Audit Section Supervisor Terri Carlock addresses cost of capital and return on equity. Ms. Carlock recommends a return on equity of 10%, updates the cost of debt and preferred equity, and recommends an overall rate of return of 8.025%. Ms. Carlock also addresses the Staff's recommended allocation of the Idaho Irrigation Load Control program costs with respect to the Revised Protocol jurisdictional allocation methodology.

Senior Staff Engineer Keith Hessing addresses class cost of service and revenue spread among the classes. Mr. Hessing accepts the Company's class cost of service methodology and recommends that all classes, except the lighting classes, be moved to full cost of service as proposed by the Company. Based on the Staff's recommended revenue requirement, Mr. Hessing recommends class revenue changes ranging from a 3.06% increase for irrigation customers, to a 12.94% increase for Monsanto. Residential customers will see an increase of 4.78%.

Staff Economist Bryan Lanspery addresses power supply expense including the Company's proposed wind integration adjustment and rate design. Mr. Lanspery recommends that system power supply costs be reduced to reflect removal of uneconomical contracts, modified treatment of non-firm transmission revenue and recalculation of Bear River hydro generation. He also recommends the Company's proposed expense addition to reflect wind integration cost be removed. The basis for this adjustment is his position that even if these costs were known and measurable, they already flow through and are recovered as part of underlying test year expenses or energy cost adjustment mechanisms. The total revenue requirement impact of these adjustments is $2.65 million on an Idaho jurisdictional basis.

With respect to rate design, Mr. Lanspery supports the Company's proposal to implement a two tiered commodity rate design for Schedule 1, residential customers. Rather than the Company proposed year round first block, Mr. Lanspery proposes seasonal first blocks of 900 kWh and 700 kWh for summer and winter, respectively. Mr. Lanspery also proposes a $5 Schedule 1 customer charge rather than the $12 customer charge proposed by the Company. Mr. Lanspery proposes a uniform increase in the rate components for all other customer classes.

Staff Utility Analyst Gary Grayson addresses the prudency of 2008 and 2009 DSM expenditures and recommends that they be found to have been prudently incurred. Mr. Grayson also addresses the Company's level of annual DSM expenditures and discusses whether the method of cost recovery through base rates or tariff rider is appropriate.

Finally Utilities Compliance Investigators Marilyn Parker and Curtis Thaden address a variety of consumer issues. Ms. Parker recommends that the Company implement a policy of meter reading and disconnect when customer accounts close to eliminate unbilled electrical consumption. Mr. Thaden addresses the impact of the economy on the customers of the Company and how customers might better cope with increased utility bills.

**Case Evaluation**

Q. What has been your role in this case?

A. My role as Utilities Division Administrator is to oversee the preparation of the Staff case with respect to identification of issues, coordination of Staff position on those issues and development of Staff policy.

Q. What are the important policy issues in this case?

A. In my opinion the most important policy issues deal with identifying revenue requirement adjustments, assuring that customer benefits properly match assigned costs and customer rates are properly established.

Q. How did Staff take the weakened economy, the impact of rate increases on the Company's customers and customer comments into account in preparing for this case?

A. The impact of rate increases on customers is always a consideration of Staff in the preparation of its case. The Staff objective is to always obtain the best deal possible for customers. With the weakened economy, the expectation of customers and the approach of Staff is to more aggressively evaluate the Company's request. Staff's recommendations on equity return, elimination of salary increases and bonuses and reasonably limiting cost recovery of investment demonstrates this approach.

Q. How did Staff identify its adjustments?

A. Staff focused its review on cost of capital, large capital additions and the level of increased operation and maintenance including employee compensation over the last two years. Based on an audit of actual costs booked during the test year, an evaluation of expense increases as compared to economic conditions and a thorough review of large capital additions, Staff identified costs that it believed were inappropriate.

