EXHIBIT 2

BEFORE THE IDAHO PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES AND A PRICE INCREASE OF $27.7 MILLION, OR APPROXIMATELY 13.7 PERCENT	)	DOCKET NO. ID PAC-E-10-07

DIRECT TESTIMONY OF

DENNIS E. PESEAU

ON BEHALF OF

MONSANTO COMPANY

October 14, 2010

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dennis E. Peseau. My business address is Suite 250, 1500 Liberty Street, S.E., Salem, Oregon 97302.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am President of Utility Resources, Inc. The firm has consulted on a number of economic, financial and engineering matters for various private and public entities since 1985.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THESE PROCEEDINGS?

A. I am testifying on behalf of Monsanto Company.

Q. DOES ATTACHMENT DEP-A ACCURATELY DESCRIBE YOUR BACKGROUND AND EXPERIENCE?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to recommend that the Commission defer its decision on PacifiCorp's requested rate base addition of $801.5 million for the Segment B portion of the Gateway Central, approximately $45 million of which is allocated to Idaho, until PacifiCorp's next general rate case. As I explain below, this Gateway Central transmission project is but an initial leg of a very speculative and massive undertaking, Energy Gateway that may or may not be built by the end of the next decade. As a result of the over sizing to accommodate a planned larger "Gateway South" 500 kV line, that may be completed in 2020, the requested rate base of Segment B from Populus (near Downey, ID) to Terminal (NW Utah) is far greater than that necessary to upgrade this path on a stand-alone basis.

Q. WHAT IS THE GENERAL BASIS FOR YOUR RECOMMENDATIONS?

A. As explained very clearly by PacifiCorp in its direct testimony and exhibits, and also its 2008 IRP and in multiple company documents, Gateway Central is but a 135 mile line that is the initial segment of perhaps the most ambitious and expensive planned transmission network expansion ever attempted in the United States. PacifiCorp estimates that the entire 2,000 mile network, if completed as Energy Gateway, will have project costs exceeding $6 billion. Most of the actual legal, environmental, permitting, rights of way, etc. has only just begun on the remaining 1,865 miles of proposed facilities.

For perspective, if the entire $6 billion Energy Gateway project is ever completed, Idaho's allocation would be approximately 6%, or $360 million of rate base addition. The Energy Gateway transmission project alone will have increased the <u>total</u> Idaho rate base (generation, transmission and distribution plant) by over 60% compared with the year end 2009 rate base. The magnitude of this project's impact on Idaho customers' rates warrants careful and cautious scrutiny by this Commission. My proposal to defer the proposed rate base treatment of Gateway Central is the best means to protect both customers and shareholders of PacifiCorp. As I argue below, most of the Gateway Central rate base will not be used and useful at the outset due to its over sizing. I believe that shareholders as well as customers would be best served by holding open the issue of rate base treatment of Gateway Central until the larger issues of the entire Energy Gateway project are better known.

Q. WHAT ARE YOUR SPECIFIC RECOMMENDATIONS IN THIS CASE WITH RESPECT TO THE COMMISSION'S TREATMENT OF THE REQUESTED APPROXIMATE $45 MILLION GATEWAY CENTRAL RATE BASE ADDITION?

A. I recommend that the Commission:

1. Not make a determination regarding the degree of "used and usefulness," if any, of the proposed Gateway Central project in this case even if it does come online December 31, 2010.

2. Defer the consideration of Gateway Central as an Idaho rate base component until the next general rate case.

3. Remove $5.9 million (reduced by power cost offset) from PacifiCorp's requested rate increase.

4. Order PacifiCorp to place all Gateway Central plant into Plant Held for Future Use, with no carrying charge until such time as the degree of used and usefulness can be determined.

5. Require PacifiCorp to submit a specific progress report on the status of the proposed Gateway South project as the proposed Gateway Central project makes sense only when Gateway South is completed.

6. Require PacifiCorp to hold an open season or nomination process for capacity on Gateway Central as a means to gauge the degree of excess rate base that Idaho's network customers will be required to pay for until OATT customers develop.

7. Require PacifiCorp to revisit its 2008 IRP justification of system load forecast and the proposed Energy Gateway project in light of the prolonged recession and economic uncertainty.

<u>OVERVIEW OF GATEWAY CENTRAL AND ENERGY GATEWAY</u>

Q. PLEASE DESCRIBE THE PROPOSED GATEWAY CENTRAL PROJECT.

A. PacifiCorp's filing in this case, particularly the testimonies of Messrs. Gerrard, Cupparo and McDougal, provides detailed descriptions of the proposed Gateway Central, or "Populus to Terminal" transmission line. I summarize those aspects of the proposed line that bear on the recommendation I make in this case. As a considerable portion of Gateway Central's description has been labeled "CONFIDENTIAL," I will only generally summarize these elements in relation to the much larger plan to construct Energy Gateway.

Q. WHAT IS ENERGY GATEWAY?

A. Energy Gateway is PacifiCorp's program to invest over $6 billion for approximately 2,000 miles of high voltage transmission lines, primarily 500 kV, throughout the western United States. If completed as planned, the project would have a total capacity of 6,000 MW with the intention of transmitting electricity generated primarily from wind energy planned in Wyoming and elsewhere, to markets in California, southern Nevada and to a lesser extent Utah and the Pacific Northwest. My Exhibit 221 (DEP-1), taken from PacifiCorp's website on Energy Gateway Transmission Project's "Frequently Asked Questions," Page 5, provides a schematic of the proposed project.

The proposed "Gateway West" segment of Energy Gateway, with an estimated in-service date in the 2014-2018 timeframe,[1] would connect areas of Wyoming that have potential for wind-generated power, to the Captain Jack substation near Malin, Oregon. My Exhibit 222 (DEP-2) is a copy of PacifiCorp's website description of Gateway West, with key milestones. The Captain Jack substation is the hub or connection between the California-Oregon transmission intertie and provides access to several 500 kV lines running south throughout California.

[1]Recent deferral of draft EIS may push timeframe back. See Bureau of Land Management announcement at http://www.blm.gov/wy/st/en/info/news_room/2010/july/22gatewaywest.html

The proposed "Gateway South" segment of Energy Gateway, with an in-service date in the 2017-2019 timeframe,[2] would connect potential Wyoming wind generators to the Crystal substation in Nevada Power's service territory. My Exhibit 223(DEP-3) is a copy of PacifiCorp's website description of Gateway South, with key milestones. The Crystal substation connects a number of transmission lines and provides access to several 500 kV, 345 kV, and 230 kV lines running through Las Vegas Valley and west into California.

Q. HOW DOES PACIFICORP DESCRIBE PLANNING ASPECTS OF THE PROPOSED ENERGY GATEWAY AND GATEWAY CENTRAL PROJECTS?

A. PacifiCorp differentiates this over $6 billion project from more conventional resource planning approaches. The Company states:

> Unlike the conventional "generation before transmission" approach, this transmission project [Energy Gateway] is a relatively new approach, constructing transmission ahead of specific generation resources. With increasing development of location – constrained renewable resources, one project often can no longer form an anchor for transmission.
>
> [Page 1, "Frequently Asked Questions"]

Elsewhere, PacifiCorp characterizes the Energy Gateway project as more of an overall strategy rather than one single transmission project. PacifCorp is

[2]According to the Company's response to Monsanto Data Request 4.4, Energy Gateway is now anticipated to be completed in the 2018-2020 time frame.

proposing to construct Energy Gateway in anticipation of future development of generation resources, and future markets for such resources.

