Oregon

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July 23, 2008

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 2148
SALEM OR 97308-2148

RE: **Docket No. UE 200 – In the Matter of PACIFICORP, dba PACIFIC POWER 2009 Renewable Adjustment Clause Schedule 202.**

Enclosed for electronic filing in the above-captioned docket is the Public Utility Commission Staff's Reply Testimony.

/s/ Kay Barnes
Kay Barnes
Regulatory Operations Division
Filing on Behalf of Public Utility Commission Staff
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c: UE 200 Service List (parties)

PUBLIC UTILITY COMMISSION
OF OREGON

UE 200

STAFF REPLY TESTIMONY OF

Deborah Garcia
Lisa Schwartz
Kelcey Brown
Steve Storm

<u>REDACTED</u>

In the Matter of
PACIFICORP, dba PACIFIC POWER
2009 Renewable Adjustment Clause Schedule 202.

July 23, 2008

CASE: UE 200
WITNESS: Deborah Garcia

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Reply Testimony

July 23, 2008

Q. **PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.**

A. My name is Deborah Garcia. I am a Senior Revenue Requirements Analyst employed by the Public Utility Commission of Oregon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. **PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.**

A. My Witness Qualification Statement is found in Exhibit Staff/101.

Q. **DID YOU PREPARE ANOTHER EXHIBIT FOR THIS DOCKET?**

A. Yes. I prepared Exhibit Staff/102.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to provide an analysis of the capital costs and of the operating and maintenance (O&M) costs related to the nameplate capacity for each of the renewable resources included in PacifiCorp's 2009 Renewable Adjustment Clause (RAC) – Schedule 202 (Advice No. 08-007), docketed as UE 200. My analysis of capital costs specifically focuses on the costs associated with the procurement and installation of plant and does not address prudency of the wind resource acquisitions or issues related to capacity factors. I also introduce the other Staff witnesses who provide testimony in this docket. Finally, I present the revenue requirement results based on the Staff-recommended adjustments.

Q. **PLEASE LIST THE STAFF WITNESSES AND PROVIDE A SUMMARY OF THE WITNESSES' TESTIMONY.**

A. **Lisa Schwartz** provides staff's recommendation on whether the renewable resources included in the RAC were prudently acquired under the Commission's guidelines for integrated resource plans and competitive bidding, and the Oregon Renewable Energy Act (Senate Bill 838, 2007 Session). She also addresses the appropriate capacity factors for the Rolling Hills and Glenrock projects. Finally, she provides staff's recommendation of whether it is appropriate for PacifiCorp to include additional renewable resources in the RAC Update (expected to be filed by December 1, 2008) that were not included in the original filing.

Kelcey Brown provides a review and recommendations with regard to PacifiCorp's analysis methodologies (a) the present value revenue requirements differential [PVRR(d)] method and (b) the alternative cost compliance (ACC) method. She also provides staff's recommendation for adjustments related to the capacity factors associated with Glenrock and Rolling Hills. Finally, she includes a discussion regarding PacifiCorp's cost of equity.

Steven Storm describes the rate spread methodology authorized by Commission Order No. 07-572 in UM 1330 and presents a review of whether the rate spread methodology PacifiCorp used in this docket is consistent with the requirements of the Order.

Q. HAVE YOU COMPLETED A REVIEW OF THE COSTS AND REVENUE REQUIREMENT ASSOCIATED WITH THE NEW RENEWABLE RESOURCES INCLUDED IN PACIFICORP'S FILING?

A. Yes.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. Subject to a finding that the acquisition of these resources was prudent, I recommend that the Commission disallow $4.5 million of the O&M costs included in the RAC filing and require the Company to file compliance tariffs reflecting this, and the other Staff-proposed adjustments, for service on and after January 1, 2009.

Q. DO YOU FIND THE REVENUE REQUIREMENT AMOUNTS SOUGHT BY PACIFICORP IN THIS FILING TO BE CORRECT?

A. No. My recommended reduction to the revenue requirement, based on the O&M adjustment addressed in my testimony and the other Staff-supported adjustments, results in a revenue requirement reduction on a total Company basis of $13,338,667, for an adjusted revenue requirement of $133,784,338 as shown on page 4 of Exhibit Staff/102. On an Oregon-allocated basis, Staff's proposed adjustments result in a revenue requirement reduction of $3,532,095, for a total revenue requirement of $35,509,850.

Q. PLEASE SUMMARIZE STAFF'S OVERALL REVENUE REQUIREMENT CHANGE IN THIS PROCEEDING.

A. Subject to any RAC updates PacifiCorp files by December 1, 2008, the Company proposed an overall revenue requirement of increase of $39 million effective January 1, 2009. Staff recommends the Commission reduce the increase by $13 million, based on three adjustments:

1. $4.6 million related to O&M costs;

2. $2.1 million related to Glenrock capital costs; and
3. $6.6 million related to Rolling Hills capital costs.

Q. THE COMPANY MAY[1] UPDATE CERTAIN COSTS IN THIS RAC FILING. PLEASE BRIEFLY EXPLAIN.

A. If any of the cost elements[2] of an eligible resource cannot be verified by the final round of testimony in this annual RAC proceeding, the Company will submit cost updates by December 1, 2008, to reflect either then-current, actual resource costs, or forecasted costs if appropriate. If the updated costs are lower than the costs previously filed, the update must contain sufficient information to support a reduction in the proposed RAC charges before the January 1, 2009, effective date. If the costs are higher, the difference will be deferred.[3]

<u>Review of Resource Capital Costs</u>

Q. DID YOU CONDUCT AN AUDIT OF THE CAPITAL COSTS ASSOCIATED WITH THE PROCUREMENT AND INSTALLATION OF EACH OF THE WIND RESOURCES INCLUDED IN THE RAC?

A. No. I performed an audit of the capital costs for the following four wind resources: Leaning Juniper, Marengo, Rolling Hills, and Glenrock.

Q. PLEASE EXPLAIN.

A. Although PacifiCorp was prepared for an audit of capital costs for all of the wind resources included in the RAC, I determined that it was not necessary after I concluded an audit of 95 to 97 percent of the capital costs for each of the

[1] See Docket No. UM 1330 Order No. 07-572, Appendix A, Section (6), (e-f).
[2] Ibid., (b) (For specific cost elements.)
[3] Ibid., (f) (For the specific requirements associated with deferred accounting in this filing.)

above resources. My audit included the review of the physical invoices associated with those costs.

Q. DID YOU FIND THAT ALL AUDITED CAPITAL COST ITEMS WERE NECESSARY AND DIRECTLY RELATED TO THE PROJECTS?

A. Yes.

Q. PLEASE DESCRIBE THE PLANT AND ACTIVITIES THAT ARE ASSOCIATED WITH THE MAJORITY OF THE CAPITAL COSTS FOR THE WIND RESOURCES.

A. The primary activities that are associated with the majority of the capital costs are: the acquisition and installation of the wind towers and turbines; costs related to the sites such as land leases, easements, road and on-site building construction; and connection to transmission.

Q. PLEASE DESCRIBE THE ANALYSIS YOU CONDUCTED OF THE WIND RESOURCE CAPITAL COSTS.

A. I conducted a comparative analysis of the Company's capital costs on a dollars per kW basis against other U.S. wind resources established in the same years. Using the faceplate capacity and capital costs filed for each resource in the RAC, I calculated the individual resource capital costs on a dollars per kW basis. Then I compared the cost per kW for each resource to the weighted average capital costs per kW associated with U.S. wind resources[4] put into

[4] Data from the U.S. Department of Energy Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends from Lawrence Berkeley National Laboratory (LBNL) (Years 2007 and 2008). Among other things, the annual reports consist of various statistics including capacity, capital, and O&M costs, for the U.S. wind resources that go into service during the year. As 2008 actual costs will

service during the same period. As shown in Exhibit Staff/102, Garcia/1 (line 10), the range for PacifiCorp's resources is from 100.7 to 111.4 percent of the U.S. average.

Q. DID YOU INCLUDE ANY OTHER RESOURCES IN YOUR COMPARATIVE ANALYSIS?

A. Yes. I compared PacifiCorp's capital costs per kW for facilities that went into service during 2007 to Portland General Electric's Biglow Canyon Wind Farm Phase I (Biglow) that was completed the same year. I also compared the Company's costs to the costs for western U.S. projects as provided by the Northwest Power and Conservation Council (NPCC).

Q. WHAT DID YOUR COMPARISON OF PACIFICORP'S AND BIGLOW'S CAPITAL COSTS REVEAL?

A. The capital costs per kW for the two PacifiCorp projects, Marengo and Marengo II, that were completed in 2007, are $1,753 and $1,934, respectively. The capital costs per kW for Biglow, also completed in 2007, were $2,041.

Q. WHAT DO YOU CONCLUDE FROM THIS COMPARISON?

A. The only conclusion I make is that the capital costs for all three projects are close enough to appear generally reasonable. Although the three projects are in the Pacific Northwest and went into service the same year, there are legitimate reasons why one project's costs might be slightly higher than the others.

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not be available until the 2009 report, I obtained an estimate from LBNL that factors in resources already put in service during 2008.

Q. WHAT DID YOU FIND DURING YOUR ANALYSIS OF THE DATA PROVIDED BY NORTHWEST POWER AND CONSERVATION COUNCIL FOR CAPITAL COSTS ASSOCIATED WITH PROJECTS IN THE WESTERN REGION OF THE U.S.?

A. NPCC maintains a data base related to wind farms within the Western Electric Coordinating Council's (WECC) region that I obtained from Jeff King, NPCC Senior Resource Analyst, along with the caveat that NPCC relies for the most part on various media releases to determine construction costs for resources. Per Mr. King, many of the resources are privately held and are not subject to the same reporting requirements as an investor-owned utility. I did a spot check of resources where I had knowledge of actual reported capital costs and found that the difference between those actual costs and the costs in the NPCC data base deviated enough (with no discernible pattern) as to undermine the outcome of a comparative analysis between the UE 200 resources and the other resources contained in the NPCC database.

Q. WHY DID YOU USE A COMPARATIVE ANALYSIS IN YOUR REVIEW OF THE CAPITAL COSTS ASSOCIATED WITH THE RESOURCES?

A. I performed a comparative analysis because a more traditionally constructed analysis that is based on established current costs or historic costs plus adjustments, such as inflation, would not be appropriate given the following factors: (1) the use of wind to generate electric energy is relatively new compared to other established generation sources, such as coal or natural gas;

(2) rapid advances in technology have added to the difficulty of determining appropriate benchmarks for tower and turbine costs; (3) the market demand for equipment has been volatile partly due to renewable portfolio type-standards in other states, and to the uncertainty each year whether Congress will renew the annual Federal Renewable Production Tax Credits for wind installations; (4) wind turbine equipment has consistently been in short supply; and (5) there is significant competition for sites more favorable to wind production where transmission availability is not a major obstacle.

Q. PLEASE EXPLAIN WHY THE RESULTS OF YOUR COMPARATIVE ANALYSIS LEAD TO THE CONCLUSION THAT THE RESOURCE COSTS RELATED TO PROCUREMENT AND INSTALLATION OF PLANT FOR WIND RESOURCES INCLUDED IN THE RAC ARE GENERALLY REASONABLE?

A. My finding that the costs of the RAC resources are either somewhat lower or somewhat higher than the costs for other resources owned by different entities is what I would expect, given the variables cited earlier in my testimony. Although the costs of the RAC resources are somewhat higher than the U.S. average, they are still well below (67.4 to 78.1 percent) the highest costs for U.S. resources put into service the same year.

Q. BASED ON YOUR ANALYSIS, CAN YOU CONCLUDE THAT ACQUISITION OF THE INDIVIDUAL RAC RESOURCES WAS PRUDENT?

A. No. Although the procurement and installation of the resources on a capacity basis appear to be within a reasonable range, that does not mean that the resources were the best combination of least cost/least risk compared to other alternatives available to the Company. Staff witness Schwartz addresses that issue in Exhibit Staff/200.

Q. TURNING TO A DIFFERENT ISSUE, PLEASE SUMMARIZE THE FUNCTION OF THE BLUNDELL BOTTOMING CYCLE.

A. Blundell Bottoming Cycle (Blundell) is an add-on to the Blundell plant, a geothermal resource constructed in the 1980’s, which utilizes the latent heat associated with the operation of the plant to drive a second turbine generator.

Q. WERE YOU ABLE TO FIND ANY BENCHMARKS FOR THE CAPITAL COSTS ASSOCIATED WITH THE INSTALLATION OF A GEOTHERMAL BOTTOMING RESOURE?

A. No. At this time, geothermal resources are scarce. There are two resources currently in operation in the Western U.S., and neither of those resources includes a bottoming cycle addition.

Q. DID YOU REVIEW CAPITAL COST QUOTES ASSOCIATED WITH ANY OTHER RESOURCE INSTALLATIONS THAT HAVE A SIMILAR FUNCTION AS BLUNDELL?

A. Yes. I obtained 2005 and 2008 actual construction cost quotes for several cogeneration projects from the Energy Trust of Oregon (ETO), some of which are for bottoming cycle generation, although they are associated with capturing energy from manufacturing facilities rather than from a geothermal resource.

Q. THE ETO CONSTRUCTION QUOTES ARE FROM 2005 AND 2008. PLEASE EXPLAIN HOW YOU USED QUOTES FROM THOSE YEARS TO COMPARE TO BLUNDELL, WHICH WAS PUT INTO SERVICE IN 2007.

A. As shown on Exhibit Staff/102, Garcia/2, I determined the weighted average per kW for ETO project quotes in 2005 and 2008. The weighted average costs increased from $1,450 to $2,519 or 73.7 percent from 2005 to 2008. To derive the weighted average costs for 2006 and 2007, I calculated the compound average growth rate between 2005 and 2008 to reach an assumed average rate of growth of 20.2 percent.

Q. HOW DO THE CAPITAL COSTS ASSOCIATED WITH BLUNDELL COMPARE TO THE ETO COST QUOTES MENTIONED ABOVE?

A. As shown on Exhibit Staff/102, Garcia/3, the Blundell capital cost of $2112 per kW is 100.8% of the ETO 2007 weighted average cost quotes.

Q. DO YOU FIND THE CAPITAL COSTS FOR BLUNDELL TO BE REASONABLE?

A. Yes.

Q. PLEASE EXPLAIN.

A. I considered the following two factors in my analysis: (1) the capital costs compared to other cogeneration facilities; and (2) the capital costs compared to the wind resources included in this filing. As stated previously, the cost for Blundell on a kW basis compares favorably with construction quotes the ETO received for proposed cogeneration during the same period. To compare the capital costs of Blundell with the capital costs of the wind resources, I calculated the cost per kW for Blundell and compared it to the average cost per kW for the wind resources included in the RAC that went into service during the same year. The cost per kW for Blundell was $2,112. The cost for the two wind resources Marengo and Marengo II were $1,753 and $1,954 respectively. Given that Blundell's capital costs per kW are close to the derived ETO cost quotes mentioned above, the costs seem reasonable. Further, while the costs for Blundell are higher than for these two wind resources, it is important to note that the average available capacity for the Blundell resource, as reported by PacifiCorp, is more than 90 percent compared to an average available capacity for the wind resources of 32 and 30 percent. Blundell's significantly higher average available capacity, when compared to the RAC wind resources, means that ratepayers are getting a higher return for the investment.

<u>Review of Operating and Maintenance Costs</u>

Q. DO YOU PROPOSE AN ADJUSTMENT TO THE O&M COSTS IN THE RAC?

A. Yes. My proposed adjustment reduces O&M costs based on an analysis of the O&M cost per kW of nameplate capacity for each resource.

Q. PLEASE EXPLAIN.

A. As shown in Exhibit Staff/102, Garcia/3, line 2, I first recalculated the Goodnoe Hills O&M total to add back the annual amount of the ETO funding that PacifiCorp excluded from the filed amount, to arrive at the actual annual O&M costs. Then for all of the resources, I calculated the cost per kW and, where necessary, adjusted the costs for each resource to reflect the O&M costs for

Leaning Juniper. Last, I added back in the annual amount of the ETO funding for Goodnoe Hills to illustrate the total O&M available to the Company for this resource.

