Oregon

Theodore R. Kulongoski, Governor

Public Utility Commission
550 Capitol St NE, Suite 215
Mailing Address: PO Box 2148
Salem, OR 97308-2148
Consumer Services
1-800-522-2404
Local: (503) 378-6600
Administrative Services
(503) 373-7394

July 12, 2006

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

RE: **Docket No. UE 179** - In the Matter of PACIFICORP, dba PACIFIC POWER AND LIGHT COMPANY Request for a general rate increase in the company's Oregon annual revenues.

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

/s/ Kay Barnes

Kay Barnes
Regulatory Operations Division
Filing on Behalf of Public Utility Commission Staff
(503) 378-5763
Email: kay.barnes@state.or.us

c: UE 179 Service List - parties

CASE: UE 179
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Direct Testimony

July 12, 2006

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

A. My name is Ed Durrenberger. I am a Sr. Revenue Requirement Analyst for the Oregon Public Utility Commission. 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/201.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is two-fold. First, as the revenue requirement summary witness for the Commission Staff (Staff) in this proceeding, I am generally familiar with the adjustments to PacifiCorp's (Company) filing in this docket sponsored by other Staff analysts and will speak in a general way about the status of all of the Staff proposed adjustments and the overall revenue requirement that the adjustments would produce. Second, I will provide testimony on certain adjustments that I propose for this proceeding.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared three exhibits. Exhibit Staff/201 is my one page witness qualification. Exhibit Staff /202 consisting of 8 pages, is the revenue requirement model showing all of Staff's adjustments. This exhibit also contains supporting documentation on the adjustments Staff proposes for PacifiCorp's rate filing and indicates the effect that these adjustments will have on the Company's Oregon revenue requirement. Finally, Exhibit Staff/203, consisting of 38 pages, contains supporting documents that I used to evaluate the individual adjustments I propose.

PART I:
RATE CASE SUMMARY

Q. WHAT ARE THE COMPANY AND STAFF'S PROPOSED REVENUE REQUIREMENTS?

A. On February 22, 2006, PacifiCorp filed an application for a general rate increase in its Oregon service territory. The application, docketed UE 179 proposes to increase its Oregon revenues by $112 million on an annual basis. This request represents an overall rate increase of approximately 13.2% to become effective with service on or after December 26, 2006. The Company filed testimony, exhibits and work papers supporting its rate increase request. Staff has evaluated the Company's proposal and examined the work papers and supplementary data supplied in response to data requests. Our findings are that the Company's requested rate increase is not warranted and should be rejected. Based on Staff's analysis to date, we propose that the appropriate increase in Oregon revenues should be $12.14 million on an annual basis, an overall rate increase of 1.4%.

Q. THERE IS A BIG DIFFERENCE BETWEEN WHAT THE COMPANY HAS REQUESTED AND WHAT STAFF PROPOSES. HAS THERE BEEN A SETTLEMENT MEETING TO RESOLVE THE DIFFERENCES?

A. Yes. Staff circulated a settlement proposal to all parties on June 7, 2006. A series of settlement meetings were held starting June 14, 2006.

Q. WHAT WAS THE OUTCOME OF THE SETTLEMENT MEETINGS?

A. Parties were unable to reach a settlement. The Company expressed a desired to reach an overall settlement. However, neither a comprehensive settlement nor a settlement of any individual items was reached.

Q. WHAT IS THE NEXT STEP TO RESOLVING STAFF'S ADJUSTMENTS IN THE CASE?

A. Staff will explain the adjustments it proposes in direct testimony. I will provide testimony about issues related to Maintenance (S-10 and 12) and certain other expenses (S-9 and 16), and will submit joint testimony with J.R. Gonzalez about new power delivery programs (S-11). Other Staff analysts will submit direct testimony in support of their proposed adjustments also. The S-0 Rate of Return adjustment and capital structure proposal are supported by Thomas D. Morgan (*See* Staff/800). Bryan Conway will testify about the cost of debt (*See* Staff/700). Mike Dougherty (*See* Staff/600) is submitting testimony in support of Pension, Benefits and A&G Costs Adjustments (S-7). Net Power Cost Adjustments (S-13, 14 and 15) are supported in direct testimony from Bill Wordley *(See* Staff/100). Paul Rossow (*See* Staff/400) discusses adjustments to Membership Expenses, Other Revenues and Uncollectibles in his direct testimony, (S-4, 5 and 6). Lynn Kittilson *(See* Staff/500) provides testimony on a Rebasing Adjustment (S-1) and an Incentive Adjustment (S-2). And Federal and State Income Tax adjustments (S-3) are supported by testimony from Judy Johnson (*See* Staff/300).

Q. BEFORE YOU BEGIN TO DETAIL THE ADJUSTMENTS YOU PROPOSE COULD YOU EXPLAIN THE INFORMATION CONTAINED IN YOUR EXHIBIT STAFF/202?

A. Yes. Exhibit Staff/202 is a series of interlinked spreadsheets which contain six separate elements that, together, summarize Staff's position on issues and the revenue requirement adjustments for UE 179. They are:

1. Page 1 is a summary sheet that shows the Company's original results of operations as filed and the total adjustments that Staff has made. It also includes the effect on the revenue requirement. Column (1) contains the Company's original Oregon-allocated results of operations for the CY 2007 test year as filed. Column (2) contains all Staff's adjustments to revenue and rate base. The next column, column (3), is the adjusted results of operations (column (1) plus column (2)). Column (4) shows the required change in revenues (Revenue Requirement) necessary for a reasonable rate of return. Column (5) shows the results of operations with a reasonable rate of return.

2. The Adjustment Narrative, Page 2, contains the individual adjustment numbers (**S-XX**), the initials of the Staff initiator, a brief narrative description, and its effect on the Company's requested Oregon revenue requirement. The Adjustment Narrative also contains a total revenue requirement number that is the total rate increase/(decrease) that Staff proposes.

3. Page 3 contains the overall income tax calculation for the results of operations.

4. Page 4 shows the revenue sensitive costs.

5. Page 5 contains the Staff proposed capital structure.

6. Pages 6 and 7 show Staff's adjustments. On page 6 each adjustment is detailed by individual revenue and/or rate base effects. The revenue requirement difference for each adjustment is shown on line 41. Page 7 calculates the tax consequence for each individual adjustment.

PART II:
INDIVIDUAL ADJUSTMENTS

Q. PLEASE EXPLAIN THE INDIVIDUAL ADJUSTMENTS YOU PROPOSE.

A. The first adjustment is S-9, Amortization of Capital Stock Expenses. This requested adjustment is detailed in the Company's Exhibit PPL/901, Depreciation and Amortization Adjustment, Tab 6.2. The Capital Stock Expense is the expense from issuing Common Stock. The Company is proposing to recover these costs through a 20-year amortization that would add $584,396 to Oregon allocated annual expenses. I propose to disallow this amortization expense. It represents a one-time, past, sunk cost that the company incurred outside of the test period. This cost, like any other financing cost, is factored into the calculation of the allowed return on equity (ROE) estimate. These amortization expenses have not been itemized as an expense in the past and there is no reason that these costs should be recognized separately now.

Q. WHAT IS THE NEXT ADJUSTMENT YOU PROPOSE TO THE COMPANY'S REQUEST?

A. My next adjustment is an adjustment to the Company's Generation Overhaul Normalization request. The Generation Overhaul Normalization is detailed in Exhibit PPL/901, Tab 4.8. My adjustment is S-10. The company has requested to increase its escalated 2007 test year generation overhaul budget (i.e. the budget that has already been adjusted to reject normal cost increase) from $22 million to $39 million. The Company states that this is representative of on-going overhaul generation costs in the test year and beyond (*See* PPL/700 Cunningham/4-8). The reasons Mr. Cunningham gives for the large increase (over 75% above the current budget) are changes in the scope of overhaul work, the number and size of the units being overhauled, the age of the equipment and their need for major refurbishment. Mr. Cunningham further states that the increased overhaul costs are based on actual work that is planned for each scheduled overhaul.

Q. WHAT HAVE YOU LEARNED ABOUT THIS ADJUSTMENT?

A. By far the largest part of this proposed increase is to overhaul maintenance in PacifiCorp's coal-fired power plants. Looking into historical generation overhaul spending by unit, (*See* Exhibit Staff/203 page 2) two things are apparent. One is that the overhaul maintenance spending, by unit, is highly variable year to year, and the other is that the total annual generation overhaul maintenance spending, system wide, is also highly variable from year to year and can go up or down over 20% from one year to the next. The Company's testimony states that the overhaul normalization adjustment is based on actual work that is planned but did not satisfactorily provide a detailed list of planned overhaul projects, by unit, that make up this adjustment (*See* Exhibit Staff/203 pages 3-18). The Company's responses did provide the following information:

1. The number of days each year that one of the facilities is off-line for overhaul maintenance is variable just like the spending, year-to-year, but on average, was about the same in the past as what is planned for future years. The company stated that in 2005 there were lower that average overhaul costs (and fewer days on outage); their data supports this and further indicates that it was preceded by a year that had the highest number of outage days (and higher spending) of all the years reported. On average, the number of outage days in historic years reported is comparable to future years reported in the data responses. The year 2005 is not unusually small nor the year 2007 and beyond unusually large.
2. The addition of the Currant Creek facility makes a significant change to the overhaul outage numbers both in costs and in days per year off line for overhaul. This is a new generation source that has not been in the mix before.
3. From the descriptions of the planned critical path work contained in the Thermal Outage Schedule provided, it is not possible to distinguish a greater

number of age or wear related refurbishment projects going forward than seemed to occur in the past, from 2001 to the present.

Except for overhauls related to Currant Creek (which I discuss below) I am not persuaded that the dramatic increase requested for generation overhaul maintenance is warranted for the Steam Plant category. The burden is with the Company to lay out the plans for the overhauls that would justify the spending they have requested and demonstrate that these costs would be on-going and incremental to the current budgets. PacifiCorp has not made this case.

Q. DO YOU PROPOSE TO TREAT THE COMPANY'S CURRANT CREEK OVERHAUL EXPENSES INCREASE REQUEST DIFFERENTLY THAN OTHER OVERHAUL EXPENSES?

A. Yes. In fact, PacifiCorp has singled out the overhaul costs for this plant in its "Other Generation" category. Currently the unit is operating in a simple-cycle mode as a peaking facility. In the test year it will operate in a more efficient combined-cycle mode as a base load facility. The cost the company has proposed for overhaul maintenance for this unit is $3,209,740, system-wide, per year, $854,686 Oregon-allocated. I would propose that this addition to the Generation Overhaul Adjustment be allowed.

Q. ARE THERE OTHER ASPECTS OF THE COMPANY'S GENERATION OVERHAUL ADJUSTMENT THAT YOU ADDRESS?

A. The Company proposed an adjustment to Steam Plant generation overhaul expense that reduced the seasonal Cholla plant maintenance by $4,631,595 (Oregon-allocated). I accepted this adjustment without any proposed change.

The Company also requested a Hydro East and West Generation Overhaul cost increase of a total of $290,563, Oregon-allocated. I propose disallowing this increase in its entirety. The Company Hydro facilities have not had a generation overhaul budget in the past and the testimony offered no convincing evidence that establishing one now was warranted.

Finally, the adjustment proposed by the company for an increase to seasonal system combustion turbine generation should be rejected. From the data provided by the Company this appears to be for the Gadsby Peaking Facility, which has been in rates for a number of years and whose overhaul costs should not be incremental where a special adjustment is warranted. As shown below, the total Generation Overhaul Normalizing adjustment PacifiCorp requested is $17.8 million system wide, $4.7 Oregon-allocated per year. The adjustments I propose reduce the Oregon revenue requirement by $5.1 million.

Q. PLEASE SUMMARIZE YOUR PROPOSED TREATMENT OF PACIFICORP'S GENERATION OVERHAUL NORMALIZATION REQUEST.

Item	PacifiCorp Request (000)	Staff Position	Difference System	Oregon Alloc. Staff Adjustment
Steam Plant Overhaul	$17,338	$0	($17,338)	($4,617)
Steam Plant Overhaul (Ch)	($4,632)	($4,632)	$0	$0

Hydro E	$612	$0	($612)	($163)
Hydro W	$479	$0	($479)	($127)
Other Gen.	$3,210	$3,210	$0	$0
Other Gen. (CT)	$771	$0	($771)	($197)
Total	$17,778	($1,422)	($19,200)	($5,104)

Q. ARE THERE ANY OTHER ADJUSTMENTS THAT YOU WOULD LIKE TO DISCUSS?

A. There are. Another proposal that the Company has made is a Generation O&M Normalizing Adjustment.

Q. WHAT IS THE COMPANY'S GENERATION O&M NORMALIZATION PROPOSAL?

A. It is discussed by Barry Cunningham in PPL/700 pages 9-12, and detailed in the work papers in Exhibit PPL/901 Tab 4.14. Normalizing adjustments are intended to develop costs in the test year results that reflect a normal level of recurring costs for the subsequent period that rates are in effect. The Company's proposed adjustment to test year generation O&M does not include fuel or labor and is distinct from the generation overhaul adjustment discussed earlier. The Company has requested this adjustment because it expects that special maintenance, contracts and materials will cost more on an on-going basis in the test year and beyond than the escalated budget would support.

The Company's proposed increase, on a system-wide basis, is $14.8 million per year; the Oregon-allocated amount is $3.9 million.

Q. CAN YOU GIVE MORE DETAILS OF WHAT THE COMPANY IS PROPOSING?

A. This adjustment would increase the non-labor budget for generation maintenance by an additional 17% above the escalated test year numbers. The largest portion of this requested adjustment is the special maintenance category. The Company has asserted that its generation equipment is aging and the number and size of special maintenance projects is expected to increase, thus causing costs to go up. Some of the special projects are said to include rebuilding unspecified large equipment, dredging ponds and waterways and arc flash program maintenance. Also included are costs associated with O&M for Hydro projects that have resulted from relicensing requirements.

Q. WHAT HAS THE COMPANY PROPOSED FOR THE SPECIAL MAINTENANCE ADJUSTMENT?

A. The Company identified a lengthy list of items in the Special Maintenance category for the steam plants but did not identify which items would be part of their "large identifiable maintenance projects" for which particular unit in which year. My data request and supplemental information furnished by the Company did not produce a plan that demonstrated that these special projects were going to occur with any greater regularity than in the past. A spread sheet did detail, by facility, not unit, the expected expenditures in the three main categories, Special Maintenance, Contracts and Materials for what appeared to be a one year period without any specifics and no forecasts that demonstrated that the extra spending would continue into future years (*See* Exhibit Staff/203 page 22). For the Hydro system it was another matter entirely. PacifiCorp provided a very detailed list of special O&M it said was necessary due to relicensing requirements (*See* Exhibit Staff/203 pages 23-36). Included in the list were individual project descriptions, schedules and expected costs. It was not possible to determine if all the hydro projects were incremental and the result of relicensing agreements that could be considered incremental to the current O&M budgets.

Q. WHAT DO YOU PROPOSE?

A. The lack of specificity on the special maintenance adjustments to the steam plants made this request seem very uncertain and for this reason I propose that it not be allowed. For Hydro plants I analyzed the detailed list of projects and cost projections provided. I propose that the appropriate amount for hydro O&M is the difference between what was reported spent in 2005 and the projected expenditures for 2007 based on relicensing requirements, a total system increase of $1.2 million annually.

Q. WHAT ARE THE OTHER COMPONENTS TO THE O&M NORMALIZATION ADJUSTMENTS?

A. Contracts and materials are the other components. For materials I propose to include a normalizing adjustment of $1.3 million per year for scrubber reagent for the new Huntington Scrubber that was not part of the test year costs (*See* Exhibit Staff/203 page 22). I do not propose any normalizing increases for contracts other that what is contained in the escalation figure for the test year. In evaluating contracts I looked primarily at the shared plant maintenance table (*See* Exhibit Staff/ 203 page 37). Absent additional information about any scope change to routine O&M work loads and the nature of any special projects, I am unable to determine that an increase is justified.

Q. PLEASE SUMMARIZE THE O&M NORMALIZATION ADJUSTMENT AND WHAT YOU PROPOSE.

A. PacifiCorp has asked for an annual increase to system wide O&M generation costs of $14.8 million. For the reasons stated above, I propose that the total increase to generation O&M be $2.2 million. On an Oregon allocated basis this decreases the filed revenue requirement by $3.4 million.

Item	Company Request ($000)	Staff Position	System Difference	Oregon Allocated Staff Adjustment
Steam Plant	$11,018	$1,300	($9,718)	($2,588)
Seam Plant (Choilla)	($144)	($144)	$0	$0
Hydro	$3,025	$1,151	($1,874)	($499)
Other Generation	$1,053	$0	($1,053)	($281)
Other Generation (CT)	($120)	($120)	$0	$0

Total	$14,832	$2,187	($12,645)	($3,368)

Q. ARE THERE ANY MORE ADJUSTMENTS THAT YOU HAVE EVALUATED AND WOULD LIKE TO DISCUSS?

A. Yes, I have proposed an adjustment to Hydro Relicensing costs. This adjustment is S-17 and detailed in Exhibit PPL/901 Tab. 8.5.

Q. WHAT DO YOU PROPOSE?

A. I propose that the expenses that the Company has included in the test year budget for cash payments associated with its Hydro relicensing agreements at Bear River and North Umpqua be removed. The cash payments are a part of the hydro license. These nonrecurring expenses should be added to the test year rate base and the expenses amortized over the life of the facility licenses, in the case of Bear River, 24 years and in the case of North Umpqua. 33 years. This adjustment results in a revenue requirement of $102,000 related to the expenditures, which is a reduction of $584,000.

Q. DO YOU HAVE ANY MORE ADJUSTMENTS TO RECOMMEND?

A. No, that is all the adjustment I would propose.

Q. DO YOU HAVE ANY FURTHER TESTIMONY YOU WOULD LIKE TO PRESENT?

A. No.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

CASE: UE 179
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION
OF
OREGON

EXHIBIT STAFF 201

Witness Qualification Statement

July 12, 2006

WITNESS QUALIFICATION STATEMENT

NAME:	Ed Durrenberger
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Revenue Requirement Analyst
ADDRESS:	550 Capitol St. NE, Ste. 215, Salem, Oregon 97301
EDUCATION:	B.S. Mechanical Engineering Oregon State University, Corvallis, Oregon
EXPERIENCE:	I have been employed at the Public Utility Commission of Oregon since February of 2004. My current responsibilities include staff research, analysis and technical support on a wide range of electric and natural gas cost recovery issues.
OTHER EXPERIENCE:	I have over twenty years of operations and maintenance experience managing a boiler plant in a heavy industrial manufacturing environment. I have also managed manufacturing and production in high tech equipment manufacturing.

CASE: UE 179
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 202

Exhibits in Support of Direct Testimony

July 12, 2006

PACIFICORP UE 179
OREGON ALLOCATED RESULTS OF OPERATIONS
YEAR ENDING DECEMBER 31, 2007
($000)

		2007 Oregon Results Per Company Filing (1)	Adjustments (2)	2007 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
	SUMMARY SHEET					
1	**Operating Revenues**					
2	Retail Sales	$845,831	$0	$845,831	$12,144	$857,975
3	Wholesale Sales	278,958	13,253	292,211	0	292,211
4	Other Revenues	34,396	1,239	35,635	0	35,635
5	**Total Operating Revenues**	$1,159,185	$14,492	$1,173,677	$12,144	$1,185,821
6	**Operating Expenses**					
7	Steam Production	$208,897	($10,019)	$198,878	$0	$198,878
8	Hydro Production	10,895	(1,312)	9,583	0	9,583
9	Other Power Supply	344,596	(5,991)	338,605	0	338,605
10	Transmission	34,631	(1,671)	32,960	0	32,960
11	Distribution	74,778	(3,064)	71,714	0	71,714
12	Customer Accounts	36,313	(750)	35,563	0	35,563
13	Customer Service & Info	2,686	0	2,686	78	**2,764**
14	Sales	0	0	0	0	0
15	Administrative and General	69,288	(10,503)	58,785	0	58,785
16	**Total Operation & Maintenance**	$782,085	($33,310)	$748,775	$78	$748,853
17	Depreciation	121,382	0	121,382	0	121,382
18	Amortization	18,573	0	18,573	0	18,573
19	Taxes Other than Income	45,968	0	45,968	290	46,258
20	Income Taxes	52,652	15,932	68,584	4,468	73,052
21	Miscellaneous Revenue & Expense	(3,168)	0	(3,168)	0	(3,168)
22	**Total Operating Expenses**	$1,017,494	($17,378)	$1,000,116	$4,836	$1,004,952
23	**Net Operating Revenues**	$141,691	$31,870	$173,561	$7,306	$180,867
24	**Average Rate Base**					
25	Electric Plant in Service	$4,450,735	($2,940)	$4,447,795	$0	$4,447,795
26	Less: Accumulated Depreciation & Amortization	(1,914,195)	0	(1,914,195)	0	(1,914,195)
27	Accumulated Deferred Income Taxes	(324,880)	0	(324,880)	0	(324,880)
28	Accumulated Deferred Inv. Tax Credit	(7,435)	0	(7,435)	0	(7,435)
29	**Net Utility Plant**	$2,204,225	($2,940)	$2,201,285	$0	$2,201,285
30	Plant Held for Future Use	0	0	0	0	0
31	Acquisition Adjustments	19,855	0	19,855	0	19,855
32	Working Capital	25,678	(362)	25,316	101	25,417
33	Fuel Stock	18,042	0	18,042	0	18,042
34	Materials & Supplies	29,929	0	29,929	0	29,929
35	Customer Advances for Construction	0	0	0	0	0
36	Weatherization Loans	33	0	33	0	33
37	Prepayments	7,211	0	7,211	0	7,211
38	Misc. Deferred Debits	26,071	0	26,071	0	26,071
39	Misc. Rate Base Additions/(Deductions)	(28,846)	0	(28,846)	0	(28,846)
40	**Total Average Rate Base**	$2,302,198	($3,302)	$2,298,896	$101	$2,298,997
41	**Rate of Return**	6.15%		7.55%		**7.87%**
42	**Implied Return on Equity**	5.96%		8.60%		9.50%

PACIFICORP UE 179
STAFF ISSUE SUMMARY SHEET
PERIOD ENDING DECEMBER 31, 2007
($OOO)

Item	Staff	Proposed Staff Adjustments Issue	Revenue Requirement Effect
		Revenue Requirement on the Company's Filed Results	**$111,977**
S-0	BC/TM	Rate of Return-UE 179 Staff ROR 7.87%	**($46,370)**
S-1	LK	Rebasing Adjustment Adjusts O&M expenses to reflect additional benefits from Rebasing Program not included in test period results.	**($1,087)**
S-2	LK	Incentives Adjustment Staff adjusts test year incentive expenses to the traditional sharing percentages approved in previous GRCs (disallowing 50% of non-exec. and all of exec. Incentives.)	**($4,140)**
S-3	JJ	FIT and SIT Adjustments Adjusts test period income taxes based on Staff's proposed capital structure.	**($3,743)**
S-4	PR	Membership Adjustments Adjustment reflects EEI membership status.	**($58)**
S-5	PR	Other Revenues Adjustment Adjusts Other Revenues to properly reflect test year revenue projections.	**($1,277)**
S-6	PR	Uncollectibles Adjustment Represents the difference between the results of operations and a 3 year average of uncollectibles from FERC Form 1 data.	**($774)**
S-7	MD	A&G, Benefits and Pension Adjustments Includes RTO adjustment and adjusts A&G, Benefits and Pensions.	**($5,140)**
S-8	ED	RTO Adjustment This is included in the A&G adjustment S-7 .	**$0**
S-9	ED	Amortization of Capital Stock Expenses Removes costs associated with issuing common stock from test year results of operations.	**($603)**
S-10	ED	Generation Overhaul Expenses Adjusts certain supplemental increases to generation overhaul O&M expenses.	**($5,271)**
S-11	ED	PD Program Adjustment Adjusts some Power Distribution new system O&M and support costs.	**($5,036)**
S-12	ED	O&M Normalization Adjustments Adjusts generation, contracts and special maintenance O&M normalization in some areas.	**($3,478)**

PACIFICORP UE 179
STAFF ISSUE SUMMARY SHEET
PERIOD ENDING DECEMBER 31, 2007
($OOO)