Q. What policy issues fall into the category of customer benefits matching assigned customer costs?

A. The issues that I believe fall into this category are the treatment of Idaho Irrigation Load Control program costs and benefits, and the determination of what is "used and useful" with respect to large plant additions. Staff witness Carlock and I will address the treatment of Irrigation Load Control program costs and Staff witness

Leckie and I will address the issue of cost recovery associated with the Dunlop I wind project and the Populus to Terminal transmission line, respectively.

Q. What are the most important policy issues in this case with respect to rate design?

A. I believe there are two important rate design issues in this case. The first is revenue spread to the various customer classes and the second is the tiered rate design for Residential Schedule 1 customers. It is important that class revenue requirement reflects class cost of service and rate design reflects cost of service within customer classes. With cost of service in mind and in response to customer concerns, Staff maintained the differential between Residential Schedule 1 and Residential Schedule 36. Staff witness Hessing discusses revenue spread and Staff witness Lanspery discusses rate design.

**Idaho Irrigation Load Control Program**

Q. Please explain the Idaho Irrigation Load Control program.

A. The Idaho Irrigation Load Control program is offered to Idaho irrigation customers receiving retail electric service under Schedule 10. Participants agree to allow the Company to curtail their electricity usage, and in exchange participants receive credits valued on a per kW basis. The Idaho Irrigation Load Control Program is provided under Schedules 72 and 72A. Schedule 72 is a pre-scheduled service interruption, whereas Schedule 72A is a dispatchable service interruption.

Q. How many Schedule 10 irrigation customers participate in the program?

A. In 2009 there were 938 customers participating in the program, or nearly 46% of those eligible.

Q. How many Schedule 10 irrigation customers participate in the dispatchable Schedule 72A option?

A. In 2009 there were 826 customers participating in the dispatchable option, or approximately 88% of eligible participants. Most of the customers participate under Schedule 72A.

Q. Has the Idaho Irrigation Load Control program (Schedules 72 & 72A) grown?

A. Yes. According to the Company's annual DSM reports, the program participation has grown as follows:

| Year | Participation | Annual MW |
|---|---|---|
| 2006 | 478 | 51 |
| 2007 | 405 | 78 |
| 2008 | 609 | 215 |
| 2009 | 938 | 276 |

Q. How have program costs grown since the Company started reporting results?

A. According to the Company's annual DSM reports, program costs have increased as follows:

| Year | Program Cost | Annual % Increase |
|---|---|---|
| 2006 | $ 1,299,129 | --- |
| 2007 | $ 2,584,508 | 99% |
| 2008 | $ 8,908,216 | 245% |
| 2009 | $11,114,948 | 25% |

Q. Has the Company calculated the system benefit of the Idaho Irrigation Load Control program?

A. Yes. In its 2009 DSM Report, the Company calculates a system benefit value of over $20 million for the Idaho Irrigation Load Control program over ten years.

Q. Is the Idaho Irrigation Load Control program deemed to be cost effective?

A. Yes. According to the Company's 2009 DSM report the Idaho Irrigation Load Control program meets all cost effectiveness tests including the Total Resource Cost Test (TRC), the Ratepayer Impact Test (RIM) and the Utility Cost Test (UCT).

Q. How does the Company propose to treat costs and benefits associated with the Idaho Irrigation Load Control program?

A. The Company proposes to directly assign all $11.4 million in program cost to customers in the Idaho jurisdiction. The Company then credits or decrements the Idaho jurisdictional demand allocator used in the allocation of system costs to Idaho. The reduced jurisdictional allocation factor, reflecting the demand reducing affect of the Idaho Irrigation Load Control program, benefits Idaho customers by reducing the Idaho jurisdictional revenue requirement.

Q. What is the revenue requirement impact of this allocation methodology on Idaho?

A. The total proforma cost of the Irrigation Load Control program directly assigned to Idaho is $11.4 million. These costs include $7.6 million in program incentive credits paid to customers participating in the Irrigation Load Control program, and $3.82 million in administrative costs. The cost of the incentive payments are recovered through Idaho base rates and the administrative costs are recovered from Idaho customers through the Customer Efficiency Service Rate Adjustment (Schedule 191, tariff rider).