Q. WHAT IS THE COMPANY'S OVERALL STRATEGY WITH THE PROPOSED ENERGY GATEWAY?

A. If PacifiCorp succeeds in completing the entire Energy Gateway project by 2020, the Company will dominate transmission services throughout the western U.S. This circumstance would place shareholders in the enviable position of earning a return on over $6 billion in new rate base, as well as providing the "highway" to California and southern Nevada for sales of PacifiCorp's existing and developing wind projects. The reason I say "enviable" is because, unlike unregulated third party developers of new transmission facilities, PacifiCorp is attempting to earn on Energy Gateway immediately by placing the large, initially over-built segments into rate base as each is completed. Private third party developers are not, of course, able to earn on the excess investment prior to the facilities reaching full capacity and coming on line, when they then can charge OATT wheeling tariff rates.

Q. PLEASE EXPLAIN.

A. The proposed Gateway Central project for which PacifiCorp is requesting rate base treatment in these proceedings is a good example of this enviable position. The overwhelming amount of this $801.5 million investment is for interconnection with planned future Energy Gateway segments. Thus, in this docket, Idaho customers, by virtue of PacifiCorp's request to place the Idaho allocation of the entire $801.5 million into rate base, are being asked to fund the carrying costs of this initially over built segment B until this path will become functional with later segments, particularly Gateway South.

Q. WHEN IS GATEWAY SOUTH PREDICTED TO BE COMPLETED?

A. Gateway South is in the early planning, siting and permitting stages. Rights of way and EIS are not expected to be completed until 2015. The Company projects an in-service date in the 2017-2020 timeframe. As this particular segment of Energy Gateway is the principal driver for the over-building of Gateway Central, this late date and early stage of development causes major concern for the equity and reasonableness to Idaho customers funding and carrying the over built Gateway Central for so many years. Most of this Gateway Central will not be "used and useful" unless and until Gateway South is energized.

Q. WHAT IS THE BASIS FOR YOUR CONCLUSION THAT THE INITIAL LEG OF ENERGY GATEWAY, WHICH IS GATEWAY CENTRAL, IS OVER BUILT?

A. I base my conclusion on a number of factors. First, as a part of the approval of MEHC's acquisition of PacifiCorp in 2005, both Companies agreed to upgrade this same Path C by the 300 MW required to enhance reliability, facilitate the receipt of renewable resources and to enable further optimization on this segment of Path C. The Path C upgrade was an important commitment to get from MEHC/PacifiCorp because this segment had been previously identified as a potential congested transmission path. Prior to the conception of Energy Gateway, the 300 MW Path C upgrade committed to by MEHC/PacifiCorp was seen as sufficient for this path.

Q. WHAT WAS PACIFICORP'S ESTIMATE OF THE COSTS OF THE REQUIRED UPGRADE TO THE PATH C SEGMENT BETWEEN SOUTHWEST IDAHO AND NORTHERN UTAH?

A. The Company indicated that this upgrade would cost approximately $78 million, or less than 1/10 of the $801.5 million requested in these proceedings for the Path C upgrade. Clearly this ambitious request is for the benefit of interconnecting to the planned Gateway South. This is explained on Page 6 of Order No. 29973 approving the acquisition, attached as my Exhibit 224 (DEP-4).

Q. IS THE ANTICIPATED CAPACITY RATING FOR THE POPULUS TO TERMINAL SEGMENT B OF PATH C DIFFERENT BEFORE AND AFTER THE PLANNED GATEWAY SOUTH?

A. Yes. PacifiCorp's response to Monsanto Data Request 4.4 indicates:

> **Monsanto Data Request 4.4**
>
> Reference Testimony of Mr. John Cupparo. What is the expected megawatt line rating or capacity of the 345 kV Populus to Terminal facility before and after completion of the Gateway West and Gateway South segments?
>
> **Response to Monsanto Data Request 4.4**
>
> The incremental capacity is expected to be 700 MW in the southbound direction and 350 MW in the northbound direction prior to completion of Gateway South in 2018-2020. Once Gateway South is completed the capacity in both directions is expected to increase to 1400 MW.

Q. DOES THE FACT THAT THIS SEGMENT WILL HAVE ITS CAPACITY INCREASED BY 1,050 MW (1400-350) WITHOUT MATERIAL ADDITIONAL INVESTMENT DEMONSTRATE THAT IT IS OVER-BUILT TODAY IN ANTICIPATION OF THE 2018-2020 PLANNED GATEWAY SOUTH?

A. Yes. Let me state that my characterization of Segment B as "over-built" here is not to suggest that this line may not someday become fully used and useful. It is not unusual for a utility to "over-build" facilities at the outset in order to accommodate a near-term expansion of other facilities. What is unusual with PacifiCorp's request is to include a rate base addition, and charge Idaho ratepayers initially, at a level that is approximately ten times its previously approved commit level ($79 million compared to $801.5 million) ten years in advance of the transmission line being fully used and useful. And, if the planned Gateway South segment faces the hurdles typical of siting and constructing 500 kV transmission lines in the western U.S., there is a real possibility that Gateway South may be delayed or disapproved by virtue of other competing high voltage transmission line servicing similar markets.

Q. ARE YOU SUGGESTING THAT THE $801.5 MILLION INVESTMENT IN SEGMENT B IS IMPRUDENT?

A. No. I cannot conclude on the prudence or not of the level of investment absent a more thorough understanding of the segment in relation to the uncertainty and risk associated with Gateway South. My recommendation to defer any rate base treatment of the $801.5 million investment is to better understand these issues, and avoid any decision at present as to how much of the $801.5 million investment is "used and useful" in the traditional regulatory sense.

Q. IS YOUR RECOMMENDATION FAIR AND EQUITABLE TO IDAHO CUSTOMERS AND PACIFICORP SHAREHOLDERS?

A. Yes, I believe it is the most equitable position to take in these proceedings. Ratepayers are being requested to carry a huge investment made for a future planned project that would ordinarily be borne by shareholders. And, in my opinion, shareholders are better served by having the Commission defer full approval rather than force it to determine what degree of present "used and usefulness" Segment B serves in 2011. The latter decision could be viewed negatively by financial markets and should be avoided in favor of a more comprehensive, integrative review of the Segment B Gateway South Gateway West projects.

Q. DID YOU CONDUCT ADDITIONAL ANALYSES TO DETERMINE WHETHER THE POPULUS TO TERMINAL SEGMENT B IS BEING OVER BUILT?

A. Yes. There are a number of other high voltage transmission projects in the western U.S. in both the planning and construction phase. A simple comparison of the investment per transmission mile serves as a rough check of the investment per mile of Segment B if completed as a stand-alone project.

Q. PLEASE EXPLAIN.

A. A simple and straightforward manner in which the Segment B investment costs can be benchmarked is to compare its investment per mile with the remainder of the Energy Gateway planned projects. This is a conservative, but not completely comparable basis for comparison because the 135 mile Segment B line is 345 kV, while the majority of the remaining 1,865 miles of the planned Energy Gateway project is the higher voltage, higher cost 500 kV transmission line. As such, the comparison is conservative.

My Exhibit 225 (DEP-5) shows the simple calculations comparing the investment costs of Segment B with the remainder of Energy Gateway. The assumptions shown include the total investment in the planned Energy Gateway of (over) $6 billion for the 2,000 mile project. The 135 segment from Populus to Terminal is $801.5 million.

Q. WHAT ARE THE RELATIVE INVESTMENT COSTS PER MILE OF THE GATEWAY CENTRAL PROJECT COMPARED WITH THE REMAINING SEGMENTS OF ENERGY GATEWAY?