Q. WHY DID YOU ADJUST THE LEVEL OF O&M COSTS TO REFLECT THE COSTS FOR LEANING JUNIPER?

A. PacifiCorp provided actual O&M costs for 12 months ending December 31, 2007 for the Leaning Juniper wind resource that went into service in September 2006. That is the only resource for which actual costs are available. Therefore, I recommend the Commission find that the Leaning Juniper cost per kW for 2009 represents a reasonable level for the Company's wind resources in this RAC.

Q. WHY DO YOU PROPOSE TO LOWER O&M COSTS FOR RESOURCES PUT INTO SERVICE IN LATER YEARS?

A. Although it may seem counterintuitive to propose level O&M costs for later resources when the capital costs associated with procurement and installation of those resources is annually rising at a significant rate, industry data[5] reflects a strong trend of annual O&M decreases. Based on the data, it appears that the Commission would have a foundation to reduce O&M costs on an annual basis as resources are put into service. For example, O&M costs for resources put into service in 2007 would be reduced 10 to 15 percent from the level of O&M approved for the Leaning Juniper 2006 resource, and O&M costs for 2008 resources would be reduced 10 to 15 % from 2007 costs. Staff is not

[5] Data from the U.S. Department of Energy Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends from Lawrence Berkeley National Laboratory (Years 2007 and 2008.)

proposing an adjustment of that magnitude in this RAC in an effort to make a reasonable accommodation for the fact that the majority of the O&M costs associated with the RAC resources are forecasts and there is no certainty of what the final costs will be. However, Staff does recommend that the Commission order PacifiCorp to complete a 3rd party audit of actual costs (including the prudence of those costs) to be used as a basis for O&M costs in each future RAC filing; and that O&M amounts in this case not be used as the basis for these costs when resources in this RAC are added to rate base in a general rate case. An adjustment of O&M costs to the level of those for Leaning Juniper is a reasonable compromise for purposes of this RAC filing.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 200
WITNESS: Deborah Garcia

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

July 23, 2008

WITNESS QUALIFICATIONS STATEMENT

NAME: DEBORAH A. GARCIA

EMPLOYER: PUBLIC UTILITY COMMISSION OF OREGON

TITLE: SENIOR REVENUE REQUIREMENT ANALYST

ADDRESS: 550 CAPITOL ST NE SUITE 215, SALEM, OREGON 97301-2551

EDUCATION:

- Western Utility Rate School, San Diego, California. (2002)
- The Center For Public Utilities at New Mexico University and the National Association of Regulatory Commissioners' Annual Regulatory Studies Program. (2000)
- National Association of Regulatory Utility Commissioners' Annual Regulatory Studies Program at Michigan State University. (2000)
- Certificate in Mediation Training (1994)
- College-level coursework in financial accounting, business law, business management, and economics.

WORK EXPERIENCE:

- Sr Revenue Requirement Analyst --Public Utility Commission of Oregon Lead accounting witness for revenue requirement in various proceedings. (2007 - present)
- Utility Analyst -- Public Utility Commission of Oregon Focus on utility policies, natural gas purchased gas adjustment issues, utility territory allocation issues, consumer issues, tariff review, promotional concessions, rate case review & witness, and rulemakings. (2002 - 2007)
- Research Analyst -- Public Utility Commission of Oregon Focus on SB 1149 implementation, rulemaking, various utility and electric service supplier policies, including certification of electric service suppliers, tariff review, rate case review & witness. (2000 -2002)
- Compliance Specialist -- Public Utility Commission of Oregon--Handled consumer complaints, liaison between the public, regulated utilities and various Commission staff, reviewed proposed tariffs, administrative rules, and policies with an emphasis on potential impact to consumers. Identified trends, services, and policies where no statute, rule or precedent applied and recommended appropriate action. (1992 - 2000)

CASE: UE 200
WITNESS: Deborah Garcia

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 102

Exhibits In Support Of Reply Testimony

July 23, 2008

Capital Costs -- Wind Resources

1	Project	Leaning Juniper	Marengo	Goodnoe Hills	Marengo II	Glenrock	Seven Mile Hill	Rolling Hills	Project Avg. Totals
2	In-service date	Sept. '06	Aug. '07	June '08	Aug. '07	Dec. '08	Dec. '08	Dec. '08	
3	Resource Capital Costs	$175,714,195	$246,087,156	$196,642,063	$135,784,147	$210,292,077	$201,359,265	$206,460,230	$1,372,339,133
4	No. of Turbines	67	78	47	39	66	66	66	429
5	MW per turbine	1.5	1.8	2	1.8	1.5	1.5	1.5	1.6
6	Total MW	100.5	140.4	94	70.2	99	99	99	675.7
7	Construction cost per turbine	$2,622,600	$3,154,964	$4,183,874	$3,481,645	$3,186,244	$3,050,898	$3,128,185	$3,198,926
8	Cost per MW	$1,748,400	$1,752,758	$2,091,937	$1,934,247	$2,124,162	$2,033,932	$2,085,457	$2,030,989
9	Cost per kW	$1,748	$1,753	$2,092	$1,934	$2,124	$2,034	$2,085	$2,031
10	Percent of U.S. Wtd. Avg. (line 9/ line 13, 14, or 15)	111.4%	102.5%	109.0%	100.7%	110.6%	105.9%	108.6%	N/A
11	Percent of U.S. High (line 9/ line13, 14, or 15)	78.1%	67.4%	71.8%	74.4%	72.9%	69.8%	71.6%	N/A

	US Wind Resource Capital Costs per kW				
12	Year	Low	High	Weighted Average	% increase
13	2006	$1,150	$2,240	$1,570	
14	2007	$1,240	$2,600	$1,710	8.9%
15	2008 estimated	$1,389	$2,912	$1,920	12.3%

Capital Costs -- Blundell Bottoming Cycle

1	In-service date	Dec. '07
2	Resource Capital Costs	$23,237,159
3	Total MW	11
4	Construction Cost per MW	$2,112,469
5	Total kW	11,000
6	Cost per kW	$2,112
7	Percent of ETO 2007 avg cogeneration	100.8%

	ETO Cogeneration Capital Cost Quotes per kW				
		Low	High	Weighted Average	% increase 2005 -2008
8	2005	1350	2400	$1,450	N/A
9	2006*****	N/A	N/A	$1,743	20.2%
10	2007*****	N/A	N/A	$2,095	20.2%
11	2008	1823	4132	$2,519	20.2%
	*Derived weighted avgs for 2006 & 2007 assume equal annual increases from 2005 to 2008				

Operations & Maintenance --Staff-proposed adjustment detail

		Wind							Geothermal	Totals
		Leaning Juniper	Marengo	Goodnoe Hills	Marengo II	Glenrock	Seven Mile Hill	Rolling Hills	Blundell	
1	2009 O&M Total	$3,351,019	$4,866,477	$3,195,887	$2,321,109	$4,395,966	$3,551,906	$3,862,750	$540,000	$26,085,114
2	ETO funding 12 months ($4,500,000/23*12) See note below	$0	$0	$2,347,826	$0	$0	$0	$0	$0	$2,347,826
3	O&M Adjusted to include ETO funding	$3,351,019	$4,866,477	$5,543,713	$2,321,109	$4,395,966	$3,551,906	$3,862,750	$540,000	$28,432,940
4	Total MW	100.5	140.4	94	70.2	99	99	99	11	713.1
5	Total kW	100,500	140,400	94,000	70,200	99,000	99,000	99,000	11,000	713,100
6	2009 O&M per kW	$33	$35	$59	$33	$44	$36	$39	$49	
7	Staff-proposed adj per kW	0	$1	$26	$0	$11	$3	$6	0	
8	Staff-proposed total adj.	$0	$185,053	$2,409,427	$0	$1,094,962	$250,902	$561,746	0	$4,502,091
9	Staff-proposed total	$3,351,019	$4,681,424	$786,460	$2,321,109	$3,301,004	$3,301,004	$3,301,004	$540,000	$21,583,023
10	Actual O&M w/ ETO funding added back	$3,351,019	$4,681,424	$3,134,286	$2,321,109	$3,301,004	$3,301,004	$3,301,004	$540,000	$23,930,849

Note: ETO funding per OPUC Data Response #25

Revenue Requirement -- Staff-Proposed Adjustments and Totals

		UE 200 Totals				Staff-Proposed Adjustments				Staff-Proposed Totals			
		Total	Factor	Factor %	OR Allocated	Total	Factor	Factor %	OR Allocated	Total	Factor	Factor %	OR Allocated
1	Electric Plant In Service	1,395,576,291	SG	26.4114%	368,591,655	(58,964,043)	SG	26.4114%	(15,573,247)	1,336,612,248	SG	26.4114%	353,018,408
2	Depreciation Reserve	(65,977,176)	SG	26.4114%	(17,425,516)	1,277,554	SG	26.4114%	337,420	(64,699,622)	SG	26.4114%	(17,088,095)
3	Accumulated DIT Balance	(219,091,708)	SG	26.4114%	(57,865,253)	7,571,035	SG	26.4114%	1,999,619	(211,520,673)	SG	26.4114%	(55,865,635)
4	Net Rate Base	1,110,507,407			293,300,886	(50,115,453)			(13,236,208)	1,060,391,954			280,064,678
5		11.26%			11.26%	11.26%			11.26%	11.26%			11.26%
6	Pre-Tax Return on Rate Base	125,004,047			33,015,356	(5,641,236)			(1,489,931)	119,362,811			31,525,425
7	Operation & Maintenance	26,085,114	SG	26.4114%	6,889,452	(4,502,090)	SG	26.4114%	(1,189,066)	21,583,024	SG	26.4114%	5,700,385
8	Depreciation	55,623,444	SG	26.4114%	14,690,947	(2,358,562)	SG	26.4114%	(622,930)	53,264,883	SG	26.4114%	14,068,017
9	Property Taxes	8,822,023	GPS	28.4419%	2,509,155	(437,750)	GPS	28.4419%	(124,505)	8,384,273	GPS	28.4419%	2,384,650
10	Federal Renewable Energy Tax Credit	(71,966,781)	SG	26.4114%	(19,007,456)		SG	26.4114%	0	(71,966,781)	SG	26.4114%	(19,007,456)
11	Oregon/Utah State Energy Tax Credits	(846,055)	SG	26.4114%	(223,455)		SG	26.4114%	0	(846,055)	SG	26.4114%	(223,455)
12	Rev. Reqt. Before Franchise Tax & Bad Debt	142,721,792			37,873,998	(12,939,638)			(3,426,432)	129,782,153			34,447,566
13	Franchise Taxes	3,442,678			913,582	(312,125)			(82,651)	3,130,554			830,930
14	Bad Debt Expense	958,535			254,366	(86,904)			(23,012)	871,631			231,354
15	Total Revenue Requirement	147,123,005			39,041,946	(13,338,667)			(3,532,095)	133,784,338			35,509,850

		%'s from UE 179	Bumped up to Rev. Req. %
	Franchise Tax and Bad Debt Percentage from UE 179		
16	Franchise Tax (Exhibit PPL/901, Page 1.2)	2.340%	2.412%
17	Bad Debt Percentage (Exhibit PPL/901, Page 1.2)	0.652%	0.672%

Revenue Requirement -- Staff-Proposed Adjustment Detail

		Glenrock Capital Adj. S-1	Rolling Hills Capital Adj. S-2	O&M Adj. S-3	Total Staff-Proposed Adj.
1	Electric Plant In Service	(14,225,508)	(44,738,535)		(58,964,043)
2	Depreciation Reserve	308,219	969,335		1,277,554
3	Accumulated DIT Balance	1,826,568	5,744,467		7,571,035
4	Net Rate Base	(12,090,721)	(38,024,733)		(50,115,453)
5		11.26%	11.26%	11.26%	11.26%
6	Pre-Tax Return on Rate Base	(1,360,990)	(4,280,247)		(5,641,236)
7	Operation & Maintenance			(4,502,090)	(4,502,090)
8	Depreciation	(569,020)	(1,789,541)		(2,358,562)
9	Property Taxes	(105,610)	(332,140)		(437,750)
10	Federal Renewable Energy Tax Credit				
11	Oregon/Utah State Energy Tax Credits				
12	Rev. Reqt. Before Franchise Tax & Bad Debt	(2,035,620)	(6,401,928)	(4,502,090)	(12,939,638)
13	Franchise Taxes	(49,102)	(154,425)	(108,598)	(312,125)
14	Bad Debt Expense	(13,671)	(42,996)	(30,237)	(86,904)
15	Total Revenue Requirement	(2,098,394)	(6,599,349)	(4,640,924)	(13,338,667)

CASE: UE 200
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Reply Testimony

July 23, 2008

PARTS OF STAFF EXHIBIT 200

ARE CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 08-190. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 200 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Lisa Schwartz. I am a lead worker/senior analyst employed by the Public Utility Commission of Oregon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Staff Exhibit 201.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide staff's recommendation on whether the renewable resources included in PacifiCorp's 2009 Renewable Adjustment Clause (RAC) are prudently acquired under the Commission's guidelines for integrated resource plans (IRPs) and competitive bidding and the Oregon Renewable Energy Act (Senate Bill 838, 2007 Session). Staff witness Brown addresses another key aspect in assessing the prudency of these acquisitions – the economic analysis used in decision-making. My testimony also addresses the appropriate capacity factors to use for the Rolling Hills and Glenrock projects. Finally, my testimony addresses whether it is appropriate for PacifiCorp to include in the RAC Update filed by December 1, 2008, additional renewable resources not included in the original filing.

Q. DID YOU PREPARE EXHIBITS?

A. Yes. Staff Exhibit 202 is PacifiCorp's responses to selected data requests. Staff Exhibit 203 is selected pages from PacifiCorp's renewable resources update to the Commission at the June 10, 2008, regular public meeting.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

Issue 1, IRP acknowledgment of renewable resources

Issue 2, Competitive bidding

Issue 3, PacifiCorp's renewable portfolio standard (RPS) obligations

Issue 4, Resources not included in the April 1st filing

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend the Commission find the resources in the RAC filing consistent with PacifiCorp's 2004 and 2007 IRPs as acknowledged by the Commission and PacifiCorp's future obligations under the Oregon Renewable Energy Act. However, I recommend the Commission find PacifiCorp's acquisition of the Rolling Hills project inconsistent with the competitive bidding guidelines established in Order No. 06-446 and therefore imprudently acquired. I also recommend the Commission use a [redacted] capacity factor for the Glenrock project. Staff proposes alternative adjustments for these items for the Commission's consideration in Docket Nos. UE 199 and UE 200. In addition, I recommend the Commission not allow PacifiCorp to include in any RAC Update resources the Company did not include in its April 1st filing.

ISSUE 1, IRP ACKNOWLEDGMENT OF RENEWABLE RESOURCES

Q. PLEASE EXPLAIN WHAT COMMISSION ACKNOWLEDGMENT MEANS IN INTEGRATED RESOURCE PLANNING.

A. Acknowledgment simply means the resource plan seems reasonable at the time. In order for the Commission to make that determination, the utility must follow the resource planning guidelines set out in Order No. 07-002, provide analysis demonstrating the selected portfolio represents the best combination of cost and risk for ratepayers and demonstrate the proposed action plan is reasonable.

Q. IS ACKNOWLEDGMENT A PRUDENCE DETERMINATION?

A. No. Decisions on cost recovery for resources can only be made in a rate proceeding. However, consistency of resource investments with acknowledged resource plans is among the factors the Commission considers in determining prudence. Consistency may be evidence in support of favorable ratemaking treatment, but it is not a guarantee. Conversely, the utility must justify any action that is inconsistent with an acknowledged plan in order to receive favorable ratemaking treatment.

Q. DID THE COMMISSION ACKNOWLEDGE SPECIFIC RESOURCES IN PACIFICORP'S RECENT RESOURCE PLANS?

A. No. The Commission prefers to acknowledge general, or "proxy," resources in the planning process, leaving to the procurement process the selection of specific resources.