S-13	BW	Wholesale Margin Adjustment Adjusts for additional margin that the company will realize from wholesale market sales and purchase transactions not captured in GRID.	**($13,656)**
S-14	BW	Ancillary Services Adjustment Reduces contingency reserve adjustment to net variable power costs to match ancillary services revenues in the filed case.	**($1,132)**
S-15	BW	Extrinsic Value Adjustment Reflect the option value of flexible power resources not dispatched in GRID.	**($7,301)**
S-16	ED	Hydro Relicensing Adjustment Adjusts cash payments from test year expenses.	**($709)**
S-17	BW	Station Service This adjustment was dropped.	**$0**
S-18	ED	Miscellaneous Differences Accounts for differences between company and Staff working capital allowance and rounding differences.	**($58)**
		Other Issues	
			(99,833)
		<u>Staff' Adjusted Revenue Requirement</u>	**$12,144**
		Percent change	1.43%

PACIFICORP UE 179
OREGON ALLOCATED RESULTS OF OPERATIONS
YEAR ENDING DECEMBER 31, 2007
($000)

	Income Tax Calculations	2007 Oregon Per Company Filing (1)	Adjustments (2)	2007 Oregon Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	Book Revenues	$1,159,185	$14,492	$1,173,677	$12,144	$1,185,821
2	Book Expenses Other than Depreciation	843,458	($33,310)	810,148	368	810,516
3	State Tax Depreciation	121,382	$0	121,382	0	121,382
4	Interest	67,763	($106)	67,657	3	67,660
5 Less:	Schedule M Differences(Deductions less Additions)	862	$0	862	0	862
6	State Taxable Income	$125,720	$47,908	$173,628	$11,773	$185,401
7	Add OR Depletion Adjustment	$0				
8	Total State Taxable Income	$125,718		$173,628	$11,773	$185,401
9	State Income Tax @ 4.540%	$5,708	$1,897	$7,605	$534	$8,139
10	State Tax Credits	$192	$0	192	0	192
11	Net State Income Tax	$5,900	$1,897	$7,797	$534	$8,331
12	Additional Tax Depreciation	0	0	0	0	0
13 Plus:	Other Schedule M Differences	0	0	0	0	0
14	Federal Taxable Income	$119,818	46,011	$165,829	$11,239	$177,068
15	Federal Tax @ 35%	41,936	14,035	55,971	3,934	59,905
16	Federal Tax Credits	(436)	0	(436)	0	(436)
17	Current Federal Tax	$41,500	$14,035	$55,535	$3,934	$59,469
18	ITC Adjustment		-			
19	Deferral	0	0	0	0	0
20	Restoration	0	0	0	0	0
21	Total ITC Adjustment	$0	$0	$0	$0	$0
22	Provision for Deferred Taxes	$5,252	$0	$5,252	$0	$5,252
23	Total Income Tax	$52,652	$15,932	$68,584	$4,468	$73,052

PACIFICORP UE 179
OREGON ALLOCATED RESULTS OF OPERATIONS
YEAR ENDING DECEMBER 31, 2007
($000)

REVENUE SENSITIVE COSTS	
Revenues (Operating Income)	1.00000
Operating Revenue Deductions	
Uncollectible Accounts	0.00652
Taxes Other - Franchise	0.02340
- Other	0.00000
- Resource supplier	0.00050
State Taxable Income	0.96958
State Income Tax	0.04402
Federal Taxable Income	0.92556
Federal Income Tax @ 35%	0.32395
ITC	0.00000
Current FIT	0.32395
Other	0.00000
Total Excise Taxes	0.36797
Total Revenue Sensitive Costs	0.39839
Utility Operating Income (NOI)	0.60161
Net-to-Gross Factor	**1.66219**

Input:		
	4.540%	STATERATE (Income Tax Rate)
	2.080%	WORKINGCAP

PACIFICORP UE 179
OREGON ALLOCATED RESULTS OF OPERATIONS
YEAR ENDING DECEMBER 31, 2007
($000)

STAFF INPUT ASSUMPTIONS

COST OF CAPITAL - STAFF	% of CAPITAL	COST	WEIGHTED COST
Long Term Debt	50.50%	6.330%	3.197%
Preferred Stock	1.00%	6.300%	0.063%
Common Equity	48.50%	9.500%	4.608%
Total	100.00%		7.867%

PACIFICORP
UE 179
ADJUSTMENTS TO OREGON ALLOCATED RESULTS
YEAR ENDING DECEMBER 31, 2007
($000)

	Staff Adjustments	(S-1) Rebasing	(S-2) Incentives	(S-3) FIT/ SIT	(S-4) Memberships	(S-5) Other Revenues	(S-6) Uncollectible	(S-7) A&G Benefits and Pensions	(S-8) RTO Adjustment	(S-9) Amortization of Common Stock Expenses	(S-10) Generation Overhaul Expense	(S-11) Power Delivery Adjustment	(S-12) O&M Normalization Adjustment	(S-13) Wholesale Margin Adjustment	(S-14) Ancillary Services Adjustment	(S-15) Extrinsic Value Adjustment	(S-16) Hydro Relicensing adjustment	(S-17) Station Service Adjustment	Total Adjustments (Base Rates)
1	**Operating Revenues**																		
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Wholesale Sales	0	0	0	0	0	0	0	0	0	0	0	0	13,253	0	0	0	0	$13,253
4	Other Revenues	0	0	0	0	1,239	0	0	0	0	0	0	0	0	0	0	0	0	$1,239
5	**Total Operating Revenues**	**$0**	**$0**	**$0**	**$0**	**$1,239**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$13,253**	**$0**	**$0**	**$0**	**$0**	**$14,492**
6	**Operating Expenses**																		
7	Steam Production	0	0	0	0	0	0	0	0	0	(4,780)	0	(2,588)	0	0	(2,651)	0	0	($10,019)
8	Hydro Production	0	0	0	0	0	0	0	0	0	(127)	0	(499)	0	0	0	(686)	0	($1,312)
9	Other Power Supply	0	0	0	0	0	0	0	0	0	(197)	0	(281)	0	(1,096)	(4,417)	0	0	($5,991)
10	Transmission	0	0	0	0	0	0	0	0	0	0	(1,671)	0	0	0	0	0	0	($1,671)
11	Distribution	0	0	0	0	0	0	0	0	0	0	(3,064)	0	0	0	0	0	0	($3,064)
12	Customer Accounting	0	0	0	0	0	(750)	0	0	0	0	0	0	0	0	0	0	0	($750)
13	Customer Service & Info	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	$0
14	Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
15	Administrative and General	(1,053)	(3,857)	0	(54)	0	0	(4,813)	0	(584)	0	(142)	0	0	0	0	0	0	($10,503)
16	**Total Operation & Maintenance**	**($1,053)**	**($3,857)**	**$0**	**($54)**	**$0**	**($750)**	**($4,813)**	**$0**	**($584)**	**($5,104)**	**(4,877)**	**($3,368)**	**$0**	**($1,096)**	**($7,068)**	**($686)**	**$0**	**($33,310)**
17	Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
18	Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
19	Taxes Other than Income	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
20	Income Taxes	400	1,481	(2,248)	19	470	285	1,846	0	222	1,938	1,852	1,279	5,029	416	2,683	260	0	$15,932
21	Miscellaneous Revenue and Expense	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
22	**Total Operating Expenses**	($653)	($2,376)	($2,248)	($35)	$470	($465)	($2,967)	$0	($362)	($3,166)	($3,025)	($2,089)	$5,029	($680)	($4,385)	($426)	$0	($17,378)
23	**Net Operating Revenues**	**$653**	**$2,376**	**$2,248**	**$35**	**$769**	**$465**	**$2,967**	**$0**	**$362**	**$3,166**	**$3,025**	**$2,089**	**$8,224**	**$680**	**$4,385**	**$426**	**$0**	**$31,870**
24	**Average Rate Base**																		
25	Electric Plant in Service	$0	($1,410)	$0	$0	$0	$0	($1,530)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2,940)
26	Accumulated Depreciation & Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
27	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
28	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
29	**Net Utility Plant**	$0	($1,410)	$0	$0	$0	$0	($1,530)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2,940)
30	Plant Held for Future Use	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
31	Acquisition Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
32	Working Capital	(14)	(49)	(47)	(1)	10	(10)	(62)	0	(8)	(66)	(63)	(43)	105	(14)	(91)	(9)	0	($362)
33	Fuel Stock	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
34	Materials & Supplies	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
35	Customer Advances for Construction	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
36	Weatherization Loans	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
37	Prepayments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
38	Misc. Deferred Debits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
39	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
40	**Total Average Rate Base**	**($14)**	**($1,459)**	**($47)**	**($1)**	**$10**	**($10)**	**($1,592)**	**$0**	**($8)**	**($66)**	**($63)**	**($43)**	**$105**	**($14)**	**($91)**	**($9)**	**$0**	**($3,302)**
41	**Revenue Requirement Effect**	**($1,087)**	**($4,140)**	**($3,743)**	**($58)**	**($1,277)**	**($774)**	**($5,140)**	**$0**	**($603)**	**($5,271)**	**($5,036)**	**($3,478)**	**($13,656)**	**($1,132)**	**($7,301)**	**($709)**	**$0**	**($53,405)**

PACIFICORP UE 179
STAFF ADJUSTMENTS TO OREGON ALLOCATED RESULTS
YEAR ENDING DECEMBER 31, 2007
($000)

	Income Tax Calculations	(S-1) Rebasing	(S-2) Incentives	(S-3) FIT/ SIT	(S-4) Memberships	(S-5) Other Revenues	(S-6) Uncollectible	(S-7) A&G Benefits and Pensions	(S-8) RTO Adjustment	(S-9) Amortization of Common Stock Expenses	(S-10) Generation Overhaul Expense	(S-11) Power Delivery Adjustment	(S-12) O&M Normalization Adjustment	(S-13) Wholesale Margin Adjustment	(S-14) Ancillary Services Adjustment	(S-15) Extrinsic Value Adjustment	(S-16) Hydro Relicensing adjustment	(S-17) Station Service Adjustment	Total Adjustments (Base Rates)
1	Book Revenues	$0	$0	$0	$0	$1,239	$0	$0	$0	$0	$0	$0	$0	$13,253	$0	$0	$0	$0	$14,492
2	Book Expenses Other than Depreciation	(1,053)	(3,857)		(54)	0	(750)	(4,813)	0	(584)	(5,104)	(4,877)	(3,368)	0	(1,096)	(7,068)	(686)	0	($33,310)
3	State Tax Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
4	Interest	(0)	(47)	(2)	(0)	0	(0)	(51)	0	(0)	(2)	(2)	(1)	3	(0)	(3)	(0)	0	($106)
5	Schedule M Differences	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
6	State Taxable Income	$1,053	$3,904	$2	$54	$1,239	$750	$4,864	$0	$584	$5,106	$4,879	$3,369	$13,250	$1,096	$7,071	$686	$0	$47,908
7	Add OR Depletion Adjustment-Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
8	Total State Taxable Income	$1,053	$3,904	$2	$54	$1,239	$750	$4,864	$0	$584	$5,106	$4,879	$3,369	$13,250	$1,096	$7,071	$686	$0	
9	State Income Tax	$48	$177	($277)	$0	$56	$34	$221	$0	$27	$232	$222	$153	$602	$50	$321	$31	$0	$1,897
10	State Tax Credits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
11	Net State Income Tax	$48	$177	($277)	$0	$56	$34	$221	$0	$27	$232	$222	$153	$602	$50	$321	$31	$0	$1,897
12	Additional Tax Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
13	Other Schedule M Differences	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
14	Federal Taxable Income	$1,005	$3,727	$279	$54	$1,183	$716	$4,643	$0	$557	$4,874	$4,657	$3,216	$12,648	$1,046	$6,750	$655	$0	$46,011
15	Federal Tax @ 35%	352	1,304	($1,971)	19	414	251	1,625	0	195	1,706	1,630	1,126	4,427	366	2,362	229	0	$14,035
16	Federal Tax Credits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
17	Current Federal Tax	$352	$1,304	($1,971)	$19	$414	$251	$1,625	$0	$195	$1,706	$1,630	$1,126	$4,427	$366	$2,362	$229	$0	$14,035
18	ITC Adjustment																		$0
19	Deferral	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
20	Restoration	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
21	Total ITC Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
																			$0
22	Provision for Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
																			$0
23	Total Income Tax	$400	$1,481	($2,248)	$19	$470	$285	$1,846	$0	$222	$1,938	$1,852	$1,279	$5,029	$416	$2,683	$260	$0	$15,932

REVENUE REQUIREMENTS EFFECTS OF ADJUSTMENTS

	(S-1) Rebasing	(S-2) Incentives	(S-3) FIT/ SIT	(S-4) Memberships	(S-5) Other Revenues	(S-6) Uncollectible	(S-7) A&G Benefits and Pensions	(S-8) RTO Adjustment	(S-9) Amortization of Common Stock Expenses	(S-10) Generation Overhaul Expense	(S-11) Power Delivery Adjustment	(S-12) O&M Normalization Adjustment	(S-13) Wholesale Margin Adjustment	(S-14) Ancillary Services Adjustment	(S-15) Extrinsic Value Adjustment	(S-16) Hydro Relicensing adjustment	(S-17) Station Service Adjustment		Total Adjustments (Base Rates)
Revenues and Expenses	($1,085)	($3,949)	($3,737)	($58)	($1,278)	($773)	($4,932)	$0	($602)	($5,262)	($5,028)	($3,472)	($13,670)	($1,130)	($7,289)	($708)	$0		($52,973)
Rate Base	(2)	(191)	(6)	0	1	(1)	(208)	0	(1)	(9)	(8)	(6)	14	(2)	(12)	(1)	0	0	($432)
Total	($1,087)	($4,140)	($3,743)	($58)	($1,277)	($774)	($5,140)	$0	($603)	($5,271)	($5,036)	($3,478)	($13,656)	($1,132)	($7,301)	($709)	$0		($53,405)

CASE: UE 179
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support of
Direct Testimony

July 12, 2006

UE-179/PacifiCorp
March 23, 2006
OPUC Data Request 140

OPUC Data Request 140

Referring to PPL Exhibit 901, Tab 4.8, Generation Overhaul Normalization, please provide historical data, by unit and by the categories listed on page 4.8 for FY 2001 through 2005 overhaul costs.

Response to OPUC Data Request 140

See Attachment OPUC 140 on the enclosed CD for historical overhaul data for FY 2001 through FY 2005 by unit.

Generation

Historical Overhaul O&M Our Share ($000)

	2001 Actual	2002 Actual	2003 Actual	2004 Actual	2005 Actual
Hunter U1	2,185	512	-	-	199
Hunter U2	202	537	2,600	803	-
Hunter U3	995	4,085	878	650	-
Huntington U1	193	6,689	806	-	1,511
Huntington U2	716	-	6,741	-	-
DaveJohnston U1	115	73	685	1,604	26
DaveJohnston U2	949	65	-	-	845
DaveJohnston U3	767	-	-	-	203
DaveJohnston U4	212	855	-	4,714	115
Wyodak U1	2,413	-	-	87	652
JimBridger U1	401	501	3,971	850	12
JimBridger U2	392	3,291	131	422	165
JimBridger U3	131	218	375	4,227	-
JimBridger U4	2,060	796	473	118	3,917
Naughton U1	-	-	4,570	85	804
Naughton U2	-	570	3,762	370	-
Naughton U3	317	-	311	5,680	-
Carbon U1	1,133	-	283	-	2,455
Carbon U2	-	303	-	686	1,900
Gadsby U1	-	-	1,418	-	-
Gadsby U2	143	-	-	1,293	-
Gadsby U3	-	1,703	-	-	-
Gadsby U4	-	-	-	-	-
Gadsby U5	-	-	-	-	-
Gadsby U6	-	-	-	-	-
LittleMt U1	-	-	431	-	-
Blundell	-	554	-	-	-
WValley U1	-	-	-	40	-
Craig U1	-	-	449	2,131	-
Craig U2	500	1,200	-	-	815
Hayden U1	98	-	80	414	-
Hayden U2	-	145	-	-	198
Cholla U4	2,989	-	-	705	5,066
Hermiston U1	1,224	735	800	1,626	729
Hermiston U2	330	745	2,783	615	490
Colstrip U3	-	755	-	100	839
Colstrip U4	1,067	-	100	588	75
Camas U1	201	-	-	788	-
Hydro	-	-	-	-	-
Sub-Total	19,733	24,331	31,646	28,595	21,016
Other Adjustments		(699)		85	1,237
Remove Thermal Labor	(940)	(1,515)	(1,977)	(2,330)	(1,587)
Total	18,792	22,117	29,669	26,350	20,666

UE-179/PacifiCorp
May 19, 2006
OPUC Data Request 333

OPUC Data Request 333

Referring to the Generation Overhaul Normalization adjustment 4.8:

a. Please provide a unit by unit breakdown of the major refurbishment or replacement projects contained in this adjustment. Please indicate the calendar year in which these projects are expected to be executed/completed. Indicate the expected benefits of each extraordinary maintenance projects in terms of higher capacity factors, improved efficiency, or unit life extension.

b. Testimony states "The overhaul expenditures for the Test Period are representative of the level of O&M that are forecast for the foreseeable future." Is the company aware of or have they performed any benchmarking studies comparing these test year O&M cost projections on a per customer or per unit of production basis (for instance) to similarly situated peers or to industry averages that indicate that O&M costs at these projected levels are reasonable? If so what are the results?

c. Please provide a schedule of the planned Overhaul O&M for each unit listed on OPUC 140 including major and minor outages from 2001 through 2008. Indicate the type of outage and duration. If there are any deviations from the past routine overhaul schedules in the test period please explain them.

Response to OPUC Data Request 333

a. & c: The table in Attachment OPUC 333 -1 summarizes the plant overhaul expenditures by unit and contains an additional 3 years of planned overhaul expenditures for 2009, 2010, and 2011. The scope of work for each overhaul is determined from unit inspections, operating experience, analyzing performance data, and consulting with original equipment manufactures. Typical overhaul projects consist of rebuilding components that affect plant reliability and impact unit availability. The comments column of Attachment OPUC 333 -2 contains critical path overhaul projects that usually drive the overhaul duration. Plant component life cycles are a function of age, wear, and load factor. Components have varying life cycles and the plants base planning decisions on accepted industry practices for timely repairs.

The forecasting methodology used in developing planned overhaul expenditures is based on a number of factors. First, the number of generating units in the fleet is increasing. Second, total overhaul costs reflect the number of units that are off-line during any given year and that number is determined by examining the condition, the performance, and the potential risk to reliability and safety for each unit. As a result, the number of units off-line in any given year will vary. Third, overhaul costs reflect the size of the units that are off-line. A large unit will require a larger contractor workforce and more materials than a smaller unit.

Fourth, overhaul costs also reflect the amount of work required to complete the necessary maintenance on the units. The rising age of plant equipment is increasing the amount of work required to maintain reliability. Finally, plant personnel assess equipment condition and review component life cycles to optimize component reliability and budget work to the appropriate overhaul cycle.

Attachment OPUC 333 -3 contains an overhaul schedule history and future overhaul schedule that corresponds with the same period as Attachment OPUC 333 -1. The time interval between overhauls and duration of overhauls dictate the overhaul schedule and are driven by the aging condition of each generating unit. The length of the interval between major planned maintenance outages is based on the equipment's design, condition and age, PacifiCorp's specific experience operating and maintaining the equipment, and PacifiCorp's knowledge of current and past industry experience with similar equipment. Planning and scheduling of unit overhauls is a continuous and detailed process. The overall objective is to maintain high equivalent availability. A second objective is to schedule the unit overhauls in a manner such that resources are available to meet system load requirements. The length of intervals between overhauls for each unit is based on the factors discussed above, as well as the condition of the generating unit, performance of the generating unit, system requirements, and PacifiCorp's experience with similar units. The overhaul schedule is revised from time to time as new information on the condition of units and resource needs are available. Generally, the major overhaul interval is between four and five years for each unit with an inspection overhaul in between major overhauls.

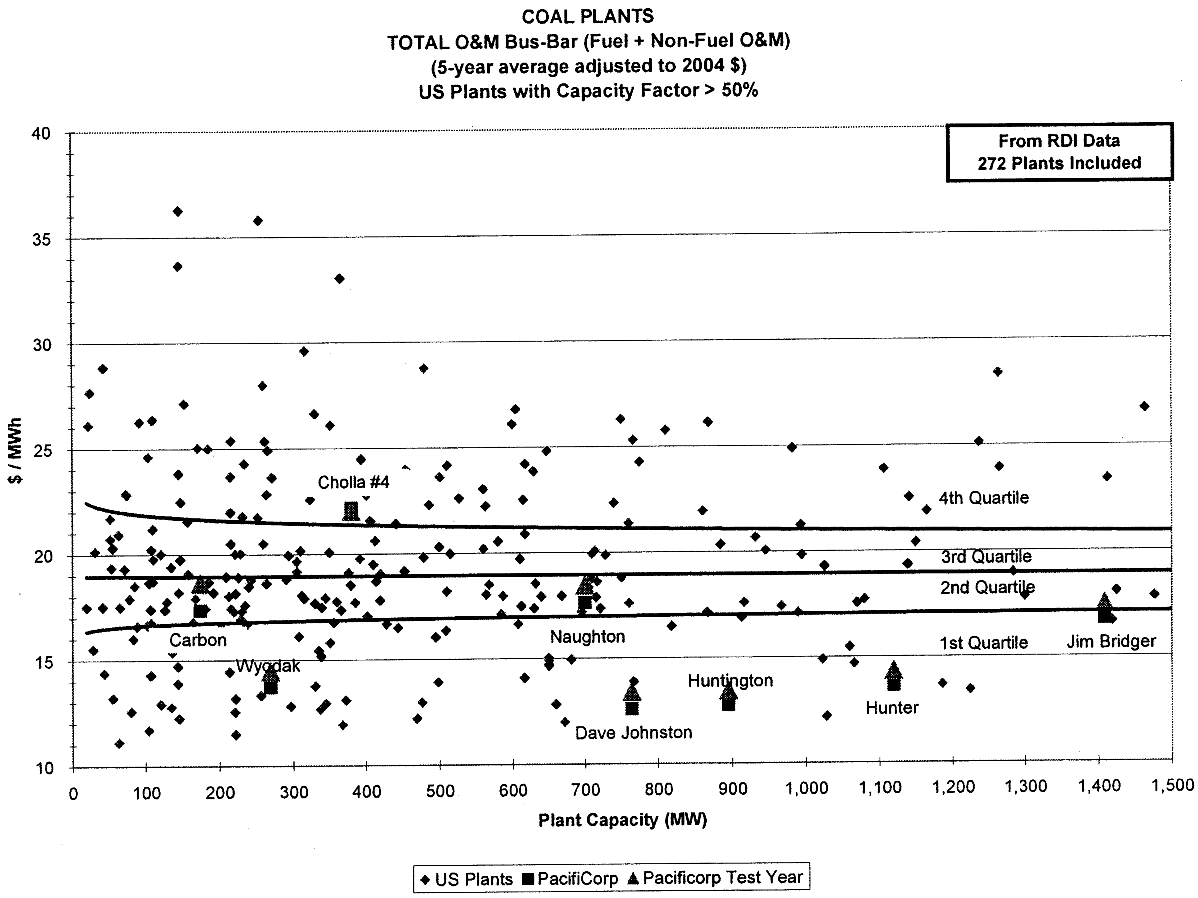
The costs on 4.8.2 are planned inspection overhauls and major overhauls for each plant. There are no unplanned outage costs in the overhaul cost table 4.8.2. Unplanned outage costs are forecasted in the routine O&M budgets.

b. PacifiCorp uses the Platts RDI POWERDAT database to compare the costs of PacifiCorp coal fired plants against coal fired plants of other utilities. The Platts company collects public information from the federal government on power utilities and compiles it into a database that is useful for making comparisons. The following charts have been used in the past to compare PacifiCorp costs with other utilities. They were produced using all the POWERDAT data available on coal fired plants of similar size for the most recent five years of published data: 2000 through 2004.