The revenue requirement benefit to Idaho is captured by reducing Idaho's jurisdictional allocation of PacifiCorp system costs. This is accomplished by reducing Idaho's share of system demand to reflect the impact on system demand of the Idaho Irrigation Load Control program. When this demand decrement is applied, Idaho's jurisdictionally allocated revenue requirement is reduced by approximately $7.48 million. The net effect is that directly assigned Idaho program costs of $11.4 million exceed allocated Idaho revenue requirement benefits of

$7.48 million by approximately $3.9 million a year.

Q. Is this reasonable?

A. No. Idaho receives a reduction of system costs that equate to a program benefit of approximately 66% ($7.5 million/$11.4 million) of the costs. This is unfair when 100% of the program costs are directly assigned to Idaho.

Q. Does the Company assign any program costs to the system to reflect benefits derived to the system from the Irrigation Load Control program?

A. No program costs are directly allocated to the system or other jurisdictions under the Company method. Through the decrement in the demand allocator used to jurisdictionally allocate system costs, other PacifiCorp jurisdictions do receive $7.48 million more in other system costs due to the shift in load responsibility. This amount represents about 66% of total Idaho Irrigation Load Control program costs.

However, all other PacifiCorp system production costs and thereby production costs avoided by implementing the Idaho Irrigation Load Control Program are normally allocated to jurisdictions other than Idaho at the rate of approximately 94%. Consequently, non Idaho jurisdictions are receiving 94% of the program benefits but only pick up additional system costs equal to 66% of the program costs.

Q. How do you propose to treat the Idaho Irrigation

Load Control program costs?

A. I propose that the Company treat the program costs as system purchase power cost and allocate them just as it would any other system power supply expense. This will assure that the costs allocated to each jurisdiction follow the benefits received by each jurisdiction.

Q. How does the Company view the capacity provided from the Idaho Irrigation Load Control program in comparison to existing supply side resources?

A. The Company identifies the Idaho Irrigation Load Control program as a Class 1 DSM resource defined as follows:

> Class 1 DSM: Resources from fully dispatchable or scheduled firm capacity product offerings/programs - Class 1 programs are those for which capacity savings occur as a result of active Company control or advanced scheduling. Once customers agree to participate in a Class 1 DSM program, the timing and persistence of the load reduction is involuntary on their part within the agreed limits and parameters of the program. In most cases, loads are shifted rather than avoided.

The Company goes on to identify Class 1 DSM as a resource type with its other supply side resources in Table 5.6 - Capacity Ratings of Existing Resources, as part of its 2008 IRP.

Q. What is the revenue requirement effect of treating Idaho Irrigation Load Control program costs as a system power supply expense in jurisdictional cost allocation?

A. Idaho's net revenue requirement would be reduced by approximately $3.25 million when Idaho Irrigation Load Control program costs previously collected through the tariff rider are included. The reduction in revenue requirement collected from Idaho would be collected from PacifiCorp's other jurisdictions through the dynamic system cost allocation of additional system power supply expenses under the Staff's proposal. This proposed distribution of Class 1 Irrigation Load Control program costs more accurately and fairly matches system benefits with system costs.

Q. Does your recommended treatment of the Irrigation Load Control program costs violate the Revised Protocol jurisdictional allocation methodology?

A. I do not believe treating these Idaho Irrigation Load Control Class 1 DSM expenditures as system production costs violates the intent of the jurisdictional allocation methodology. The Company views this program as comparable to production resources in its IRP and the size of this program has grown by 300% since Revised Protocol was approved. Moreover, I believe that the magnitude of the program costs relative to the size of the Idaho jurisdiction makes situs cost recovery difficult when benefits are based on reduced allocation of unrelated system costs. Staff witness Carlock provides additional testimony regarding treatment of Idaho Irrigation Load Control program costs in conjunction with the Revised Protocol Allocation methodology.