A. As shown on my exhibit, the requested investment for Gateway Central is $5.94 million per mile. The remaining Energy Gateway project is estimated to be $2.79 million per mile. The fact that the proposed Gateway Central project investment is well more than twice as expensive as the remaining, higher voltage Energy Gateway transmission system is a further indication that Gateway Central is being over-built to accommodate Gateway South.

If Gateway South was a certain project that was expected to come on-line at a time similar to the expected December 2010 on-line date of Gateway Central and there was true demand for that amount of transmission, this investment mismatch would not be a problem. However, this is not the case. Gateway South will not even be permitted in the near future and will not be energized before 2020, if indeed it is constructed at all.

Q. HAVE YOU PARTICIPATED RECENTLY IN THE SITING AND APPROVAL OF OTHER SIMILAR AND COMPETITIVE HIGH VOLTAGE TRANSMISSION PROJECTS IN THE U.S.?

A. Yes. I have for many years participated in some of the financial planning for the Southwest Intertie Project, or "SWIP" as it has been called. This project, originally proposed by Idaho Power Company, has been planned in various stages since as early as 1992. Today, SWIP is a similar and competing project with Gateway South and is owned jointly by NV Energy and Great Basin Transmission, LLC. The project originates at Midpoint, Idaho and terminates initially in Nevada Power's territory, similar to Gateway South plans. The SWIP project is being constructed in two phases, the first being called "ON Line" and will originate in Sierra Pacific Power's service territory in eastern Nevada (Robinson Summit substation) and run south for 235 miles to major markets in the southern Nevada and California markets. ON Line is a 500 kV transmission line approved and under construction.

Q. WHAT ARE THE INVESTMENT COSTS FOR ON LINE THAT HAVE BEEN APPROVED BY THE PUBLIC UTILITIES COMMISSION OF NEVADA?

A. $509.6 million. The investment cost per mile for this 500 kV, 235 mile line is:

$509.6/235 = $2.17 million/mile

The ON Line 500 kV line is below, but in line with $2.79 million/mile investment in the remaining Energy Gateway project, but vastly below the $5.94 million/mile investment cost estimate for the proposed Gateway Central segment.

Q. IS THE ON LINE TRANSMISSION PROJECT IN COMPETITION WITH THE PROPOSED GATEWAY SOUTH PROJECT?

A. Yes. The ON Line project is being built to serve renewable energy projects in northern Nevada, Idaho and Wyoming. The 2000 MW project is well ahead of and in direct competition with Gateway South.

Q. DOES THE ON LINE PROJECT PRECLUDE GATEWAY SOUTH FROM EVER BEING BUILT ECONOMICALLY?

A. No. But clearly the current clamor for renewable resources in southern Nevada and in California is moderating and would have to grow significantly in order to accommodate and justify a second major 500 kV project such as Gateway South.

Q. BESIDES ON LINE, WHICH IS APPROVED AND UNDER CONSTRUCTION, ARE THERE OTHER PLANNED HIGH VOLTAGE TRANSMISSION PROJECTS DESIGNED TO SIMILARLY CONNECT AND DELIVER POTENTIAL WIND GENERATION IN WYOMING TO THE DESERT SOUTHWEST?

A. Yes, there are several. While I make no attempt here to rank the probabilities of each being completed in relation to the proposed Gateway South project, the mere existence of several proposed competing transmission projects demonstrates the inherent uncertainty attached to any single project's success.

Q. WHAT OTHER COMPETING PROJECTS ARE UNDER DEVELOPMENT?

A. My Exhibit 226 (DEP-6) provides a map of a number of competing 500kV and above projects currently being proposed and developed. I have not studied the progress of each, but have generally been aware of their intentions in industry press. Most of these projects have been proposed prior to Gateway South and as such are competitors to it. If one or more of these competitor projects advances prior to Gateway South, there is a distinct possibility that Gateway Central would become a largely stranded investment. My testimony anticipates this, and requests that the Commission guard today against the potential for Gateway Central to be carried by ratepayers in the event that Gateway South never develops. This complex issue is best considered in future proceedings where the risks and rewards of this investment can be analyzed.

Q. ARE YOU CHALLENGING PACIFICORP'S PROPOSED RATE BASE TREATMENT OF IDAHO'S SHARE OF THE $801.5 MILLION GATEWAY CENTRAL INVESTMENT BECAUSE YOU BELIEVE THAT THIS SEGMENT WILL SERVE NO PURPOSE FOR THE FORESEEABLE FUTURE?

A. No, I am not. Even if Gateway South is never completed, the Populus to Terminal segment will relieve congestion on this transmission path. In response to Monsanto Data Request 4.5, PacifiCorp listed a number of potential benefits that would derive from an upgrade to this path. I attach the one page response as my Exhibit 227 (DEP-7). I do not challenge this response. I do challenge the proposed decade long inclusion of the $801.5 million investment in rate base, and its associated large increase in revenue requirements, so long in advance of it being used and useful for Gateway South.

Q. DO YOU RECOMMEND THAT A SMALL PORTION OF THE PROPOSED $801.5 MILLION BE PLACED IN IDAHO'S RATE BASE IN THIS CASE?

A. No. Again this issue is complex and needs a more thorough review. And, from PacifiCorp's viewpoint, the Company may well wish to postpone consideration until the entire investment could logically be determined to be used and useful.

Q. HAS THIS COMMISSION SPECIFICALLY CONSIDERED PACIFICORP RATE BASE ADDITIONS PREVIOUSLY THAT WERE REQUESTED EITHER OUT-OF-PERIOD OR MUCH LONGER THAN CURRENTLY NECESSARY?

A. I do not believe so. It is my understanding that the Commission has not issued an order pertaining to PacifiCorp in a fully contested rate case since sometime in the 1980s.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. I conclude that the Commission should defer consideration of Pacificorp's proposed Gateway Central rate base addition to the next general rate case, for the reasons developed in my testimony.

Q. **DO YOU HAVE CONCLUDING REMARKS REGARDING THE COURSE OF IDAHO WITH REGARD TO MULTI-STATE ALLOCATORS FOR THIS COMMISSION?**

A. Yes I do. I have participated in numerous studies and proceedings in Idaho since the early 1980s. My preparation for the testimony I sponsor here has raised major concerns in regard to my assessment of how the new era of renewable resource development and major speculative transmission investments in the western United States will affect this state, and especially the Idaho service territory served by PacifiCorp. We all know that Idaho is less than 6% of PacifiCorp's total customer base. We further know that certain of PacifiCorp's larger state jurisdictions are "driving" the surge for more expensive and potentially excess resources through ambitious resource portfolio standards ("RPS"). The fact that PacifiCorp is driven to serve these requirements, and potentially to profit greatly from them, will not in my opinion, bode well for the State of Idaho. I say this because of the multi-state protocols and resulting costly allocations that are headed Idaho's way as a result these multi-billion dollar investments that would likely not arise in the absence of such requirements. The largest drivers of the need for these investments are those large states that either are not rich in generation resources, or simply will not allow such development in their own back yard. Idaho, on the other hand, can independently pursue its rich renewable and other generation resource potential largely without the aid of the massive type projects such as Energy Gateway and wind generation. Idaho ratepayers I fear may be in for indefinite rate increases that could be avoided if the state would opt out of the multi-state policies. These rate increases are certainly disastrous not only for Monsanto, but for the general livelihood of eastern Idaho. I urge the Commission to consider whether it wishes to adopt a more parochial view of the western U.S. energy future and focus on what is best for Idaho.