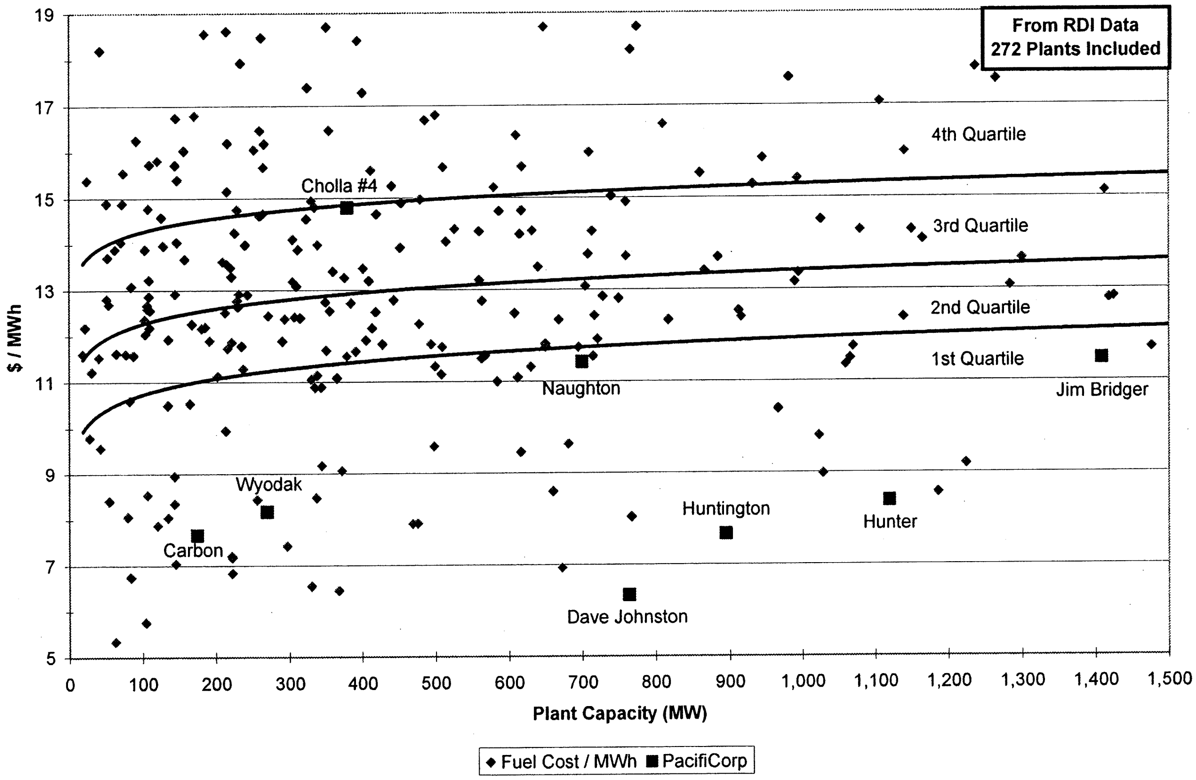
The first chart (Total O&M Bus-bar) is a comparison of operation, maintenance and fuel costs per megawatt hour of net generation for the plants listed in the POWERDAT database. As shown, PacifiCorp had some of the lowest costs in the nation in 2004 (indicated by the blue squares). The Test Period operation and maintenance costs for PacifiCorp operated coal plants are expected to increase by roughly 13 percent while no increases are expected for Cholla Unit 4 (see the green triangles). So, even if the costs of other utilities don't increase at all (which is not likely), PacifiCorp will still remain in the first and second quartiles of the industry and remain a very low cost provider of electricity.

The second chart (Fuel Bus-bar) shows the fuel cost per megawatt hour of net generation. The main reason PacifiCorp's costs are so low is that fuel costs are low. However, there are reasons for the fuel costs being low. The fuels used by PacifiCorp have some undesirable qualities. Some of the fuels have high quantities of ash and are very abrasive causing high wear rates on the boilers as well as the fuel and ash handling equipment. Other fuels have constituents that cause excessive fouling and plugging in the boilers and flue-gas handling equipment resulting in frequent cleaning and special operating procedures.

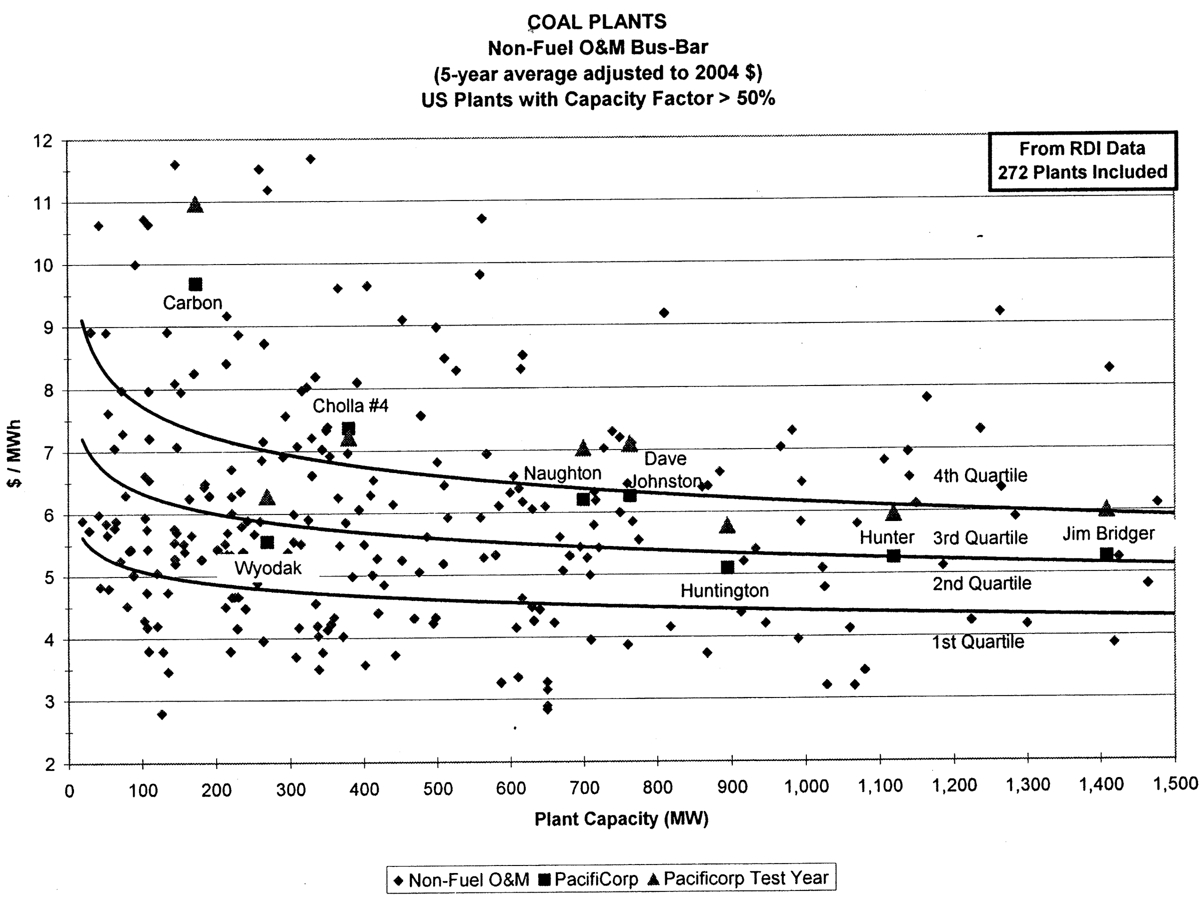
The third chart (Non-fuel O&M Bus-bar) shows the non-fuel operations and maintenance costs per megawatt hour of net generation. As you can see by the blue squares on the chart, most of PacifiCorp's plants have Operation and Maintenance costs that are near the industry average: second and third quartiles. If industry costs were frozen at current levels, PacifiCorp operation and maintenance costs would, at worst case, move into the third and fourth quartiles based on proposed Test Period increases (see the green triangles). This may seem high if you don't consider the fuel impacts. On the down side, PacifiCorp will be forced to spend more in operation and maintenance to keep up with the extra wear and tear caused by the fuel. But, on the up side, the low cost of that fuel offsets the increase in operation and maintenance costs to such an extent that PacifiCorp will continue to be a very low cost supplier of electricity.


COAL PLANTS
TOTAL O&M Bus-Bar (Fuel + Non-Fuel O&M)
(5-year average adjusted to 2004 $)
US Plants with Capacity Factor > 50%
From RDI Data
272 Plants Included
$ / MWh
40
35
30
25
20
15
10
0
100
200
300
400
500
600
700
800
900
1,000
1,100
1,200
1,300
1,400
1,500
Plant Capacity (MW)
Cholla #4
4th Quartile
3rd Quartile
2nd Quartile
1st Quartile
Carbon
Wyodak
Naughton
Huntington
Hunter
Jim Bridger
Dave Johnston
US Plants
PacifiCorp
Pacificorp Test Year

COAL PLANTS
FUEL Bus-Bar
(5-year average adjusted to 2004 $)
US Plants with Capacity Factor > 50%



UE-179/PacifiCorp
May 19, 2006
OPUC Data Request 333



Attachment OPUC 333 -1

Unit Detail to 4.8.2 Table with 3 Additional Forecast Years

Generation					
2007 Ten-Year Plan - Overhaul O&M Our Share ($000)					
		2008 $			
	2007	2008	2009	2010	2011
	Budget	Budget	Plan	Plan	Plan
Hunter U1	-	1,219	1,688	6,281	-
Hunter U2	3,491	-	784	1,086	4,041
Hunter U3	1,538	6,437	-	1,300	7,470
Huntington U1	-	992	-	7,577	-
Huntington U2	8,014	-	992	-	7,426
DaveJohnston U1	-	-	3,837	-	640
DaveJohnston U2	4,096	-	640	-	-
DaveJohnston U3	-	989	-	4,064	-
DaveJohnston U4	-	5,058	-	925	250
Wyodak U1	5,888	-	-	-	610
JimBridger U1	5,414	-	709	-	4,899
JimBridger U2	-	709	-	5,124	-
JimBridger U3	-	5,585	-	709	-
JimBridger U4	848	-	5,446	-	755
Naughton U1	664	4,703	-	1,792	-
Naughton U2	4,168	-	1,792	1,613	6,035
Naughton U3	-	924	6,412	-	1,792
Carbon U1	319	-	2,600	-	-
Carbon U2	-	2,245	-	-	330
Gadsby U1	-	-	-	1,081	-
Gadsby U2	-	-	-	-	1,081
Gadsby U3	-	-	1,216	-	-
Gadsby U4	-	1,028	-	-	-
Gadsby U5	-	-	1,028	-	-
Gadsby U6	-	-	-	1,028	-
LittleMt U1	113	-	529	-	-
Blundell	50	459	-	-	-
WValley U1	-	-	-	1,028	-
WValley U2	-	-	1,028	-	-
WValley U3	-	1,028	-	-	-
WValley U4	-	-	-	-	1,028
WValley U5	-	-	-	-	-
CurrantCreek	524	4,480	4,065	4,635	3,225
LakeSide	-	-	74	373	74
Craig U1	500		957	-	-
Craig U2	-	1,307	-	250	750
Hayden U1	314	-	-	1,050	-
Hayden U2	-	305	-	-	405
Cholla U4	500	700	7,800	-	500
Hermiston U1	1,800	824	848	2,420	892
Hermiston U2	900	824	2,698	896	923
Colstrip U3	125	815	-	45	852
Colstrip U4	865	-	45	825	-
Camas U1	-	780	-	430	-
Hydro	895	1,157	2,375	2,304	2,548
Remove Thermal Labor	(2,378)	(2,967)	(2,899)	(2,495)	(3,559)
Total	**38,648**	**39,600**	**44,663**	**44,341**	**42,968**

Attachment 333 -2 – Thermal Outage Schedule (FY06R8 06Jan06)

FY	Unit	Days	Comments
FY2001	Dave Johnston 2	30	Minor
FY2001	Cholla 4	30	Minor, Controls Change, Date Change
FY2001	Colstrip 3	16	Preheater Baskets, Chemical Clean
FY2001	Dave Johnston 1	9	Inspection. Date Change
FY2001	Jim Bridger 1	9	Short. Date Change.
FY2001	Bonanza	44	Replace HP-IP-LP, Replace Controls & 3 Pulv.
FY2001	Gadsby 3	16	Cooling Tower, Turbine Valves, ID Pedestal.
FY2001	Jim Bridger 4	37	Turbine Upgrade
FY2001	Wyodak	30	Major
FY2001	James River	7	3 Yr Inspection
FY2001	Colstrip 4	30	Turbine – Generator Work. Pre Heater Baskets.
FY2001	River Road	21	Minor
FY2001	Centralia 1	16	Minor
FY2001	Hermiston 2	7	Combustion Inspection
FY2001	Little Mountain	28	Unit Available – GSL Off
FY2001	Hayden 1	28	Boiler Inspection. Possible move to March.
FY2001	Hunter 2	7	Inspection
FY2001	Dave Johnston 4	3	Inspection/Tube Leak Repair
FY2001	Carbon 2	4	Chemical Clean
FY2001	Dave Johnston 3	9	Inspection
FY2001	Hermiston 1	7	Combustion Inspection * Possible move to 05/01*
FY2001	Huntington 2	7	Inspection, Economizer Clean, Circ Water Pump
FY2001	Craig 2	50	Boiler Inspection, new Controls
FY2001	Colstrip 3	56	Boiler Work, Replace Nose Arch
FY2001	River Road	20	Hot Gas Path Inspection
FY2001	Hunter 3	35	Boiler Bottom Repair
FY2001	Jim Bridger 2	35	Boiler,LP Insp.,BFPR, CT
FY2002	Dave Johnston 1	4	Air Heater & Condenser Cleaning, Precip.
FY2002	Hayden 2	28	2-4,5 fwh replace, cc, boiler insp, b.a. repairs
FY2002	Dave Johnston 2	4	Air Heater & Condenser Cleaning, Precip.
FY2002	Blundell	33	Major – Turbine Repairs, Brine System
FY2002	Huntington 1	30	Controls Upgrade
FY2002	Jim Bridger 3	8	Inspection, Air Heater Wash
FY2002	Hermiston 2	7	Combustion Inspection
FY2002	Dave Johnston 4	20	Extended Mini
FY2002	Gadsby 3	50	Major – Turbine and Generator
FY2002	Carbon 2	6	Insp- 4 day reduction Jan Chemical Clean
FY2002	Hermiston 1	7	Combustion Inspection
FY2002	Jim Bridger 4	9	Inspection
FY2003	River Road	10	Combustion Inspection
FY2003	Hunter 2	72	Boiler, Generator, (change turbine controls)
FY2003	Craig 1	16	
FY2003	Naughton 2	39	Major
FY2003	Dave Johnston 3	4	Econ Duct, APH
FY2003	Sunnyside	14	Planned Maintenance
FY2003	Blundell	3	Replace Stop Valve
FY2003	Hunter 3	8	Chemical Clean, Inspection
FY2003	Hermiston 2	28	Major Inspection
FY2003	Jim Bridger 1	30	Boiler, LP, (no controls upgrade)
FY2003	Dave Johnston 1	8	Inspection
FY2003	Little Mountain	42	Major – Turb Insp, Gear Box Installation

Attachment 333 -2 – Thermal Outage Schedule (FY06R8 06Jan06)

FY	Unit	Days	Comments
FY2003	Colstrip 4	4	Short Mini
FY2003	Naughton 1	38	APS ends 09/15
FY2003	Carbon 1	7	Inspection
FY2003	Huntington 2	42	Controls Upgrade
FY2003	Gadsby 6	7	Replace Rotor, GE install new compressor blades (warranty)
FY2003	Hayden 2	9	Scrubber Duct Repairs
FY2003	Sunnyside	7	
FY2003	Gadsby 1	56	HP/LP
FY2003	Naughton 3	5	Planned Maintenance
FY2003	West Valley 3	3	Blade Change, Inspection, F Sock
FY2003	Hermiston 2	7	Major Inspection
FY2003	Jim Bridger 4	4	Air Pre-Heater Wash
FY2003	West Valley 1	3	Blade Change, Inspection, F Sock
FY2003	Huntington 1	7	Inspection, Turbine Foam Clean, Boiler Chemical Clean, Burner Wk.
FY2003	West Valley 5	3	Blade Change, Inspection, F Sock
FY2003	Colstrip 4	58	Boiler Major – Crosses Fiscal Year
FY2003	Dave Johnston 4	35	Crosses Fiscal Year 2003/2004
FY2004	Bonanza	16	Exciter Controls – possible 2 days at various loads for testing…
FY2004	Hunter 3	48	Running Equip. Mtc. Outage – Coal Mills, Scrubber – 120 MW DeRate
FY2004	Jim Bridger 2	9	Planned Maintenance and Inspection
FY2004	Blundell	3	HV114, Brine Valves, Control Valve Actuator
FY2004	Craig 2	9	Bag House and Precipitator – Yampa Env Project
FY2004	Hayden 1	44	Boiler Inspection
FY2004	Sunnyside	14	
FY2004	Hermiston 1	28	Combustion Inspection
FY2004	Cholla 4	6	Planned Maintenance
FY2004	Camas Cogen	19	Turbine Inspection, Replace #2 Bearing, Generator Testing
FY2004	Jim Bridger 3	44	Major, Controls Upgrade
FY2004	Dave Johnston 3	12	Short Outage
FY2004	River Road	10	Combustion Inspection
FY2004	Craig 1	44	Major
FY2004	Naughton 3	49	Boiler Major, Generator Rewind, Major Economizer Work
FY2004	Dave Johnston 1	30	Boiler, Precip, Turbine Valves, Condensor, Chemical Clean
FY2004	Blundell	3	HV-114, Brine Valves, Production Well 28-3
FY2004	Carbon 2	4	Mini OH
FY2004	Naughton 2	16	Boiler Repairs, Chemical Clean
FY2004	Sunnyside	7	
FY2004	Gadsby 2	35	Major, HP Minor, HP Water Seals OK 09/30/03
FY2004	Hermiston 1	8	Combustion Inspt – degas and check the main lead on the CT rotor
FY2004	Hermiston 2	3	Inspection
FY2004	Craig 2	44	Major
FY2004	Jim Bridger 1	9	Inspection…..Moved From FY05.. Date Is Official
FY2005	Cholla 4	32	Minor

Attachment 333 -2 – Thermal Outage Schedule (FY06R8 06Jan06)

FY	Unit	Days	Comments
FY2005	Naughton 1	9	Critical Pipe, Hot Reheat Inspection….Moved From Fall
FY2005	Wyodak	9	Inspection - Moved from March to April
FY2005	Colstrip 3	44	Major………One week after unit start up…Chem Clean Planned
FY2005	Dave Johnston 2	9	New…….Mini Inspection
FY2005	Carbon 2	35	Boiler Major and Trb Vlv Inspt,Chem Cln., Low Nox
FY2005	Jim Bridger 4	42	Controls Upgrade, Idaho Power Needs On Line By 06/01/04
FY2005	Huntington 1	6	Mini. Inspection….Moved from March FY 2004
FY2005	Hayden 2	25	Inspection, FWH, Valves,** New sch dates: 11 days shorter
FY2005	Hermiston 2	7	Combustion Inspection
FY2005	River Road	31	Steam Turbine-Major………..changed to 31 days
FY2005	Little Mountain	7	
FY2005	Colstrip 4	9	Inspection, Boiler Chemical Clean
FY2005	Blundell	5	Mini Outage
FY2005	Carbon 1	35	Economizer, Major boiler and Turbine,
FY2005	Sunnyside	7	
FY2005	Hermiston 1	8	Combustion Inspection, HSRG Load center repairs
FY2006	Hunter 3	5	Turbine chemical clean
FY2006	Jim Bridger 2	56	Low Nox Burnr, Gen Rewind, Cntrls Upgrde,
FY2006	Dave Johnston 4	16	L-0 Bucket replacement, Boiler Inspt, Boiler Chem. Cln.
FY2006	Hunter 1	28	Major, Cooling Twr, DEH, Gen Warranty Inspection, SDCC
FY2006	Sunnyside	14	
FY2006	Dave Johnston 3	30	Trb. Vlv Inspt, Blr Lwer Arch , Air Htr baskets, Chem Cln
FY2006	River Road	31	Combustion Inspection – Gas Turbine Major…
FY2006	Hermiston 2	16	Hot Gas Path Inspection, Stm. Turbine overhaul
FY2006	Jim Bridger 3	9	Mini -
FY2006	Dave Johnston 1	9	Boiler Inspection, Air Heater Basket Replacement
FY2006	Little Mountain	45	Foundation repairs, expansion jt replacement, Combustion inspection.
FY2006	Huntington 1	37	Turbine OH, Gen Rotor Rewind, RH & SH repl, Major scrub
FY2006	Naughton 3	9	Air Htr, Econ, Scrubber, Clean – Replace CRH safety valves,
FY2006	CurrantCrk-1A	0	Tie In Period
FY2006	CurrantCrk-1B	0	Tie In Period
FY2006	Blundell	6	Added 3 days to original outage
FY2006	Sunnyside	7	
FY2006	West Valley 1	3	Minor Generator Inspections
FY2006	West Valley 2	3	Minor Generator Inspections
FY2006	West Valley 3	3	Minor Generator Inspections
FY2006	West Valley 4	3	Minor Generator Inspections
FY2006	West Valley 5	3	Minor Generator Inspections
FY2006	West Valley 1	2	Bushing Replacement
FY2006	West Valley 2	2	Bushing Replacement
FY2006	West Valley 3	2	Bushing Replacement
FY2006	West Valley 4	2	Bushing Replacement

Attachment 333 -2 – Thermal Outage Schedule (FY06R8 06Jan06)

FY	Unit	Days	Comments
FY2006	Gadsby 4	3	Bushing Replacement & Svc Bulletins
FY2006	Gadsby 5	3	Bushing Replacement & Svc Bulletins
FY2006	Gadsby 6	3	Bushing Replacement & Svc Bulletins
FY2006	Cholla 4	6	Fan repairs, Scrubber clean, Inspections, Dog Bone Replacement (cp); Scrubber moved outage up from May
FY2006	Carbon 2	7	Mini
FY2007	Hermiston 2	8	Combustor inspection; Moved start from 4Mar06 to 1Apr06
FY2007	Jim Bridger 1	42	Controls Upgrade, Low Nox Burners deferred
FY2007	Naughton 2	30	Major HP/IP turbine, vlvs & brgs,Blr, Burners,Air htr,retube condenser,rpl HP fwh's, trb ctrls, ASI sootblower controls, rpl sootblowers – critical pipe inspection
FY2007	Hayden 1	35	Boiler insp, throttle vlvs, econ header & bull nose, DCS
FY2007	Camas Cogen	7	Turbine Valves
FY2007	Colstrip 3	9	FIRM DATE NOT SET – Boiler Chemical Clean
FY2007	Hunter 2	35	Major Turbine Insp.,Gen Warr.Insp., LTSH
FY2007	Hermiston 1	18	Hot Gas Path Inspection; Steam Turbine Major
FY2007	River Road	31	Combustion Inspection; Extended outage from 10 to 31 days
FY2007	Colstrip 4	51	
FY2007	Sunnyside	14	; Changed from 16Apr06 start to 13May06, 14-days each
FY2007	Wyodak	42	H2Owall Tube Replace, Cntrls Upgrd, GenRewind
FY2007	Jim Bridger 4	9	Mini -
FY2007	Little Mountain	35	25000 hr inspection -
FY2007	Dave Johnston 2	37	Major turbine/gen, major boiler, APH basket replacement, minor controls upgrade, ignitor replacement, exciter replacement, ww inlet header replacements.
FY2007	Huntington 2	65	Low Nox Burners, Major, scrubber/baghouse project, SH & RH, Gen Rotor
FY2007	CurrantCrk-1B	2	CTG Borescope -
FY2007	Blundell	6	6 Day Mini ; Changed start from Oct 14 to May13, Turbine Inspection & MCC Tie In
FY2007	CurrantCrk-1B	7	CTG Combustion Inspection & Off line wash
FY2007	CurrantCrk-1A	2	Off line wash
FY2007	Sunnyside	7	
FY2007	Carbon 1	7	Mini -
FY2007	Hermiston 1	8	Combustion Inspection
FY2007	Craig 1	16	Major; Changed to minor, 16 days
FY2007	CurrantCrk-1A	2	CTG Borescope -
FY2007	Jim Bridger 3	56	Low Nox Installation
FY2008	CurrantCrk-1A	12	ST Minor O/H, CT OH, Off Line Wash, switchyard
FY2008	CurrantCrk-1B	12	ST Minor O/H, Off Line Wash, switchyard
FY2008	Dave Johnston 3	9	Mini – boiler inspection,
FY2008	Hunter 3	42	Low Nox, MjrTrb Inspt, Gen & Rotor Rewind, Exciter, DCS, SDCC
FY2008	West Valley 1	7	Combustor Exchange
FY2008	Blundell	30	Controls Upgrade, Gen. Inspection, Major turbine

Attachment 333 -2 – Thermal Outage Schedule (FY06R8 06Jan06)