**Populus to Terminal Transmission**

Q. What is the Populus to Terminal Transmission line?

A. The Populus to Terminal transmission line is the first of eight proposed new high voltage transmission segments that will make up PacifiCorp's Energy Gateway Transmission Expansion project. Energy Gateway consists of Gateway West, Gateway South and Gateway Central. Populus to Terminal is one of three segments that make up Gateway Central. It is a dual circuit 345 kV, 135 mile long high voltage transmission line stretching from Downey, Idaho to Salt Lake City, Utah.

Q. What is the cost of the Populus to Terminal project and how does it compare to the overall estimated cost of Energy Gateway and the transmission plant in service of PacifiCorp?

A. The total cost of the 135 mile Populus to Terminal project is $802 million. In 2008, the 1700 mile Energy Gateway project was estimated at over $4 billion. In 2010, Energy Gateway is described as a 2000 mile long project at an estimated cost of approximately $6.6 billion. PacifiCorp currently has only $2.2 billion in transmission plant in service.

Q. What does the Company request in terms of cost recovery for Populus to Terminal in this case?

A. The Company requests that the entire cost of the Populus to Terminal project, or approximately $802 million, be placed in rate base as part of this case.

Q. How does the Company justify construction of the Populus to Terminal transmission line and including all of the project cost in rate base in this case?

A. The Company describes the Populus to Terminal transmission segment as a "key element in Gateway Central", which is described as an "essential reliability backbone allowing Gateway West and Gateway South to operate at a higher reliability and an overall higher capacity". The Company maintains that the Energy Gateway investment will support future generation resource development. Cupparo Di., p. 7, line 8

Q. What is the Company's estimated time frame for completion of the Energy Gateway Transmission expansion project?

A. The original estimate in February of 2008 was for completion of Gateway South in 2013 and Gateway West in 2014. 2010 estimates now show completion of Gateway South in the 2018 to 2020 time frame and Gateway West in the 2014 to 2018 time frame.

Q. Does the Company provide other justification for its proposed treatment of the Populus to Terminal transmission costs?

A. Yes. The Company maintains that the project satisfies a Mid American Energy Holdings Company (MEHC) merger commitment to improve the transfer capability over Path C. The Company also maintains that overall reliability is improved and the Company can cover reserve requirements without building new generation.

Q. What was the commitment by PacifiCorp to improve transfer capability over Path C as part of the MEHC merger?

A. The Path C upgrade commitment as stated in Commission Order No. 29998 (Case No. PAC-E-05-08) issued in March of 2006 was as follows:

> Path C Upgrade (~$78 million) - Increase Path C Capacity by 300 MW (from S.E. Idaho to Northern Utah). The target completion date is 2010.
>
> - Enhances reliability because it increases transfer capability between the east and west control areas,
> - facilitates the delivery of power from wind projects in Idaho, and
> - provides PacifiCorp with greater flexibility and the opportunity to consider additional options regarding planned generation capacity additions.

Q. As constructed, does the Populus to Terminal Transmission line simply fulfill the Path C Commitment?

A. No. The Populus to Terminal project was oversized to satisfy the future requirements of the Energy Gateway Transmission Expansion project. Rather than the 300 MW specified in the MEHC merger commitment, the Populus to Terminal project provides 700 MW of immediate additional capacity and 1400 MW of additional future capacity. Rather than $78 million, the project actually cost $802 million or over ten times the estimated cost identified in the MEHC merger commitment.

This section of Staff's direct testimony contains confidential information subject to protective agreement.

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Q. What is your recommendation in this case for treating the costs of the Populus to Terminal transmission line?

A. As Staff stated in its comments filed in Certificate Case No. PAC-E-08-03, "the actual costs subject to recovery from Idaho ratepayers [related to the Populus to Terminal 345 kV transmission line project] will not be determined until the project is completed, costs are fully known and project usefulness is fully quantified." I recommend that 50% or approximately $401 million of the investment in the Populus to Terminal transmission line be allowed in rate base as part of this case and 50% or the remaining $401 million be classified as capacity not yet "used and useful" and placed in plant held for future use. This recommendation is justified based on the undisputed fact that the project is oversized and will not be fully utilized unless or until Energy Gateway is completed. Given the changing economic conditions and the planned delays in completion dates of future Energy Gateway segments, it is unclear and speculative when or if the full benefits of the Populus to Terminal investment will accrue to Idaho customers.