Q. PLEASE DESCRIBE THE RENEWABLE RESOURCES THE COMMISSION HAS ACKNOWLEDGED, STARTING WITH PACIFICORP'S 2003 RESOURCE PLAN.

A. The Commission acknowledged 1,400 megawatts (MW) of renewable resources by 2011 in PacifiCorp's 2003 resource plan with the following planned build pattern.

In the Western control area:

- 100 MW - 2006
- 200 MW - 2008
- 200 MW - 2010

In the Eastern control area:

- 200 MW - 2007
- 200 MW - 2009
- 200 MW - 2011

Under the acknowledged plan, the Company agreed to move up acquisition dates if economic to do so.

Q. WHAT LEVEL OF RENEWABLE RESOURCES DID THE COMMISSION ACKNOWLEDGE IN THE NEXT RESOURCE PLAN, IN 2004?

A. The Commission reaffirmed its acknowledgment of 1,400 MW of renewable resources with the Company's modified planning horizon through 2015. The Company agreed to refine targets by testing cost and risk metrics and further refining its method for assessing wind's capacity contribution.

Q. WHAT DID THE COMPANY'S ANALYSIS OF RENEWABLE RESOURCES DEMONSTRATE IN THE MOST RECENT PLAN?

A. PacifiCorp's 2007 resource plan tested various levels of proxy wind resources on the east and west sides of its system. PacifiCorp determined that on a risk-adjusted least-cost basis, the Company should acquire 2,000 MW of renewable resources by 2013, including 400 MW expected to be on-line by the end of 2007. The Company planned to acquire renewable resources at a rate of 200 MW per year, thereby meeting its previous target of 1,400 MW by 2010 — several years ahead of schedule. The Commission acknowledged this item.

Q. HOW DO THESE ACKNOWLEDGED AMOUNTS OF RENEWABLE RESOURCES COMPARE TO THE LEVELS IN THE 2009 RAC FILING?

A. By year-end 2007, PacifiCorp had acquired about 600 MW of renewable resources[1] toward its 1,400 MW target. The RAC filing includes 713 MW of renewable resources. Excluding projects on-line by 2007 (Blundell, Leaning Juniper and Marengo), the RAC filing includes about another 600 MW of capacity toward the target. This level of acquisitions is in line with PacifiCorp's acknowledged 2007 IRP, leaving roughly another 200 MW to acquire by 2010.

Q. WHAT COSTS DID PACIFICORP ESTIMATE FOR WIND RESOURCES IN ITS 2007 IRP?

A. The Company estimated the capital cost of a 50 MW wind plant in Oregon or Idaho with a 2008 on-line date at $1,729 per kilowatt (kW). The company estimated the capital cost of a 50 MW Wyoming wind plant at $2,011 per kW. Fixed operation and maintenance (O&M) costs added another $29.78 per kW. After accounting for other fixed costs, proxy site capacity factors and tax

[1] Not all of these resources are eligible for the Oregon RPS.

credits, the Company estimated the total resource cost at about 55 mills per kWh for wind plants in Oregon and southwest Wyoming and about 51 mills per kWh for a wind plant in Idaho.[2]

Q. HOW DO THESE PLANNING ESTIMATES COMPARE TO THE COSTS OF THE RENEWABLE RESOURCES IN THE COMPANY'S RAC FILING?

A. Staff witness Garcia summarizes the cost of the resources in Staff Exhibit 102. Her testimony shows that actual costs for wind resources with a 2008 in-service date are higher than PacifiCorp assumed in its 2007 IRP. PacifiCorp states that the market for equipment, labor and services for renewable energy projects is not in balance on a supply and demand basis. *See* Staff's Opening Comments in Docket UM 1368 at 14-15.[3] Further, as I explain later, the Company must meet its obligations under the Oregon Renewable Energy Act, subject to a cost off-ramp.

[2] These figures are from Tables 5.1 to 5.4 in PacifiCorp's 2007 IRP, and all costs are in 2006 dollars.
[3] Pursuant to OAR 860-014-0050(1)(e), staff asks the Commission and Administrative Law Judge to take official notice of its opening comments at 14-15 filed in Docket No. UM 1368.

ISSUE 2, COMPETITIVE BIDDING

Q. DID PACIFICORP ACQUIRE ALL OF THE RESOURCES IN THE FILING THROUGH A COMPETITIVE BIDDING PROCESS?

A. No. PacifiCorp acquired only the Leaning Juniper and Marengo projects through a competitive bidding process. Further, PacifiCorp owns all resources in the filing; none was acquired through a power purchase agreement.

Q. DID PACIFICORP'S COMMITMENTS UNDER THE MIDAMERICAN ENERGY HOLDING COMPANY (MEHC) ACQUISITION AFFECT THE ACQUISITION PROCESS FOR RENEWABLE RESOURCES?

A. Yes. In Docket UM 1209, MEHC agreed to add at least 100 MW of wind resources within one year of the close of the transaction and up to 400 MW by year-end 2007, inclusive of the initial 100 MW commitment. MEHC also agreed to file a plan with the Commission to achieve its 1,400 MW goal and evaluate the cost-effectiveness of increasing generation from the Blundell geothermal plant. The Commission adopted a stipulation including these commitments in February 2006. The 400 MW by 2007 renewable resources target was particularly aggressive given the circumstances: the federal production tax credit was set to expire in 2007, increasing demand for wind turbines, project sites and labor.

Q. PLEASE EXPLAIN THE COMPETITIVE PROCESS USED TO ACQUIRE THE LEANING JUNIPER AND MARENGO PROJECTS.

A. PacifiCorp acquired these projects through a Commission-approved 2006 amendment to a Request for Proposals (RFP) originally issued in February

2004 (Docket UM 1118). Under the amendment, PacifiCorp asked existing bidders to update their proposals and invited new bidders to participate. The amended RFP sought resources that could be on-line in 2006 or 2007.

Q. PLEASE SUMMARIZE THE RESULTS OF THE 2006 RFP AMENDMENT.

A. The 2006 amendment attracted 13 bidders that submitted 29 bids totaling 2,107 MW.[4] Bidders offered a mix of power purchase agreements, turnkey and site offers. PacifiCorp short-listed eight bids and selected the Leaning Juniper and Marengo projects from that list. *See* PacifiCorp's Summary Report on RFP 2003-B, filed May 15, 2007, and revised June 6, 2007 (Docket No. UM 1118).

Q. DID AN INDEPENDENT EVALUATOR OVERSEE THE PROCESS?

A. No. The Commission's competitive bidding guidelines in effect at that time did not require an independent evaluator.

Q. HOW DID PACIFICORP ACQUIRE THE BLUNDELL EXPANSION?

A. PacifiCorp owns the Blundell geothermal plant. The Company hired a third party to study the potential addition of a "bottoming cycle" and hired a firm for engineering, procurement and construction services to add the bottoming cycle to drive a second turbine generator. The project increased capacity by 11 MW while raising plant efficiency and reducing unit production costs. *See* PPL/200, Tallman/31.

Q. HOW DID PACIFICORP ACQUIRE THE REMAINING PROJECTS?

A. PacifiCorp acquired the Goodnoe Hills project from enXco Development Corp. PacifiCorp simply states, "The decision to acquire Goodnoe Hills was informed

[4] Bidders were allowed to submit more than one bid per project.

by the then-current market for similarly situated assets." PacifiCorp developed the Seven Mile Hill and Glenrock/Rolling Hills projects on its own. The Company acquired land leases for the Seven Mile Hill project from Eurus Wind Power Development, LLC. PacifiCorp owns the Glenrock/Rolling Hills site, portions of which are on the reclaimed Dave Johnston coal mine.

Q. HOW DID THE COMPANY MAKE THE DECISION TO MOVE FORWARD WITH THESE WIND PROJECTS?

A. For Goodnoe Hills, subject area experts performed due diligence on various aspects of the asset and wrote an internal memo reporting their findings. The due diligence process for the Seven Mile Hill, Rolling Hills and Glenrock projects was part of the project management plans implemented by the Company.

Company executives made the decision to acquire each project after reviewing a detailed overview, the contract support and counterparty guarantees for executing the project, project risks, the IRP-established need for the project, and a financial assessment and justification. *See* PPL/200; Tallman/19, 23-24, 26-27 and 29.

Q. HOW DOES THE COMMISSION KNOW WHETHER THESE WIND PROJECTS WERE THE BEST DEAL FOR RATEPAYERS?

A. Without a competitive bidding process, there is no price discovery to demonstrate these projects represent the best opportunities to acquire renewable resources on behalf of customers.

Q. WHAT RATIONALE DOES PACIFICORP PROVIDE FOR ACQUIRING THESE PROJECTS OUTSIDE OF A COMPETITIVE BIDDING PROCESS?

A. Misapplying the Commission's direction in Order No. 07-018 at 6 that PacifiCorp consider in-house conservation and demand response programs instead of relying solely on RFPs to acquire these resources, the Company asserts it used acquisition processes other than competitive solicitations as appropriate to acquire renewable resources. PacifiCorp further states that it "…considered factors such as market changes, the rise in major equipment and construction costs, and the reasonable expectation that a resource could be placed in-service before the then-current expiration of the Federal production tax credit." *See* PacifiCorp's response to Staff Data Request No. 1, Staff Exhibit 202 at 1.

According to PacifiCorp, the Company was concerned it would not be able to take advantage of the tax credit, set to expire year-end 2008, if it conducted a competitive bidding process under Utah's then-current procurement laws and the Oregon Commission's established competitive bidding process. *See* PacifiCorp's response to Staff Data Request No. 19, Staff Exhibit 202 at 7.

Q. BUT ISN'T THE COMPANY CONTINUING TO ACQUIRE RENEWABLE RESOURCES OUTSIDE A COMPETITIVE SOLICITATION WITH IN-SERVICE DATES AFTER THE TAX CREDIT SUNSETS?

A. Yes. PacifiCorp is developing three wind projects on a single site with on-line dates beyond 2008. The first two projects are the 99 MW High Plains facility expected to be in service in 2009 and the 88.5 McFadden Ridge project expected to be in service in 2010. *See* Staff Exhibit 203. PacifiCorp has not yet defined the third project at the site. The Company submitted a single permit application to the Wyoming Industrial Siting Council for all three projects. PacifiCorp plans to own, construct and operate the facilities.[5]

Q. DOES PACIFICORP EXPECT THE TAX CREDIT WILL BE EXTENDED?

A. It appears so. In addition to developing these three additional wind projects that won't be on-line by the tax credit sunset date, PacifiCorp states the following in response to a recommendation that the Utah Public Service Commission impute the value of the federal production tax credit (PTC) if the wind projects included in the Utah proceeding do not come on line by year-end 2008:

> Q. Is it possible PTCs will be applicable to wind turbines that are placed in service during 2009?
> A. Yes; both the House and Senate have passed versions of legislation that would extend PTCs to wind turbines placed in service during 2009.
>
> *See* Rebuttal Testimony of Mark R. Tallman at 14, Public Service Commission of Utah Docket No. 07-035-93.

Q. DID PACIFICORP HAVE TIME FOR A COMPETITIVE SOLICITATION TO UNCOVER THE MOST BENEFICIAL WIND PROJECTS, WITHOUT RISKING THE TAX CREDIT?

A. Under Oregon's process, yes. The Commission has previously approved RFPs within several months of filing. For example, the Commission approved the 2006 amendment to PacifiCorp's renewable resources RFP about three weeks

[5] Permit application available at: http://deq.state.wy.us/out/downloads/High_Plains_ISA_All_Sections_(070708).pdf.

after filing[6] and recently approved the Company's 2008 "all source" RFP three months after filing. In addition, PacifiCorp sets tight deadlines for bids. For example, the Company issued its amended renewable resources RFP on March 21, 2006, and required bids on April 12, 2006. The recently approved 2008 all-source RFP requires bids 75 days after RFP issuance. *See* Docket Nos. UM 1118 and UM 1360. Even assuming PacifiCorp would not have issued another renewable resources RFP in 2006, the Company had all of 2007 to undertake a competitive solicitation for resources with a 2008 in-service date.

Q. WHAT ABOUT RFP REQUIREMENTS IN OTHER STATES?

A. To the extent that, prior to passage of Utah SB 202,[7] the Company faced constraints in Utah that hampered timely acquisition of renewable resources, Oregon customers should not suffer the consequences. PacifiCorp bears the risk of regulation in other states.

Q. WHAT IS YOUR RELATED RECOMMENDATION FOR THE ROLLING HILLS PROJECT?

A. I recommend the Commission find PacifiCorp's acquisition of the Rolling Hills plant inconsistent with the competitive bidding guidelines established in Order No. 06-446 and therefore imprudently acquired. As I explained in my UE 199 direct testimony, the estimated capacity factor of the Rolling Hills project (31

[6] The approval process for the original RFP took 3-1/2 months in order to address issues related to the risk mitigation benefits of renewable resources and potential debt imputation for power purchase agreements. The Commission has since addressed these issues in Docket No. UM 1182.
[7] Utah Senate Bill 202, the Energy Resource and Carbon Emission Reduction Initiative, went into effect March 18, 2008. Section 14 provides an exemption from many of Utah's competitive bidding requirements, including RFP approval, for resources up to 300 MW. *See* http://le.utah.gov/~2008/htmdoc/sbillhtm/SB0202S01.htm.

percent) is significantly lower than other Wyoming wind projects, which have capacity factors in the high 30s to low 40s. If PacifiCorp had issued an RFP for renewable resources, the Company likely would have acquired a resource with a far higher capacity factor. The Commission requires that Major Resources — those 100 MW or greater and for a term of five years or longer — be acquired through a Commission-approved competitive bidding process unless the Company requests a waiver. *See* Order No. 06-446 at 3. While PacifiCorp is attempting to distinguish the Rolling Hills and Glenrock projects as separate resources, they are both on the same site, both to be completed this year and both 99 MW. PacifiCorp did not acquire the Rolling Hills project through the Commission-established competitive bidding process or request a waiver. Further, the Company is adding another 39 MW of capacity at the Glenrock/ Rolling Hills site to be in-service by year-end. *See* Staff Exhibits 200, 202 and 203 in Docket UE 199.[8]

Q. WHAT IS THE IMPACT OF CAPACITY FACTOR ON ELECTRICITY COSTS?

A. Capacity factor is the most direct measure of a wind project's productivity and, therefore, its economic benefit. A small difference in average wind speed among sites translates into a large difference in the amount of electricity produced and, therefore, a large difference in the cost of the electricity generated. The impact is evident when comparing PacifiCorp's estimated annual output (in megawatt-hours) and levelized resource cost (in dollars per

[8] Pursuant to OAR 860-014-0050(1)(e), staff asks the Commission and Administrative Law Judge to take official notice of its direct testimony Staff/200, Staff/202 and Staff/203 filed in Docket No. UE 199.

megawatt-hour) for the three 99 MW Wyoming wind plants included in the RAC filing — Seven Mile Hill, Rolling Hills and Glenrock. *See* PacifiCorp's response to Staff Data Request 33, Attachment 33-2, Staff Exhibit 202 at 8-11.

Q. WHAT OTHER EVIDENCE DO YOU HAVE REGARDING THE PRUDENCE OF ACQUIRING THE ROLLING HILLS PROJECT?

A. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Q. DID PACIFICORP ANALYZE WHETHER A BETTER WYOMING SITE WOULD HAVE BEEN AVAILABLE?

A. Staff is not aware of any analysis PacifiCorp performed to determine whether another Wyoming site would have provided a greater benefit to customers than the Rolling Hills site, with its relatively low capacity factor for that state. PacifiCorp originally planned to develop another site in another state and used the turbines instead for Rolling Hills. PacifiCorp states the following as the basis for its decision to proceed with the Rolling Hills project: [redacted] *See* PacifiCorp's response to ICNU Data Request No. 1.1-7, Staff Exhibit 202 at 50.