Q. **WOULDN'T IDAHO'S OPTING OUT OF MANY OF PACIFICORP'S EXPANSION PROGRAMS HURT THE COMPANY?**

A. No, not at all. Idaho is such a small percentage of PacifiCorp that neither the Company nor other states would necessarily be affected.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Attachment DEP-A

QUALIFICATIONS OF
DENNIS E. PESEAU

1985 - Present	President of Utility Resources, Inc., a firm that provides consulting and technical services on economic and financial matters. Dr. Peseau has conducted numerous studies on economic, energy and competitive and regulated markets, including complex litigation. His regulatory experience includes studies and testifying on a number of regulatory revenue requirement, cost of service, rate of return and rate design issues in more than 100 civil and administrative proceedings.
1978 - 1985	Vice President, Zinder Companies, Inc. Dennis headed the west coast office of the national consulting organization headquartered in Washington, D.C. His primary responsibilities included marginal and incremental cost of service studies, rate of return and rate design for a number of public utilities companies.
1974 - 1978	Senior Economist, Oregon Public Utility Commissioner. Dr. Peseau conducted numerous studies on behalf of the Commissioner's staff on various financial capital structure, rate of return, econometric and forecasting issues.
1972 - 1974	Senior Economic Analyst, Southern California Edison Company. Dennis worked in Southern California Edison's economics department on matters of economic growth and energy pricing, cost of service and econometric and statistical analysis.

Education

PhD, M.A., Claremont Graduate School

B.A., California State University, Chico

Dr. Peseau has conducted studies on regulatory revenue requirements, cost of service, rate of return, system planning and resource plans and general financial feasibility analyses in the states of

Alaska	Minnesota	Virginia
California	Montana	Washington
Colorado	Nevada	Washington, DC
Idaho	New York	Wyoming
Maryland	Oregon	

He has participated in energy matters before the Federal Energy Regulatory Commission, the federal Bonneville Power Administration, and in Alberta, Canada and Pemex in Mexico City.

PACIFICORP

Energy Gateway

Bringing New Transmission to the West

Attention is focusing on our nation's electrical transmission system, especially in the West where there has been very little investment in new transmission infrastructure for nearly 20 years. During that time, population, communities and electricity demand in the region have all grown significantly. The transmission system is reaching capacity in many places and is bottlenecked in others.

PacifiCorp is leading the way to change that. In May 2007, PacifiCorp launched the Energy Gateway Transmission Expansion - an ambitious, multi-year $6 billion-plus investment plan that will add approximately 2,000 miles of new transmission line across the West. Energy Gateway, and projects planned by other entities, will alleviate constraints and address current and future growth of many kinds.

Today, construction is underway on one Energy Gateway segment and outreach, siting and permitting processes continue for several others. Major segments are scheduled to be in service by 2014.

Among its benefits, Energy Gateway will provide access to conventional energy sources and connect areas where renewable energy development possibilities are strong, as shown in these regional maps of wind (PDF), solar, biomass **and** geothermal (PDF) **potential. Learn more about how** Energy Gateway supports renewable resource development (PDF).

Along with population and energy demand growth, investment in our transmission system also is driven by our Integrated Resource Plan. **This plan identifies a need for more transmission lines to deliver electricity from new generating resources – either from new generating plants, or to provide a path for additional energy purchases from other entities in the region.**

The Energy Gateway map shows the individual segment additions to the transmission system to complete the expansion at its potential full build. Depending on regional, third-party and local participation, the final lines may vary somewhat. PacifiCorp is taking every reasonable step to accommodate broad regional transmission needs but will, at minimum, build Energy Gateway to first meet our commitment to provide our customers with safe, reliable and reasonably priced electrical service.

Read more about this important investment in the Energy Gateway fact sheet (PDF), **or get answers to** frequently asked questions (PDF).

Links to Energy Gateway and local transmission project segment information can be found below. We update these pages regularly as new information becomes available.

Energy Gateway Segments

Segment A - Walla Walla to McNary

Gateway Central

Segment B - Populus to Terminal

Segment C - Mona to Oquirrh

Segment C - Oquirrh to Terminal

Gateway West

Segment D - Windstar to Populus

Segment E - Populus to Hemingway

Gateway South

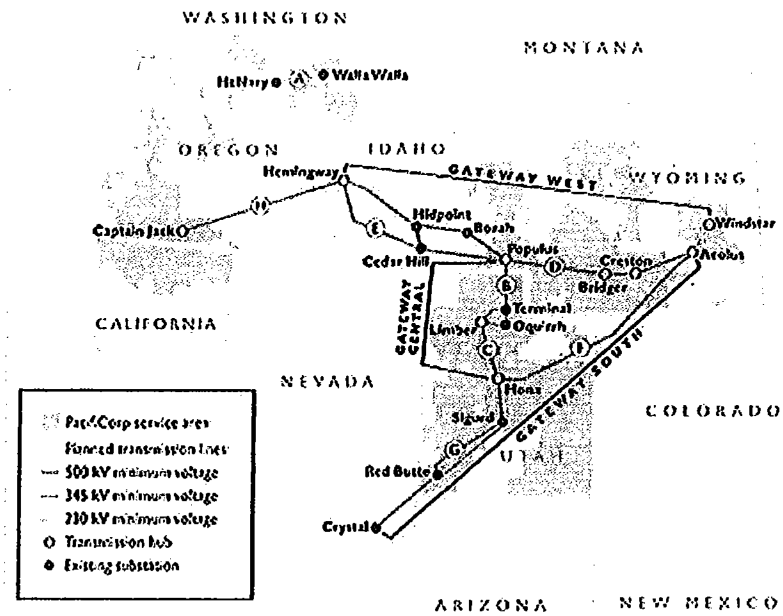
Segment F - Aeolus to Mona

Segment G - Mona to Crystal

Segment G - Sigurd to Red Butte

Segment H - Hemingway to Captain Jack

Monsanto Company
Exhibit 221 (DEP-1)
Page 1 of 2
Case No. PAC-E-10-07
Witness: Dennis E. Peseau



(Updated February 19, 2010)

This map is for general reference only and reflects the expansion necessary to construct Energy Gateway to its full capacity of 6000 MW. It may not reflect the final routes or construction sequence.

Monsanto Company
Exhibit 221 (DEP-1)
Page 2 of 2
Case No. PAC-E-10-07
Witness: Dennis E. Peseau

PACIFICORP

Gateway West

Energy use is on the rise and demand is fast approaching the limits of the existing electrical system. This growth comes from both new and existing customers. Individually, consumers today are using 26 percent more electricity than they did 20 years ago. To meet this increasing demand, new facilities are needed.

As part of PacifiCorp's Energy Gateway Transmission Expansion Project, Idaho Power and Rocky Mountain Power are planning to build a new high-voltage transmission line across southern Wyoming and southern Idaho. This project, called Gateway West , will stretch approximately 1,100 miles and supply present and future needs of customers. The project also will enhance electric system reliability in the service areas of both companies. In addition, Gateway West will enable electricity generated from existing and new resources, including wind, to be delivered to customers throughout the region.

The proposed route for Gateway West's Windstar to Populus segment extends from eastern Wyoming to a hub near Downey, Idaho, where it will connect with a segment that will continue through to western Idaho. The proposed route for the Populus to Hemingway segment runs from a planned transmission hub near Downey, Idaho, across the state to a point southwest of Boise, Idaho.

Project Timeline

- Public Scoping – June 2008
- Environmental Impact Statement process – 2008 - 2012
- Public outreach – June 2008 - project completion
- Permitting and obtaining rights of way – 2011 - 2014
- Estimated line in service for customers – 2014 - 2018

Additional Information About the Project

Under the National Environmental Policy Act, the Bureau of Land Management is currently developing an Environmental Impact Statement on Gateway West – a process that began in June 2008 with open house Public Scoping meetings. BLM has oversight of this process and hosted these meetings to collect official public comments. For more information, please visit BLM's Web site.