FY	Unit	Days	Comments
			inspection
FY2008	Naughton 1	30	Sect114, LP trb, gen, vlvs, repl hot rht pipe, ASI blwing ctrls, trb ctrls, repl sootblwrs, repl AH,
FY2008	West Valley 2	7	Combustor Exchange
FY2008	Sunnyside	14	
FY2008	Camas Cogen	21	Generator Inspection
FY2008	River Road	10	Combustion Inspection
FY2008	Hermiston 2	8	Combustion Inspection
FY2008	Colstrip 3	44	
FY2008	Jim Bridger 2	9	
FY2008	Little Mountain	42	30000 hr major turbine inspection
FY2008	Dave Johnston 4	56	Low Nox burners – boiler controls upgrade, gen magor, gen rewind, GE TIL 1292, economizer replacement, FWH replacements, APH basket replacement,
FY2008	Hunter 1	7	
FY2008	Craig 2	16	Minor
FY2008	CurrantCrk-1B	2	CTG Borescope -
FY2008	Hayden 2	35	HP/IP Upgrade, DCS upgrades
FY2008	Blundell	3	Mini
FY2008	CurrantCrk-1B	14	CT OH, Offline wash
FY2008	Sunnyside	7	
FY2008	CurrantCrk-1A	2	Offline wash
FY2008	Huntington 1	8	
FY2008	Gadsby 4	7	Combustor Exchange, Hot section 1t stage disc
FY2008	Carbon 2	28	Major Turbine & Boiler
FY2008	Hermiston 1	8	Combustion inspection -
FY2008	West Valley 3	7	Combustor Exchange
FY2008	CurrantCrk-1A	2	CTG Borescope -
FY2008	West Valley 4	7	Combustor Exchange
FY2008	Cholla 4	42	PRB Conversion/Enviromental Upgrades
FY2008	Jim Bridger 1	9	
FY2009	CurrantCrk-1A	14	CT OH (HGP), Off Line Wash
FY2009	Dave Johnston 1	37	Turb/Gen major, boiler major, PSH, arch tube replacements, ww inlet header replacements,
FY2009	Jim Bridger 4	56	Low Nox
FY2009	Naughton 3	44	Gen RtrRewind, repl trb ctrls, new precip bag house, replace LP fwt's, replace burners, scrubber startup transformer replacement
FY2009	West Valley 5	7	Combustor Exchange
FY2009	Sunnyside	14	
FY2009	CurrantCrk-1B	2	Offline wash
FY2009	River Road	21	Hot Gas Path
FY2009	Hermiston 2	44	MAJOR -
FY2009	Little Mountain	7	Combustion Inspection
FY2009	Colstrip 4	9	Boiler Chemical Clean
FY2009	CurrantCrk-1B	2	CTG Borescope -
FY2009	Hunter 2	7	Changed from Unit 3 to Unit 2
FY2009	Naughton 2	9	Air Htr, Economizer clean
FY2009	Blundell	6	Mini
FY2009	CurrantCrk-1B	7	CTG Combustion Inspection & Off line wash

Attachment 333 -2 – Thermal Outage Schedule (FY06R8 06Jan06)

FY	Unit	Days	Comments
FY2009	Sunnyside	7	
FY2009	CurrantCrk-1A	2	Offline wash
FY2009	Huntington 2	8	Minor – Inspection
FY2009	Gadsby 5	7	Combuster Change out
FY2009	Gadsby 3	35	Major – HP and LP Turbine
FY2009	Carbon 1	28	Minor – Turbine Vlv inspt & Boiler
FY2009	Hermiston 2	8	Combustion inspection -
FY2009	CurrantCrk-1A	2	CTG Borescope -
FY2009	Dave Johnston 2	9	Mini – boiler inspection,
FY2009	Colstrip 4	44	Crosses Fiscal Year
FY2010	Dave Johnston 4	9	Mini – boiler inspection,
FY2010	Jim Bridger 3	9	
FY2010	Craig 1	16	
FY2010	CurrantCrk-1A	20	STG vlv major, CTG CI, Catalyst change, off line wash, switchyard
FY2010	CurrantCrk-1B	20	STG vlv major, CTG CI, Catalyst change, off line wash, switchyard
FY2010	Hunter 1	56	Low Nox, Turbine Major, DCS
FY2010	Dave Johnston 3	42	Low Nox burners, turb/gen major, turbine controls, econo hopper addition, boiler major, reheater and superheater replacements,
FY2010	Hayden 1	42	HP/IP Overhaul, Valves, Boiler Inspection, Boiler Chemical Clean
FY2010	Sunnyside	14	
FY2010	Jim Bridger 2	37	Turbine OH,
FY2010	River Road	10	Combustion Inspection
FY2010	Camas Cogen	14	
FY2010	Hermiston 1	44	Major -
FY2010	Naughton 1	9	Air Htr, Economizer clean
FY2010	Little Mountain	7	
FY2010	CurrantCrk-1B	2	CTG Borescope
FY2010	Huntington 1	65	Low Nox, baghouse project, Stator rewind, Final SH
FY2010	Blundell	6	Mini
FY2010	Hunter 3	7	
FY2010	CurrantCrk-1B	14	CTG HGP Outage, Offline wash, catalyst change
FY2010	Sunnyside	7	
FY2010	CurrantCrk-1A	2	Offline wash
FY2010	Gadsby 6	7	Combustor
FY2010	Gadsby 1	35	Major Trb/Gen OH, (6 yr interval)
FY2010	Hermiston 1	8	
FY2010	CurrantCrk-1A	2	CTG Borescope
FY2011	Dave Johnston 1	9	Mini – boiler inspection,
FY2011	Hunter 2	56	Low Nox, DCS
FY2011	Jim Bridger 1	56	Low Nox
FY2011	Naughton 2	56	Low Nox, LP turbine, valves, generator, replace reheater, Section 114 Work -
FY2011	Cholla 4	5	Reliability Outage- Fan repairs, Scrubber cleaning,Inspections
FY2011	Craig 2	16	
FY2011	CurrantCrk-1A	14	HGP Inspection & Off line wash
FY2011	Dave Johnston 2	9	Mini – boiler inspection,

Attachment 333 -2 – Thermal Outage Schedule (FY06R8 06Jan06)

FY	Unit	Days	Comments
FY2011	Sunnyside	14	
FY2011	CurrantCrk-1B	2	Offline wash
FY2011	River Road	10	Combustion Inspection
FY2011	Hermiston 2	8	Combustion Inspection
FY2011	Wyodak	9	
FY2011	Colstrip 3	44	
FY2011	Jim Bridger 4	9	
FY2011	Little Mountain	7	
FY2011	CurrantCrk-1B	2	CTG Borescope
FY2011	Naughton 3	9	Air Htr, Economizer, Scrubber clean
FY2011	Hayden 2	28	Boiler Outage, HP/IP Overhaul, Valves, Boiler Safeties
FY2011	Blundell	6	Mini
FY2011	CurrantCrk-1B	7	CTG Combustion Inspection & Off line wash
FY2011	CurrantCrk-1A	2	Offline wash
FY2011	Huntington 2	37	Stator Rewind, Final SH Replacement
FY2011	Sunnyside	7	
FY2011	Carbon 2	7	Mini
FY2011	Gadsby 2	35	Major
FY2011	Hermiston 1	8	Combustion Inspection
FY2011	Hunter 3	28	Minor Boiler & Balance of Plant
FY2011	CurrantCrk-1A	2	CTG Borescope -

OREGON

2006 GENERAL RATE CASE

UE-179

PACIFICORP

OPUC STAFF DATA REQUEST

ATTACHMENT OPUC 333 -3

Attachment OPUC 333 -3 – Current Overhaul Schedule with Past History

PacifiCorp FISCAL (April 1 - March 31) Outage Schedule, 2002 - 2011 (PPW Share Only)

		Actual						Planned				
FY06R8 06Jan06	Unit MW	2001	2002	2003	2004	FY2005	FY2006	FY2007	FY2008	FY2009	FY2010	FY2011
Unit	Rating	Weeks	Weeks	Weeks	Weeks	Weeks	Weeks	Weeks	Weeks	Weeks	Weeks	Weeks
Blundell	23		4	1	1	1	1	0.9	4.4	0.9	0.9	0.9
Carbon 1	67	4		1		5		1		4		
Carbon 2	105	1	1		1	5	1		4			1
Cholla 4	380	4			1	4	1			6		0.7
CurrantCrk-1A	263							1	2.3	2.6	3.6	2.6
CurrantCrk-1B	262							1.3	4	1.6	5.3	1.6
Dave Johnston 1	106	1	1	1	4		1			5.3		1
Dave Johnston 2	106	4	1			1		3/2		1.3		1
Dave Johnston 3	220	1		1	2		4		1		6	
Dave Johnston 4	330	1	3		5		2		8		1	
Gadsby 1	60			8							5	
Gadsby 2	75				5							5
Gadsby 3	100		7							5		
Gadsby 4	40			1			0.4		1			
Gadsby 5	40						0.4			1		
Gadsby 6	40			1			0.4				1	
Hunter 1	403						4		1		8	
Hunter 2	259	1		10				5		1		8
Hunter 3	460		5	1			1		6		1	4
Huntington 1	445		4	1		1	5.3		1		9.3	
Huntington 2	450	1		6				9.3		1		5
Jim Bridger 1	353	1		4	1			6	0.4	0.9		8
Jim Bridger 2	353		5		1		8		1		5	
Jim Bridger 3	353		1		6		1		8		1	
Jim Bridger 4	353	5	1	1		6		1		8		1
Naughton 1	160			5		1			4		1	
Naughton 2	210			6	2			0		1.3		8
Naughton 3	330			1	7		1			6		1
Wyodak	268	4				1		6				1
Hermiston 1	237	1	1	4	5	1		4	1		7.3	1
Hermiston 2	237	1	1	8	1	1	2	1	1	7.3		1
West Valley 1	40			1			1.0		1			
West Valley 2	40						1.0		1			
West Valley 3	40			1			1.0		1			
West Valley 4	40						1.0		1			
West Valley 5	40			1						1		
Camas Cogen	52	1			3			1	3		2	
Colstrip 3	74	2	6			6		1	6			6
Colstrip 4	74	4	1	8	5	1		7.3		1.4	5.9	
Craig 1	83			2	6			4.0	2.6		2.3	
Craig 2	83	3	4		3	4			2.3			2
Sunnyside	50			3	3		3	3	3	3	3	3
River Road	240		3	1	1	4	4	4	1	3	1	1
Hayden 1	45	4			6			5			6	
Hayden 2	33		4	1		3			5			4
Little Mountain	14	4		6		1	6.5	5	6	1	1	1
Capacity on Maintenance	8036	2423	3712	4664	3939	3158	4374	3720	5033	3957	4167	4971

OPUC Data Request 332

Please elaborate on the on the specifics of the "Generation Normalization O&M Adjustment", 4.14:

a. Are there other environmental additions and upgrades besides the Huntington Unit 2 Scrubber that are being rolled up into this adjustment? Please detail the expected test year O&M costs for each environmental addition or upgrade project.

b. Please provide a comprehensive list, by generation facility, of the large, identifiable maintenance projects" from this adjustment category, that are planned for 2006 through 2009. Please provide a cost estimate, expected service life between maintenance cycles and the last time each item listed above underwent a similar procedure. Are any projects on your list non-reoccurring?

c. Please provide the details about the analysis that went in to the increased expenditures related to materials; What materials does this pertain to, what quantities are used in 2005 compared to 2006 and how did you determine the cost change from current costs to test year costs that need the normalizing adjustment?

Response to OPUC Data Request 332

a. No, the Generation Escalation adjustment does not contain any environmental additions and upgrades besides the Huntington Unit 2 Scrubber.

b. Power plant components have varying life expectancies based on load factor, system redundancy, fuel quality, and the number of starts. Plant budgets forecast the maintenance interval based on predictive maintenance technology, operating data, operating experience, and physical inspections. Many component repairs require an outage and are scheduled to occur during the most appropriate overhaul period. Special maintenance projects by unit will vary in scope of work, repair cycles, and component age. Predicting component life and maintenance interval is difficult because the age of the unit, component load factor, system redundancy, and fuel quality each have an effect on component life. The Company's plants are forecasting higher special maintenance expenditures due to age of components, excessive wear due to fuel quality and high load factors, operating experience, and routine maintenance inspections. Shifting overhauls has a minimal effect on special maintenance projects overall.

   Refer to Table 1, below, "Adjustment for Material, Contracts, and Special Maintenance – Generation Escalation Adjustment by Unit" for a breakdown of special maintenance projects by unit. The following plants influence the special maintenance expenditures as follows:

   - Dave Johnston plant expenditures are due to an increase in age and condition related components

- Hunter plant expenditures are due to a shift of accounting category
- Huntington plant expenditures are due to a shift of accounting category
- Wyodak plant expenditures are due to a shift in overhaul from FY 2006 to FY 2007
- Hydro expenditures are due to established contract obligations for relicensing of hydro units. Refer to Attachment OPUC 332.b for a listing of budgeted hydro relicensing expenditures.

Examples of special maintenance expenditures are:

Boiler tuning
Bottom ash crusher rebuilds
Building repairs (elevators, doors, etc)
Compressor rebuilds
Condenser cleaning
Control upgrades
Conveyor rebuilds
Cooling tower repairs
Dredging
Engine rebuilds
Engineering studies
Environmental projects
Environmental testing
Fan rebuilds
Fire system
Flyash system repairs
HVAC repairs
Hydro relicensing contract commitments
Mill overhauls
Motor rewinds
Piping repairs
Plant paving
Plant roofing
Pond cleaning
Predictive maintenance inspections
Pump repairs
Safety programs
Scrubber repairs
Security upgrades
Service agreements
Sewage treatment reconditioning
Transformer refurbishment
Water treatment repairs

c. The Generation Escalation adjustment was derived by taking FY 2005 budget and using the DRI index to arrive at a CY 2007 escalated value. The FY 2007 & FY 2008 values were converted to a CY 2007 value. Table 1, below, "Material, Contracts, and Special Maintenance Adjustment by Unit" shows the adjustment differential by unit. These values do include start up fuel; therefore, a start up fuel adjustment is at the bottom of the table.

The material portion of the adjustment consists predominately of scrubber reagent and obsolete parts inventory. The values in the Table 2, below, "Material Quantities and Cost Data" are budget expenditures for FY 2005, FY 2007, and FY 2008.

UE-179/PacifiCorp
May 19, 2006
OPUC Data Request 332

Table 1 – Adjustment for Material, Contracts, and Special Maintenance – Generation Adjustment by Unit*

	Adjustment Worksheet			
	Routine		Special	
	Matl	Contracts	Maint	Total
Blundell	(115)	(15)	140	10
Carbon	97	(254)	462	305
DaveJohnston	99	(62)	2,396	2,433
Gadsby	6	598	567	1,171
Hunter	(502)	(1,310)	1,725	(87)
Huntington	1,499	(979)	992	1,512
JimBridger	740	708	(376)	1,072
LittleMt	22	26	120	169
Naughton	635	461	(128)	968
WValley	(191)	(86)	157	(120)
Wyodak	(653)	(386)	557	(483)
Camas	-	50	-	50
Cholla	(94)	(51)	-	(144)
Colstrip	118	198	-	316
Craig	15	855	-	870
FooteCreek	-	267	-	267
Hayden	(1)	154	-	153
Hermiston	-	567	-	567
Hydro	(532)	(69)	3,626	3,025
AdminG	914	751	-	1,666
Engr	16	780	-	796
Env	7	408	-	415
ResD	4	1,515	-	1,519
Safety	(128)	(476)	-	(605)
Start-Up Fuel	(1,015)	-	-	(1,015)
Total	942	3,652	10,238	14,832

*These numbers reflect the actual Generation Escalation Adjustment rather than a specific year.

Table 2 – Material Quantities and Cost Data

	Tons (Naughton 2005 = gallons)			$/ton			Cost			CY2007	DRI		Comments
	2005	2007	2008	2005	2007	2008	2005	2007	2008	TOTAL	CY2007	Difference	
Huntington	10,103	16,956	27,471	52.84	72.13	74.02	533,843	1,223,036	2,033,403	1,830,812	556,516	1,274,295	Scrubber Reagent - cost is a delivered cost
Jim Bridger	126,802	119,015	121,337	41.90	46.26	49.57	5,313,004	5,505,634	6,014,675	5,887,415	5,538,662	348,753	Scrubber Reagent - delivery is contracted cost
Naughton	59,557,405	53,400	53,400	0.0143	17.88	19.17	851,000	954,792	1,023,678	1,006,457	887,145	119,312	Scrubber Reagent - delivery is contracted cost
AdminG							451	1,289	1,416	1,384	470	914	Obsolete Parts Inventory

Staff/203
Durrenberger/23

HYDRO IMPLEMENTATION
2007 - Special Maintenance ($000)

	2005 Actual	2006 Budget	2007 Budget	2008 Budget	2009 Plan	P&N
IMPLEMENTATION			-			
Bear River Implementation		-	-	-	-	
Art. 409. Fish salvage	-	-	5	5	5	Salvaging fish stranded by release of recreation flows in Grace bypass, in compliance with procedures prepared with and approved by Idaho Department of Fish and Game.
Art. 416. Recreation Management Plan	12	2	15	15	15	Implementation of recreation plan; contract labor and miscellaneous costs.
Art. 417. Dust abatement	5	5	5	5	5	Implementation of action associated with Traffic Safety Plan; treatment of Oneida road 200 feet at the entrances of Maple Grove and Redpoint campgrounds twice annually to improve traffic safety.
Art. 416. Put-in Take-out facilities	-	2	2	2	2	Maintenance of sites associated with recreation plan; for Grace and Oneida boater access sites, April through October.
Art. 408. River gage maintenance	-	2	15	15	15	Maintenance of equipment and data at river gage stations; preparation of data for publishing on USGS web site; provides information regarding minimum flow compliance.
Art. 408. Web Site maintenance	2	10	2	2	2	Maintenance of information on PacifiCorp's flow phone for the Bear River; provides information regarding whitewater recreation to the public.
Art. 423. HPMP implementation	68	7	50	20	7	Implementation of Historic Propoerties Management Plan in compliance with Programmatic agreement with the FERC and SHPO; implementing procedures to protect NHPA-eligible structures and sites in designated Area of Potential Effect. Contract labor
Art. 424. Land Management Plan	140	67	67	52	31	Implementation of LMP for Project area; Preparation of Site Plans, surveying property boundaries, lease revisions, fencing, monitoring; contract labor
427 Expansion of FERC project boundary	-	80	-	-	-	In compliance with License Article 427, expand FERC boundary to ensure continued recreational access on ~40 ac of PacifiCorp land upstream of the Grace plant, and on PacifiCorp and BLM land from the Oneida plant to lowermost campground (~3 mi); revised Ex
Art. 413. Water quality monitoring	50	50	21	21	21	Compliance w/ 401 Certification, implementation of Water Quality Monitoring Plan in consultation with IDEQ; collect water quality data at 4 stations at Grace-Cove for 6 years and 1 station at Oneida for 18 continuous months; prepare reports
Art. 402. Bear River Implementation Project Management	65	65	65	68	52	Project management of license implementation; resource management planning, strategic planning, project scheduling, contract administration; conducting stakeholder (ECC) meetings to make decisions on use of funding, ECC meeting expenses; Eastside PC funding
Art. 415. Operations and Implementation Reporting	25	15	10	10	10	Annual preparation of report to the FERC describing describing minimum flow and ramp rate compliance and monitoring procedures; 401 Certification requirements.
Bear River Implementation Commitments	25	15	17	-	-	Annual preparation of report to the FERC describing describing minimum flow and ramp rate compliance and monitoring procedures; 401 Certification requirements.
Big Fork Implementation			-			
Art 403 Flow monitoring plan/reporting	15	8	8	3	3	Develop flow monitoring plan w/agencies per License Art. 403, file plan with FERC ,2004; annual data collection, reduction, monitoring/reporting
Art 404 WQ monitoring plan/reporting	6	8	8	8	8	Develop WQ monitoring plan w/agencies per License Art 404, file plan with FERC Jan 25th,2004, four years of WQ data collection, data redcution and analyses, annual monitoring/ reporting
Art 406 Ops Maint.& Screen Monitoring plan	16	8	8	-	-	Develop plan w/agencies per License Art 406; annual monitoring, inspection and repair of fish screens; study to determine triggers for installing trash rakes; meetings and agency consultation
Art 406(1,2,3) Screen maint,,inspections, velocity	8	13	13	16	10	Procedures for periodically measuring water velocities just upstream of the screens, requires video camera equipment, velocity meters. Data collection and reporting
Art 406(4) Fish recovery/salvage/monitoring	3	4	4	4	4	License requirement, scope & $ dependent on plan and agency negotiation
Art 406(7) Annual reporting	4	4	-	4	4	Periodic monitoring reports documenting the operation, maintenance, and screen effectiveness monitoring efforts, with the MFWP, USFWS, and the Commission.
Art 409 Erosion Control plan	1	-	-	2	2	License requirement, requires filing with FERC by Jan 25,2004, includes site specific control measure implementation; periodic monitoring of remediated sites
Art 410 Noxious Weed Control Plan/Measures	13	5	5	5	5	License requirement, in consultation with MFWP,USFWS, and Flathead County Weed Control District , prepare and file a noxious weed control plan with FERC. Annual maintenance
Art 411 RRMPlan/O&M/Reporting	8	5	5	8	10	License requirement and Settlement Agreement, requires filing with FERC by July 25,2004; annual reporting and monitoring activities

HYDRO IMPLEMENTATION
2007 - Special Maintenance ($000)

	2005 Actual	2006 Budget	2007 Budget	2008 Budget	2009 Plan	P&N
411(7,8) Whitewater feasibility study	17	17	17	10	8	License requirement to assess WQ, fish stranding, effects on proj. ops, ramping, & reporting, related to whitewater feasibility study
SA 3.10 Toilet-portable unit year-round/Swan R. trail	2	2	-	2	2	Lease and maintin portable toilet on Swan River nature trail
Art 412 Program. Agree. Implem. and CRMP	12	5	5	15	5	License requirement, requires filing with FERC by July 25,2004; mgt and protection of historic properties w/ periodic reevaluation and public education of historic values
Program Implementation management/technical support	21	21	21	10	10	Proj mgt, includes borrowed labor, business exp. &contractor-related costs
Lewis River Implementation			-			
Aquatics	-	285	-	-	-	
4.2 Merwin Trap b) Merwin Trap Upgrades	-	-	-	102	102	As necessary to reduce fish crowding and injury, provide 2 additional staffers to clear Merwin Trap on daily basis
4.3 Merwin Upstream Collection and Transport Facility	-	-	-	-	372	Operate the fish collection facility and trucks to move adult anadromous fish upstream of Swift dam.
4.9.1 Collect and Haul Bull Trout	-	-	-	-	35	Conduct program to collect Bull Trout in Yale and Swift #2 tailraces and truck transport to reservoirs
4.9.3 Yale and Merwin Bull Trout Entrainment Reduction	-	-	-	26	51	Operate the entrainment reduction barriers to keep fish out of power intakes; includes cleaning and repairs
5.5 Bull Trout Limiting Factors Analysis	-	-	50	-	-	Complete Analysis in consultation with ACC. Results may direct AQ Fund distributions to benefit Bull Trout
5.7 Public Info Program - Anadromous Fish	-	-	6	1	1	Complete public information actions (signage and flyers) to describe Bull Trout and need to protect the species and habitat.
6.1 Flow Releases into Swift Bypass	-	-	5	31	31	Release and measure flow into Swift Bypass for benefit of aquatics
6.1.3 Constructed Channel Maintenance	-	-	-	-	10	Maintain the constructed channel; inspect annually and consult on activities with ACC; Remaining capital funds (adjust for inflation) are to be used for any maintenance
6.2.3 Stranding Study and Habitat Evaluation	-	-	-	-	367	Develop study in consultation with ACC to identify measurable factors affecting potential fish stranding, factor relationships and when stranding may occur. May result in changes to Merwin Ops or use of Aquatics Fund
6.2 Merwin Minimum/Low Flows	-	-	1	1	1	Follow minimum flows and as needed in low flow years convene a Flow Coordination Committee to decide adjustments to flow schedule
7.1 Large Woody Debris Program	-	-	72	2	2	In consultation with ACC complete LWD study; annually gather and hold LWD for ACC use; provide $2,000 for LWD transportation.
7.4 Habitat Preparation Plan	-	-	2	7	7	Develop HP Plan in consultation with ACC to truck and release adult fish above Merwin dam, once HP Plan is finalized, implement Plan.
8.2 Hatchery and Supplementation Plan and Implementation	-	-	20	51	51	In consultation with ACC produce a H&S Plan that addresses hatchery operations, supplementation, and facilitites. Implement Plan including monitoring and evaluation and report to ACC.
8.3 and 8.4 Hatchery Operations - Anadromous Fish	-	-	200	204	204	Incremental addition to operate hatchery facilities to achieve hatchery adult targets in SA. Production is based on needs for supplementation and adult harvest.
8.5 Supplementation Program	-	-	-	77	77	Per H&S Plan transport juvenile and adult fish to locations upstream of Merwin. Use supplementation to "jump start" natural production
8.6 Hatchery Operations - Resident Fish	-	-	100	102	102	Incremental addition to operate hatchery facilities to achieve production requirements for rainbow trout and kokanee in SA. Both are produced for recreation harvest.
S 8.7 Lewis Hatchery Water Intake Repair	-	-	25	143	20	Modification to hatchery intake screen to meet agency criteria and maintenance of hatchery pumps
S 8.7 Merwin Hatchery Flow Enhancement	-	-	-	-	31	Hatchery valving and new risers to improve flow characteristics in rearing ponds
S 8.7 Speelyai Hatchery Spawning Area Improvements	-	-	-	-	92	
9.1 Monitoring and Evaluation Plan - Fish Passage	-	-	96	98	98	Develop monitoring and evaluation plan in consultation with ACC. Plan to include such components as monitroing juvenile migration, reservoir survival, collection efficency of facilities, survival, injury and survival of fish. Fish tagging is a subcomponent. May result in facility modifications and operational changes
9. 3 Monitoring and Evaluation Plan - Wild FACH & Chum	-	-	-	-	87	Monitor wild fall chinook and chum spawner populations and effect of PM&E measures
9.4 Water Quality Monitoring	-	-	-	21	21	Fund monitoring necessary to comply 401 & other WQ permits