Q. ARE THERE SITE ADVANTAGES THAT OUTWEIGH THE LOW CAPACITY FACTOR OF THE ROLLING HILLS PROJECT?

A. While there are advantages to owning a site — no land leases or royalty payments, for example — the quality of the wind resource at the site is so important that it can easily overwhelm such advantages. Further, benefits resulting from expansion at an existing project site, such as making use of existing roads and transmission facilities, also are present at third-party owned sites, where expansion of existing projects is routine.

Q. DID STAFF RECOMMEND A RELATED ADJUSTMENT FOR THE ROLLING HILLS PROJECT IN UE 199?

A. Yes. Staff recommended an adjustment in PacifiCorp's Transition Adjustment Mechanism (TAM) to protect ratepayers from this imprudent acquisition. *See* Staff/100, Brown/13-14 and Staff/200, Staff/202 and Staff/203 in Docket UE 199.[9] Staff's proposed adjustment in that proceeding is designed to capture the benefits ratepayers would receive if PacifiCorp had selected an appropriate wind site by testing self-build options against market bids, as the Company is required to do for Major Resources under Order No. 06-446.

Q. DID STAFF CONSIDER AN ALTERNATIVE ADJUSTMENT IN UE 200?

A. Yes. As an alternative to the adjustment staff recommends for the TAM in UE 199, the Commission could adjust the revenue requirement for the RAC to achieve the same effect. Staff witness Brown provides the alternative adjustment for the Commission's consideration in Staff Exhibit 300.

Q. DOES ROLLING HILLS IMPACT THE GLENROCK PROJECT?

A. Yes. As I stated previously, these projects are at the same site and are in close proximity. *See* Staff/203, Schwartz/3-4, in Docket UE 199. [redacted]

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[9] Pursuant to OAR 860-014-0050(1)(e), staff asks the Commission and Administrative Law Judge to take official notice of its direct testimony Staff/100 at 13-14 filed in Docket No. UE 199. *Also see* footnote 8.

[redacted] *See* PacifiCorp's response to ICNU Data Request No. 1.1-6, Staff Exhibit 202 at 32. [redacted] *See* PacifiCorp's response to ICNU Data Request 10.1-9, Staff Exhibit 202 at 57.

Q. WHAT IS YOUR RECOMMENDATION ON WHAT CAPACITY FACTOR SHOULD BE USED FOR THE GLENROCK PROJECT?

A. Consistent with the third-party analysis of the wind resource for the Glenrock project, and in consideration of the imprudent acquisition of the Rolling Hills project, staff recommends the Commission make an adjustment to reflect a [redacted] capacity factor for the Glenrock project in this proceeding or, alternatively, in Docket UE 199. Staff witness Brown provides the adjustment alternatives in Staff Exhibit 300.

Q. DID STAFF PROVIDE AN ALTERNATIVE ADJUSTMENT FOR THE GLENROCK PROJECT IN DOCKET UE 199?

A. No, staff did not raise this issue in direct testimony in UE 199. However, staff intends to file a motion in UE 199 that addresses the relationship between Docket Nos. UE 199 and UE 200 regarding renewable resources. Staff intends to include in its UE 199 surrebuttal testimony an adjustment to the TAM as an alternative to making the adjustment recommended in UE 200 for the Glenrock project.

ISSUE 3, PACIFICORP'S RPS OBLIGATIONS

Q. PLEASE EXPLAIN PACIFICORP'S OBLIGATIONS UNDER THE OREGON RENEWABLE ENERGY ACT.

A. The Company must meet 25 percent of its energy needs by 2025 with qualifying renewable resources. The requirement for the first compliance year, 2011, is 5 percent. The requirement increases rapidly to 15 percent in 2015 and 20 percent in 2020. *See* ORS 469A.052.

Q. HOW DOES THE ACT AFFECT COMMISSION RATEMAKING DECISIONS RELATED TO RENEWABLE RESOURCES?

A. The Act imposes mandatory requirements to acquire renewable resources. However, the Commission retains its responsibility to ensure that rates reflect prudent resource decisions and prudently incurred costs. Utilities are not required to comply with the standard in a compliance year to the extent the incremental cost of compliance, the cost of unbundled renewable energy certificates (RECs), and the cost of alternative compliance payments exceed 4 percent of the utility's annual revenue requirement.[10] *See* ORS 469A.100.

Q. HOW DOES THIS COST "OFF-RAMP" AFFECT THE COMMISSION'S CONSIDERATION OF RENEWABLE RESOURCES?

A. The RAC test year, 2009, is not an RPS compliance year. However, when the Commission reviews the cost of renewable resources for RPS compliance

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[10] At its June 10, 2008, public meeting, the Commission established the methodology for determining this annual revenue requirement. The Commission has not yet defined the other components of this cost "off-ramp." Staff will propose such rules later this year in Docket AR 518.

years, it will consider the cost of all qualifying resources acquired over time and remaining in rates, including resources included in this RAC filing.

Q. WHAT OTHER PROVISIONS IN THE ACT SHOULD THE COMMISSION CONSIDER IN RATEMAKING DECISIONS?

A. Under the Act, the Commission must allow electric companies to recover in rates all prudently incurred costs associated with RPS compliance. *See* ORS 469A.120(1). The Act also required the Commission to establish a method to allow timely recovery of these costs. *See* ORS 469A.120(3). The Commission established the RAC to do so. *See* Order No. 07-572 (Docket UM 1330). In addition, the Act allows an electric company to make an alternative compliance payment instead of meeting the renewable resource target in a compliance year. *See* ORS 469A.180. All of these provisions reduce PacifiCorp's risk for cost recovery. Staff witness Brown explains the ramifications in Staff Exhibit 300.

Q. PLEASE EXPLAIN HOW THE RESOURCES IN THE RAC FILING ARE CONSISTENT WITH THE COMPANY'S FUTURE RPS OBLIGATIONS.

A. Excluding Qualifying Facilities under the Public Utility Regulatory Policies Act, where PacifiCorp may not own the RECs, as of year-end 2007 the Company had 426 MW of resources with fuel types and commercial operation dates compliant with SB 838. *See* PacifiCorp's response to Staff Data Request No. 65, Staff Exhibit 202 at 17-20. The RAC filing includes 713 MW of resources eligible for the Oregon RPS, of which an incremental 461 MW are expected to be on-line in 2008. To meet the Oregon RPS, the Company projects it will need the following levels of renewable resources system-wide, including resources already acquired:

	System-wide	Oregon's allocated share
2011	1,031 MW	263 MW
2015	3,359 MW	796 MW
2020	4,733 MW	1,070 MW
2025	6,325 MW	1,388 MW

See PacifiCorp's response to Staff Data Request No. 14, Staff Exhibit 202 at 2-6.

These figures are based on the Company's October 2007 load forecast and assuming wind resources will provide all of the remaining capacity to be acquired.[11] The system-wide figures also assume the other states in which PacifiCorp operates that do not have an RPS, or standards as aggressive as Oregon's, will pay their allocated share of the resources.[12] The resources in the RAC filing, together with earlier acquisitions, position the Company to meet its near- and mid-term Oregon RPS requirements.

Q. WILL THE RESOURCES INCLUDED IN THE RAC COUNT TOWARD FUTURE RPS COMPLIANCE?

A. Yes. In addition to meeting eligibility criteria related to resource type, on-line date and location, RECs from these resources generated on or after January 1, 2007, can be banked indefinitely toward future RPS compliance. *See* OAR

[11]Wind has a low capacity factor compared to geothermal and biomass resources. All other factors being equal, actual capacity additions to meet Oregon's RPS will be lower because the standard is energy-based, not capacity-based.
[12] Multi-state agreements addressing assignment of resources could reduce system-wide (but not Oregon) requirements for renewable resources.

330-150-0030(1)[13] and ORS 469A.140(2).

Q. DID THE COMPANY'S 2007 IRP ANALYSIS INDICATE THAT 2,000 MW OF RENEWABLE RESOURCES WERE PART OF THE BEST COST/RISK PORTFOLIO ABSENT CONSIDERATION OF THE OREGON RPS?

A. Yes. PacifiCorp filed its 2007 IRP on May 30, 2007, before SB 838 was enacted. The Company's IRP analysis showed that acquiring 2,000 MW of renewable resources by 2013 was part of the best cost/risk portfolio absent consideration of the Oregon RPS.

[13] The Oregon Department of Energy is re-noticing its RPS-related rules due to a filing error.

ISSUE 4, RESOURCES NOT INCLUDED IN THE APRIL 1ST FILING

Q. PLEASE EXPLAIN THE ISSUE.

A. PacifiCorp stated that it plans to include the 39 MW Glenrock Hills III and 19.5 MW Seven Mile Hill wind projects in its RAC Update to be filed by December 1, 2008. *See* PacifiCorp's response to Staff Data Request No. 49, Staff Exhibit 202 at 13. The Company did not include these resources in its April 1st filing.

Q. DOES STAFF AGREE THAT THE RAC UPDATE MAY BE USED TO ADD RESOURCES NOT INCLUDED IN A UTILITY'S APRIL 1ST FILING?

A. No. The purpose of the RAC update is to update "*cost elements* as described in section 6(b) of an eligible resource [which] cannot be verified by the final round of testimony in an annual RAC proceeding … to reflect then-current, prudently-incurred actual resource costs, or forecasted costs where appropriate…. If the updated costs are lower than the projected costs *in the record of the proceeding*, the update will contain sufficient information to support a reduction in the proposed RAC charges before the January 1 effective date. *If the updated costs are higher than the projected costs in the record*, *the difference will be treated in accordance with Section 6(f) below* [Deferred Accounting Under SB 838]." *See* Stipulation at 5, Order No. 07-572 (Docket UM 1330); emphasis added. It is clear that the purpose of the December 1st RAC update is not to add entirely new resources just before they are intended to go into rates on January 1st.

Q. PLEASE EXPLAIN THE TIMING IMPLICATIONS.

A. The established RAC process provides seven months for review of resources before a Commission order on November 1st. Including new resources in any filing after April 1st would not provide sufficient review time for staff and parties or give the Commission sufficient time to review the matter and issue an order.

Q. IS THE COMPANY HARMED BY EXCLUDING ADDITIONAL RESOURCES FROM THE DECEMBER 1ST RAC UPDATE?

A. No. The Commission provides for deferral of costs for eligible projects not timely submitted for RAC filings. *Id.* at 5-6.

Q. ARE RATEPAYERS HARMED BY EXCLUDING ADDITIONAL RESOURCES FROM THE RAC UPDATE?

A. No. Recovery of prudently incurred costs through deferred accounting is net of dispatch benefits. *Id.* at 6. Therefore, customers will receive the power cost benefit of these zero dispatch-cost resources through deferred accounting. Further, PacifiCorp estimates the Oregon-allocated revenue requirement in 2009 for the Glenrock III and Seven Mile Hill II projects at $2,828,662 million and $1,417,778 million respectively. *See* PacifiCorp's response to Staff Data Request No. 63, Staff Exhibit 202 at 14-16. A comparison of revenue requirements and power cost benefits of projects included in the RAC and TAM filings demonstrates revenue requirements in 2009 far outweigh the power cost benefits in that year. In addition, customers will be far better off with a reasonable review period for these projects.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 200
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualification Statement

July 23, 2008

WITNESS QUALIFICATION STATEMENT

NAME: Lisa Schwartz

EMPLOYER: Oregon Public Utility Commission

TITLE: Lead Worker/Senior Analyst, Electric and Natural Gas Division

ADDRESS: 550 Capitol Street NE #215
Salem, OR 97301-2551

EDUCATION: Master of Science, Land Resources (1982)
University of Wisconsin - Madison, Wisconsin

Bachelor of Science, Environmental Studies (1980)
George Washington University - Washington, D.C.

EXPERIENCE: I have worked at the Oregon Public Utility Commission since May 2002. I am staff lead for electric utility resource planning, competitive bidding and renewable resources. I also provide analysis and recommendations on other electricity issues including advanced metering, demand response, distributed generation and climate change. I was a policy and communications analyst at the Oregon Department of Energy for more than six years and a research assistant and assistant administrator of the Oregon State University Extension Energy Program for about nine years.

CASE: UE 200
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits In Support
Of Reply Testimony

July 23, 2008

PARTS OF STAFF EXHIBIT 202

ARE CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 08-190. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 200 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

UE-200/PacifiCorp
April 17, 2008
OPUC Data Request 1

OPUC Data Request 1

Please state which of the eight projects included in the RAC filing resulted from a PacifiCorp Request for Proposals (RFP) process. Also state how in each of the other cases the Company determined that the acquired project was the most cost-effective means of achieving its targeted renewable resource acquisitions.

Response to OPUC Data Request 1

Leaning Juniper 1, Marengo, and Marengo II resulted from RFP 2003-B (Docket UM 1118). More specifically, the development asset, turbines, and construction services for Leaning Juniper 1 resulted from RFP 2003-B. The development asset and construction services for Marengo resulted from RFP 2003-B. The Marengo bidder linked the purchase of the Marengo II development asset and a construction encumbrance to the Marengo transaction.

The decision to acquire Goodnoe Hills was informed by the then-current market for similarly situated assets.

The engineer, procure, construct services and collector substation transformer for Seven Mile Hill, Glenrock, and Rolling Hills resulted from a PacifiCorp RFP issued by the Company's procurement department. The engineer, procure, construct services and the major generation equipment supply for the Blundell Bottoming cycle project resulted from a PacifiCorp RFP issued by the Company's procurement department.

Each renewable resource included in the filing was pursued with the intent of meeting the 1400 MW acquisition target defined in the Company's preferred portfolio beginning with the 2003 Integrated Resource Plan (IRP) in Docket LC 31, as well as the 2004 IRP in Docket LC 39. In Order No. 07-018 at 6, the Oregon Commission indicated that it expected "the company to fully explore * * * renewable resources * * * at levels incremental to the amounts in the acknowledged 2004 IRP Action Plan." The Commission noted in this regard "that competitive bidding may not be the appropriate mechanism to acquire all resources that may be part of the best cost/risk portfolio." *Id.*

The Company followed the Commission's direction in working to meet its renewable resource targets, using both the competitive bidding process and other acquisition processes as appropriate. The Company considered factors such as market changes, the rise in major equipment and construction costs, and the reasonable expectation that a resource could be placed in-service before the then-current expiration of the Federal production tax credit. In each case, whether or not the competitive bidding process was used, the Company employed prudent analytical tools to determine the cost-effectiveness of the resource.

UE-200/PacifiCorp
April 17, 2008
OPUC Data Request 14

OPUC Data Request 14

Using PacifiCorp's most recent load forecast, please provide an up-to-date analysis of the Company's projected renewable resource requirements for each state, by year through 2015, under renewable portfolio standards enacted by Oregon (with RECs issued on or after January 1, 2007, qualifying for banking), Washington, California and Utah.

Response to OPUC Data Request 14

Please refer to Attachment OPUC 14 for the projected renewable resource requirements for California, Oregon, Washington and Utah, using the Company's actual loads from calendar year 2007 and the most recent load forecast (October 2007) for years 2008 and beyond. The attachment provides estimates for years 2007 through 2025.