Gateway West maps can be viewed below:

- Project overview map
- Segment maps
- Land ownership maps

Further information also can be found on our Gateway West newsletter (PDF) or at our Gateway West Web site .

Public Participation

Public input is an important part of the transmission line development process and is welcomed at all stages. In addition to public, group and individual meetings, project materials and newsletters also have been sent to landowners and other interested parties.

The Bureau of Land Management held open house meetings June 2008 as part of the environmental review process for this project. Rocky Mountain Power and Idaho Power hosted additional meetings in December 2008 to gather input from landowners and other interested parties in Montpelier, Murphy, Pocatello and Twin Falls, Idaho, and in Glenrock, Kemmerer, Rawlins and Rock Springs, Wyoming. Follow-up landowner meetings were then held in Douglas, Glenrock and Sinclair, Wyoming, and in American Falls, Bruneau, Burley, Gooding, Grand View, Kuna, Melba and Twin Falls, Idaho. For a more comprehensive listing of the various outreach efforts, please see the meeting list (PDF).

To submit an official public comment on the Gateway West Transmission Line Project, please contact the BLM directly at:

Bureau of Land Management
Gateway West Project
P. O. Box 20879
Cheyenne, WY 82003
Ore-mail Gateway_West_WYMail@blm.gov

To contact us about this transmission project, please call 801-220-4221 or e-mail ConstructionProjects@pacificorp.com. Please be sure to include the project name –"Gateway West" – in your inquiry.

Monsanto Company
Exhibit 222
Page 1 of 1
Case No. PAC-E-10-07
Witness: Dennis E. Peseau

PACIFICORP

Gateway South

With energy use on the rise and electrical demand fast approaching the limits of the existing transmission system, new facilities are needed to meet the growing needs. This growth in demand for electrical energy comes from both new and existing customers. Individually, consumers today are using 26 percent more electricity than they did 20 years ago.

As part of PacifiCorp's Energy Gateway Transmission Expansion Project, the company is planning to build a high-voltage transmission line project across southern Wyoming, potentially crossing northwest Colorado, through Utah to a point north of Las Vegas, Nevada. This line segment, Gateway South, will be approximately 800 miles long, supplying present and future needs of customers and enhancing electric system reliability throughout the region. In addition, the project will enable delivery of existing and new generating resources, including wind, to more customers.

The proposed route for Gateway South, Aeolus to Mona, extends from eastern Wyoming to a hub near Mona, Utah, where it will connect with another segment that continues through southern Utah.

The proposed route for Gateway South, Mona to Crystal, is from a new substation that will be built near Mona, Utah, connecting to multiple substations through southwest Utah to a point north of Las Vegas, Nevada.

Sigurd to Red Butte, another transmission line that is part of the Gateway South project, will start in Sigurd, Utah, and continue south to the Red Butte Substation north of St. George, Utah.

Gateway South maps will be available following Public Scoping in Spring 2010.

Project Timeline

- Public Scoping – August/September 2010
- Informational Meetings – August/September 2010
- Environmental Impact Statement – December 2008-2015
- Estimated line in service for customers – 2017-2019

Public Participation

Public input is a very important part of this process and will be welcomed at all stages of this transmission line development. Public Scoping meetings are expected to be held as part of the environmental review process. The Bureau of Land Management will oversee this process under the National Environmental Policy Act and will host these meetings to collect official public comments on the project for the draft Environmental Impact Statement.

Additional Information About the Project

The company welcomes your comments at all stages of this transmission line development. For more information, please call us at (801) 220-4221 or e-mail ConstructionProjects@pacificorp.com. Please be sure to include the project name –"Energy Gateway South" – in your inquiry.

(Updated January 14, 2010)

Monsanto Company
Exhibit 223 (DEP-3)
Page 1 of 1
Case No. PAC-E-10-07
Witness: Dennis E. Peseau

Office of the Secretary
Service Date
February 13, 2006

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE JOINT APPLICATION OF MIDAMERICAN ENERGY HOLDINGS COMPANY (MEHC) AND PACIFICORP DBA UTAH POWER & LIGHT COMPANY FOR AN ORDER AUTHORIZING MEHC TO ACQUIRE PACIFICORP	)))))))	CASE NO. PAC-E-05-8 ORDER NO. 29973

On July 15, 2005, PacifiCorp dba Utah Power & Light Company ("PacifiCorp") and MidAmerican Energy Holdings Company ("MidAmerican") filed a Joint Application requesting that the Commission authorize MidAmerican's acquisition of PacifiCorp. PacifiCorp is a public utility subject to the Commission's jurisdiction and provides retail electric service to nearly 60,000 customers in southeastern Idaho. At present, PacifiCorp is a wholly-owned subsidiary of Scottish Power plc.

If the Joint Application is approved, PacifiCorp would become an indirect, wholly-owned subsidiary of MidAmerican. MidAmerican's principal owner is Berkshire Hathaway, Inc. The Applicants must obtain approval from the Idaho Commission and the regulatory commissions of the other five states where PacifiCorp provides electric service for MidAmerican to acquire PacifiCorp. In addition, the acquisition must also be approved by several federal agencies including the Federal Energy Regulatory Commission (FERC).[1]

On August 18, 2005, the Commission issued its Notice of Application setting this matter for hearing. On December 16, 2005, most of the parties in this proceeding executed a settlement Stipulation urging the Commission to approve the Joint Application conditioned upon 76 "commitments." On January 17, 2006, the Commission convened a technical hearing to consider the Stipulation. Based upon our review of the Joint Application, the settlement Stipulation, the testimony of the parties and the public comments, the Commission approves the acquisition conditioned upon the commitments incorporated in this Order.

---

[1] The Wyoming and Utah Commissions approved the acquisition on January 26 and 27, 2006, respectively. FERC authorized the transaction on December 20, 2005 in Docket No. EC05-110-000, 113 FERC ¶ 61,298 (2005), *rehearing granted* (for limited purpose of further consideration), 113 FERC ¶ _____ (Feb. 6, 2006).

Monsanto Company
Exhibit 224 (DEP-4)
Page 1 of 3
Case No. PAC-E-10-07
Witness: Dennis E. Peseau

30) PacifiCorp will continue to produce Integrated Resource Plans according to the then current schedule and the then current Commission rules and orders.

31) When acquiring new generation resources in excess of 100 MW and with a dependable life of 10 or more years, PacifiCorp and MEHC will issue Requests for Proposals (RFPs) or otherwise comply with state laws, regulations and orders that pertain to procurement of new generation resources for PacifiCorp.

32) Nothing in these acquisition commitments shall be interpreted as a waiver of PacifiCorp's or MEHC's rights to request confidential treatment for information that is the subject of any commitments.

33) Unless another process is provided by statute, Commission regulations or approved PacifiCorp tariff, MEHC and PacifiCorp encourage the Commission to use the following process for administering the commitments. The Commission should give MEHC and PacifiCorp written notification of any violation by either company of the commitments made in this application. If such failure is corrected within ten (10) business days for failure to file reports, or five (5) business days for other violations, the Commission should take no action. The Commission shall have the authority to determine if the corrective action has satisfied or corrected the violation. MEHC or PacifiCorp may request, for cause, an extension of these time periods. If MEHC or PacifiCorp fails to correct such violations within the specified time frames, as modified by any Commission-approved extensions, the Commission may seek to assess penalties for violation of a Commission order, against either MEHC or PacifiCorp, as allowed under state laws and regulations.