HYDRO IMPLEMENTATION
2007 - Special Maintenance ($000)

	2005 Actual	2006 Budget	2007 Budget	2008 Budget	2009 Plan	P&N
9.5 Monitoring of Hatchery and Supplemention	-	-	-	63	63	Monitor effectiveness of H&S Plan through comparison of hatchery releases to ocean recruits, and the effects of hatchery fish on reintroduced salmon.
9.6 Bull Trout Monitoring	-	-	-	-	33	Monitor bull trout populations following T&E Plan
9.7 Resident Fish Assessment	-	-	7	7	7	Monitor interaction between reintroduced salmon and resident fish; and kokanee spawner population size to inform adaptive management. Cost to be developed in M&E Plan
9.8 Monitoring of Flows - Aerial gage O&M	-	-	-	-	16	Monitor flows at USGS gage downstream of Merwin and Swift bypass flows. Provide notification and reports per SA.
14.2 Aquatics Coordination Committee	-	-	10	51	51	Provide a forum for SA Parties to coordinate on Aquatic implementation actions. In some cases this is a decision body. Cost is for facilitiation, work products, meeting expenses, etc.
Recreation	-	-	-	-	-	
11.2.1.1 Swift Dispersed Shoreline Use Sites Monitoring and Evaluation	-	-	30	51	51	Reassess sites for appropriate action such as site development or closure, conduct waste disposal mgmt program and sign areas for appropriate use/no use
11.2.1.2 Eagle Cliff Trail	-	-	-	-	-	Periodic trail maintenance after trail is constructed.
11.2.1.3 Control of Swift Forest Campground	-	65	65	71	77	Enter into long term lease agreement with Washington Dept of Natural Resources (Property owner) unless land is available for purchase and financial analysis favors purchase.
11.2.1.7.1 Swift Annual Recreation Facility O&M	-	-	-	-	82	Maintain rec facilities pursuant to maintenance stds and frequencies ser forth in Exhibit J of the RRMP
11.2.1.7.2 Swift Campground Schedules	-	-	-	-	-	Keep campground open for hunter camping - Current Practice NO COST
11.2.1.7.3 Swift Shoreline Use Sites O&M	-	-	13	13	13	Maintain shoreline use sites pursuant to maintenance stds and frequencies ser forth in Exhibit J of the RRMP
11.2.1.8 Swift Boat Launch	-	-	-	-	-	If new launch constructed by other party, PPW to maintain
11.2.2.1 Yale Dispersed Shoreline Use Sites Monitoring and Evaluation	-	-	30	51	51	Maintain shoreline use sites consistent with the RDSUP. Reassess sites for appropriate action such as site development or closure, conduct waste disposal mgmt program and sign areas for appropriate use/no use
11.2.2.15.1 Yale Annual Recreation Facility O&M	-	-	-	-	102	Maintain rec facilities pursuant to maintenance stds and frequencies ser forth in Exhibit J of the RRMP
11.2.2.15.2 Yale Shoreline Use Sites O&M	-	-	13	13	13	Maintain shoreline use sites pursuant to maintenance stds and frequencies ser forth in Exhibit J of the RRMP
11.2.3.1 Merwin Dispersed Shoreline Use Sites Monitoring and Evaluatio	-	-	30	51	51	Maintain shoreline use sites consistent with the RDSUP. Reassess sites for appropriate action such as site development or closure, conduct waste disposal mgmt program and sign areas for appropriate use/no use
11.2.3.2 Merwin Trails	-	-	-	7	-	Promote existing and new trails with signs and brochures
11.2.3.4 South Shore Mewin Trail Access	-	-	20	-	-	Evaluate feasibility of establishing easement over PPW land to provide trail connection to future VCPRD County park
11.2.3.12.1 Merwin Ann Recreation Facility O&M	-	-	-	-	102	Maintain rec facilities pursuant to maintenance stds and frequencies ser forth in Exhibit J of the RRMP
11.2.3.12.2 Cresap Bay Campground Schedule	-	-	10	10	10	Keep Cresap Bay campground open through September
11.2.3.12.3 Merwin Shoreline Use sites O&M	-	-	13	13	13	Maintain shoreline use sites pursuant to maintenance stds and frequencies ser forth in Exhibit J of the RRMP
11.2.4.3.1 Annual PPW Recreation Facility O&M (Lower Lewis)	-	-	8	8	8	Maintain PacifiCorp's downstream recreation sites pursuant to maintenance stds and frequencies ser forth in Exhibit J of the RRMP
11.2.4.3.2 Annual WDFW Recreation Facility O&M (Lower Lewis)	-	-	12	12	12	Maintain downstream WDFW recreation sites pursuant to maintenance stds and frequencies ser forth in Exhibit J of the RRMP
11.2.5 I & E Program	-	-	117	22	22	Develop Interpretation and Education Program. Include watchable wildlife component, recreation resources, hydro power, natural resources and cultural resources. Info to be distributed via kiosks, signs, printed material, and continuation and expansion of campground programs.
11.2.6 Visitor Management Control	-	-	10	20	20	To enhance recreation experience and public safety, implement additional visitor mgmt controls
11.2.7 Communications on Recreation Facility Availability	-	-	5	5	5	Provide public notice when day use and campgrounds are approaching capacity

HYDRO IMPLEMENTATION
2007 - Special Maintenance ($000)

	2005 Actual	2006 Budget	2007 Budget	2008 Budget	2009 Plan	P&N
11.2.8 Recreation Access to Project Lands	-	-	-	-	-	Allow appropriate public access to all PacifiCorp owned lands when possible -- Current Practice NO COST
11.2.9 Land Ownership retentionfor Recreation purposes (Switchback prc	-	-	-	-	-	Maintain ownership of site and develop site similar to Johnson Creek access site (parking, vault toilet and picnic table)
11.2.10 Overnight parking and Dispersed Shoreline Use at Yale Lake and	-	-	-	-	-	Permit overnight parking at boat launch areas for dispersed campers
11.2.11 Campground Gate Access and Scheduling	-	-	-	-	-	Close but not lock campground gates
11.2.12 Dispersed Camping Management Funding to USDA-FS	-	-	7	7	7	Payment to USFS for Project related dispersed camping on USFS lands
11.2.13 Vehicular Access and Use Control	-	-	3	3	3	Discourage dispersed upland use and restrict motorized access
11.2.15 Public Use of Project RV Dump Stations	-	-	3	3	3	Subject to existing capacity, allow public use of existing RV sanitation dump site stations for nominal fee; provide signs that direct to stations
11.2.16 Communications with the Parties	-	-	10	10	10	Create a Lewis River Recreation Advisory Committee to provide information to interested parties at least once a year
Vistor Use Monitoring	-	-	5	5	5	Annually monitor visitor use in light of new recreation facility triggers. Complete analysis and report
SocioEcon	-	-	-	-	-	
13.2.1 Law-Enforcement	-	-	201	201	201	To increase patrols and police presence, fund 2 county law enforcement officers including reasonable cost for vehicle and equipment; fund 1 WDFW law enforcement officer including reasonable cost for vehicle and equipment
13.2.2 USFS Forest Road 90	-	40	35	36	36	PacifiCorp and CPUD payment for maintenance of FR 90.
13.2.3 Pine Creek Comm Link	-	-	-	-	-	Provide existing level of support for comm link between Swift dam and Work Center - Cost is expected to be very minimal and infrequent as support is for small building and pole
Cultural	-	-	-	-	-	
13.1.1 Implement HPMP	-	-	66	67	67	Implement the conditions of the final HPMP to protect historic artifacts and NRHP eligible facilities, provide tribal access, designate a Cultural Resource coordinator and program training for employees.
Terrestrial	-	-	-	-	-	
10.8.1 Develop Wildlife Habitat Management Plans	25	100	50	51	51	In consultation with TCC, develop WHMP with specific stds and guidelines per SA objectives. WHMP will direct on the ground actions and land management on Company lands to benefit wildlife. Complete field verifying and site specific surveys to further direct mgmt Plan.
10.8.2.1 WHMP Funding - annual	-	-	100	367	367	Fund implementation of WHMP at defined cost per acre of company land. Unused $ roll with interest into following year. Increased land holdings will increase total budget cost.
10.8.3 Management of WHMP - Annual Reports/Planning	-	-	35	39	42	Provide the TCC with Annual reports of work accomplished and work planned; includes GIS work needed for reporting
10.8.4.1 Update Existing HEP information	-	-	15	15	15	Mapping and cover typing of newly acquired lands to update the existing HEP data
10.8.4.2 Review Effectiveness of WHMPs	-	-	-	-	-	At year 17 of new license repeat HEP study for all WHMP lands to determine effectiveness of WHMP implementation.
11.2.1.1 Dispersed shoreline use sites	-	-	5	5	5	Complete activities to minimize impacts of dispersed camping on wildlife habitat and resources.
14.0 Coordination and Decision Making TCC	50	50	30	51	51	Provide a forum for SA parties to coordinate on Terrestrial implementation actions. Cost is for facilitation, work products, meeting expenses, etc.
Lewis River Mapping (GIS)	-	-	-	-	-	GIS support for Project CMS setup and ongoing actions
Lewis River Noxious weed control	-	-	35	36	36	Prepare Noxious Weed Mgmt Plan and implement actions to meet state and county weed control regulations
Flood Ops	-	-	-	-	-	
12.0 Flood Management	-	-	59	115	120	O&M of flow related monitoring equipment and high runoff forecasting
Other	-	-	-	-	-	
Side Agreement - Cowlitz-Skamania Co Fire District 7	-	-	24	24	24	Supplemental funding to District to offset costs associated with increased recreation demand for emergency services Payments adjusted for inflation
Cowlitz Tribe Side Agreement			40	-	-	
Yakama Nation Side Agreement			40	-	-	

HYDRO IMPLEMENTATION
2007 - Special Maintenance ($000)

	2005 Actual	2006 Budget	2007 Budget	2008 Budget	2009 Plan	P&N
Lewis River Implementation Team (Pro Mgmt Expenses)	-	-	50	112	79	Process costs not specific to Implementation line items; for example may include planning and scheduling contractors, travel expenses
Yale Interim Measures-O&M cultural/terrestrial activities	5	5	-	-	-	Yale draft application commitments for early implementation (training curriculum)
Powerdale Implementation			-			
3.2.3 Ramping Monitoring	4	4	-	-	-	Study project ramp rates under varying flow regime (eg., low summer, high flows, etc) s to determine if higher seasonal ramp rate acceptable
3.2.4 Unplanned Outages/fish recovery	2	2	2	2	2	Conduct fish stranding observations/salvage after unplanned outages in order to evlaute down ramp effects to fish
3.3.1/3.3.2 Minimum flow compliance	8	4	4	4	4	Develop real time flow monitoring plan in consultation w/agencies, calibration, and maintenance of device; periodic calibration flow measurements .
3.3.3 Temperature Monitoring after Effective Date	4	4	4	4	4	monitor stream temperatures hourly from July 1 through October 15 (period of warmest stream temperatures) each year at two bypass sites; For the period July 1 through October 15, PacifiCorp will also record average hourly flows released into the bypass r
3.3.4.1 Annual temperature and flow monitoring report	3	3	3	3	3	annual reporting and meeting
3.3.4.2 Measures to reduce stream warming from Sept 15 - Oct 15(3 yr st	1	4	-	-	-	3 yr stream temp monitoring study, develop alt. And plan to meet water quality stds
3.4.1/3.4.2 Annual WQ monitoring	7	7	7	7	7	Equipment rental and contractor labor for weekly surveys from April 15 to October 15
3.4.3 Alternative measures(after 3yrs)	1	9	-	-	-	Plan/report to examine alternatives to meet water quality stds based on monitoring/study results
3.7/3.8 Intake fish screen /Fishway auxiliary water intake maintenance	3	3	3	3	3	1) Annual maintenance, repair, rehab of intake screens; 2) obtain NMFS, USFWS, ODFW and CTWS written approval of a method for maintaining the fish ladder auxiliary attraction water bar rack within the ladder sufficiently free of debris to allow adequate
3.9 Ground-Disturbing activities	2	2	2	2	2	Ground disturbance requires survey for cult, RTE, etc, contractor support prior to initiating action
3.10 RTE surveys	2	2	2	2	2	Cost share with federal agencies on RTE surveys in the project area, annual survey work with contractor support
3.11 Cultural Resources Management Plan	10	30	-	10	-	Develop revised CRMP to reflect new FERC order and decommission program. HABSER (FY08?) required prior to action to document project, contractor support
3.12 Recreation Facility maintenance	8	8	8	8	8	Powerdale Park: (i)provide ADA-accessible toilet; (ii), provide picnic table each year for first two years after Effective Date; and (iii) within 30 days after the Final FERC Order, install trail and Project interpretive sign. Powerhouse day-use site: (i
3.13.1/3.13.2 Information sharing	3	3	3	3	3	Project records and reporting, compile annually
Powerdale Implementation Management (PMT)	20	20	5	5	5	Project Mgt./Compliance reporting, agency negotiation and consultation, Borrowed hrs for PC(15%@?), business exp & contractor support
Rogue Implementation	-		-	-		
Rogue Environmental O&M - Prospect 1	-	-	-	-	-	
Recreation - River Access	-	-	-	10	10	Annual O&M related to river access facilities (ie., stairs, trials etc). expected in new license
Mid Fork Dam - Fish Screen Maintenance	-	-	-	-	10	Contractor assistance (i.e., labor) and materials for maintaining new facilities
Mid Fork Dam - Ladder Maintenance	-	-	-	-	10	Contractor assistance (i.e., labor) and materials for maintaining new facilities
Mid Fork Dam - Stream Gauge	-	-	13	13	13	Contractor assistance (i.e., labor USGS) and materials for maintaining new facilities
Mid Fork Dam - Wildlife Crossings	-	-	-	5	5	Contractor assistance (i.e., labor) and materials for maintaining new facilities
Red Blanket Dam - Fish Screen Maintenance	-	-	-	-	-	Contractor assistance (i.e., labor) and materials for maintaining new facilities
Red Blanket Dam - Ladder Maintenance	-	-	-	-	-	Contractor assistance (i.e., labor) and materials for maintaining new facilities
Red Blanket Dam - Instream Habitat Enhancement	-	-	-	-	-	Annual maintenance and repair of instream structures and stream bank stabilization structures
Red Blanket Dam - Stream Gauge	-	-	13	14	14	Contractor assistance (i.e., labor USGS) and materials for maintaining new facilities
Red Blanket Dam - Wildlife Crossings	-	-	-	5	5	Inspection, maintenance, and monitoring of the crossings and fences, and annual reporting to agencies
N Fork Dam - Fish Screen Maintenance	-	-	-	33	33	Contractor assistance (i.e., labor) and materials for maintaining new facilities
N Fork Dam - Gravel Augmentation	-	10	-	-	-	Gravel placement in NF Rogue below dam every other year
N Fork Dam - Recreation - Park Maintenance	-	-	-	16	16	Contractor assistance (i.e., labor) and materials for maintaining new facilities
N Fork Dam - Stream Gauge	-	-	13	13	13	Contractor assistance (i.e., labor USGS) and materials for maintaining 3 new gaging facilities

HYDRO IMPLEMENTATION
2007 - Special Maintenance ($000)

	2005 Actual	2006 Budget	2007 Budget	2008 Budget	2009 Plan	P&N
N Fork Wildlife Crossing	-	-	-	-	5	Inspection, maintenance, and monitoring of the crossings and fences, and annual reporting to agencies
Water Quality Monitoring	-	-	22	16	16	Water temp. monitoring in order to demonstrate compliance with 401 and new instream flows
Cultural Protection/HPMP	-	25	20	21	21	Protection and maintenance of cultural, historic and archaelogical properties required under the new FERC license
Whitewater Feasibility Studies	-	-	16	26	26	Potential license requirement to assess WQ, fish stranding, effects on proj. ops, ramping, & reporting, related to flow releases in the NF bypass for whitewater feasibility.
Wildlife Plan Development and Reporting	-	-	20	5	5	Development of a wildlife management plan, and updating of Compliance Handbook. Contractor assistance with data collection, analysis and preparation of annual report
Instream flow/ramp rate release maintenance	-	-	5	5	5	Contractor assistance for new instream flow release structures to assure that flow compliance can be met. These flows will be required within a year of license issuance.
So. Fork Gage Maintenance	-	-	13	13	13	Reporting flows on the SF Rogue will be required. This budget item will provide for flow reporting as required by new license, annual maintenance and re-rating the flow curve for this gage when needed.
Aquatic Resources Issues Coordination	-	-	10	10	10	Coordination will be required on all aquatic related monitoring programs, as well as final fish passage facility designs/testing. Examples of annual coordiantion inlcudes flow monitoring/reporting, water quality monitoring/reporting. This budget item will cover the costs of meetigs, contractor assistance with monitoring activities, and annual reporting.
Little Butte Creek Dam Maintenance	-	-	7	7	7	PacifiCorp is required to annually maintain the passage improvements at Little Butte Creek in accordance with the Oregon Fish and Wildlife Commission fish passage waiver .
Rogue River Implementation Process costs	-	50	60	78	78	Preparation of annual report; contractor expenses; travel, team meeting expenses, scheduling, implementation planning
North Umpqua Implementation			-	-		
1.1.6 DEQ 401 Permit	160	80	80	82	82	The ODEQ issued the 401 Water Quality Certificate for the North Umpqua Project. The Certificate specifies monitoring and operational measures that PacifiCorp must perform to comply with conditions of the Certificate. These include monitoring of physical and chemical parameters.
4.0 Fish Passage	-		-	-	-	Provide effective upstream and downstream passage of fish
4.1.1 Soda Upstream Passage-Ladder [L7]	-		-	-	-	Provide effective upstream and downstream passage of anadromous fish and restore access to areas above SS
4.1.1 Soda Fish Counting equipment [L5]	-		-	-	-	
4.1.1 (d/e) Soda up stream passage monitoring [L7+]	-		-	-	-	postconstruction evaluation plan and monitoring for testing passage, includes biological and hydraulic evaluations
4.1.1 f SS Tailrace Barrier Maintenance [L1]	-		-	26	26	Maintenance of tailrace barrier including daily debris removal, occasional repairs, upkeep to keep the barrier functional with minimal head loss in the tailrace. Fish exclusion is required in the SA, and minimizing head loss will maximize efficiency of generation.
4.3.1 (c/d) Lem. Operations, Maintenance, and Evaluation Program [L0/C	18	30	-	-	-	The existing upstream fish passage facilities at Fish Creek and Lemolo 2 diversion dams require written operation and maintenance plans and post construction evaluation programs that include biological and hydraulic evaluations. The Settlement Agreement
4.3.1 d Lemolo 2 Fish Ladder Maintenance [05]	-	5	5	5	5	Periodic cleaning and repairs to fish ladder to keep it functional. Fish passage is required in the SA, and maintenance will also facilitate delivery of instream flows.
4.3.2b Fish Creek screens monitoring program [L1, 05]	-	20	-	-	105	Post construction evaluation of fish screening / passage effectiveness. Required to demonstrate propoer operation o new fish screen. Required to justify continued operation of Fish Creek canal and powerhouse.
4.3.2 Fish Creek screens Maintenance [L2/06]	-		-	10	10	Maintenance of new fish screens to ensure effective fish passage and water capture into canal system for generation. Required componenet of continuing to operate Fish Creek canal and powerhouse.
5.0 Instream Flow	-		-	-	-	Measures to implement the minimum in-stream flow regimes for the NU River reaches as set forth in the SA (sectior 5.1) and in Tables 1&2 in Appendix C. See NU Automation and Communication
5.3 NU In-stream Flow Modification Study	-	25	-	-	-	

HYDRO IMPLEMENTATION
2007 - Special Maintenance ($000)

	2005 Actual	2006 Budget	2007 Budget	2008 Budget	2009 Plan	P&N
5.5- Gage monitoring and maintenance [03]	105	180	200	240	240	Maintain 8 bypass reach gaging stations plus 2 full-river gages: equipment, data acquisition, and data validity throughout the year. Partially contracted with USGS, also requires ComTech and hydrology support. The OWRD and ODEQ require this as part of our water right, the SA requires data acquisition to conform to USGS standards. The 401 Certification and Flow Monitoring plan requires we provide agencies annual compliance reports.
7.2.2 Monitoring Plan	20	20	-	-	-	Develop and implement (with the agencies) a monitoring plan to assess the results of the 4,000 ton gravel experiment (above). Define specific locations for long-term gravel enhancement to maintain spawning habitat for salmon and steelhead and compensate
8.0 Mainstem Habitat Enhancement	-		-	-	-	Maximize spawning habitat for anadromous fish in mainstem with priority to chinook, implement measures to restore, create, and or enhance
8.2.2 Slide Reach Monitoring Plan/Program [02]	-		26	26	26	Monitor habitat quality in Slide Creek bypass reach related to PacifiCorp's habitat creation work. Follow protocols of Monitoring Plan, use TWG as much as possible.
8.3 North Umpqua River Habitat Restoration/Creation Project [03]	-	23	24	26	-	Monitor habitat quality in Soda Springs bypass reach related to PacifiCorp's habitat creation work. Follow protocols of Monitoring Plan, use TWG as much as possible. Add gravel and repair structures as necessary over term of license. Fixed-fund account managed by RCC.
9.0 Reservoir and Forebay Management	-		-	-	-	
9.1 Stocking of Rainbow Trout;Production funding [L0/04]	15	15	15	16	16	Fund the production of 15,000 hatchery rainbow trout for ODFW to stock into reservoirs and forebays. Stocking is required mitigation for continuing to operate unscreened forebays and canals. Estimated cost is $15k/year in 2001 dollars. Required by the SA and may improve recreational fishing in some project waters.
9.5-Fish Salvage during Shutdowns	-	20	21	21	21	Salvage of live fish for relocation during planned and emergency shutdowns, in coordination with agencies. Permit and report on related activities. See Routine O&M.
10.0 AQUATIC CONNECTIVITY	-		-	-	-	
10.3 Clearwater Reconnection [L0]	-		-	16	16	New structure installed to split flows and provide aquatic passage. Funds are for potential maintenance to the new facility basedon agency requirments for monitoring. Funds may be used for plantings, in-stream boulders, or woody debris transport.
10.4 Breaching Diversions [L1]/Named Creeks	-		-	10	-	Stream diversions are required to be returned to their original stream course and all diversion facilities removed from the Forest. Funds will be used for any site repair required from the USDA-FS related to removing the buried facilities. This could include vegetation plantings or seeding.
10.5 White Mule Creek Restoration [L2/06]	-		-	-	5	Replanting or streamside armoring of the restoration site. State and federal permitting agencies and the SA requires ongoing monitoring to the satisfaction of agencies. This monitoring will result in the replacement of unsuccessful plantings or stream features.
10.5 Potter Creek Restoration [RCC-04]	-		21	5	-	Replanting or streamside armoring of the restoration site. SA requires ongoing monitoring to the satification of agencies.
10.6 Aquatic Re-Connectivity Projects	5	5	10	21	31	Maintenance of reconnection sites over license term to ensure that aquatic connection remains established. Could entail culvert unplugging to armoring of downslope areas or monitoring of the sites to determine if they have met design criteria. The USDA-FS and ODFW have discretion to require monitoring and improvements at these sites.
11.0 TERRESTRIAL RESOURCES	-		-	-	-	
11.1, 11.2; 11.4 Big Game Bridges, Wildlife Crossings, and underpasses	-	8	8	8	8	Maintenance of existing and new bridges and wildlife underpasses. This will include replacement of outside rails, woody debris, and dirt to meet USFS and ODFW standards.
11.3 Monitoring Plan Development and implementation [L3/07]	-		15	5	5	Develop (07) and implemention (05) of a monitoring plan with agencies to evaluate use and value of the wildlife crossings. Outcome of the monitoring could require additional wildlife crossings (4) to be installed.
11.5 Wetland maintenance [L1+]	-		-	10	10	Wetland enhancement maintenance at 8 sites enhaced or created. Currently the Lemolo Lake wetland is being designed. All new wetlands will require a monitoring and ehancement phase if the wetland is not performing as designed. Funds are for monitoring and performing any mainteance on the wetland.
12.0 VEGETATION MANAGEMENT	-		-	-	-	