Attachment OPUC 14

Utah and PacifiCorp Total System Retail MWH Sales Projections(1), (2)

year	Projected Utah Retail MWH Sales	Assumed Utah RPS % Targets	Estimated Utah Required Renewable MWH(5)	Projected Total System Retail MWH Sales	Projected Utah Energy Consumption Allocation Share
2007	22,352,159	0%	-	51,980,340	41.6706%
2008	22,648,466	0%	-	53,599,783	42.4346%
2009	23,235,671	0%	-	55,300,432	42.2865%
2010	23,655,214	0%	-	57,239,924	42.4737%
2011	24,176,698	0%	-	58,774,217	42.6944%
2012	**24,764,205**	**0%**	**-**	**60,031,769**	**43.2948%**
2013	25,301,811	0%	-	61,203,595	43.0227%
2014	25,841,248	0%	-	62,312,823	43.2391%
2015	**26,335,019**	**0%**	**-**	**63,458,246**	**43.6109%**
2016	26,982,405	0%	-	64,852,909	44.1965%
2017	27,519,827	0%	-	66,343,353	44.4438%
2018	28,125,925	0%	-	67,777,100	45.3687%
2019	28,657,312	0%	-	69,277,100	45.7959%
2020	**29,410,548**	**0%**	**-**	**70,908,289**	**46.7428%**
2021	30,093,015	0%	-	72,347,248	46.9020%
2022	30,727,958	0%	-	73,670,637	47.1785%
2023	31,596,933	0%	-	75,130,263	47.7192%
2024	32,450,844	0%	-	76,647,510	48.7102%
2025	**33,317,624**	**20%**	**5,686,684**	**77,898,856**	**48.7446%**

Projected Total Company Installed MWCapacity Including Capacity Value of Power Purchases(4)	17,158
% of 2025 Co. Capacity that Must be Renewable in Order To Meet 20% of Utah Load RPS Standard	25%

(1) 2007: Actual, based on 12 month period ending December 31, 2007
(2) 2008 - 2025: Load forecast, October 2007

(3) Consists geothermal resources:
Blundell (COD 1984): 26 MW
Blundell Unit 2 (COD 2007): 11 MW

(4) Based on 2007 IRP data (assumes 12% planning margin)

2016 existing resources	10,598 MW
2025 cumulative system additions	6560 MW
Total capacity with 15% wind credit	17,158 MW

(5) Assumes annual MWh savings in Utah attributed to DSM in 2022 2,294,538

(6) Assumes 58 MW of hydro electric facilities in Utah with a capacity factor of 27% (calendar year 2007)

PacifiCorp System-level RPS-Eligible Renewable Resource Amounts and Additions Required to Meet Utah Proposed RPS Standards in 2012, 2015, 2020, & 2025

	Total Company New Renewable MW	Utah's Allocated Share Renewables MW	Assumed Capacity Factor	Total Company Annual Renewables MWH Production	Utah's Share Renewables MWH
				Avg Hrs / Yr	8766
UT 2025 Allocation Share	48.7446%				
Assumed On-Line Geothermal Resource Capacity(3)	37	18	85%	275,691	134,384
Assumed On-Line Utah Hydro Electric Resource Capacity(6)	58	28	27%	137,276	66,914
Required On-line Wind to Meet UT 20% 2025 Reqt	4,279	2,086	30%	11,253,326	5,485,385
Total Company & Utah's Share 2025	4,374	2,132		11,666,293	5,686,684

Updated as of April 16, 2008

Attachment OPUC 14

Washington and PacifiCorp Total System Retail MWH Sales Projections(1), (2)

year	Projected Washington Retail MWH Sales	Assumed Washington RPS % Targets(5)	Estimated Washington Required Renewable MWH	Projected Total System Retail MWH Sales	Projected Washington Energy Consumption Allocation Share(5)
2007	4,078,370	0%	-	51,980,340	7.8339%
2008	4,128,754	0%	-	53,599,783	7.9325%
2009	4,144,071	0%	-	55,300,432	7.7634%
2010	4,168,016	0%	-	57,239,924	7.6387%
2011	4,196,540	3%	125,896	58,774,217	7.6045%
2012	**4,220,014**	**3%**	**126,600**	**60,031,769**	**7.4626%**
2013	4,240,348	3%	127,210	61,203,595	7.3623%
2014	4,277,007	3%	128,310	62,312,823	7.3051%
2015	**4,324,229**	**9%**	**389,181**	**63,458,246**	**7.2757%**
2016	4,347,854	9%	391,307	64,852,909	7.2091%
2017	4,369,328	9%	393,240	66,343,353	7.1638%
2018	4,402,078	9%	396,187	67,777,100	7.1664%
2019	4,430,050	15%	664,507	69,277,100	7.1448%
2020	**4,482,605**	**15%**	**672,391**	**70,908,289**	**7.1072%**
2021	4,531,995	15%	679,799	72,347,248	7.1348%
2022	4,582,512	15%	687,377	73,670,637	7.1295%
2023	4,646,361	15%	696,954	75,130,263	7.1290%
2024	4,705,747	15%	705,862	76,647,510	6.9822%
2025	**4,770,461**	**15%**	**715,569**	**77,898,856**	**7.1257%**

Projected Total Company Installed MWCapacity Including Capacity Value of Power Purchases (4)	17,158
% of 2025 Co. Capacity that Must be Renewable In Order To Meet 15% of Washington Load RPS Standard	22%

(1) 2007: Actual, based on 12 month period ending December 31, 2007
(2) 2008 - 2025: Load forecast, October 2007

(3) Assumes no qualifying geothermal resources located in the Pacific Northwest.

(4) Based on 2007 IRP data (assumes 12% planning margin)

2016 existing resources	10,598 MW
2025 cumulative system additions	6560 MW
Total capacity with 15% wind credit	17,158 MW

(5) Based on interpretation of compliance rulemaking, UE-06-1895.

(5) Allocation factor based on Revised Protocol.

PacifiCorp System-level RPS-Eligible Renewable Resource Amounts and Additions Required to Meet Washington Proposed RPS Standards in 2012, 2015, 2020, & 2025

	Total Company New Renewable MW	Washington's Allocated Share Renewables MW	Assumed Capacity Factor	Total Company Annual Renewables MWH Production (Avg Hrs / Yr)	Washington's Share Renewables MWH (8766)
WA 2012 Allocation Share	7.4626%				
Assumed On-Line Geothermal Resource Capacity(3)	-	-	85%	-	-
Required On-line Wind to Meet WA 3% 2012 Reqt	645	48	30%	1,696,460	126,600
Total Company & Washington's Share 2012	645	48		1,696,460	126,600
WA 2015 Allocation Share	7.2757%				
Assumed On-Line Geothermal Resource Capacity(3)	-	-	85%	-	-
Required On-line Wind to Meet WA 9% 2015 Reqt	2,034	148	30%	5,349,016	389,181
Total Company & Washington's Share 2015	2,034	148		5,349,016	389,181
WA 2020 Allocation Share	7.1072%				
Assumed On-Line Geothermal Resource Capacity(3)	-	-	85%	-	-
Required On-line Wind to Meet WA 15% 2020 Reqt	3,598	256	30%	9,460,734	672,391
Total Company & Washington's Share 2020	3,598	256		9,460,734	672,391
WA 2025 Allocation Share	7.1257%				
Assumed On-Line Geothermal Resource Capacity(3)	-	-	85%	-	-
Required On-line Wind to Meet WA 15% 2025 Reqt	3,819	272	30%	10,042,071	715,569
Total Company & Washington's Share 2025	3,819	272		10,042,071	715,569

Updated as of April 16, 2008

Attachment OPUC 14

Oregon and PacifiCorp Total System Retail MWH Sales Projections(1), (2)

year	Projected Oregon Retail MWH Sales	Assumed Oregon RPS % Targets	Estimated Oregon Required Renewable MWH	Projected Total System Retail MWH Sales	Projected Oregon Energy Consumption Allocation Share
2007	14,077,356	0%	-	51,980,340	27.4404%
2008	14,119,401	0%	-	53,599,783	26.9377%
2009	14,154,906	0%	-	55,300,432	26.4114%
2010	14,114,863	0%	-	57,239,924	25.8320%
2011	**14,100,118**	**5%**	**705,006**	**58,774,217**	**25.4985%**
2012	14,082,813	5%	704,141	60,031,769	24.7647%
2013	14,069,672	5%	703,484	61,203,595	24.4673%
2014	14,053,982	5%	702,699	62,312,823	24.1288%
2015	**14,037,974**	**15%**	**2,105,696**	**63,458,246**	**23.6979%**
2016	14,017,485	15%	2,102,623	64,852,909	23.3762%
2017	14,004,483	15%	2,100,672	66,343,353	23.3506%
2018	14,039,917	15%	2,105,988	67,777,100	23.2070%
2019	14,069,614	15%	2,110,442	69,277,100	23.0288%
2020	**14,132,775**	**20%**	**2,826,555**	**70,908,289**	**22.6123%**
2021	14,207,855	20%	2,841,571	72,347,248	22.5972%
2022	14,280,614	20%	2,856,123	73,670,637	22.6074%
2023	14,393,946	20%	2,878,789	75,130,263	22.4239%
2024	14,514,603	20%	2,902,921	76,647,510	21.9054%
2025	**14,649,657**	**25%**	**3,662,414**	**77,898,856**	**21.9471%**

Projected Total Company Installed MWCapacity Including Capacity Value of Power Purchases(4)	17,158
% of 2025 Co. Capacity that Must be Renewable in Order To Meet 25% of Oregon Load RPS Standard	37%

(1) 2007: Actual, based on 12 month period ending December 31, 2007
(2) 2008 - 2025: Load forecast, October 2007

(3) Consists of geothermal resources:
Blundell Unit 2 (COD 2007): 11 MW

(4) Based on 2007 IRP data (assumes 12% planning margin)

2016 existing resources	10,598 MW
2025 cumulative system additions	6560 MW
Total capacity with 15% wind credit	17,158 MW

PacifiCorp System-level RPS-Eligible Renewable Resource Amounts and Additions Required to Meet Oregon Proposed RPS Standards in 2011, 2015, 2020, & 2025

	Total Company New Renewable MW	Oregon's Allocated Share Renewables MW	Assumed Capacity Factor	Total Company Annual Renewables MWH Production (Avg Hrs / Yr)	Oregon's Share Renewables MWH (8766)
OR 2011 Allocation Share	25.4985%				
Assumed On-Line Geothermal Resource Capacity(3)	11	3	85%	81,962	20,899
Required On-line Wind to Meet OR 5% 2011 Reqt	1,020	260	30%	2,682,928	684,107
Total Company & Oregon's Share 2011	1,031	263		2,764,890	705,006
OR 2015 Allocation Share	23.6979%				
Assumed On-Line Geothermal Resource Capacity(3)	11	3	85%	81,962	19,423
Required On-line Wind to Meet OR 15% 2015 Reqt	3,348	793	30%	8,803,628	2,086,273
Total Company & Oregon's Share 2015	3,359	796		8,885,590	2,105,696
OR 2020 Allocation Share	22.6123%				
Assumed On-Line Geothermal Resource Capacity(3)	11	2	85%	81,962	18,533
Required On-line Wind to Meet OR 20% 2020 Reqt	4,722	1,068	30%	12,418,129	2,808,021
Total Company & Oregon's Share 2020	4,733	1,070		12,500,091	2,826,555
OR 2025 Allocation Share	21.9471%				
Assumed On-Line Geothermal Resource Capacity(3)	11	2	85%	81,962	17,988
Required On-line Wind to Meet OR 25% 2025 Reqt	6,314	1,386	30%	16,605,508	3,644,426
Total Company & Oregon's Share 2025	6,325	1,388		16,687,470	3,662,414

Attachment OPUC 14

California and PacifiCorp Total System Retail MWH Sales Projections(1), (2)

year	Projected California Retail MWH Sales	Assumed California RPS % Targets(5)	Estimated California Required Renewable MWH	Projected Total System Retail MWH Sales	Projected California Energy Consumption Allocation Share
2007	**884,865**	**17%**	**150,427**	**51,980,340**	**1.8409%**
2008	852,665	18%	153,480	53,599,783	1.6639%
2009	856,885	19%	162,808	55,300,432	1.6372%
2010	863,827	20%	172,765	57,239,924	1.6171%
2011	**870,249**	**20%**	**174,050**	**58,774,217**	**1.5988%**
2012	876,857	20%	175,371	60,031,769	1.5630%
2013	884,326	20%	176,865	61,203,595	1.5561%
2014	892,873	20%	178,575	62,312,823	1.5415%
2015	**903,501**	**20%**	**180,700**	**63,458,246**	**1.5329%**
2016	913,998	20%	182,800	64,852,909	1.5283%
2017	925,102	20%	185,020	66,343,353	1.5191%
2018	935,042	20%	187,008	67,777,100	1.5278%
2019	944,461	20%	188,892	69,277,100	1.5250%
2020	**955,314**	**33%**	**315,254**	**70,908,289**	**1.5112%**
2021	966,146	33%	318,828	72,347,248	1.5184%
2022	977,417	33%	322,548	73,670,637	1.5237%
2023	991,122	33%	327,070	75,130,263	1.5063%
2024	993,254	33%	327,774	76,647,510	1.4859%
2025	**1,020,413**	**33%**	**336,736**	**77,898,856**	**1.5060%**

Projected Total Company Installed MWCapacity Including Capacity Value of Power Purchases(4)	17,158
% of 2025 Co. Capacity that Must be Renewable In Order To Meet 33% of California Load RPS Standard	49%

(1) 2007: Actual, based on 12 month period ending December 31, 2007
(2) 2008 - 2025: Load forecast, October 2007

(3) Consists geothermal resources:
Blundell (COD 1984): 26 MW
Blundell Unit 2 (COD 2007): 11 MW

(4) Based on 2007 IRP data (assumes 12% planning margin)
2016 existing resources 10,598 MW
2025 cumulative system additions 6560 MW
Total capacity with 15% wind credit 17,158 MW

(5) Assumes California Target incrases to 33% by 2020

(6) Assumes 299 MW of small hydro electric facilities (<30 MW) with a capacity factor for those facilities of 36% (calendar year 2007)

PacifiCorp System-level RPS-Eligible Renewable Resource Amounts and Additions Required to Meet California Proposed RPS Standards in 2007, 2011, 2015, 2020, & 2025

	Total Company New Renewable MW	California's Allocated Share Renewables MW	Assumed Capacity Factor	Total Company Annual Renewables MWH Production (Avg Hrs / Yr)	California's Share Renewables MWH (8766)
CA 2007 Allocation Share	**1.8409%**				
Assumed On-Line Geothermal Resource Capacity(3)	37	1	85%	275,691	5,075
Assumed On-Line Small Hydro Resource Capacity	299	6	36%	943,572	17,370
Required On-line Wind to Meet CA 17% 2007 Reqt	2,644	49	30%	6,952,296	127,982
Total Company & California's Share 2007	2,980	55		8,171,559	150,427
CA 2011 Allocation Share	**1.5988%**				
Assumed On-Line Geothermal Resource Capacity(3)	37	1	85%	275,691	4,408
Assumed On-Line Small Hydro Resource Capacity(6)	299	5	36%	943,572	15,086
Required On-line Wind to Meet CA 20% 2011 Reqt	3,676	59	30%	9,666,873	154,556
Total Company & California's Share 2011	4,012	64		10,886,136	174,050
CA 2015 Allocation Share	**1.5329%**				
Assumed On-Line Geothermal Resource Capacity(3)	37	1	85%	275,691	4,226
Assumed On-Line Small Hydro Resource Capacity(6)	299	5	36%	943,572	14,464
Required On-line Wind to Meet CA 20% 2015 Reqt	4,019	62	30%	10,568,850	162,010
Total Company & California's Share 2015	4,355	67		11,788,113	180,700
CA 2020 Allocation Share	**1.5112%**				
Assumed On-Line Geothermal Resource Capacity(3)	37	1	85%	275,691	4,166
Assumed On-Line Small Hydro Resource Capacity(6)	299	5	36%	943,572	14,260
Required On-line Wind to Meet CA 33% 2020 Reqt	7,469	113	30%	19,641,463	296,828
Total Company & California's Share 2020	7,805	118		20,860,726	315,254
CA 2025 Allocation Share	**1.5060%**				
Assumed On-Line Geothermal Resource Capacity(3)	37	1	85%	275,691	4,152
Assumed On-Line Small Hydro Resource Capacity(6)	299	5	36%	943,572	14,211
Required On-line Wind to Meet CA 33% 2025 Reqt	8,039	121	30%	21,139,888	318,374
Total Company & California's Share 2025	8,375	126		22,359,151	336,736

Update: April 17, 2008

UE-200/PacifiCorp
May 13, 2008
OPUC Data Request 19

OPUC Data Request 19

Please refer to PacifiCorp's response to Staff Data Request No. 2. Explain the factors that the company considered in making "...the reasonable expectation that purchased turbines could be incorporated into a wind project prior to the expiration of the federal production tax credit at the end of 2008." Include in your explanation how Utah's procurement requirements and the Oregon Commission's competitive bidding guidelines for Major Resources affected the company's determination regarding a 99 MW project size for the Glenrock, Rolling Hills and Seven Mile Hill projects.