The 50% distribution between rate base and plant held for future use was determined based on a usable capacity of 700 MW out of a total design capacity of 1400 MW. Additional justification for the distribution includes a cost per mile that is twice that of the remaining Energy Gateway segments and a standalone economic analysis that I believe over estimates the cost of transmission alternatives. The rate base and revenue requirement impact of this adjustment is presented in the testimony of Staff witness Vaughn.

Q. Could you please summarize your testimony on Populus to Terminal cost recovery?

A. Yes. The Company has made it clear through the testimony of Mr. Cupparo and Mr. Gerrard and responses to numerous production requests that Populus to Terminal was constructed in large part to provide the potential future benefits that only completion of Energy Gateway can ultimately ensure. The capacity oversizing of Populus to Terminal is designed for future use and that oversized portion of the Company's investment is not presently "used and useful". Under *Idaho Code* § 61-502A, rate basing of investment that is not presently "used and useful" in providing utility service is prohibited. While some of the project costs are justified by benefits customers receive today, 50% of the costs incurred do not generate current benefits. It is unfair and inappropriate for current Idaho customers to pay today for benefits that may only become available when Energy Gateway is completed and Populus to Terminal is fully utilized. Therefore, approximately $401 million of the Populus to Terminal project costs should be placed in an account containing plant held for future use, Account No. 105.

**Wind Resource Acquisition**

Q. Has Staff reviewed PacifiCorp's acquisition of new wind resources for which it requests cost recovery in this general rate case?

A. Yes, under my direction, Staff reviewed four separate wind acquisition processes. First, Staff reviewed acquisition of the Seven Mile Hill, Glenrock, Rolling Hills, Seven Mile Hill II, Glenrock III, High Plains and McFadden Ridge I projects. Together, these resources provide a nameplate capacity of approximately 483 MW, and represent an investment by PacifiCorp of $1.04 billion. Acquisition of these resources is consistent with the Company's 2004, 2007, and 2008 Integrated Resource Plans (IRPs). Staff reviewed the economic analysis conducted by the Company for each of these resources and concluded that each is cost effective and was prudently acquired.

Next, Staff reviewed the Company's resource acquisitions in the 2008R, 2008R-1, and 2009R Request for Proposal (RFP) process. In the 2008R RFP, PacifiCorp signed a 20-year power purchase agreement (PPA) for the energy and renewable energy credits (RECs) from the 99 MW Three Buttes project. In the 2008R-1 RFP, a 20-year PPA was negotiated for energy and RECs from the 200 MW Top of the World project, and in the 2009R RFP the 111 MW Dunlap I project, a $261 million Company-owned benchmark project, was selected. Staff carefully reviewed all price and non-price analysis conducted by the Company in each RFP process, including a detailed review of the modeling used to evaluate and score all of the short-listed bids submitted under each RFP. In addition to the Company's own analysis, Staff also reviewed all reports prepared by independent evaluators hired to monitor and evaluate the 2008R-1 and 2009 RFP processes. In each of those RFP processes, the independent evaluators concluded that the selected proposals represented the resources with the greatest net benefits to customers; that the processes were fair and competitive; that the selected proposals represented the lowest cost alternatives for customers, with an accounting for risk.

Q. What do you conclude based on Staff's review of the wind projects?

A. Based on Staff's review, I conclude that all of the new wind resources acquired by PacifiCorp, both those that are Company-owned and those for which the output is purchased under PPAs, were competitively acquired, are consistent with Company IRPs, and are prudent. Costs for acquisition of each Company-owned project should be allowed to be included in rate base, and costs associated with each of the PPAs should be included in the Company's revenue requirement.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

## CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 14TH DAY OF OCTOBER 2010, SERVED THE FOREGOING **NON-CONFIDENTIAL DIRECT TESTIMONY OF RANDY LOBB**, IN CASE NO. PAC-E-10-07, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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