34) Transmission Investment: MEHC and PacifiCorp have identified incremental transmission projects that enhance reliability, facilitate the receipt of renewable resources, or enable further system optimization. Subject to permitting and the availability of materials, equipment and rights-of-way, MEHC and PacifiCorp commit to use their best efforts to achieve the following transmission system infrastructure improvements[1]:

a) Path C Upgrade (~$78 million) – Increase Path C capacity by 300 MW (from S.E. Idaho to Northern Utah). The target completion date for this project is 2010. This project:
   - enhances reliability because it increases transfer capability between the east and west control areas,

[1] While MEHC has immersed itself in the details of PacifiCorp's business activities in the short time since the announcement of the transaction, it is possible that upon further review a particular investment might not be cost-effective, optimal for customers or able to be completed by the target date. If that should occur, MEHC pledges to propose an alternative to the Commission with a comparable benefit. The Commission may investigate the reasonableness of any determination by MEHC/PacifiCorp that one or more of the identified transmission investments is not cost-effective or optimal for customers.

Monsanto Company
Exhibit 224 (DEP-4)
Page 2 of 3
Case No. PAC-E-10-07
Witness: Dennis E. Peseau

- 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.

b) Mona - Oquirrh (~$196 million) – Increase the import capability from Mona into the Wasatch Front (from Wasatch Front South to Wasatch Front North). This project would enhance the ability to import power from new resources delivered at or to Mona, and to import from Southern California by "wheeling" over the Adelanto DC tie. The target completion date for this project is 2011. This project:
- enhances reliability by enabling the import of power from Southern California entities during emergency situations,
- facilitates the acceptance of renewable resources, and
- enhances further system optimization since it enables the further purchase or exchange of seasonal resources from parties capable of delivering to Mona.

c) Walla Walla - Yakima or Mid-C (~$88 million) – Establish a link between the "Walla Walla bubble" and the "Yakima bubble" and/or reinforce the link between the "Walla Walla bubble" and the Mid-Columbia (at Vantage). Either of these projects presents opportunities to enhance PacifiCorp's ability to accept the output from wind generators and balance the system cost effectively in a regional environment. The target completion date for this project is 2010.

35) Other Transmission and Distribution Matters: MEHC and PacifiCorp make the following commitments to improve system reliability:

a) investment in the Asset Risk Program of $75 million over the three years, 2007-2009,

b) investment in local transmission risk projects across all states of $69 million over eight years after the close of the transaction,

c) O & M expense for the Accelerated Distribution Circuit Fusing Program across all states will be increased by $1.5 million per year for five years after the close of the transaction, and

d) extension of the O&M investment across all states for the Saving SAIDI Initiative for three additional years at an estimated cost of $2 million per year.

e) MEHC and PacifiCorp will support the Bonneville Power Administration in its development of short-term products such as conditional firm. Based on the outcome from BPA's efforts, PacifiCorp will initiate a process to collaboratively design similar products at PacifiCorp. PacifiCorp will continue its Partial Interim Service product and its tariff provision that allows transmission customers to alter pre-scheduled transactions up to twenty minutes before any hour, and will notify parties to this proceeding if it proposes changes to these two elements of its OATT.

Monsanto Company
Exhibit 224 (DEP-4)
Page 3 of 3
Case No. PAC-E-10-07
Witness: Dennis E. Peseau

Exhibit 2xx (DEP-5)

ENERGY GATEWAY
Comparative Costs per Mile

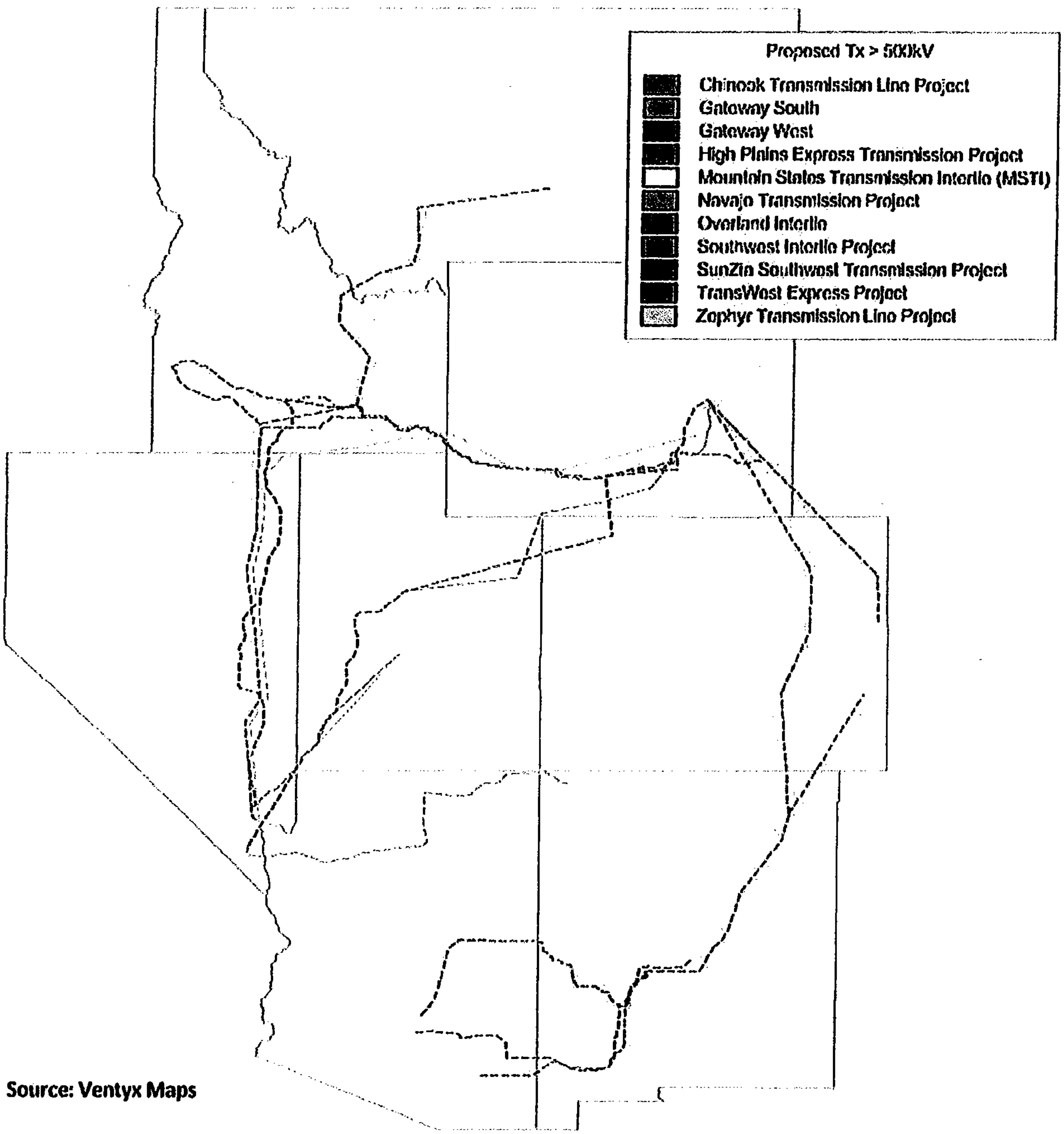
Gateway Central 345kV	\$801.5/135	=	\$5.94 million per mile
Remaining Energy Gateway 500kV	(\$6,000-801.5)/1865	=	\$2.79 million per mile
Nevada Power's ON Line 500kV	\$509.6/235	=	\$2.17 million per mile

Assumptions:
1. Gateway Central Investment of \$801.5 million
2. Segment length of 135 miles
3. Energy Gateway Investment of \$6 billion
4. Energy Gateway length of 2000 miles
5. Nevada Power's ON Line Investment of \$509.6 million
6. On Line segment length of 235 miles

Monsanto Company
Exhibit 225 (DEP-5)
Page 1 of 1
Case No. PAC-E-10-07
Witness: Dennis E. Peseau

Exhibit_____(DEP)

Western U.S. Proposed 500kV+ Transmission Lines



Source: Ventyx Maps

Monsanto Company
Exhibit 226 (DEP-6)
Page 1 of 1
Case No. PAC-E-10-07
Witness: Dennis E. Peseau

PAC-E-10-07/Rocky Mountain Power
July 8, 2010
Monsanto Data Request 4.5

Monsanto Data Request 4.5

What function would the Gateway Central serve if either or both of the South and West segments are not completed?