Response to OPUC Data Request 19

As explained in the Company's response to OPUC Data Request 2, the federal production tax credit (PTC) will expire at the end of 2008. At the time each project decision was made, there was no assurance that Congress would extend the PTC. The decision to size certain wind projects at the 99 MW level was made due to the combination of wind turbine availability and the reasonable expectation that purchased turbines could be incorporated into a wind project prior to the expiration of the PTC. Based on what the Company knew at the time, it was reasonable to expect that the timing involved in acquiring new resources under Utah's then-current procurement laws[1] and the Oregon Commission's procurement rule would result in sufficient delays such that the wind turbines made available to the Company would not have remained available and the wind projects could not practically be completed prior to the expiration of the PTC.

[1] Utah has passed a law (SB-202) that increases the 100 MW procurement limit in Senate Bill 26 to 300 MW under certain criteria.

UE-200/PacifiCorp
June 12, 2008
OPUC Data Request 33

OPUC Data Request 33

Please refer to the "May 1, 2008, PUC Staff's Revised Draft Proposed Methodology for Determining the Annual Revenue Requirement Under ORS 469A.100" at http://www.oregon.gov/PUC/Senate_Bill_838.shtml. Perform the calculation prescribed in paragraph 1b for calendar year 2009. For incremental cost of compliance with a renewable portfolio standard, include the items designated in ORS 469A.100(4), a through e. Provide workpapers and spreadsheets in their original format with formula intact, itemizing costs by renewable resource project and cost category, and document assumptions. *For the purpose of this data request*, assume the following:

a. 2009 is the first "compliance year" under SB 838.

b. The Commission has made the following determinations regarding the incremental cost of compliance with a renewable portfolio standard:
   i. Qualifying electricity acquired prior to June 6, 2007, has zero incremental cost.
   ii. The levelized annual delivered cost of qualifying electricity includes the company's filed 2009 RAC costs and Commission-approved costs of qualifying electricity under SB 838 acquired on or after June 6, 2007.
   iii. The levelized annual delivered cost of an equivalent amount of reasonably available electricity that is not qualifying electricity is the Commission-approved avoided cost under PacifiCorp's Oregon Schedule 37.

c. "Net power costs" are the company's filed 2009 TAM costs.

d. The "compliance year forecasted load" is the company's projected 2009 load in its 2009 TAM filing.

Response to OPUC Data Request 33

PacifiCorp objects to this request on the basis that: (1) it seeks information that is not relevant to this proceeding, which addresses RAC cost recovery, not cost off-ramp or incremental compliance cost issues; (2) it calls for speculative information because the cost off-ramp and incremental compliance cost issues are currently the subject of the AR 518 rulemaking and the Commission has not adopted the assumptions stated in the data request by rule; (3) 2009 is not a compliance year under SB 838; and (4) in violation of the Commission's discovery guidelines, it requests that the Company conduct original analysis when the Company is neither uniquely situated to prepare the analysis nor is the information critical to the resolution of this proceeding.

Notwithstanding this objection, please see Attachment OPUC 33 – 1 and Confidential Attachment OPUC 33 - 2. The Company has calculated the revenue requirement calculation (Attachment OPUC 33-1), the methodology for which was approved by the Commission at its June 10, 2008 public meeting.

The Company has not calculated the incremental costs of compliance. However, in order for Staff to perform the requested analysis, the Company has provided Confidential Attachment OPUC 33-2, which has the levelized cost for the qualifying facilities acquired on or after June 6, 2007. The sources of the levelized costs are the Company's project approval documents that were provided in response to OPUC 15 (ICNU 1.1). The Company has also provided a levelized avoided cost based on the Company's Oregon Schedule 37.

OPUC Attachment OPUC 33-2 is confidential.

You must have signed the protective order in this docket in order to view this page.

Response to OPUC DR 33

2009 Annual Revenue Requirement

Based on May 1, 2008 PUC Staff's Revised Draft Proposed Methodology in AR 518

Line No.			Notes
1	Revenue requirement from most recent general rate case	$890,034,000	UE 179 - Order No. 06-530, Appendix A, p 20, line 2
2	Load from recent general rate case (MWh)	14,737,239	UE 179 - Exh PPL/901, p 10, line 79
	Subtract		
3	Energy efficiency	0	
4	Low income bill assistance	0	
5	Incremental cost of compliance (Base rate resources)	0	
6	Net power costs	$225,000,000	UE 191 - Nov 15, 2007 compliance filing, revised PPL/101
7	Sub-Total	$665,034,000	
8	Compliance year forecasted load (MWh)	15,392,368	UE 199 (Net System Load (PPL/102, p 6) * SE Factor (PPL/101))
9	Adjusted compliance year revenue requirement	$694,597,403	Line (8)*(1)/(2)
	Add base rate adjustments (authorized subsequent to last general rate case)		
10	Net power costs	$288,600,000	UE 199 (Exh PPL/101)
11	Renewable Adjustment Clause	$39,041,949	UE 200 (Exh PPL/301)
12	Subtract Incremental cost of compliance (RAC resources)	see Confidential Attachment OPUC 33-2	
13	**Annual Revenue Requirement**	**$1,022,239,352**	Line (9)+(10)+(11)+(12)

UE-200/PacifiCorp
June 27, 2008
OPUC Data Request 49

OPUC Data Request 49

Please explain why PacifiCorp did not include in its 2009 RAC filing the Seven Mile Hill II (19.5 MW) and Glenrock III (39 MW) projects under development by the company and expected to be on-line by year-end. Include in your response whether the company plans to include these resources in a 2009 RAC update and whether the company plans to update its net power cost estimates to include these resources in the TAM.

Response to OPUC Data Request 49

Seven Mile Hill II and Glenrock III were not included in the initial RAC filing because the Company had not received state approvals for the Industrial Siting Permits and the Certificates for Public Convenience and Necessity of these facilities prior to the April 1, 2008 filing date.

The Company plans to include these resources in the RAC update and the net power cost update.

UE-200/PacifiCorp
July 17, 2008
OPUC Data Request 63

OPUC Data Request 63

Please refer to PacifiCorp's response to Staff Data Request No. 49. Provide the 2009 revenue requirement for Glenrock III and Seven Mile Hills II in the same format as PPL/301.

Response to OPUC Data Request 63

Please refer to Attachment OPUC 63.

Attachment OPUC 63

Docket: UE-200 / Oregon RAC 2008
OPUC Data Request 63

Pacific Power
Oregon
Renewable Adjustment Clause
Glenrock III Revenue Requirement
In Service Date: December 31, 2008

	CY 2009 Total Company	Factor	Factor %	Oregon Allocated
Electric Plant In Service	87,173,625	SG	26.4114%	23,023,801
Depreciation Reserve	(1,888,762)	SG	26.4114%	(498,849)
Accumulated DIT Balance	(11,193,170)	SG	26.4114%	(2,956,276)
Net Rate Base	74,091,693			19,568,676
	11.26%			11.26%
Pre-Tax Return on Rate Base	8,340,117			2,202,744
Operation & Maintenance	1,539,960	SG	26.4114%	406,725
Depreciation	3,486,945	SG	26.4114%	920,952
Property Taxes	647,179	GPS	28.4419%	184,070
Renewable Energy Tax Credit	(3,674,354)	SG	26.4114%	(970,449)
Oregon Business Energy Tax Credit (BETC)	-	SG	26.4114%	-
Rev. Reqt. Before Franchise Tax & Bad Debt	10,339,846			2,744,042
Franchise Taxes	249,414			66,191
Bad Debt Expense	69,444			18,429
Total Revenue Requirement	**10,658,704**			**2,828,662**

Attachment OPUC 63

Docket: UE-200 / Oregon RAC 2008
OPUC Data Request 63
Pacific Power
Oregon
Renewable Adjustment Clause
Seven Mile Hill II
In Service Date: December 31, 2008

CY 2009

	Total Company	**Factor**	**Factor %**	**Oregon Allocated**
Electric Plant In Service	45,737,658	SG	26.4114%	12,079,970
Depreciation Reserve	(990,983)	SG	26.4114%	(261,733)
Accumulated DIT Balance	(5,872,756)	SG	26.4114%	(1,551,079)
Net Rate Base	38,873,920			10,267,158
	11.26%			11.26%
Pre-Tax Return on Rate Base	4,375,835			1,155,721
Operation & Maintenance	797,715	SG	26.4114%	210,688
Depreciation	1,829,506	SG	26.4114%	483,199
Property Taxes	339,557	GPS	28.4419%	96,577
Renewable Energy Tax Credit	(2,161,260)	SG	26.4114%	(570,820)
Oregon Business Energy Tax Credit (BETC)	-	SG	26.4114%	-
Rev. Reqt. Before Franchise Tax & Bad Debt	5,181,354			1,375,364
Franchise Taxes	124,983			33,176
Bad Debt Expense	34,799			9,237
Total Revenue Requirement	5,341,135			1,417,778

UE-200/PacifiCorp
July 16, 2008
OPUC Data Request 65

OPUC Data Request 65

Please provide PacifiCorp's response to Staff Data Request No. 36 in Docket UM 1368.

Response to OPUC Data Request 65

Please refer to Attachment OPUC 65 for a copy of the Company's response to OPUC Data Request 36 in Oregon Docket UM-1368.

OPUC Data Request 36

Please provide a spreadsheet in the original format with formula intact showing the following:

a. Project-specific and total existing capacity (in MW) of renewable resources owned or contracted to PacifiCorp and eligible for renewable portfolio standards in one or more states served by PacifiCorp
b. Project-specific and total estimated energy production (in MWh) in 2011, 2015, 2020 and 2025 for renewable resources owned or contracted to PacifiCorp and eligible for renewable portfolio standards in one or more states served by PacifiCorp
c. Project-specific and total capacity (in MW) of committed renewable resources expected to be on-line by year-end 2008 that will be eligible for renewable portfolio standards in one or more states served by PacifiCorp
d. Project-specific and total estimated energy production (in MWh) in 2011, 2015, 2020 and 2025 of committed renewable resources expected to be on-line by year-end 2008 that will be eligible for renewable portfolio standards in one or more states served by PacifiCorp
e. Which state renewable portfolio standard the facility is eligible for
f. Estimates of remaining renewable energy production requirements (in MWh) to meet the company's Oregon RPS requirements in 2011, 2015, 2020 and 2025
g. Estimated renewable resource capacity (in MW) represented by item f, above, in 2011, 2015, 2020 and 2025
h. Estimates of remaining renewable energy production requirements (in MWh) to meet the company's RPS requirements in 2011, 2015, 2020 and 2025 in each of the other states PacifiCorp serves
i. Estimated renewable resource capacity (in MW) represented by item h, above, in 2011, 2015, 2020 and 2025

State all assumptions, including resource type (wind, geothermal, hydro, etc.), capacity factor and load forecasts.

Response to OPUC Data Request 36

The Company has not undertaken detailed analyses such as those contemplated in OPUC Data Request 36. Notwithstanding, the Company provides the following in response to this request:

a. Please refer to Attachment OPUC 36a for renewable resources owned or contracted to PacifiCorp. Please note Qualifying Facilities (QFs) have been grouped by fuel type, as it is unknown if these facilities can be used toward the Company's RPS compliance.

b. Please refer to Attachment OPUC 36b for average capacity factor for each renewable type.

c. Please refer to Attachment OPUC 36c.

d. Please refer to Attachment OPUC 36b for average capacity factor for each renewable type.

e. Each state defines eligible renewable resources differently based on legislation passed in its respective state. The eligibility of a facility is not determined by the Company, such determinations are made exclusively by the state renewable portfolio standard program administrator. In California, it is the California Energy Commission; in Oregon, it is the Oregon Department of Energy; in Utah, it is the Utah Public Service Commission; and in Washington, it is the Washington Utilities and Transportation Commission.

   In general, three factors are used to determine if a resource is eligible for a state's renewable portfolio standard, 1) age of facility, 2) fuel type, and 3) geographic location. The Company has provided, as appropriate, the location, commercial online date and the fuel type for the resources identified in OPUC 36a and OPUC 36c.

   The definition of eligible renewable resources for each state is summarized in Attachment OPUC 36e. More specific detail is available from each state.

f. The Company's current best estimate of future renewable energy requirements is provided as Attachment OPUC 36f.

g. Please refer to the Company's response to subpart f. above.

h. Please refer to subpart f. above.

i. Please refer to subpart f. above.

Asset/Contract	Type	Installed Capacity	State	On-line (Year)
PPA 1	Biomass	20.0	OR	1960
BLUNDELL (UNIT 1)	Geothermal	26.1	UT	1984
BLUNDELL (UNIT 2)	Geothermal	11.0	UT	2007
COPCO 1	Hydro Small	20.0	CA	1922
COPCO 2	Hydro Small	27.0	CA	1925
FALL CREEK	Hydro Small	2.2	CA	1903
IRON GATE	Hydro Small	18.0	CA	1962
ASHTON	Hydro Small	6.9	ID	1917
BEND	Hydro Small	1.1	OR	1913
BIG FORK	Hydro Small	4.2	MT	1910
CLEARWATER 1	Hydro Small	15.0	OR	1953
CLEARWATER 2	Hydro Small	26.0	OR	1953
CONDIT	Hydro Small	13.7	WA	1913
CUTLER	Hydro Small	30.0	UT	1927
EAGLE POINT	Hydro Small	2.8	OR	1957
EAST SIDE	Hydro Small	3.2	OR	1924
FISH CREEK	Hydro Small	11.0	OR	1952
FOUNTAIN GREEN	Hydro Small	0.2	UT	1922
GRANITE	Hydro Small	2.0	UT	1896
GUNLOCK	Hydro Small	0.8	UT	1917
LAST CHANCE	Hydro Small	1.7	ID	1983
OLMSTED	Hydro Small	10.3	UT	1922
ONEIDA	Hydro Small	30.0	ID	1920
PARIS	Hydro Small	0.7	ID	1910
PIONEER	Hydro Small	5.0	UT	1897
PROSPECT 1	Hydro Small	3.8	OR	1912
PROSPECT 3	Hydro Small	7.2	OR	1932
PROSPECT 4	Hydro Small	1.0	OR	1944
SAND COVE	Hydro Small	0.8	UT	1926
SLIDE CREEK	Hydro Small	18.0	OR	1951
SNAKE CREEK	Hydro Small	1.2	UT	1910
SODA	Hydro Small	14.0	ID	1924
SODA SPRINGS	Hydro Small	11.0	OR	1952
STAIRS	Hydro Small	1.0	UT	1895
VEYO	Hydro Small	0.5	UT	1920
WALLOWA FALLS	Hydro Small	1.1	OR	1921
WEBER	Hydro Small	3.9	UT	1911
WEST SIDE	Hydro Small	0.6	OR	1908
COMBINE HILLS	Wind	41.0	WA	2003
FOOT CREEK I	Wind	19.6	WY	1999
LEANING JUNIPER	Wind	100.5	OR	2006
MARENGO	Wind	140.0	WA	2007
ROCK RIVER I	Wind	50.0	WY	2001
WOLVERINE CREEK	Wind	64.5	ID	2006
QF	Biogas	10.0	Multiple states	Multiple years
QF	Biomass	51.0	OR	Multiple years
QF	Hydro	71.3	Multiple states	Multiple years
QF	Solar	0.1	OR	2004
		900.8		

UE-200/PacifiCorp
April 22, 2008
ICNU 1st Set Data Request 1.1

ICNU Data Request 1.1

Please provide any additional documents provided to Company executives and/or the board of directors regarding the decision to move forward with the renewable energy projects included in the test year.