HYDRO IMPLEMENTATION
2007 - Special Maintenance ($000)

	2005 Actual	2006 Budget	2007 Budget	2008 Budget	2009 Plan	P&N
12.1 Vegetation Management Plan Implementation [03]	20	40	41	78	37	Program oversight, management, and reporting. Vegetation Management Plan for noxious weed control and prevention, weed control strategies and treatments and/or payment to USFS for this work, weed inventory and monitoring, ground cover, native plants, eros
13.0 AVIAN PROTECTION	-		-	-	-	
13.4 Records and Data base management [01]	2		2	2	2	The USFWS Biological Opinion (ESA legal coverage) and the SA requires that we report any and all bird mortality on an annual basis. This effort is to be partnered with the Power Delivery annual reporting through the Corp Bird Powerline Agreement. Funds would be for specific circuit requests to ID mortialities on the NU.
14.0 EROSION CONTROL	-		-	-	-	
14.1 Erosion Control Program [03]	-	15	15	16	16	Management and oversight of Erosion Control Program (ECP) which includes meeting with agency members, reporting activities, and ECP updating. This is to fulfill commitments for SA 14.1 Erosion Control Plan.
14.2 Shut off and Drainage System Maintenance [L1]	-		-	10	10	Maintenance on Canal Shut-off and Drainage Systems such as cleaning of debris, adjusting, and testing of drainage facilities. This is to fulfill commitments for SA 14.2-Maintenance and monitoring of Shut off and Drainage system.
14.5 Erosion Control Plan-Monitoring and reporting [03]	15	20	21	21	21	Erosion monitoring and reporting program that evaluates current ranked erosion sites and identifies new erosion sites. This includes coordinating and performing the annual site evaluation and report monitoring activities to agencies. This is to fulfill commitments for SA 14.5 Annual monitoring and reporting.
14.7 Seismic and Geologic Hazard Evaluation [03]	30	20	-	-	-	Part 12 and a "high level" analysis per settlement agreement.
15.O TRANSPORTATION MANAGEMENT PLAN	-		-	-	-	
15.1-TMP Program [03]	25	20	21	21	21	Management and oversight of the Transportation Management Program (TMP). This includes annual development of 3-yr rolling action plan with outlined maintenance, cost share arrangements, and end of the year accounting and monitoring.
15.2a-PPL Hydro Roads to FS standards [02+]	100	100	103	105	-	Work performed on PacifiCorp-Maintained Hydro Roads identified through monitoring to meet operation levels, standards and serviceability requirements. Sub-standard roads will be identified by PacifiCorp and USDA-FS using the TMP process. The work could include asphalt overlays, road resurfacing, drainage ditches, retaining wall reconstruction, side cast removal, slide correction and repair, and road widening. This is to fulfill commitments for SA 15.2 PacifiCorp Maintenance Responsibility (100% maintenance on PacifiCorp roads).
15.3-Cost Sharing for joint roads [05+]	-	30	31	31	31	Cost sharing on Joint Use Hydro Roads with USDA-FS for maintenance and improvements in accordance with the cost-sharing ratio listed in SA Schedule 15.2. The Company's share is determined during the annual meeting with USDA-FS and is based on work being performed on Joint Use Hydro roads. This is to fulfill commitments for SA 15.3 Cost Sharing.
15.5.1-Critical Bridge Maintenance [05]	125	70	-	-	-	Work performed on PacifiCorp-Maintained Hydro Bridges identified through the inventory and inspection program to meet operation levels, structural standards, and safety requirements. Maintenance on Bridges will be identified by PacifiCorp and presented to the USDA-FS using the TMP process. The work could include replacement of rotten wood, painting, cleaning, brush clearing, signage, asphalt repair, and activities to meet safety requirements. This is to fulfill commitments for SA 15.5.1 Bridge Cost Sharing.
15.5.1 Non-Critical Bridge Maintenance [L10]	-	80	82	42	10	Work performed on PacifiCorp-Maintained Hydro Bridges identified through the inventory and inspection program to meet operation levels, structural standards, and safety requirements. Maintenance on Bridges will be identified by PacifiCorp and presented to the USDA-FS using the TMP process. The work could include replacement of rotten wood, painting, cleaning, brush clearing, signage, asphalt repair, and activities to meet safety requirements. This is to fulfill commitments for SA 15.5.1 Bridge Cost Sharing.

HYDRO IMPLEMENTATION

2007 - Special Maintenance ($000)

	2005 Actual	2006 Budget	2007 Budget	2008 Budget	2009 Plan	P&N
15.5.1-Cost sharing for bridge maintenance [05+]	-	20	21	21	21	Cost sharing on Joint Use Hydro Bridges with USDA-FS for maintenance and improvements in accordance with the cost-sharing ratio listed in SA Schedule 15.2. The Company's share is determined during the annual meeting with USDA-FS and is based on work being performed on Joint Use Hydro roads. This is to fulfill commitments for SA 15.5.1 Bridge Cost Sharing.
15.5 Bridge Inventory/Inspection [every 2 years]	-	40	-	42	-	Conduct visual inspections and monitoring of 40+ PacifiCorp and Jointly Maintained Bridges for safety and maintenance related issues. Inspections conducted on Maintenance Level 3 roads and higher every two years, and Level 2 road and lower every 4 years. This is to fulfill commitments for SA 15.5 Bridges.
15.6 Culvert maintenance [02]	10	10	10	10	10	Perform ongoing maintenance of culverts that are Q100 upgraded, fish passage, road/stream crossings, aquatic reconnect and erosion control associated. Work to be performed includes ditch clearing, culvert cleaning, repair, slope stabilization and plug provention. This is to fulfill commitments for SA 15.6 Upgrading Culverts
16.0 AESTHETICS	-	-	-	-	-	Operation and maintenance practices per the VRMP to preserve and enhance the visual resources of the area.
16.1 Visual Resources Management Plan Implementation [03]	25	25	26	26	26	Address maintenance of project facilities per the VRMP and FS/BLM standards.
16.2 Clearwater Shop and Switchyard Landscape Maintenance	-		-	-	5	
17.0 RECREATION MANAGEMENT PLAN	-		-	-	-	
17.1 RRMP Program [03]	10	20	21	21	21	Program management, oversight, reporting, annual development of 3-yr action plans per settlement agreement, FS fund exchange accountability.
17.2 Recreation Management Estimated O & M pay'ts to FS.	178	147	158	169	178	Fund to FS for annual costs for O & M. Cash pay't.
17.7 Law Enforcement	8	9	10	12	13	Funds to FS for Law Enforcement.
17.8 Rec-Deferred Improvement $$ to FS.	-		-	183	-	Final Payment
17.9 Public Information	6	8	8	8	8	Annual funding to FS for public information and and visitor center operation and maintenance
17.10 Annual Recreation Monitoring Fee	6	8	8	8	8	Funds to FS for monitoring of facilities for increased use. Annual cash pay't.
17.11 Rec-NW FP Compliance $$ to FS.	-		164	-	-	Direct cash pay't($150k) to FS for compliance with NWFP. See Schedule 17.1
18.0 CULTURAL RESOURCES	-		-	-	-	
18.1 CRMP Program [03]	20	20	21	21	21	Historic Properties Management Program (faka Cultural Resources Management Plan) program requires oversight, annual reporting, annual development of 3-yr action plan, meetings with the USDA-FS, , BLM, tribe and SHPO. This would include GIS data base updates, maintenance, and development.
18. 4 Cultural Resources Protection Restoration and Recovery [tbd]	25	50	150	77	52	The HPMP 07 Funds will cover several requirements from the HPMP. 1) a historic facility mainteance inspection by a historic architect . This will identify critical mainteance issues that are jeopardizing the structural integrity of a protected building. The need for this was identified by the agencies in their approval of the HPMP. A maintenance plan will then be developed for each historic building that is in need of critical mainteance. 2) Preparation of Data Recovery Plans for sites that have insufficeint data to determine their eligibility. 3) Prepare data recovery plans for new sites identified. 4) Conduct Data Recovery for those sites that are continuously damaged by ongoing operations. Coordination with Power Delivery will be necesssary for additional funds. PC to oversee work, not a cash pay't. 2008 work will include Data Recovery Plans for remaining archeological sites; performing critical maintenance at one historic building.
18.6-Cultural Site Monitoring [01]	10	10	10	10	10	Monitoring of culturally sensitive sites pre and post work as required by the CRMP for O/M activiites. Funds may be directly paid to the FS for such service..
19.0 MITIGATION	-		-	-	-	
19.1, 19.3- Mitigation Funds	-		-	21	10	Per ODFW MOU PacifiCorp is responsible for monitoring easements to ensure landowners' compliance. Funds are for providing periodic monitoring, reporting and action on easement land.
19.3.1-Annual Reporting and Fund management	2	2	-	2	2	PacifiCorp is required to provide oversight and monitoring of fund with annual report per settlement agreement Section 19.
21.0 COORDINATION AND DECISION MAKING	-		-	-	-	

HYDRO IMPLEMENTATION
2007 - Special Maintenance ($000)

	2005 Actual	2006 Budget	2007 Budget	2008 Budget	2009 Plan	P&N
21.1 Resource Coordination Plan, RCC	150	175	102	131	131	Project management expenses of staff and consultants for license implementation. Includes resource management and strategic planning, project scheduling, contract administration, annual agency reporting and reports, and interna implementation team expens
21.7 NEPA/ESA, Survey and Manage, and Permitting Costs	50	50	25	26	52	Funds for permitting studies required by the state and federal agencies for O/M related work. ESA may require additional owl and eagle monitoring based on USFWS Biological Opinion annual reporting requirments, or reconsultation. Monies would be used for additional studies if req'd or preparation of Biological Opinions if necessary.
MANDATED			-			
Merwin Part 12/PFMA	-	-	-	21	82	Part 12 dam inspection is mandatory requirement by FERC
Swift Part 12/PFMA	-	-	22	82	-	Part 12 dam inspection is mandatory requirement by FERC
Yale Part 12/PFMA	-	-	-	21	82	Part 12 dam inspection is mandatory requirement by FERC
Condit Part 12/PFMA	-	-	22	82	-	Part 12 dam inspection is mandatory requirement by FERC
Powerdale Hazardous Waste Disposal	-	-	-	-	-	
Copco 1 Part 12	72	-	-	-	-	Costs for the standard Part 12 Report is approximately $45k. Per the 2004 PFMA a stability analyses of the C1 dam intake structure ($10k) is required for the next Part 12 (FY2010).
Iron Gate Part 12	72	-	-	-	-	Costs for the standard Part 12 Report is approximately $45k. Per the 2004 PFMA a stability analyses for the IG diversion tunnel gate tower structure ($10k) is required for the next Part 12 (FY2010).
JC Boyle Part 12	72	-	-	-	-	Costs for the standard Part 12 Report is approximately $45k. Per the 2004 PFMA a stability analyses of the JCB spillway structure ($10k) is required for the next Part 12 (FY2010).
Keno Tainter Gates & Deck Support Beams Coating	-	180	-	-	-	FERC Mandated Issue, similar to the Copco/Boyle gate and support beams.
N. Umpqua Vegetation Removal for Fire Suppression Plan	-	-	35	35	35	This 3-year project will provide tree trimming and vegetation removal in established Fire Reduction Zones around powerhouses, residences, and other Company facilities. These requirements are set forth in the Fire Suppression Plan agreed to between the Company and USFS.
N. Umpqua Project Tree Trimming	-	-	30	30	-	This 2-year project provides for tree-trimming and vegetation removal around Company assets not specified in the Fire Suppression Plan (eg. overhead control cables, spill channels, penstocks.)
Lemolo 1 Part 12	-	-	-	-	46	Part 12 dam inspection is mandatory requirement by FERC
Soda Springs EAP Studies	-	-	-	-	-	EAP documents must be re-issued in there entirety every 5 years. The inundation base maps for the North Umpqua Projects have not been updated since the original issuance of the North Umpqua EAP documents. The development of new maps requires an updated
Soda Springs Part 12	-	-	-	-	46	Part 12 dam inspection is mandatory requirement by FERC
Toketee PFMA	-	-	57	-	-	Perform Potential Failure Mode Analysis (PFMA) as required by FERC. The PFMA process is a mandated program as outlined in FERC's Dam Safety Performance Monitoring Program (DSPMP), and described in Chapter 14 of the Engineering Guidelines.
Toketee Part 12	-	-	-	-	46	Part 12 dam inspection is mandatory requirement by FERC
Prospect - North Fork Dam Paint Spillway Gates	-	-	-	77	-	Paint the North Fork Dam tainter gates by 12/31/07 as per the recommendations from the 2003 Prospect Part 12 Report. The Plan and Schedule to address the recommendations made in the 2003 Part 12 Report were sent to FERC by PacifiCorp letter dated 1/30/04.
Prospect Dam Break Analysis	-	40	-	-	-	It is proposed that a Dam Break analysis be performed for North Fork dam and inundation limits be identified in an attempt to make the case for exemption of the North Fork dam and Propsect No.2 project from the Part 12 review process.
Prospect PFMA	-	-	57	-	-	Perform Potential Failure Mode Analysis (PFMA) as required by FERC. The PFMA process is a mandated program as outlined in FERC's Dam Safety Performance Monitoring Program (DSPMP), and described in Chapter 14 of the Engineering Guidelines.
Prospect Part 12 Inspections	-	-	-	-	46	Part 12 dam inspection is mandatory requirement by FERC
Ashton Part 12/PFMA	61	80	-	-	-	The standard Part 12 safety inspection report required by the FERC to be completed every 5 years must be supplemented by a Probable Failure Mode Analysis. This effort effectively doubles the cost for this effort.

HYDRO IMPLEMENTATION
2007 - Special Maintenance ($000)

	2005 Actual	2006 Budget	2007 Budget	2008 Budget	2009 Plan	P&N
Cutler Part 12/PFMA	21	80	-	-	-	The standard Part 12 safety inspection report required by the FERC to be completed every 5 years must be supplemented by a Probable Failure Mode Analysis. This effort effectively doubles the cost for this effort. Money is needed to be budgeted for FY 20
Grace Part 12/PFMA	59	-	-	-	46	The standard Part 12 safety inspection report required by the FERC to be completed every 5 years must be supplemented by a Probable Failure Mode Analysis. This effort effectively doubles the cost for this effort. Money is needed to be budgeted for FY 20
Lifton Plant Dredging	-	50	-	150	-	Dredge a channel through the sandbar from Bear Lake to the Lifton forebay to insure that Bear Lake storage water can be pumped from the lake to meet irrigation demands and contracts. With rising lake levels more of the inlet channel is exposed to sand deposition from cross currents and wave action.
Oneida Part 12/PFMA	20	80	-	-	-	Part 12 dam inspection is mandatory requirement by FERC
Oneida Facility Painting	-	-	-	308	-	The Oneida surge tank and radial gates are in need of corrosion protection. The existing paint contains lead, is peeling/flaking off and falling to the ground. The last Part 12 (1999) addressed this issue and painting will be recommend as a part of the next Part 12 due in 2005 due to the critical failure modes of these components.
Soda Part 12/PFMA	20	80	-	-	-	The standard Part 12 safety inspection report required by the FERC to be completed every 5 years must be supplemented by a Probable Failure Mode Analysis. This effort effectively doubles the cost for this effort. Money is needed to be budgeted for FY 20
Pioneer Water Purchase	-	-	63	63	63	Purchase of excess irrigation water for generation at the Pioneer Plant. At current power prices, generation profit will be about 4 times the cost of this water.
American Fork Decommisisoning	-	-	-	-	-	
Hydro General WECC Generator Testing	-	250	195	-	-	In order to comply with WECC Generator testing requirements, engineering will contract with an experienced vendor to perform testing on 23 hydro units
NON-MANDATED			-			
Merwin Headgate Lifting Structure Coating	-	-	-	66	-	The Merwin Headgate Lifting Structure provides a means for installing a common headgate to all three of the Merwin units. The xisting lead base paint and primer are failing and a new coating system is required.
Merwin Transformer Coating U2 & U3	-	-	-	32	-	Both transformers were completed rebuilt in FY2004 with the exception of exterior coating. Due to cut backs this project was deferred from FY2005 to FY2006.
Merwin U1 & 2 Turbine Shaft Packing	-	35	-	-	-	Turbine Shaft Packing old, no adjustment remains, has excessive leaking, and is in need of replacement.
Merwin U123 Cooling water System Piping Replacement	-	24	-	-	-	The piping provides cooling water to all (3) units. Some of the piping has been in service for over 70-years. No protective coating remains and the metal is badly pitted and corroded.
Merwin - Bridge Coating	-	-	-	215	-	Incorrect coating utilized on last paint application (over coal tab). Better surface preparation will be required next time coating is applied.
Merwin Powerhouse Exterior Arch Repairs	-	-	-	-	261	Repair is to arrest degradation of concrete above the Unit #2 tailrace. Work will be performed in conjunction with the Merwin sorting & handling facility
Swift 1, Units 11,12 & 13 Turbine Shaft Packing	-	50	-	-	-	Turbine Shaft Packing old, no adjustment remains, has excessive leaking, and is in need of replacement.
Swift Switch Gear Breaker Maintenance and Conversions	-	50	-	-	-	Replace all remaining oil dash pot trip devices with solid state electronic trip devices.
Swift 1 Spillway Gate Coating (Upsteam Face)	-		-	-	-	The existing paint coating has deteriorated and rusting has started. Painting is required to prevent rust pitting of the steel surface and preserve the gates
Speelyai Raceway Coating	-		-	78	79	The (24), 100' long concrete raceways provide containment for fingerlings. The concrete is nearly 50-years old and the surface is badly deteriorated.
Hatchery/Ozone Building Exterior Painting	-		-	18	-	The hatchery is mandated under the FERC license . The hatchery was built in 1993 and the building exteriors are showing the signs of the weather.
JCB Rewiring Butterfly Valves	-	30	-	-	-	
JC Boyle Fish Ladder Inlet Repairs	-	100	60	-	-	

Staff/203
Durrenberger/34

HYDRO IMPLEMENTATION
2007 - Special Maintenance ($000)

	2005 Actual	2006 Budget	2007 Budget	2008 Budget	2009 Plan	P&N
JCB Dam Spillgates Apply Protective Coating Upstream Side	-		-	102	-	This project completes the installation of a coating system on the JCBoyle Dam spillgates per the request of FERC. The downstream side of the gates have been repainted. The upstream side contains a tar coating applied over a lead based paint that requires environmental containment.
P2 Penstock Painting	-		-	-	204	Weathering has removed most of the original coating on the top half of the pipe in a portion of the steep section of the penstocks and rust is apparent. This project will apply a complete paint coating (primer/intermediate coat/top coat) to those surfaces. Penstock surfaces where the original primer is exposed or where the top coating has worn thin will be top-coated only. Painting will prevent further deterioration of the exterior surface of the penstocks.
P2 Surge Tank Painting	-		-	-	204	The project will paint the south-west exposure of the surge tank where the coating has weathered off and the surfac is rusting. Tank support trusswork, tank walkway, surge tank manifold, riser pipe and surge tank valves including external clamping system will be spot painted. Painting will significantly improve the appearance of the prominent surge tank and prevent deterioration of the tank and accessories.
P3 Penstock Painting	-		-	102	-	The project will spot paint the penstock where the existing coating has worn off and the steel is rusting or where the existing coating has worn down to the primer. Painting will preserve the penstock exterior surface.
P4 & P2 Repair Roofs	-	50	-	-	-	
Prospect South Fork Woodstave flowline Saddle Repair	-	80	-	-	-	The existing concrete support saddles for the P3 flowline have deteriorated to the point the reinforcing the steel is exposed. These areas must be repaired to prevent further structural damage. As part of the same project the large boulders that are now
Eagle Point Deferred Mtc Payments	-	300	-	-	-	11/20/2002: Per today's Abeyta Email, there will be 3 annual payments; a FY2004 payment of 125K, a FY2005 payment of 200,000, a FY2006 payment of 300,000 (Zero thereafter).
Middle Fork Dredging	-	25	-	-	-	
NU Water Conveyance Condition Evaluation	-		50	-	-	This is an engineering evaluation to identify and prioritize maintenance activites on the North Umpqua water conveyance facilities.
Slide Creek Forebay Headgate Coating	-		-	31	-	The existing coating on this headgate has deteriorated to the point where bare metal and lead-oxide primer is exposed to the elements. This project will recoat this headgate and eliminate continued deterioration.
Clearwater 2 Rebabit Turbine Bearing	-		12	-	-	This project will provide for rebabbetting of a spare turbine bearing to allow for the installation of a pressurized lubricating system as opposed to the existing gravity fed system, reducing the risks of excess oil leaking into the tailrace.
Lemolo 2 Forebay Dredging	-		-	15	15	Project will dredge the Lemolo 2 forebay during the scheduled plant overhaul and canal outage. Dredging work can be performed more economically in the dry and create less environmental disturbance than a wet-dredge project. The restored forebay capacity will allow for increased overnight storage and benefit the plant's load shaping capabilities and increase system reserves.
Fish Creek Diversion Dredging	-		-	41	-	This project will allow for the removal of accumulated gravel and sediment from in front of the Fish Creek diversion dam. The accumulation since the last dredging in 1999 has impacted the hydraulic capacity of the diversion structure.
Ashton Unit 2 - Unit Cleaning	-		-	-	157	7/23/2001: Increased from $82K to $150K by JR, & GN.
Ashton Unit 3 - Unit Cleaning	-		-	-	-	7/23/2001: Increased from $82K to $150K by JR, & GN.
Grace Flowline Repairs	440	440	-	347	347	Annual maintenance of the wood flowline to reduce the leakage caused by the deterioration of the wood staves and reduce the risk of failure of the flowline from ice buildup. Forestalls $24 million Capex for several years. Capex project is no longer on the 10 year forecast sheet. Old staves are removed and replaced with new materials. Entry manholes are also being installed to reduce (approx 50%) interior walking time minutes for each man (entry & exit). Failure to perform the annual maintenance puts generation (33 megawatt hrs) at risk.
Grace Flowline Clean & Paint	-		-	26	26	
Lifton Exterior Walls	-		-	-	-	

HYDRO IMPLEMENTATION
2007 - Special Maintenance ($000)

	2005 Actual	2006 Budget	2007 Budget	2008 Budget	2009 Plan	P&N
Lifton Plant Foundation	-		-	-	-	
Grace Unit 3 - Unit Cleaning	-		-	-	20	
Stairs Paint Flowline & Penstock Surge Tank	-		-	42	-	The existing paint coating of the 1-mile long, partially-buried penstock has deteriorated along the top and near the ground level. Bare surfaces are covered with rust. The project proposes to paint only those surfaces of the penstock and surge tank wher
Weber Paint PenstockTrestle	-	45	-	-	-	The existing paint coating has deteriorated and the trestle and penstock have started to rust. Painting is required to prevent further deterioration and preserve the structures.
Weber Repair Butterfly Valve	-	-	-	-	22	
Weber Repour Generator/Turbine Bearings	-	-	31	-	-	The Weber bearings were scraped in April, 2004 due to babbitt wiping damage. This inspection identified the poor condition of the bearings and the need for repair. The bearings continue to run hot. The four bearings will be removed, babbit removed, repoured, machined and reinstalled.
Oneida Surge Tank Painting	-		-	-	-	
Granite Needle and Seat Replacement	-		-	-	31	Efficiency and Performance Upgrade
Upper Beaver Surge Tank Painting	-		60	-	-	This item is listed in Exhibit B, Section A of the 2004-2005 Beaver Operation and Maintenance Plan that has been reviewed with the USFS. The USFS views this as a commitment on the part of the owner, whether PacifiCorp or the City of Beaver (COB) in the future. The USFS has made this clear to the COB, who has in turn made it clear to PacifiCorp that this item needs to be addressed prior to sale of the facility. The USFS will be reviewing, by the end of 2005CY, whether the existing SUP can be transferred to COB, or whether both PacifiCorp and COB need to apply for two new permits, which would trigger the need for public hearings and NEPA. A permit transfer will save both COB and PacifiCorp considerable time in the sale process.
Gunlock Needle and Seat	-		-	-	5	Efficiency and Performance Upgrade
Soda Spill Gate repair and painting	-		-	-	102	
Sand Cove Needle and Seat	-		-	-	5	
Snake Creek Needle and Seat	-		-	-	10	
Project Boundary Survey Hydro East	77	40	40	45	-	Three phase process to develop workable site/project boundaries on the ground to avoid delays, tresspass, and ensure property control; also compliance with FERC requirements on various projects. Work scope of each phase is based on current or proposed pro
Hydro Geographic Information System(GIS)	-	50	150	128	26	This maintains the mapping infrastructure and relational database for Hydro necessary to support the implementation on the new license and SA for Hydro. It includes data entry, analysis, surveying, modeling, record keeping, map design and development, reports and application adjustments for Hydro' GIS. It supports various implementation and operation projects. Currently, existing spatial information collected during relicensing has limited assessability due to software limitation and conversion requirements. This data represents a major resource for license implementation and a significant investment by the Company. Likewise, the new license present major challenges for compliance and operations that require large amounts of map info and related data. This accesses current map and data attributes and supports ongoing data conversion and formatting. It also supports adjustments to application and functionality necessary to meet the new compliance requirements using the Company's GIS (ESRI) platform and interconnecting to CMS,P8, GPS, etc.
Hydro Document Sys Development	-		50	-	-	
OVERHAUL			-			
Merwin U1 & U2 Rebuild Butterfly Cylinder	-	-	-	102	-	
Swift 13 Generator Rewind	-	-	-	-	304	O&M portion of project estimated at 10% of rewind capital cost.
Swift 13 Runner	-	-	-	-	632	O&M portion of project estimated at 20% of runner capital cost.
Bend Unit #2 Runner Replacement	-	-	-	-	157	O&M portion of project estimated at 20% of runner capital cost.
Big Fork Unit 2 Turbine Bearing Repairs	-	-	-	-	41	
JCB 1 Generator Rewind	124	-	-	-	-	O&M portion of project estimated at 25% of rewind capital cost.
JCB 2 Generator Rewind	-	185	-	-	-	O&M portion of project estimated at 10% of rewind capital cost.
JCB 2 Runner Replacement	-	470	-	-	-	O&M portion of project estimated at 20% of runner capital cost.