Response to Monsanto Data Request 4.5

If Gateway South and/or Gateway West were not completed, Gateway Central will continue to provide significant benefits to the Company's customers. Please refer to pages Di-3 and Di-4 in the direct testimony of Darrell T. Gerrard below.

- Increase the overall transmission capacity in the existing transmission corridor between southeast Idaho and northern Utah, where the existing system has limited capacity and demonstrated operational limitations.
- Meet the immediate need to: (1) Improve system reliability in the area and maintain compliance with national electrical system reliability standards by installing new transmission capacity to ensure the system can sustain transmission outages north of Terminal Substation without curtailing loads, generation or impacting PacifiCorp's East Control Area and neighboring transmission balancing authority areas; and (2) 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.
- Meet the transmission capacity and reliability requirements to deliver resources to loads.
- Provide PacifiCorp with greater flexibility when considering future planned resources to meet customers' growing demands for energy 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, Idaho and Oregon, and help support economic development in those states.

Further, Gateway Central will reduce the impacts to customers during system disturbances. Please refer to pages Di-9, Di-10, Di-11 in the direct testimony of Darrell T. Gerrard.

Recordholder: Darrell T. Gerrard
Sponsor: Darrell T. Gerrard

Monsanto Company
Exhibit 227 (DEP-7)
Page 1 of 1
Case No. PAC-E-10-07
Witness: Dennis E. Peseau

EXHIBIT 3

BEFORE THE

RECEIVED
2010 OCT 14 PM 1:45
UTILITIES COMMISSION

IDAHO PUBLIC UTILITIES COMMISSION

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

ALLEGEDLY PROPRIETARY DATA HAS BEEN DELETED FROM THIS DOCUMENT

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:

> <u>Path C Upgrade (~$78 million)</u> - 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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EXHIBIT 4

PacifiCorp Load Ratio Share Effective Date ---->	4/1/2006	8/1/2007	8/1/2008	8/1/2009	1/14/2010	8/1/2010	Annual Rate
Total Tariff Network Load	7,865.58	8,536.45	8,448.90	8,638.89	8,618.34	8,396.27	1.5%
Total non-Tariff Network Load	1,032.31	1,154.68	1,168.33	1,238.36	1,238.36	1,154.85	2.6%
Total Network Load	8,897.89	9,691.12	9,617.24	9,877.24	9,856.70	9,551.12	1.6%
P-t-P Reservations	6,920.18	4,027.13	5,388.92	5,592.17	5,592.17	5,496.92	-5.2%
Transmission System Load	15,818.07	13,718.25	15,006.15	15,469.41	15,448.86	15,048.03	-1.1%
PacifiCorp							
California Retail	146.58	150.97	151.68	150.20	150.20	147.44	0.1%
Idaho Retail	453.91	488.96	511.32	500.37	500.37	436.05	-0.9%
Oregon Retail	882.34	953.67	930.30	976.81	976.81	1,073.33	4.6%
Oregon Direct Access	1,275.50	1,416.03	1,381.52	1,449.72	1,449.72	1,270.64	-0.1%
Utah Retail	3,113.25	3,381.26	3,315.42	3,521.94	3,521.94	3,418.62	2.2%
Washington Retail	681.53	722.47	676.72	695.45	695.45	713.74	1.1%
Wyoming Retail	1,047.36	1,084.95	1,134.13	1,184.33	1,184.33	1,202.22	3.2%
Requirement Wholesale	30.25	32.87	33.63	34.43	34.43	32.10	1.4%
Other Wholesale	173.09	229.32	211.79	17.87	17.87	23.38	-37.0%
Total PacifiCorp Network Load	7,803.80	8,460.50	8,346.50	8,531.11	8,531.11	8,317.52	1.5%
Basin Electric Power Corp.							
S.A. 228	9.66	10.25	14.82	19.12	-		
S.A. 233	7.85	12.52	10.79	-	-		
S.A.505 (POD #1)				10.49	10.49		
S.A.505 (POD #2)				0.71	0.71	0.563	
Black Hills Corp	39.81	42.61	42.38	42.60	42.60	43.82	
BPA S.A. 229	2.62	2.98	2.95	3.02	3.02	3.31	
BPA S.A. 328		5.40	5.31	5.84	5.84	6.00	
BPA S.A. 370			24.07	20.15	20.15	20.007	
BPA S.A. 538				1.00	1.00	0.08	
BPA S.A. 539				1.81	1.81	0.47	
Flathead Electric Coop	0.52	0.83	0.67	-	-		
Tri-State Generation & Trans						3.00	
U.S. Bureau of Reclamation				1.72	0.29	0.27	
WAPA	1.31	1.36	1.43	1.33	1.33	1.225	
Total Other Network	61.78	75.95	102.41	107.78	87.23	78.74	5.8%
Total Tariff Network Load	7,865.58	8,536.45	8,448.90	8,638.89	8,618.34	8,396.27	1.5%

PacifiCorp Load Ratio Share 6 FERC Filings from 4/1/06 through 8/1/10	Average of 6 Filings	
Total Tariff Network Load	8,417.40	55.80%
Total non-Tariff Network Load	1,164.48	7.72%
Total Network Load	9,581.88	63.52%
P-t-P Reservations	5,502.91	36.48%
Transmission System Load	15,084.80	100.00%
PacifiCorp		
California Retail	149.51	1.78%
Idaho Retail	481.83	5.72%
Oregon Retail	965.54	11.47%
Oregon Direct Access	1,373.85	16.32%
Utah Retail	3,378.74	40.14%
Washington Retail	697.56	8.29%
Wyoming Retail	1,139.55	13.54%
Requirement Wholesale	32.95	0.39%
Other Wholesale	112.22	1.33%
Total PacifiCorp Network Load	8,331.76	98.98%
Basin Electric Power Corp.		
S.A. 228	10.77	0.13%
S.A. 233	6.23	0.07%
S.A.505 (POD #1)	10.49	0.12%
S.A.505 (POD #2)	0.66	0.01%
Black Hills Corp	42.30	0.50%
BPA S.A. 229	2.98	0.04%
BPA S.A. 328	5.68	0.07%
BPA S.A. 370	21.09	0.25%
BPA S.A. 538	0.69	0.01%
BPA S.A. 539	1.36	0.02%
Flathead Electric Coop	0.40	0.00%
Tri-State Generation & Trans	3.00	0.04%
U.S. Bureau of Reclamation	0.76	0.01%
WAPA	1.33	0.02%
Total Other Network	85.65	1.02%
Total Tariff Network Load	8,417.40	100.00%

EXHIBIT 5

10-035-89/Rocky Mountain Power
October 7, 2010
UIEC Data Request 5.1

UIEC Data Request 5.1

Please confirm that the data for the five effective dates indicate that, on average,

(a) Network transmission service represented 63.52% of total firm usage of the PacifiCorp transmission system,

(b) PacifiCorp retail load represented 55.8% total firm usage of the PacifiCorp transmission system, and

(c) Firm Point-to-Point transmission service represented 36.48% of total firm usage of the PacifiCorp transmission system.