Response to ICNU Data Request 1.1

The following confidential documents were provided to Company executives and/or the board of directors regarding the decision to move forward with the renewable energy projects included in the test year:

Renewable Resource	Document
Leaning Juniper 1	Attach ICNU 1.1 -1 CONF
Marengo	Attach ICNU 1.1 -2 CONF
Goodnoe Hills	Attach ICNU 1.1 -3 CONF
Marengo II	Attach ICNU 1.1 -4 CONF
Seven Mile Hill	Attach ICNU 1.1 -5 CONF
Glenrock	Attach ICNU 1.1 -6 CONF
Rolling Hills	Attach ICNU 1.1 -7 CONF
Blundell Bottoming cycle	Attach ICNU 1.1 -8 CONF

This information is confidential and is provided subject to the terms and conditions of the protective order in this proceeding.

ICNU Attachment ICNU 1.1-6 is confidential.

You must have signed the protective order in this docket in order to view this page.

ICNU Attachment ICNU 1.1-7 is confidential.

You must have signed the protective order in this docket in order to view this page.

UE-200/PacifiCorp
July 7, 2008
ICNU 10th Set Data Request 10.1

ICNU Data Request 10.1

In the confidential attachments to ICNU Data Request ("DR") 1.1, several of the reports mention consultant's reports regarding the amount of wind energy available from the projects. For example, on page 11 of Attachment to ICNU DR 1.1-6, there is reference to consultants reporting regarding the capacity factor of the Glenrock project. Similar comments appear in a number of the other attachments provided in the response to ICNU DR 1.1. Please provide copies of these consultants' reports and supporting workpapers and other documentation used to create the consultants reports.

Response to ICNU Data Request 10.1

To the extent this data request requires supporting work papers and/or other documentation consisting of, for example, the underlying data used by the consultants in their analyses; then the Company objects on the basis it is overly burdensome. Notwithstanding, please refer to Confidential Attachments ICNU 10.1 -1 through ICNU 10.1 -10 for the requested consultant studies. This confidential information is provided subject to the terms and conditions of the protective order in this proceeding.

ICNU Attachment ICNU 10.1-9 is confidential.

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ICNU Attachment ICNU 10.1-10 is confidential.

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CASE: UE 200
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits In Support
Of Reply Testimony

July 23, 2008

High Plains

Acquisition of project rights subject to a contract with GreenWing Pacific Energy Co.

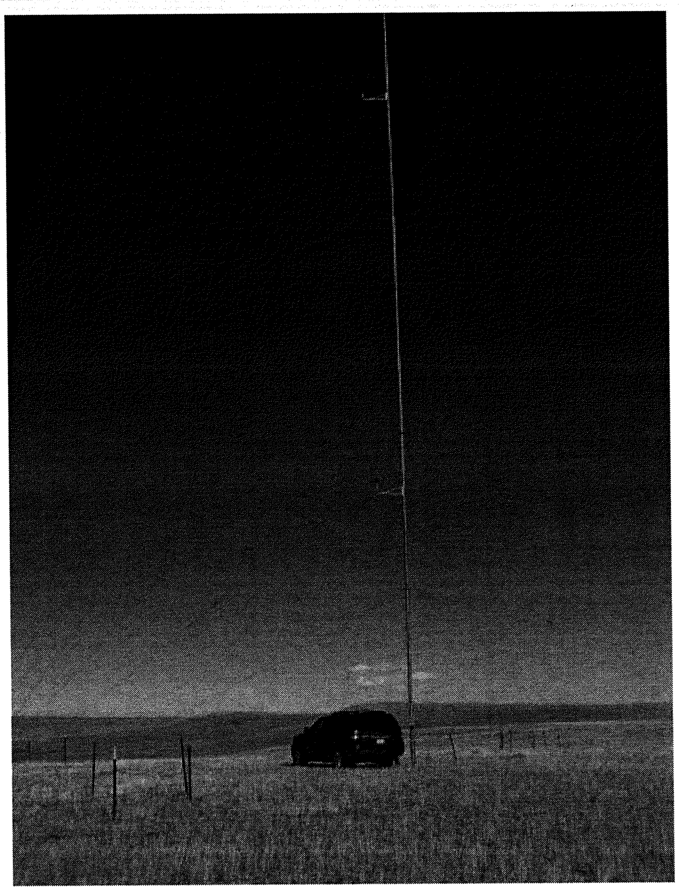
- 99 MW
- capacity factor analysis in due diligence
- 66 General Electric 1.5 megawatt turbines
- 80 meter (263 feet) hub height
- 77 meter (253 feet) rotor diameter

Located near McFadden, Wyoming

Expected to be in-service 2009

PACIFIC POWER
A DIVISION OF PACIFICORP

McFadden Ridge



Acquisition of project rights subject to a contract with GreenWing Pacific Energy Co.

- 88.5 MW
- capacity factor analysis in due diligence
- turbines to be determined
- 80 meter (263 feet) hub height
- 77 meter (253 feet) rotor diameter

Located near McFadden, Wyoming

Expected to be in-service 2010

CASE: UE 200
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Reply Testimony

July 23, 2008

PARTS OF STAFF EXHIBIT 300

ARE CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 08-190. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 200 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Kelcey Brown. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301. I am a Senior Economist in the Electric and Natural Gas Division of the Utility Program of the Public Utility Commission of Oregon (OPUC).

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE?

A. My witness qualification statement is found in Exhibit Staff/301, Brown/1.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to review PacifiCorp's economic analysis of the resources it is proposing to include in its rate base in this filing.

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. My testimony will cover three topics:

(1) A summary review and recommendations with regard to PacifiCorp's analysis methodologies, specifically, "the present value revenue requirements differential" (PVRR(d)) method and the "alternative cost for compliance" (ACC) method;

(2) The Glenrock and Rolling Hills wind project capacity factor adjustment; and

(3) A recommendation for PacifiCorp's cost of equity.

Analysis Methodologies

Q. PLEASE IDENTIFY THE METHODS USED BY PACIFICORP IN THE EVALUATION OF THE SEVEN WIND PROJECTS PROPOSED IN THIS FILING.

A. PacifiCorp used the PVRR(d) method and the ACC method to evaluate its proposed wind resources. Which method the Company used depended on when it made the decision to proceed with the project. The Company used the PVRR(d) method for the earlier facilities, Leaning Juniper 1, Marengo, Marengo II, and Seven Mile Hill and the ACC method for the later facilities, Glenrock and Rolling Hills. The Company also employed the PVRR(d) model to evaluate the Goodnoe Hills project, but expressed the results in a manner consistent with the ACC method.

Q. PLEASE BREIFLY EXPLAIN THE PVRR(d) METHOD.

A. As summarized in PPL/200 Tallman/8, the PVRR(d) method uses the GRID system dispatch model or "forward price curve" (FPC) to represent the resource in terms of a project-specific benefit to customers on a "net present value" (NPV) basis. When the Company uses GRID they run the model the first time to obtain a baseline reference. GRID is then run a second time with the renewable resource added, to obtain market-based energy costs avoided as a result of adding the renewable resource. The PVRR(d) method then compares the costs and benefits of the resource against the GRID model results. A negative result denotes a financial benefit to customers whereas a positive result indicates a negative value to ratepayers. The PVRR(d) method also assumes a "renewable energy credit" (REC) value of $5.00 per megawatt-hour (MWh) for a period of five years.

Q. PLEASE EXPLAIN THE ACC METHOD.

A. The ACC method does not use the GRID system dispatch model. Instead, it uses the "Planning and Risk" (PaR) model, with the FPC as an input. With the ACC method, the Company first runs the PaR model using the IRP preferred portfolio, as updated by the Company's business plan. The Company then runs the PaR model a second time, removing from the portfolio the uncommitted renewable resources.[1] According to the Company the difference between these two runs represents the market-based energy value of renewable resources in $/MWh. The ACC model then takes this market-based energy cost and calculates a project specific ACC over the life of the project, to result in a zero net present value revenue requirement difference. A negative ACC denotes a situation in which the resource compares favorably to the PaR model results, and a positive ACC compares negatively to the PaR model results.

Q. WHAT ARE THE THREE DIFFERENCES STAFF IDENTIFIES BETWEEN THE TWO METHODS?

A. The first difference between the two methods is how the value of energy produced by the project is determined. The ACC method removes a portfolio of resources then uses this $/MWh associated with the portfolio in

[1] The uncommitted renewable resources are those resources that have been approved in the most recently acknowledged IRP but have not yet been built or acquired.

valuing the energy for each specific project. The PVRR(d) method utilizes the GRID system dispatch model or FPC to determine a project-specific energy value.

The second difference, is that the ACC method presents its results on a $/MWh basis. These results are compared against current or potential future alternative compliance costs or penalties for not complying with renewable portfolio standard (RPS) Oregon requirements, other states' requirements, or possible future federal RPS law.

For an example, using the ACC method, a positive $/MWh of $12.00 requires the Company to consider whether or not they believe the cost of federal and state compliance will be higher than $12/MWh in order to provide a positive benefit to ratepayers over the life of the project. On the other hand, the PVRR(d) method expresses its results as a total project net present value dollar amount, with a defined REC value, which explicitly demonstrates whether or not the project will provide a benefit to ratepayers over the life of the project .

Thirdly, there is no specific REC value assumed within the ACC method. Unlike the PVRR(d) method where the value is defined, the ACC method allows the value to vary in order to achieve a zero net present value revenue requirement difference, which does not provide a definable decision-making point.

Q. WITH REGARD TO THE FIRST DIFFERENCE, DOES STAFF HAVE AN ISSUE WITH THE ACC METHOD AND ITS DETERMINATION OF THE VALUE OF THE PROJECT-SPECIFIC ENERGY?

A. Yes. PacifiCorp's ACC method – specifically the process that removes the entire portfolio of uncommitted resources and then uses the results of this analysis to do a project-specific energy valuation - can lead to potential under or overvaluation of energy depending on the specific project's wind profile and its correlation to the wind profile of the uncommitted portfolio of renewable resources.

For example, if the uncommitted portfolio of resources has a wind profile that provides a significant amount of energy during peak hours, when this portfolio is removed the energy value would be higher during this peak time than if the alternative were true. Therefore, if the wind profile of a specific project produces more energy during peak times the model will overvalue the energy on a project-specific basis.

Q. WHAT ARE THE RAMIFICATIONS OF THIS OVER OR UNDERVALUATION?

A. For purposes of reviewing the prudence of an acquisition, or in comparing like bids, this type of bias may lead to choosing a less desirable resource. Over time the wind profile of a specific site will become integral in diversifying the Company's portfolio of wind resources. Under the current evaluation method this diversification may not be valued appropriately and, as stated previously, the wind profile of a site that is not correlated to the uncommitted portfolio may be undervalued. At this time, Staff is unable to quantify the magnitude of this potential bias.

Q. DOES STAFF HAVE A RECOMMENDATION FOR AN ALTERNATIVE METHOD THAT MIGHT BETTER VALUE THE ENERGY OF SPECIFIC PROJECTS WITH NO POTENTIAL BIAS?

A. Staff recommends that the Commission require PacifiCorp to perform both the PVRR(d) and the ACC methods using the same FPC. This should provide staff and intervenors the opportunity to determine whether the ACC method systematically undervalues or overvalues various wind profiles based on their correlative factor to the uncommitted wind resource portfolio.

One of the issues raised by Boston Pacific Company, the Independent Evaluator for PacifiCorp's 2008 renewable resources RFP, is the inability of the ACC method to adequately capture the locational diversity of wind projects considered for addition to the Company's system. *See* Independent Evaluator's Assessment of PacifiCorp's RFP 2008R-1 Renewables RFP Design, July 3, 2008 at 14-15.[2] Staff finds that the PVRR(d) method would potentially provide a reasonable assessment of site-specific energy value due to its use of the GRID system dispatch model, or FPC, as opposed to a PaR model process.

Q. WHAT IS STAFF'S SECOND ISSUE WITH THE ACC METHOD?

A. The presentation of the results of the ACC model, especially when comparing like bids, may be inappropriate due to the focus on the single issue of cost of compliance. While the cost of compliance is a factor that

[2] Pursuant to OAR 860-014-0050(1)(e), Staff asks the Commission and ALJ to take official notice of the Independent Evaluator report, filed in Docket UM 1368.

must be considered when making the decision to build or acquire a renewable resource, it should not be the sole emphasis when making this decision.

For example, in modeling the Leaning Juniper wind facility, one of the calculations determined the break even capacity factor as compared to the modeled capacity factor. This provided the decision maker with the perspective that given specific assumptions for cost and revenue, the project could withstand a lower revenue stream. In other words, the project could absorb potentially higher costs or lower performance and still break even. Conversely, with the results of the ACC method, the only variable being considered is whether the cost of compliance will exceed the value imputed by the model to achieve a zero NPV revenue requirement.

Q. WHY IS THIS PERSPECTIVE IMPORTANT WHEN EVAULATING RESOURCES?

A. This narrow perspective does not take into account attributes such as the estimated capacity factor, the maintenance costs, and the cost of capital. These are all variables that should be evaluated when faced with a result that does not produce a net benefit to ratepayers on a stand-alone basis. It is inadequate to base the decision solely on whether or not the Company believes the cost of compliance will be higher in the future than that needed to make the project break even.

Another important variable is project size. Given specified costs, an appropriate analysis would determine the optimal size of a facility as an output rather than as an input into the model in order to maximize revenue. This type of evaluation (profit maximization) is fairly basic in the corporate world, and a lack of consideration of the relationship between cost and revenue, given site parameters, seems inconsistent with a prudent business decision. This is where PacifiCorp's modeling falls short. It does not take into consideration the relationship between cost and revenue in order to maximize NPV for ratepayers. PacifiCorp provided no evidence of scenario analysis of the cost and revenue variables when the modeling method produced a result indicating an unfavorable result for ratepayers, this can be seen in PacifiCorp's response to OPUC DR #36, Exhibit Staff/303, Brown/1. This lack of scenario analysis, discussed further by Staff witness Schwartz, contributes to Staff's conclusion that the Rolling Hills wind facility was imprudently acquired.

Q. WHAT IS STAFF'S THIRD ISSUE, REGARDING AN UNDEFINED REC VALUE AS IT APPLIES TO OREGON RATEPAYERS?

A. The Independent Evaluator summarizes the issue:

> [T]he ACC method does not include any explicit value for Renewable Energy Credits (or Green Tags). The reason for this is mechanical. In order to calculate the precise point at which the net benefits of the bid are zero the ACC model alters one input cell over and over until the model is "balanced." The input that gets altered is the REC value. In other words, the ACC model generates an implied REC value. Because of the amortization and discounting of RECs, this implied REC value will not equal the ACC value, but it will be in the same magnitude and direction. In other words, a positive ACC means a positive implied REC value (and vice-versa) and a relatively

> large ACC means a relatively large implied REC value (and vice versa). *See Independent Evaluator report, Docket UM 1368, at 8.*

Without a defined REC value, there is an undefined decision making point at which a resource would be uneconomical given Oregon's RPS requirements (which are still being developed). The Company understandably must comply with state laws including RPS, and therefore may have RPS targets that require acquisition of renewables. However, and to the extent that such requirements raise PacifiCorp's costs, those additional costs should be allocated to the states mandating the action. Oregon rate payers should not bear the costs, for example, of resource acquisitions unnecessary for Oregon RPS standards, yet required by states such as Washington and California.

Q. SHOULD OREGON RATEPAYERS BEAR THE BURDEN OF PENALTIES ASSESSED TO PACIFICORP BY OTHER STATE MANDATES?

A. No.

<u>Capacity Factor Adjustment</u>

Q. WHAT IS STAFF'S PROPOSED ADJUSTMENT ASSOCIATED WITH THE ROLLING HILLS AND GLENROCK WIND FACILITY?

A. Staff proposed an adjustment to the capacity factor of the Rolling Hills wind facility in PacifiCorp's UE 199 Transition Adjustment Mechanism (TAM) filing which raised the capacity factor from 31% to 38%, with support for this adjustment provided by Staff witness Schwartz testimony.[3] In UE 200, Staff proposes an alternative method of calculating the capacity factor adjustment related to the Rolling Hills Wind project. In addition, Staff recommends an adjustment related to increasing the capacity factor for the Glenrock wind facility from 38% to [redacted]; this adjustment could be implemented in either UE 199 or in UE 200. Staff witness Schwartz provides support for the Glenrock Wind facility adjustment in Staff/200. My testimony describes the monetary adjustments and GRID model calculations associated with changing the capacity factors for these two projects as recommended in Staff/200 testimony.