HYDRO IMPLEMENTATION
2007 - Special Maintenance ($000)

	2005 Actual	2006 Budget	2007 Budget	2008 Budget	2009 Plan	P&N
Soda Springs Bridge Repairs	-	-	40		-	This bridge maintenance project for Soda Springs Bridge - below Dam (U-42) will include replacement of wheel guards, handrails, seal deck crack and joints, scrap and paint bridge steel components, and repair damaged member. A 1991 and 2003 bridge inspection determined several of these deficiencies and recommended the proscribed treatments. Future traffic demands will occur from the construction of a fish ladder, spillway modification, downstream fish screening, gravel augmentation, and general use by ODFW and PacifiCorp Operations personnel.
Soda Springs Runner Replacement	-	-	-	523	-	This project is necessary to cover O&M costs related to an associated capital runner replacement.
P22 Runner Replacement	-	-	-	-	488	Historical cost of runner replacement is 20% O&M -Scot Taylor
Lifton Pumps	-	389	95	82	-	O&M portion of project estimated at 20% of runner capital cost.
Grace Unit 3 New Runner & draft Tube	-	-	-	-	530	O&M portion of project estimated at 20% of runner capital cost.
Cutler #1 Runner	-	-	-	450	62	O&M portion of project estimated at 20% of runner capital cost.
Pioneer U3 Turbine Replacement	-	-	-	-	161	
Future Anticipated Special Maintenance						
Total	2,853	5,777	4,946	8,092	9,999	

SUBTOTAL SPECIAL MTC (NO OVERHAULS)	2005 Actual	2006 Budget	2007 Budget	2008 Budget	2009 Plan
Implementation	1,815	2,574	3,879	4,779	5,617
Mandated	397	840	479	868	493
Non-Mandated	517	1,319	453	1,288	1,514
TOTAL SPECIAL MTC (NO OVERHAULS)	517	1,319	4,811	6,935	7,624
Overhaul	124	1,044	135	1,157	2,375

Oregon O&M Normalization Adjustment for Joint Owned Plants

PacifiCorp's O&M costs are increasing at our partner owned plants. Our partner owned plants have similar issues to our PacifiCorp plants: their equipment is aging and increasingly in need of repair or replacement, and repair outages don't occur annually so their budgets are not smooth from year to year. The overall trend of these plants has been a steady increase in costs.

PacifiCorp does not have complete control over the O&M costs at the joint owned facilities. However, PacifiCorp does influence the costs through the approval processes provided in the various ownership agreements at the respective plants. This influence is limited by PacifiCorp's share of ownership and by long term contracts that set O&M rates. In the end, PacifiCorp is obligated to pay its portion of the O&M costs at each facility.

For more information, refer to the spreadsheet below:

O & M Normalization Adjustment for Minority Share Plants						
Plant Name	**Actual FY 2005**	**FY 2005 Escalated to FY 2006 $**	**Actual FY 2006**	**Budget CY 2007**	**Requested Adjustment**	**Method of Budgeting**
Colstrip	6,723	6,978	4,564	4,840	276	The owners' representatives meet in July to hear the budget presentations and vote to accept or reject the budgets. Budget acceptance occurs when the majority of partners and the majority of ownership accept the budget. Craig's first budget has been rejected two years in a row and they have been required to make budget cuts before presenting the budget again for approval.
Craig	1,455	1,510	6,613	7,879	1,266	
Hayden	3,141	3,260	1,571	1,805	234	
Foote Creek	4,888	5,073	3,187	3,428	241	The Foote Creek budget is set by long term contract with built in escalators based on published inflation rates. It is calculated as a percentage of the facility's generation.
Hermiston	1,793	1,861	4,477	5,734	1,257	Hermiston's operating budget is set by long term contract with built in escalations. The maintenance budget is set by agreement of both parties.
TOTAL	18,001	18,682	20,411	23,687	3,275	

Note: Costs are in thousands of dollars

Generation												4.14.2
Material, Contracts, and Special Maintenance												
	Fiscal Year 2005				**Fiscal Year 2007**				**Fiscal Year 2008**			
	Routine		Special		Routine		Special		Routine		Special	
	Material	Contracts	Maint	Total	Matl	Contracts	Maint	Total	Matl	Contracts	Maint	Total
Blundell	262	174	34	470	156	164	149	469	159	167	184	510
Carbon	1,409	1,347	-	2,756	1,509	1,125	258	2,892	1,585	1,159	530	3,274
DaveJohnston	5,362	3,338	612	9,312	5,605	3,367	2,507	11,479	5,717	3,434	3,210	12,361
Gadsby	1,051	1,530	27	2,608	1,085	2,161	365	3,611	1,107	2,204	672	3,983
Hunter	8,339	5,725	201	14,265	7,976	4,882	1,543	14,401	8,264	4,584	2,065	14,913
Huntington	5,470	4,684	937	11,091	6,126	3,754	1,470	11,350	7,560	3,954	2,135	13,649
JimBridger	9,940	4,464	1,495	15,899	11,081	5,208	590	16,879	11,111	5,413	1,380	17,904
LittleMt	82	10	8	101	108	36	149	293	110	37	122	269
Naughton	4,185	2,808	899	7,892	4,822	3,327	710	8,859	5,056	3,409	843	9,307
WValley	582	573	-	1,155	418	512	215	1,145	426	522	138	1,087
Wyodak	2,335	1,309	-	3,643	1,742	919	745	3,406	1,794	998	494	3,286
Camas	-	0	-	0	-	50	-	50	-	50	-	50
Cholla	282	15,556	-	15,838	200	16,160	-	16,360	200	16,170	-	16,370
Colstrip	9	4,330	-	4,339	128	4,712	-	4,840	128	4,712	-	4,840
Craig	48	6,675	-	6,723	65	7,647	-	7,712	65	7,870	-	7,935
FooteCreek	-	1,455	-	1,455	-	1,764	-	1,764	-	1,819	-	1,819
Hayden	28	3,113	-	3,141	28	3,400	-	3,428	28	3,400	-	3,428
Hermiston	-	4,888	-	4,888	-	5,723	-	5,723	-	5,738	-	5,738
Hydro - East	634	470	690	1,793	447	643	881	1,970	457	775	1,153	2,384
Hydro - West	1,560	5,607	2,128	9,295	1,303	5,744	4,732	11,779	1,344	5,572	5,783	~~12,699~~
AdminG	451	964	-	1,414	1,289	1,723	-	3,012	1,416	1,767	-	3,183
Engr	160	1,542	-	1,701	180	2,209	-	2,389	184	2,447	-	2,631
Env				-	7	408	-	415	7	408	-	415
ResD	8	389	-	397	13	1,920	-	1,933	13	1,920	-	1,933
Safety	123	457	-	580	-		-	-	-	-	-	-
Start-Up Fuel	(6,658)			(6,658)	(7,956)			(7,956)	(7,956)	-	-	(7,956)
Total	35,662	71,405	7,031	114,098	36,331	77,558	14,314	128,203	38,775	78,529	18,708	136,012
By Function												
Steam	32,521	42,846	4,205	79,573	33,855	46,926	8,337	89,118	36,237	47,847	11,513	95,597
Cholla	282	15,556	-	15,838	200	16,160	-	16,360	200	16,170	-	16,370
Hydro - East	634	470	690	1,793	447	643	881	1,970	457	775	1,153	2,384
Hydro - West	1,560	5,607	2,128	9,295	1,303	5,744	4,732	11,779	1,344	5,572	5,783	12,699
Other	82	6,353	8	6,443	108	7,573	149	7,830	110	7,644	122	7,876
Other - Peakers	582	573	-	1,155	418	512	215	1,145	426	522	138	1,087
	35,662	71,405	7,031	114,098	36,331	77,558	14,314	128,203	38,775	78,529	18,708	136,012
				4.14.1				4.14.1				4.14.1
Source: Generation Business Unit												

CASE: UE 179
WITNESS: Judy Johnson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Direct Testimony

July 12, 2006

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

A. My name is Judy Johnson. I am Program Manager of the Rates and Tariffs Section in the Electric and Natural Gas Division at 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/301.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am sponsoring the Federal and State Income Tax adjustment.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/302, consisting of 1 page.

Q. PLEASE DESCRIBE THE ADJUSTMENT YOU ARE SPONSORING.

A. When taxes are calculated for ratemaking purposes there are several components that are taken into consideration. For purposes of this calculation, I do not change any component except for the weighted average cost of debt, which is used to calculate interest deductions as seen on Staff/302, Johnson/1.

Q. WHY DO YOU CHANGE THE WEIGHTED AVERAGE COST OF DEBT?

A. I use the weighted average cost of debt as calculated by staff witness, Mr. Conway. It is appropriate to use staff's weighted average cost of debt to recalculate interest in order to be consistent with staff's case.

Q. HOW DOES CHANGING THE WEIGHTED AVERAGE COST OF DEBT CHANGE THE INTEREST CALCULATION?

A. The weighted average cost of debt is multiplied by the company's rate base and the result is a new figure for interest expense that reflects staff's new cost of debt and/or capital structure.

Q. WHAT IS THE RESULT OF USING STAFF'S WEIGHTED AVERAGE COST OF DEBT TO CALCULATE INTEREST?

A. The result is a decrease in State Income Taxes of $277,000 and a decrease in Federal Income Taxes of $1,971,000.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 179
WITNESS: Judy Johnson

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 301

Witness Qualification Statement

July 12, 2006

WITNESS QUALIFICATION STATEMENT

NAME:	JUDY A. JOHNSON
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	SENIOR REVENUE REQUIREMENTS ANALYST
ADDRESS:	550 CAPITOL ST. N.E., SALEM, OREGON 97310-1380
EDUCATION:	MBA with an emphasis in Statistics from Eastern Washington University Cheney, Washington BA in Accounting from Eastern Washington University Cheney, Washington

EXPERIENCE:

3/95-Present	I have been employed by the Oregon Public Utility Commission since March of 1995. My current position is Program Manager of Rates & Tariffs. I was previously a Senior Analyst for the Revenue Requirements Section.
6/77-2/95	I was employed by Avista Corporation, an electric and natural gas utility located in Spokane, Washington. The majority of my employment was spent in the Rates and Regulatory Affairs Department as a Senior Rate Analyst. I have prepared testimony and exhibits in numerous electric and natural gas rate cases, primarily in the area of results of operations and cost of service.

CASE: UE 179
WITNESS: Judy Johnson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibit in Support of
Direct Testimony

July 12, 2006

PacifiCorp - UE 179
Income Tax: Adjusted Results

2007 test period; dollars in 000

Calculates test period income tax for the adjusted results of operations based on the following:
(a) Ratemaking Interest deduction calculated using staff's proposed weighted cost of debt.

In Staff's revenue requirement model, the interest effect for individual adjustments will be included in the income tax calculation for each.

State & Federal Income Tax - Twelve months ended December 2007

Line No.	Description	Staff	As Filed	Adjustments
1	Operating Revenues	1,159,185	1,159,185	
2	Miscellaneous Revenue and Expenses	3,167	3,167	
	Total Revenue	1,162,352	1,162,352	
3	O&M Expense	782,085	782,085	
4	Depreciation	121,382	121,382	
5	Amortization	18,573	18,573	
6	Taxes - Other	45,968	45,968	
7	Total Operating Deductions	968,008	968,008	
8	Operating Income	194,344	194,344	
9	Interest Deductions	73,670	67,763	
10	Tax Schedule M	(862)	(862)	
11	Income Before State Tax	119,812	125,719	
12	State Tax Rate	4.693%	4.693%	
13	**State Tax Expense**	5,623	5,900	**(277)**
14	Taxable Income	114,189	119,819	
15	Federal Tax Rate	35.000%	35.000%	
16	Total Federal Income Tax Before Credits	39,966	41,937	
17	Alternative Fuels Credit - Wind	(436)	(436)	
18	Pollution Control Credit - Trojan	0	0	
19	**Total Federal Income Tax**	39,530	41,501	**(1,971)**
20	**Total Deferred Income Tax**	5,252	5,252	
21	**Total Income Tax (State, Federal and Deferred)**	50,405	52,653	**(2,248)**

CASE: UE 179
WITNESS: Paul Rossow

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Direct Testimony

July 12, 2006

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

A. My name is Paul Rossow. I am employed by the Public Utility Commission of Oregon (the Commission) as a Utility Analyst in the Electric and Natural Gas Division. 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. I will explain three adjustments I am recommending to PacifiCorp's rate case filing in Docket UE 179: the Membership Adjustment, the Other Revenue Adjustment, and the Uncollectible Adjustment.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared two exhibits. Exhibit Staff/401 is my one page witness qualification. Exhibit Staff/402, consisting of one page, shows calculations used to reach my membership adjustment.

ISSUE 1, MEMBERSHIP

Q. PLEASE EXPLAIN YOUR MEMBERSHIP ADJUSTMENT.

A. There are three parts to my membership adjustment. I first disallow 25% of Edison Electric Institute (EEI) Membership fees. Next, I remove 25% of dues for national and regional trade organizations. Third, and last, I remove the amount related to Unidentified Memberships.

Q. PLEASE EXPLAIN YOUR RECOMMENDATION TO DISALLOW 25 PERCENT OF THE EEI MEMBERSHIP AND THE NATIONAL AND REGIONAL TRADE ORGANIZATION DUES.

A. Pursuant to long-established PUC Staff policy that the Commission followed in Docket Number UE 94, I am disallowing 25% of EEI memberships along with national and regional trade organizations on the basis that certain activities are promotional or lobbying in nature or do not benefit ratepayers.

Q. PLEASE EXPLAIN THE UNIDENTIFIED MEMBERSHIPS.

A. Unidentified Memberships refers to Total Memberships and Subscriptions, less revised Total Memberships, less Western Electricity Coordinating Council (WECC) membership fees, with the remainder equating to Unidentified Memberships that should be disallowed because PacifiCorp has made no showing of customer benefit.

Q. PLEASE SUMMARIZE YOUR MEMBERSHIP RECOMMENDATION?

A. I recommend that the Commission decrease memberships by $54,000 on an Oregon adjusted basis. The development of the membership adjustment is summarized in Exhibit Staff/402.

ISSUE 2, OTHER ELECTRIC REVENUE

Q. PLEASE EXPLAIN THE OTHER ELECTRIC REVENUE ADJUSTMENT.

A. My Other Electric Revenue adjustment increases test period revenue from Forfeited Discounts and Interest, Miscellaneous Electric Revenue and Rent of Electric Property.

Q. PLEASE EXPLAIN WHAT IS IN FEDERAL ENERGY REGULATORY COMMISSION (FERC) ACCOUNT 450 "FORFEITED DISCOUNT AND INTEREST."

A. FERC Account 450 includes the amount of discount forfeited or additional charges imposed because of the failure of customers to pay their electric bills on or before a specified date.

Q. PLEASE EXPLAIN WHAT FACTOR WAS USED TO INCREASE ACCOUNT 450 "FORFEITED DISCOUNTS AND INTEREST."

A. I increase FERC Account 450 revenues by the change in revenues from Fiscal Year 2005 (the company's base year) to test period Calendar Year 2007, a factor of 1.1750. This factor was created from PacifiCorp's Revenue Summary page 3.0.1 and dividing PacifiCorp's Total Sales to Ultimate Customers for December 2007 Adjusted Revenues by Total Sales to Ultimate Customers Fiscal Year 2005 Unadjusted Data.

Q. PLEASE EXPLAIN WHAT IS IN FERC ACCOUNT 451 "MISCELLANEOUS ELECTRIC REVENUE."

A. FERC Account 451 includes revenue for all miscellaneous services and charges billed to customers which are not specifically provided for in other accounts. Examples of such revenues are: fees for changing, connecting or disconnecting service; profits on maintenance of appliances, wiring, piping or other installations on customers' premises; and net credit or debit on closing of work orders for plant installed for temporary service of less than one year.

Q. PLEASE EXPLAIN WHAT FACTOR WAS USED TO INCREASE FERC ACCOUNT 451 "MISCELLANEOUS ELECTRIC REVENUE."

A. My factor of 1.0419 was created from PacifiCorp's O and M Summary page 4.0.10. I divided Total Non Labor Distribution Expenses for Fiscal Year 2007 Escalated to December 2007 by March 2005 Total Adjusted Operating and Maintenance Expense. This factor is applied to adjust the company's Fiscal Year 2005 amount to the test period.

Q. PLEASE EXPLAIN WHAT IS IN FERC ACCOUNT 454 "RENT OF ELECTRIC PROPERTY."

A. This account includes rents received for the use by others of land, buildings, and other property devoted to electric operations by PacifiCorp. When property owned by PacifiCorp is operated jointly with other entities under a definite arrangement for allocating the actual expenses among the parties to the arrangement, any amount received by PacifiCorp for interest or return or in reimbursement of taxes or depreciation on the property is credited to this account.

Q. PLEASE EXPLAIN WHAT FACTOR WAS USED TO INCREASE FERC ACCOUNT 454 "RENT OF ELECTRIC PROPERTY."

A. My factor of 1.1201 was created from PacifiCorp's Rate Base Summary page 8.0.5. I divided Total Distribution Plant December 2007 Projected Rate Base by Total Distribution Plant March 2005 Unadjusted Data. This factor provides a proxy of the increased rent revenues that PacifiCorp should reasonably expect from Fiscal Year 2005 to Calendar Year 2007.

Q. WHY DO YOU BELIEVE DISTRIBUTION PLANT IS A GOOD INDICATOR FOR RENTAL INCOME?

A. As Distribution Plant is installed there is more availability for pole contacts to be connected. These additional pole contacts generate increased revenues.

Q. WHAT IS STAFF'S RECOMMENDATION FOR OTHER ELECTRIC REVENUE?

A. On an Oregon adjusted basis, I recommend that the Commission increase PacifiCorp's Other Electric Revenues by $1.2 million. The overall adjustment is to increase Other Electric Revenues to better reflect projected test period levels.

ISSUE 3, UNCOLLECTIBLE ACCOUNTS

Q. PLEASE EXPLAIN THE UNCOLLECTIBLE ACCOUNTS ADJUSTMENT.

A. I am using a three-year average to calculate an allowable level of Uncollectible expenses. My adjustment includes amounts from Oregon's Supplemental FERC FORM 1 of: $8,406,244 in 2003, $3,642,666 in 2004, and $3,933,094 in 2005. The last time Uncollectible Accounts were above $6 million, as PacifiCorp has proposed in its filing, was in 2003, when Oregon was experiencing high unemployment. I predict Oregon's job growth will be moderate for years 2006 and 2007. I believe Oregon's unemployment rate for years 2006 and 2007 will continue to be lower than previous years. My proposal to use the most recent three-year average provides Uncollectible expense of $5.3 million, an adjustment of $750,000.

Q. MIGHT THE COMMISSION CONSIDER AN EVEN LOWER LEVEL OF UNCOLLECTIBLE EXPENSE?

A. Yes. My recommendation of a $5.3 million three-year average is based on the $8.4 million Uncollectible amount from 2003 as well as much lower amounts from 2004 and 2005. As explained above, the high 2003 level reflects the effect of Oregon's recession. As an option, the Commission might consider excluding the abnormal 2003 figure and simply average the past two years of $3.8 million, an adjustment of $2.29 million from the company's filing.

Q. WHAT IS STAFF'S UNCOLLECTIBLE ADJUSTMENT RECOMMENDATION?

A. On an Oregon adjusted basis, I recommend that the Commission decrease PacifiCorp's Uncollectible Accounts by $750,000. Alternatively, using more recent and normal data, the Commission could adopt an adjustment of $2.29 million. Either adjustment provides a more reasonable estimate to the expected level of this expense. This overall adjustment is to decrease Uncollectible Accounts to better reflect account balances.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 179
WITNESS: Paul Rossow

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualification Statement

July 12, 2006

WITNESS QUALIFICATION STATEMENT

NAME:	PAUL W. ROSSOW
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	UTILITY ANALYST
ADDRESS:	550 CAPITOL ST. N.E., SALEM, OREGON 97310-1380
EDUCATION:	Professional Accounting and Computer Application Diplomas Trend College of Business 1987
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission since October of 1988. My primary area of responsibility in my current position has been the review of electric and natural gas utility new construction budgets, general rate case filings, territory allocation filings, Electricity Service Supplier and Aggregator applications.
OTHER EXPERIENCE:	I have attended the Utility Rate School sponsored by the Committee on Water of the National Association of Regulatory Utility Commissioners in May of 2005 and the Institute of Public Utilities sponsored by the National Association of Regulatory Utility Commissioners at Michigan State University in August of 2005.

CASE: UE 179
WITNESS: Paul Rossow

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibit in Support
of Direct Testimony

July 12, 2006

UE 179 PacifiCorp
PUC Staff Workpaper
Disallowed EEI Membership Calculation Worksheet

Disallow EEI Membership Fees	$177,767
Removed Total Membership in Unadjusted Results	$2,260,241
Response to Data Request 261 Revised Total Memberships	-1,141,696
WECC fees @ 100%	-774,788
Unidentified Memberships	$343,757
Response to Data Request 261 Revised Total Memberships	$1,141,696
Disallow EEI Membership Fees	-177,767
Revised Memberships	$963,929
Disallowed Rate	25%
Disallowed Memberships	$240,982
Disallow EEI Membership Fees	$177,767
Unidentified Memberships Disallowed	343,757
Disallowed Memberships at 25%	240,982
Total Disallowed	$762,506
PacifiCorp's SO Factor	28.442%
Oregon Disallowed	$216,872
EEI Membership Fees as Filed	$777,767
EEI Membership Fees Revealed During Settlement	600,000
Disallow EEI Membership Fees	$177,767
Company Disallowance as Filed	$163,131
Staff Disallowance	$216,872
Membership Adjustment	($53,741)

CASE: UE 179
WITNESS: Lynn Kittilson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Direct Testimony

July 12, 2006

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

A. My name is Lynn Kittilson. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551. I am employed by the Public Utility Commission of Oregon as a Senior Utility Analyst in the Electric & Natural Gas Division of the Utility Program.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/501, Kittilson/1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I was responsible for reviewing various labor-related expenses in PacifiCorp's (Pacific or company) rate case. Based on my review, I am proposing two adjustments to test period expenses and rate base related to the company's Rebasing Program (S-1) and employee incentives (S-2).