(d) For each of the previous statements that PacifiCorp cannot confirm, please explain why it cannot confirm and provide the correct data and percentages.

Response to UIEC Data Request 5.1

Based on PacifiCorp's review of the attached spreadsheet, we believe there are data errors. When corrected, the correct values should be:

(a) Network transmission service represents 63.59% of total firm usage of the PacifiCorp transmission system.
(b) PacifiCorp Commercial & Trading's network integration transmission service, some of which is used by the customer to facilitate its retail load service, represents 55.29% total firm usage of the PacifiCorp transmission system.
(c) Firm point-to-point transmission service represented 36.410% of total firm usage of the PacifiCorp transmission system.
(d) See above.

10-035-89/Rocky Mountain Power
October 7, 2010
UIEC Data Request 5.4

UIEC Data Request 5.4

Please state the amount of system revenue requirement allocated to firm uses of the PacifiCorp transmission system other than retail load in its most recent FERC OATT filing.

Response to UIEC Data Request 5.4

The amount of system revenue requirement allocated to firm uses of the PacifiCorp transmission system is $242,358,039. Please refer to Attachment H of PacifiCorp's Open Access Transmission Tariff ("OATT"):

http://www.oasis.pacificorp.com/oasis/ppw/PACRestatedOATT20100219.pdf.

Transmission system revenue requirement is not allocated to retail load directly. It is allocated to firm uses of the transmission system, including Network Integration Transmission Service, which is used by PacifiCorp commercial & trading as a transmission customer to facilitate its retail load service.

As PacifiCorp has previously explained (Please refer to the Company's response to UIEC Data Request 2.12, dated April 27, 2010.), it no longer makes separate filings at the Federal Energy Regulatory Commission to update Load Ratio Share allocations of transmission revenue requirement. Please refer to the below link for PacifiCorp's most recent update:

http://www.oasis.pacificorp.com/oasis/ppw/LRSCurrent20100801.pdf

10-035-89/Rocky Mountain Power
October 7, 2010
UIEC Data Request 5.5

UIEC Data Request 5.5

Please state the amount of system revenue requirement credited to the PacifiCorp transmission system annual revenue requirement in the numerator of the network transmission rate calculation as part of its most recent FERC OATT filing.

Response to UIEC Data Request 5.5

Transmission system revenues for non-firm and short-term uses of the transmission system are credited to the numerator when setting the overall transmission revenue requirement calculation. PacifiCorp cannot provide a current amount of revenue credit because it has not yet filed a rate case.

Please refer to the Company's response to UIEC Data Request 1.36 for more information regarding the last 1995 transmission rate case filing and the planned 2011 filing.

10-035-89/Rocky Mountain Power
October 7, 2010
UIEC Data Request 5.7

UIEC Data Request 5.7

Please state the time interval on which PacifiCorp's network rate calculation is updated in order to reflect long-term firm service in the denominator and revenue credits in the numerator.

Response to UIEC Data Request 5.7

PacifiCorp's network load ratio share calculation is updated in order to reflect changes in firm uses of the transmission system. Please refer to PacifiCorp's Business Practice #52 at the following link:
http://www.oasis.pacificorp.com/oasis/ppw/BP52.pdf

Load ratio share updates allocate PacifiCorp's current transmission revenue requirement among firm users of the transmission system based on their relative demand. Non-firm uses of the transmission system are not revenue credited in the calculation of load ratio share. Please refer to the Company's response to UIEC Data Request 5.5.

10-035-89/Rocky Mountain Power
October 7, 2010
UIEC Data Request 5.8

UIEC Data Request 5.8

Please state how often (the time interval on which) PacifiCorp's Utah retail rates are updated in order to reflect revenue credits for uses of the PacifiCorp transmission system other than for retail load.

Response to UIEC Data Request 5.8

PacifiCorp's Utah retail rates are updated through rate filings with the Utah Public Service Commission. There is no specific time interval on which rates are updated.

10-035-89/Rocky Mountain Power
October 7, 2010
UIEC Data Request 5.9

UIEC Data Request 5.9

Please confirm that the data in the categories of Network Service (12-cp) and Point-to-Point (contract demand) in PacifiCorp's filings are intended to include all firm usage of the PacifiCorp transmission system that are reflected in the denominator of PacifiCorp's calculation of its Network Transmission Rate. If not, please explain why not and supply the correct characterization of the data.

Response to UIEC Data Request 5.9

Confirmed.

10-035-89/Rocky Mountain Power
October 7, 2010
UIEC Data Request 5.11

UIEC Data Request 5.11

Please confirm that the data for the five effective dates indicate that, on average, Utah retail load represented 40.14% of PacifiCorp's network transmission service or 25.5% of the long-term firm usage of the PacifiCorp transmission system. If not, please explain why not and provide the correct data.

Response to UIEC Data Request 5.11

Based on PacifiCorp's review of the attached spreadsheet, we believe there are data errors. In addition, the question refers to five effective dates when there are six provided. When corrected and assuming the question meant six:

On average, Utah retail load represented 40.14% of PacifiCorp's network transmission service. The average Utah retail load represented 22.423% of PacifiCorp total transmission system load.

10-035-89/Rocky Mountain Power
October 7, 2010
UIEC Data Request 5.12

UIEC Data Request 5.12

Please state whether it is reasonable to assume that PacifiCorp retail load will continue to represent approximately 55.8% of total firm usage of the PacifiCorp transmission system as measured by PacifiCorp in calculating network transmission rates under its OATT.

(a) If not, please state what percentage of the total firm usage of the PacifiCorp transmission system is projected to be represented by PacifiCorp's retail load.

(b) If so, please explain how PacifiCorp's allocation to its retail loads of 100% of the revenue requirement associated with its existing and proposed network transmission facilities (subject to revenue credits) can be said to be consistent with:

(i) The 55.8% usage of the PacifiCorp transmission system attributed to those retail customers in its FERC OATT filings.

(ii) The benefits that retail customers derive from the PacifiCorp transmission system.

Response to UIEC Data Request 5.12

It is not

10-035-89/Rocky Mountain Power
October 22, 2010
UIEC Data Request 10.2

UIEC Data Request 10.2

In response to UIEC Data Request No. 3, you provided to us a number of point-to-point transmission agreements. Those point-to-point transmission agreements appear to be issued under the name of PacifiCorp Commercial and Trading, a wholesale transmission customer. Please explain why the point-to-point transmission rights are in the name of PacifiCorp Commercial and Trading.

Response to UIEC Data Request 10.2

PacifiCorp interprets this question to refer specifically to UIEC Data Request 3.12.

PacifiCorp Commercial and Trading is the name of a wholesale transmission customer with whom PacifiCorp Transmission has contracted for point-to-point agreements. Commercial and Trading is the name of the marketing function division within PacifiCorp Energy.

10-035-89/Rocky Mountain Power
October 22, 2010
UIEC Data Request 10.4

UIEC Data Request 10.4

(a) What is the sum of the capacity covered in the point-to-point contracts which are presently outstanding (b) plus that of the new contracts expected to be executed in the next 5 years? (c) What is the capacity of each of the contracts?

Response to UIEC Data Request 10.4

(a) 5231 MW
Note: PacifiCorp interprets "outstanding" to mean presently executed contracts.

(b) Unknown. PacifiCorp cannot predict future customer requests for service or willingness to accept contract offers.
Note: PacifiCorp interprets "new contracts" to mean any new contracts for incremental service within the next five years.

(c) The capacity is listed within each point-to-point contract which was provided in the Company's response to UIEC Data Request 3.12.

EXHIBIT 6