Q. WHAT IS STAFF'S PROPOSED ALTERNATIVE ADJUSTMENT IN THIS PROCEEDING ASSOCIATED WITH THE ROLLING HILLS WIND FACILITY?

A. Staff has calculated an adjustment to the capital costs for the Rolling Hills wind facility. This would constitute a one-time adjustment to capital cost instead of a continued annual adjustment discussed in the UE 199 TAM proceeding of changing the capacity factor within the GRID model to reflect 38% versus 31%. The capital adjustment utilizes levelized total MWh over the life of the project, and the levelized $/MWh, both of which are outputs from the project model provided by the Company. The levelized total MWh over the life of the project is taken directly from the

[3] Pursuant to OAR 860-014-0050(1)(e), Staff asks the Commission and ALJ to take official notice of testimony Staff/200, Schwartz/1-7, and Staff/100, Brown/13-14 filed in Docket No. UE 199.

model and the $/MWh is calculated using the total present value revenue divided by the levelized total MWh (Project revenue/Levelized Project Total MWh = $/MWh).[4] In order to calculate this adjustment, Staff increased the levelized total MWh to account for the increase in the capacity factor, took the difference between the two totals and then multiplied this amount times the $/MWh for an approximate capital cost adjustment [(increased total production – previous total production) * $/MWh = $44,738,535][5]. Staff witness Garcia will provide the revenue requirement effect of this capital cost adjustment.

Q. WHAT IS STAFF'S PROPOSED ADJUSTMENT FOR THE GLENROCK WIND FACILITY FOR THIS PROCEEDING AND FOR THE TAM PROCEEDING?

A. The methodology for Staff's proposed adjustment for the Glenrock wind facility in UE 200 is consistent with the methodology stated above for the Rolling Hills wind project. Using the project total levelized output, increasing this to reflect a capacity factor of [redacted], and multiplying this adjusted output times the $/MWh calculated from the project model supplied by the Company for the Glenrock Wind facility [(increased total production – previous total production) * $/MWh = $14,225,508)][6]. Staff witness Garcia will provide the revenue requirement effect of this capital cost adjustment. In addition to the capital cost adjustment, Staff is also providing the estimated alternative adjustment for the Commission's

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[4] These figures and calculations can be seen in confidential exhibit Staff 302, Brown/1.
[5] Ibid.
[6] Ibid.

consideration in UE 199. Using the same methodology as in UE 199 for the Rolling Hills wind facility, Staff used the GRID system dispatch model provided by PacifiCorp for the 2009 TAM filing and changed the capacity factor from approximately 38% to [redacted]. This resulted in a total reduction in NVPC of $294,016, on an Oregon-allocated basis, and an increase of 23,500 MWh from the facility. This change in NVPC includes additional wind integration charges of $7,075, associated with the increased production of the facility. Staff has recommended adjustments to wind integration charges in UE 199 at Staff/100, Brown/7-9, specifically a wind integration charge reduction from $1.14/MWh to $.11/MWh, which would cause the cost to drop from $7,075 to $683. This change results in a total recommended adjustment for UE 199 of $300,409.

Numerically, this adjustment is: $294,016 +$7,075 -$683 = $300,409

Cost of Equity

Q. WHAT IS STAFF'S RECOMMENDATION WITH RESPECT TO PACIFICORP'S COST OF EQUITY?

A. Due to the recent approval of the RAC, pursuant to Senate Bill 838 (SB 838), Staff recommends that the Commission consider, in future general rate reviews, the implications of annual updates and other provisions, established under the Act, on PacifiCorp's cost of equity. Staff witness Schwartz describes the provisions of the Act. It is clear that the RAC mechanism provides PacifiCorp with more timely recovery of its prudently-incurred costs, which should lower the cost of equity.

Q. HAS THE COMPANY, IN PRIOR RATE REVIEWS, IDENTIFIED TIMELY RECOVERY OF PRUDENTLY-INCURRED COSTS AS A COMPONENT THAT COULD AFFECT ITS COST OF CAPITAL?

A. Yes. In UE 179 PacifiCorp testified to three operational risks that the Commission should consider when setting the cost of capital. These were Senate Bill 408, power cost recovery mechanism (PCAM), and regulatory recovery.[7] PacifiCorp's TAM proceeding significantly mitigates fuel and purchase power risk, and PacifiCorp now has a Commission-recognized process for annually updating rates to reflect recovery of capital investment of its renewable resources. Specifically, within UE 179, PacifiCorp witness Hardaway quoted two analysts[8] in order to portray the industry perspective on regulatory lag:

Merrill Lynch[3]:

> PacifiCorp is in the early stages of a major re-investment cycle (SPW capex forecast £3bn to 2010). Given the way capex is remunerated via periodic rate cases, there is considerable scope for mismatch between capital deployment and revenue recognition, so-called "regulatory lag". This is not new. Increasing capital intensity merely exacerbates the problem.

Citigroup[4]:

> Regulatory lag has been a significant issue for PacifiCorp. The rate setting process over the last decade has required PacifiCorp to file for rate increases after it has already incurred expenditure. Once a general rate case is filed, it can then take six to eight months for a decision. Overall, it can take 18-24 months before incurred capital expenditure can begin to earn a return.

[7] UE 179 PPL/200, Hardaway/9-10.
[8] PPL/200, Hardaway/7.

These quotes illustrate Staff's point: PacifiCorp realizes reduced risk with an annual update pursuant to SB 838. In addition, in internal Company documents requesting approval of the Glenrock Wind and Rolling Hills facilities the Company states that [redacted].[9]

Q. DOES STAFF HAVE A SPECIFIC RECOMMENDATION IN REGARD TO PACIFICORP'S COST OF CAPITAL?

A. No. Staff has not conducted such an analysis. Staff intends to investigate this issue, in concert with the method of estimating PacifiCorp's cost of capital, in the context of PacifiCorp's next general rate case.[10]

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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[9] Please refer to Exhibit Staff/202, Schwartz/33, Staff/202, Schwartz/49.

[10] Since PacifiCorp is a wholly-owned subsidiary of Mid American, the cost of capital is estimated by identifying comparable companies whose stock is traded and independently priced. Therefore a comparison of these companies to PacifiCorp with respect to timely cost recovery is likely required.

CASE: UE 200
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualification Statement

July 23, 2008

WITNESS QUALIFICATION STATEMENT

NAME:	Kelcey Brown
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist, Electric and Natural Gas Division, Resource and Market Analysis
ADDRESS:	550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.
EDUCATION:	All course work towards Masters in Economics University of Wyoming B.S. University of Wyoming Major: Business Economics Minor: Finance
EXPERIENCE:	Since November 2007 I have been employed by the Public Utility Commission of Oregon. Responsibilities include research and providing technical support on a wide range of cost, revenue and policy issues for electric utilities. I have actively participated in regulatory proceedings in Oregon, including UE 195, UE 198, and UE 200. From June 2003 to November 2007 I worked as the Economic Analyst for Blackfoot Telecommunications Group, a competitive and incumbent telephone provider in Missoula, Montana. I conducted all long and short term sales and revenue forecasts, resource acquisition cost-benefit analysis, business case analysis on new products and build-outs, pricing, regulatory support, market research, and strategic planning support. From May 2002 to August 2002 I worked as an intern at the Illinois Commerce Commission in Springfield, Illinois. I performed competitive market analysis, spot market monitoring and pricing review, and extensive research on locational marginal pricing and transmission system incentives for development.

CASE: UE 200
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibit In Support
Of Reply Testimony

July 23, 2008

STAFF EXHIBIT 302

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 08-190. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 200 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

CASE: UE 200
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 303

Exhibit In Support
Of Reply Testimony

July 23, 2008

UE-200/PacifiCorp
June 12, 2008
OPUC Data Request 36

OPUC Data Request 36

Please provide both in the summary format provided in confidential testimony and within the working model provided to Staff scenario runs for the Goodnoe Hills, Glenrock, Rolling Hills and Seven Mile Hill projects using the following approximate project sizes: 50 MW, 150 MW and 200 MW. Document all assumptions (explaining any changes in assumptions), including itemized costs by cost category and project. Also provide the results on a per MWh unit basis. Explain any significant differences in results on a per MWh-unit basis, compared to PPL/202 due to the differences in capacity.

Response to OPUC Data Request 36

The Company has not previously performed the referenced analyses and the Company is unable to perform the referenced analyses given that it is an invalid assumption that some of the referenced MW amounts are within certain project permits and that major equipment supply would have been available at validly assumed prices. Also, the Company's consultant(s) did not study the capacity factor associated with projects of such sizes upon the sites.

CASE: UE 200
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Reply Testimony

July 23, 2008

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Steve Storm. I am employed by the Public Utility Commission of Oregon as a Senior Economist in the Economic & Policy Analysis Section. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/401.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses two main issues associated with rate spread and rate design in regards to PacifiCorp's Supply Service Adjustment Schedule 202, Renewable Adjustment Clause[1] (RAC) filing applicable to 2009 rates. First I review the methodology approved by the Commission in UM 1330 (*See* Commission Order No. 07-572), which adopted a joint party stipulation. I then discuss the methodology used by PacifiCorp in developing the RAC Schedule rates for 2009.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. No.

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[1] Hereafter in this testimony referred to as the RAC Schedule.

Q. WHAT IS THE METHODOLOGY APPROVED BY THE COMMISSION IN ORDER NO. 07-572?

A. Order No. 07-572 adopted a joint party stipulation regarding rate spread and rate design:

> "Costs recovered through the RAC Schedule will be allocated across customer classes using the applicable RAC Schedule forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule as determined in the then-most recent general rate case."[2]

Q. PLEASE DESCRIBE HOW STAFF INTERPRETS THE STIPULATION FOR PURPOSES OF THE CURRENT DOCKET.

A. The steps for establishing specific RAC Schedule rates are as follows:

1 Costs to be recovered through RAC Schedule rates are allocated to the various applicable rate schedules using the spread of equal percent of generation revenues across schedules as established in the utility's most recently concluded general rate case. In practice, calculating the 2009 RAC Schedule rate spread is to:

   a. Multiply the 2008 Schedule 200[3] rates for the applicable RAC Schedule rate schedules by the respective 2009 energy volume forecasts.

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[2] *Ibid.*, UM 1330 Stipulation, page 6.

[3] This assumes that 2008 Schedule 200 rates are those reflecting PacifiCorp's unbundled generation revenues as determined in UE 179 (PacifiCorp's most recently concluded general rate case) on a forecast basis for the year 2008.

b. Divide each result in “a” by the sum of results in “a.” The resulting percentages, one for each rate schedule to which the RAC Schedule rates apply and totaling 100 percent, are the allocation factors to be used in the rate spread of the costs to be recovered through the RAC Schedule rates.

c. Multiply each percentage result obtained in “b” by the dollar amount of the costs to be recovered through the RAC schedule. This provides the RAC Schedule rate spread dollar amount for each rate schedule to which the RAC Schedule rates apply. The sum of the dollar amount for each rate schedule equals the dollar amount of the costs to be recovered through RAC Schedule rates.

2. Once the dollar amount of costs to be recovered through the RAC Schedule has been allocated to the applicable rate schedules, these costs must be “applied on a cents per kWh basis” for each rate schedule; i.e, each applicable rate schedule has a specific volumetric rate intended to fully recover the costs allocated to that rate schedule.[4] So, for each applicable rate schedule, the dollars allocated in “1” (above) are divided by a forecast of energy usage (kWh) for that rate schedule.

[4] “Fully recover” is intended to be on a neutral, “best efforts,” basis. That is, the volumetric rate should be developed in such a manner that both over-recovery and under-recovery by a given amount are, *a priori*, equally likely.

Q. WHAT FORECAST SHOULD BE USED AS THE BASIS FOR DEVELOPING RAC SCHEDULE RATES?

A. The wording in the Stipulation is somewhat unclear and allows for at least two interpretations. One alternative uses the sales volumes (kWh) as set forth in the most recently concluded general rate case. The second alternative uses the sales (kWh) forecasted to occur during the time period that the RAC Schedule rates will be in effect.

Q. WHICH ALTERNATIVE DID PACIFICORP USE IN ITS DIRECT CASE?

A. PacifiCorp used the former; the volumes identified in the general rate case.

Q. DO YOU HAVE ANY CONCERNS WITH USING VOLUMES FROM THE LAST GENERAL RATE CASE AS THE BASIS?

A. Yes. Assuming loads grow over time, using historic sales volumes will result in the utility capturing revenues greater than those targeted by RAC Schedule rates.[5] Therefore staff supports the alternative interpretation which uses the forecast of sales volumes during which the RAC Schedule rates will be in effect (the rate effective period).

[5] It is equally true that, if actual usage is lower than that used to develop the volumetric rate, the utility will under-collect.

Q. HAS STAFF HAD DISCUSSIONS WITH PACIFICORP REGARDING THE APPROPRIATE ENERGY USAGE FORECAST FOR USE IN DEVELOPING THE RAC SCHEDULE RATES?

A. Yes. Staff raised concerns regarding the sales volume forecast PacifiCorp used in its direct testimony.[6]

Q. DID THE COMPANY AGREE TO REVISE ITS RATE PROPOSAL IN THE COMPANY'S REBUTTAL TESTIMONY?

A. Yes. The Company agreed that Staff's interpretation of the Stipulation regarding the year of the energy forecast was also reasonable and agreed to redesign rates in its rebuttal testimony based upon the Company's energy forecast for 2009.

Q. DOES THE COMPANY HAVE A FORECAST OF ENERGY USAGE BY RATE SCHEDULE FOR THE TIME PERIOD OVER WHICH THE RATES WILL BE IN EFFECT?

A. No, not at this time. The Company has an energy forecast by class of customers, but not by individual rate schedules. Therefore, the Company proposes using the same relationship of sales levels by rate schedule within a customer class as that existing in the last general rate case.

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6 *See* PPL/401 Ridenour/1.

Q. IS THE COMPANY'S PROPOSAL IN THIS REGARD REASONABLE?

A. Yes. However, Staff will critically review the Company's analysis as presented in its rebuttal testimony.

Q. DOES THIS CONCLUDE YOUR REPLY TESTIMONY?

A. Yes.

CASE: UE 200
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualification Statement

July 23, 2008

WITNESS QUALIFICATION STATEMENT

NAME: Steve Storm

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist, Economic Research and Financial Analysis Division

ADDRESS: 550 Capitol Street NE Suite 215
Salem, Oregon 97301-2148

EDUCATION: Master of Business Administration
University of Oregon
Eugene, Oregon

A.B. (Economics)
Harvard University
Cambridge, Massachusetts

EXPERIENCE: I have been employed at the Public Utility Commission of Oregon since October 2007 as a Senior Economist. My current responsibilities include research on a wide range of cost, revenue, and policy issues for electric, gas, and telephone utilities.

Prior regulatory experience includes four years of developing responses to data requests regarding new products and services at US WEST Communications.

OTHER EXPERIENCE: I was a self-employed financial planner for eight years following an eighteen year career in management positions in pricing and cost analysis; financial analysis, planning and management; and strategic planning in the publishing and telecommunications industries. This included five years of managing the pricing (rate spread and rate design) and cost accounting functions in the Directory department of Pacific Northwest Bell and its successor company, US WEST Direct. I was responsible for departmental budgeting and management reporting functions for three years at US West Direct and responsible for corporate financial planning, analysis, and management reporting for one year at Electric Lightwave.

I have seven years experience in capital budgeting, financial analysis, and strategic planning functions at US West Communications.

CERTIFICATE OF SERVICE

UE 200

I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-13-0070, to the following parties or attorneys of parties.

Dated at Salem, Oregon, this 23rd of July, 2008.

Kay Barnes

Kay Barnes
Public Utility Commission
Regulatory Operations
550 Capitol St NE Ste 215
Salem, Oregon 97301-2551
Telephone: (503) 378-5763

UE 200
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