Q. DID YOU PREPARE ANY EXHIBITS FOR THIS DOCKET?

A. Yes. In addition to my Witness Qualification Statement provided in Staff/501, I prepared two exhibits, Staff/502 and Staff/503, which provide documents and calculations supporting the two adjustments I propose in my testimony.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

ISSUE S-1, REBASING PROGRAM ADJUSTMENT

Q. PLEASE SUMMARIZE YOUR PROPOSED ADJUSTMENT FOR ISSUE S-1.

A. I propose to reduce Pacific's UE 179 O&M expenses by $1.053 million to reflect additional labor benefits associated with the company's 2005 Rebasing Program that are not included in the test period. A summary of my proposed Rebasing Program adjustment is provided in Exhibit Staff/502, Kittilson/1.

Q. PLEASE DESCRIBE PACIFIC'S REBASING PROGRAM.

A. Pacific's response to Staff Data Request 208 provided the following description:

> The PacifiCorp Rebasing Project conducted in early 2005 sought to find new ways to mitigate forecast increases in controllable costs going forward. The project reviewed corporate, support and shared functions to find ways to reduce workload, streamline activities and deliver organization synergies and effectiveness. The project did not focus on operational areas of the business and no cuts were made in those areas.

See Exhibit Staff/502, Kittilson/2-3.

Q. WHAT ARE THE REBASING PROGRAM COSTS INCLUDED IN THE TEST PERIOD?

A. Pacific accrued $4.037 million in June 2005 for projected severance costs to be paid to 78 employees whose positions were to be eliminated as a result of the Rebasing Program. (See Pacific's response to Staff Data Request 298(b) provided in Exhibit Staff/502, Kittilson/4.) In UE 179, Pacific proposes that the accrued costs be amortized over a five-year period. The filing includes $807,440 of amortization expense in labor O&M costs and the balance of

$3,229,760 in miscellaneous rate base systemwide ($229,651 expense and $918,605 rate base on an Oregon-allocated basis).

Q. WHAT REBASING PROGRAM BENEFITS ARE INCLUDED IN UE 179?

A. Pacific has included in the test period labor-related O&M expense reductions related to the termination of 57 employees that took place through the Rebasing Program by October 2005. (*See* Exhibit Staff/502, Kittilson/2.)

Q. WHAT IS STAFF'S PROPOSED ADJUSTMENT RELATED TO PACIFIC'S REBASING PROGRAM?

A. UE 179 includes costs associated with Rebasing Program reductions of 78 employees projected to occur during fiscal years (FY) 2006 and 2007. The test period should also include the labor-related O&M savings related to a reduction of 78 employees rather than 57. Staff estimates the labor O&M savings related to the reduction of 21 additional employees is approximately $3.7 million systemwide ($1.053 million Oregon-allocated). Staff recommends UE 179 O&M expenses be reduced by $1.053 million to reflect additional Rebasing Program cost savings projected for the test period.

ISSUE S-2, INCENTIVE ADJUSTMENT

Q. PLEASE SUMMARIZE YOUR PROPOSED ADJUSTMENT FOR ISSUE S-2.

A. I propose to reduce UE 179 O&M expenses by $3.857 million and rate base by $1.410 million based on the Commission's traditional sharing of employee incentive costs between customers and shareholders. A summary of my proposed incentive adjustment is provided in Exhibit Staff/503, Kittilson/1.

Q. WHAT INCENTIVE PLAN EXPENSES DID PACIFIC INCLUDE IN UE 179?

A. Pacific's rate case includes approximately $36 million in incentive-related expenses, including social security and Medicare taxes, on a systemwide basis ($10.2 million Oregon-allocated).

Q. DID PACIFIC MAKE ANY ADJUSTMENTS TO ITS TEST PERIOD INCENTIVE EXPENSES?

A. Pacific (PPL/900, Wrigley/19) states the company made some modifications to its annual incentive plan in FY 2006 that reduced the expected amount of incentive compensation by about $12 million over incentive payments made in the FY 2005 base period. Incentives associated with an incentive plan called Performance Unit Compensation that operated during FY 2005 were not included in UE 179.

Q. DID PACIFIC MAKE ANY ADJUSTMENTS TO PROJECTED TEST PERIOD INCENTIVE EXPENSES TO REFLECT THE COMMISSION'S POLICY ON ALLOWANCE OF INCENTIVE EXPENSES IN RATES?

A. No. UE 179 does not include any adjustments to reflect the Commission's historical policies on sharing of incentive expenses between shareholders and customers. In other words, Pacific proposes that all the costs related to the company's bonus and incentive programs be included in customers' rates.

Q. WHAT ARE THE COMMISSION'S HISTORICAL RATEMAKING POLICIES ON INCENTIVE EXPENSES?

A. The Commission's policies are to disallow 100 percent of officers' bonuses and incentives (because typically they are based solely on increased earnings and the financial performance of the utility, which benefit shareholders); disallow 75 percent of performance-based incentives (because they are generally focused on increased earnings and, therefore, bring more benefit to shareholders); and disallow 50 percent of merit-based bonuses (because they equally benefit shareholders and ratepayers). (See, for example, selected pages from the Commission's decision in Order No. 99-697 on bonuses in UG 132 provided in Exhibit Staff/502, Kittilson/2-3.)

Q. IS YOUR PROPOSED ADJUSTMENT BASED ON THE COMMISSION'S POLICIES ON ALLOWANCE OF INCENTIVE EXPENSES?

A. Yes. My adjustment proposes to disallow 100 percent of UE 179 expenses related to officers' incentives and 50% of non-officers' merit-based incentives, consistent with the Commission's general policies on incentives. My adjustment is also consistent with the ratemaking recommendations on Pacific's incentive programs in *Staff Audit Report of PacifiCorp, Audit Number 2004-002* dated December 1, 2004 (audit report). Pages 32 through 35 of the audit report summarize Pacific's incentive plans at the time of the audit that preceded the company's last rate case (UE 170) and recommend expense disallowances consistent with Commission policies on incentives. The audit report pages are included in Exhibit Staff/503, Kittilson/4-7.

Q. HAS PACIFIC MADE ANY MODIFICATIONS TO ITS INCENTIVE PLANS SINCE STAFF'S AUDIT REPORT WAS COMPLETED IN LATE 2004?

A. In response to Staff Data Request 207(a) regarding FY 2006 and test period modifications to the company's incentive plans, Pacific stated:

> For FY 2005/2006; the PacifiCorp Balance Scorecard measure for most employees is optimization of power availability to customers, with the intent of driving superior performance and line-of-sight to the customer. Corporate Support groups that had each previously based their results on individualized Business Unit Balanced Scorecards now have results based on the average scorecard achievement of the Operating Units. This change is intended to emphasize the importance and impact of the Support functions on the business. In addition; the individual performance rating scale was amended to align more favorably with the market, with 3+ representing target market (50%) for most employees. This reduction in the percentage of payout for individual performance represents further cost savings referenced in Mr. Wrigley's testimony.
>
> At this time there are no additional planned modifications that would affect test period incentive expenses.

See Exhibit Staff/503, Kittilson/8-10.

In response to follow-up Data Request No. 297 related to modifications to the Senior Management Group (SMG) incentive plan planned for 2006/2007 and the CY 2007 test period, Pacific stated:

> Details concerning changes that may occur to the Annual Incentive Program generally for 2006/2007 and CY 2007 test period are not yet known; however, it is known that the Senior Management Group (SMG) designation will no longer apply.

See Exhibit Staff/503, Kittilson/11.

Q. WHAT ARE YOUR RECOMMENDATIONS AFTER REVIEWING THE COMPANY'S RESPONSES TO STAFF'S DATA REQUESTS ON THE TEST PERIOD INCENTIVE PLANS?

A. Pacific's response to Staff's Data Request 297 above was provided after the MidAmerican Energy Holdings Company acquisition of the company was completed earlier this year. It is uncertain at this time what the structure of the test period incentive plans will be and the company's discretion in awarding incentives during 2007. Given this uncertainty and lack of actual test period incentive plans, I don't believe there is a strong basis for deviating from the Commission's historical policies for allowing incentive expenses in rates. I recommend the Commission adopt staff's proposed reductions to test period incentive expense of $3.857 million and to rate base of $1.410 million.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 179
WITNESS: Lynn Kittilson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualification Statement

July 12, 2006

WITNESS QUALIFICATION STATEMENT

NAME:	Lynn Kittilson
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst, Electric and Natural Gas Division
ADDRESS:	550 Capitol Street NE Suite 215 Salem, OR 97301-2551
EDUCATION:	Master of Business Administration in Accounting (1984) University of Oregon Eugene, Oregon Bachelor of Arts in English (1978) University of Oregon Eugene, Oregon NARUC Annual Regulatory Studies Program (1985) Michigan State University Graduate School of Business
WORK EXPERIENCE:	Senior Utility Analyst in the Electric and Natural Gas Division, Utility Program, Public Utility Commission of Oregon (OPUC) since July 1992. Primarily responsible for the analysis of utility least-cost plans, energy utility tariff filings, and demand-side resource activities. Public Utility Analyst with the Electric and Natural Gas Division of the OPUC from February 1986 through July 1992. Responsibilities included review of natural gas utility least-cost plans, energy utility tariff filings, and participation in Commission rulemaking proceedings. Utility Cost Analyst and Intern with the OPUC from June 1984 through January 1986. Primarily responsible for analyzing energy utility avoided cost filings and related issues.

CASE: UE 179
WITNESS: Lynn Kittilson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

Exhibits in Support of
Direct Testimony

July 12, 2006

PacifiCorp - UE 179
Rebasing Program Adjustment
12 Months Ended 12/31/07
Figures in $000

S-1

Staff's proposal reduces UE 179 O&M expenses to reflect additional labor benefits associated with PacifiCorp's 2005 Rebasing Program that are not included in the test period. The company accrued Rebasing Program liabilites of $4,037,200 associated with reductions in FTE counts of 78 (see DR 298b provided in Staff/502, Kittilson/4). UE 179 includes actual Rebasing reductions of 57 FTE through October 2005 (see DR 208 provided in Staff/502, Kittilson/2) leaving an additional 21 FTEs to be included in UE 179 (78-57=21).

Item	Reference	Staff	Company	Adjustment
Additional Labor O&M expense (savings)	1	($3,704)	0	**($3,704)**
Oregon allocation factor (SO)	2	0.284419		
Total O&M expense (savings), Oregon allocated		($1,053)	0	**($1,053)**

Notes
(1) $176,370 (whole dollars) est avg FTE/Yr (calculated per confidential DR 298a) times 21 FTEs = $3,703,770
(2) PPL/ 901 allocation page 10.1

OPUC Data Request 208

With reference to Exhibit PPL/900, Wrigley/18, please provide details on PacifiCorp's 2005 "Rebasing program" and its effects in the UE 179 test period. Please include information that more fully describes and supports Mr. Wrigley's statement, "Although the Rebasing program is not expected to reduce costs below the Base Period level, the Company has held manpower additions included in this filing at their October 31, 2005 level, opting not to include forecasted additions through the end of the Test Period, to reflect the possible savings related to the Rebasing program."

Response to OPUC Data Request 208

The PacifiCorp Rebasing Project conducted in early 2005 sought to find new ways to mitigate forecast increases in controllable costs going forward. The project reviewed corporate, support and shared functions to find ways to reduce workload, streamline activities and deliver organizational synergies and effectiveness. The project did not focus on operational areas of the business and no cuts were made in those areas.

Provided on the enclosed CD's are the following documentation:

- Attachment OPUC 208 -1 "Outcomes of the Rebasing Project" slide presentation
- Attachment OPUC 208 -2 "PacifiCorp Organization Activity Initiatives" organization chart.
- Confidential Attachment OPUC 208 -3 "Impact of Specific Proposed Initiatives" spreadsheet. (Provided on the enclosed Confidential CD)

Please see Confidential Attachment OPUC 208 -3. The total savings anticipated from Rebasing initiatives are $16.7 million in FY 2006 and $45.7 million in FY 2007. These were the detailed initiatives recommended by the project team to executive management. The final initiatives implemented by management may be different. However, the dollar impact is expected to be comparable to this proposal.

The effect of the Rebasing initiative in the UE179 test period can be estimated as follows: As stated in on page 18 of Mr. Wrigley's testimony, the Company has held manpower additions included in this filing at their October 31, 2005 level to reflect the possible savings related to the Rebasing program. Substantially all reductions in "filled positions" related to Rebasing were completed prior to October 31, 2005. In addition, by holding manpower levels constant at October 31 levels the Company has given full effect in this filing to reductions in "unfilled positions" contemplated under Rebasing As shown in Confidential Attachment OPUC 208 -4 on the enclosed Confidential CD, 57 employees vacated "filled positions" under Rebasing by September 9, 2005. In addition, approximately 100 "unfilled positions" were not filled. The Rebasing initiatives have and will mitigate cost increases. The rebasing initiatives relate to corporate, support and shared services costs, and as such the savings are allocated system-wide.

As a result of rebasing initiatives implemented, certain positions were identified as being displaced. Please see Confidential Attachment OPUC 208 -4. This attachment shows titles and locations of employees whose positions were eliminated as a result of rebasing initiatives. Additional future reductions of approximately 100 FTEs had not been specifically identified as of that date. Due to the requirements of the MEHC transaction, a small number of staff reductions were delayed in order to provide staffing support for the transaction; these have been reflected in the current workforce reductions information for Response to Data Request OPUC 210.

Attachment OPUC 298_b

PacifiCorp Severance Estimate (FY06 and FY07)

Business Unit	# of Employee Positions Eliminated	Estimated # of Employees for Severance Accrual	Estimated Severance Payout	SS & MC Tax at 7.65%	6 months COBRA	Outplacement	Total Severance Accrual
Corporate		39	1,323,650.00	$ 101,300	$ 181,535	$ 160,000	$ 1,766,485
C&T		1	37,500.00	$ 2,900	$ 4,655	$ 4,000	$ 49,055
Generation		0		$ -	$ -	$ -	$ -
CBS / IT		27	1,335,700.00	$ 102,200	$ 125,678	$ 38,000	$ 1,601,578
Power Delivery		11	489,480.00	$ 37,400	$ 51,202	$ 42,000	$ 620,082
Total	0	78	$ 3,186,330	$ 243,800	$ 363,070	$ 244,000	$ 4,037,200

CASE: UE 179
WITNESS: Lynn Kittilson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 503

Exhibits in Support of
Direct Testimony

July 12, 2006

PacifiCorp - UE 179
Incentives Adjustment
Twelve Months Ended 12/31/07
Figures in $000

S-2

Staff's proposal removes a portion of PacifiCorp's proposed incentive program costs from CY 2007. Staff typically proposes disallowances of 100% of executive incentives and 50% of non-executive employee incentives. Based on the recommendations of Staff's December 1, 2004 PacifiCorp Audit Report and review of UE 179 testimony and data responses, Staff proposes to disallow UE 179 incentive plan expenses based on the traditional sharing percentages.

PacifiCorp UE 179 Incentives			
CY 2007 Incentives[1]	$33,648,716		
Plus: FICA & Medicare Tax (6.96%)[2]	$2,341,951		
Total UE 179 Incentives - Systemwide	$35,990,667		
Oregon Allocation (SO Factor: 0.284419)[3]	$10,236,429		
Oregon O&M Expense (73.51%)[4]	$7,524,799		
Oregon Rate Base (26.87%)[4]	$2,750,529		
Staff Proposed Incentive Adjustments			
Executive Incentives			
CY 2007 Executive Incentives[5]	$938,432		
Plus: Medicare Expense (1.45%)[2]	$13,607		
Total CY 2007 Executive Incentives	$952,039		
Executive Incentives - 100% Disallowance		($952,039)	
Non-Executive Incentives			
CY 2007 Non-Executive Incentives[6]	$32,710,284		
Plus: FICA & Medicare Tax (6.96%)[2]	2,276,636		
Total CY 2007 Non-Executive Incentives	$34,986,920		
Non-Executive Incentives - 50% Disallowance		($17,493,460)	
Staff's Proposed Adjustment - Systemwide			($18,445,499)
Oregon Allocation (SO Factor: 0.284419)[3]	0.284419		
Proposed Total Adjustment (CY 07) - Oregon			($5,246,250)
O&M Expense Adjustment - Oregon (73.51%)[4]			**($3,856,519)**
Rate Base Adjustment - Oregon (26.87%)[4]			**($1,409,667)**

[1]PPL/901, Labor page 4.3.1.
[2]PPL/901, Labor page 4.3.20.
[3]PPL/901, Allocation page 10.1.
[4]PPL Response to Staff Data Request No. 282e.
[5]PPL Response to Staff Data Request No. 283.
[6]PPL/901, Labor page 4.3.1 and PPL Response to Staff Data Request No. 283.

ISSUE S-15: BONUS ADJUSTMENT

Summary of Issue

Two questions are presented regarding performance bonuses. For non-officer performance bonuses, NW Natural proposes a 50/50 sharing with shareholders and ratepayers, while Staff proposes a 75 percent disallowance. For merit-based bonuses, NW Natural proposes that 100 percent of the non-officers' bonuses be included in utility expense. Staff recommends a 50/50 sharing for both non-officers' and union employees' merit-based bonuses.

Positions of the Parties

NW Natural first contends that performance bonuses paid to supervisors and managers be shared 50/50 between customers and shareholders. The company believes that the 50/50 sharing of non-officer bonuses is reasonable because the bonuses are designed to make the company's total compensation package for these employees competitive with comparable jobs in the regional labor market.

Second, NW Natural proposes that 100 percent of the non-officers merit-based bonuses, Key Goals program, be included in rates. NW Natural explains that there are five Key Goals, three of which directly relate to customer interests. These include rate stability, customer satisfaction, and productivity. The other two goals, profitability and market share, benefit customers over time. Because the Key Goal program benefits customers, NW Natural maintains that the merit-based bonuses—including those paid to union employees—should be included in utility expense.

Staff proposes a 75 percent disallowance of performance-based bonuses, and a 50/50 sharing of merit-based bonuses. Staff explains that the Commission has traditionally disallowed 75 percent of performance-based bonuses, because they are generally focused on the company's increased earnings and, therefore, bring more benefit to shareholders. It adds that the Commission has generally allowed equal sharing of merit-based bonuses, because they equally benefit shareholders and ratepayers. It contends that the company's Key Goals program should be similarly treated, noting that shareholders clearly benefit through increase earnings if the profitability and market share goals are achieved. Finally, it contends that the Commission should apply these recommendations to all bonuses, including those paid to union employees. It notes that the Commission has always treated union bonuses in the same manner, because the same rationale applies.

Commission Resolution

After our review, we find Staff's bonus adjustments to be reasonable and adopt them. Staff's recommendations are consistent with past ratemaking treatment of bonuses in prior electric and natural gas rate cases. NW Natural has not persuaded us that a change in policy is warranted.

ISSUE S-18: CIS

Summary of Issue

The history of NW Natural's Customer Information System (CIS) development is complex. The analysis of the argument is also difficult, caused primarily by the different approaches used by the parties to evaluate the CIS. There are, however, just two primary questions presented for Commission resolution.

First, the Commission must decide the standard of review for the recovery of NW Natural's CIS investment. Second, the Commission must determine whether the CIS stipulation allows for a reasonable level of CIS recovery and, therefore, should be approved. To fully understand this issue, a review of the history of NW Natural's CIS development is necessary.

Facts

In 1991, NW Natural began an effort to develop a new CIS to serve its residential and commercial accounts. The company's old CIS, the Legacy system, had been constructed in stages beginning in the 1960s. Over the years, NW Natural made numerous modifications and upgrades to the system, but encountered increasing reliability problems and functional limitations. Moreover, the Legacy system was not Year-2000 compliant.

After a bidding process, NW Natural hired IBM to perform a study on CIS implementation strategies. Based on the results of the study, NW Natural awarded a fixed-price contract to IBM for the development of a customized CIS. The overall projected budget, as approved by NW Natural's Board of Directors, was $24 million, which included a $12 million fixed fee to be paid to IBM for its services. NW Natural hoped to have the new system in place and operational by January 1996.

The CIS project was intended to proceed in five phases, whereby each succeeding phase added increased functionality. The first phase, called Application Function Group 1 (AFG1), was intended to allow inquiry of customer data that had been converted from the Legacy system. During AFG1 development, however, the project team experienced significant difficulties in two primary areas. The first problem pertained to the use of an object-oriented database. The project team initially chose to use a relational database[11] in combination with an object-oriented graphical user

[11] A relational database essential stores data in a matrix format of columns and rows, while an object-oriented

Salary/Overhead benefits include a myriad of benefits such as medical, vision, dental, life insurance, pension, post employment benefits and others. Salary assessments include various administration and other assessments.

These overheads/assessments increased from 25.17 percent in fiscal year 2002, to 31.57 percent in fiscal year 2004. Part of this increase is that payroll tax expenses are now loaded on to labor as opposed to previously being expensed to *Account 408, Taxes other than income taxes.*

As Table 10 indicates, regular labor consists of only 44.4 percent of total labor costs. As an example, a PacifiCorp employee earning $22.20 per hour will actually cost the Company $50 per hour.

One assessment at 0.08 percent is for a Senior Executive Retirement Plan (SERP) Assessment. Consistent with the Commission Order in UE 116, the Company removed $2.8 million in pension costs associated with SERP from the UE 170 submission.

Incentive Plans

PacifiCorp offers two Annual Incentive Plans. One plan is for its exempt employees and a similar plan is for Officers and PacifiCorp's Senior Management Group. As a result of union negotiations, collective bargaining personnel no longer receive an AIP as a result of increases in base wages.

All regular, full, and part-time non-union employees of PacifiCorp are eligible to participate in the Annual Incentive Plan (AIP), except for employees excluded due to participation in alternative incentive plans. Alternative incentive plans include PPM, PKE, C&T FO&SP, and ScottishPower (for International Assignees with the U.K. as their home country). Per PacifiCorp, the AIP is designed to:

- Drive higher levels of performance by establishing, measuring and achieving line-of-sight goals for individual, business unit and company.
- Communicate and evaluate progression against goals several times during the year thereby allowing employees to maintain focus relative to goal attainment.
- Reward individuals for their dedication, hard work, and demonstration of key/leadership behaviors leading to the successful achievement of objectives.[19]

[19] PacifiCorp's Annual Incentive Plan.

Maximum award percentages are based on job classification derived from competitive market data. All non-union employees (excluding Officer and Senior Management Group) will have an award opportunity based upon the following components:

- 10% - PacifiCorp Balanced Scorecard - For fiscal year 2005, the PacifiCorp Scorecard will align to the incentive plan by measuring EBIT performance.

- 30% - Business Unit Balanced Scorecard - Each Business Unit Balanced Scorecard contains four elements; Financial, Stakeholder/Customer, Employee and Process. Every business unit can assign different weights to the four elements; however, no element can exceed 40 percent or be less than 10 percent. In the case of a customer-focused business unit, the weighting given to the customer perspective will be proportionately high.

- 60% - Individual Performance - Individual Performance is measured based on the employee's performance to predetermined individual performance goals, and the employee's performance against key behaviors.

The Officer and Senior Management Group AIP are similar to the exempt AIP; however, there is a difference in the weighting of goals. For Officers and Senior Management Group, the weighting is:

- 20% - PacifiCorp Balanced Scorecard;
- 20% - Business Unit Balanced Scorecard
- 60% - Individual Performance

Per PacifiCorp's performance appraisal system, 85 percent of the score is based on Business & Individual Objectives. Exempt employees could expect to receive three to five Business & Individual Objectives that are weighted by the employee, employee's manager, and manager's supervisor. The remaining 15 percent of the performance appraisal is based on five "Behaviors" of Customer Focus, Delivery, Initiative, Teamwork, and Continuous Improvement, which each compose 3 percent of the final score.

The following table highlights PacifiCorp's Officer and Director Incentive Plan costs for fiscal year 2004:

Table 12 - PacifiCorp's FY 2004 Officer & Director Incentive Plan Costs

SMG LEVEL	Count	ANNUAL INCENTIVE (AIP)	FO&SP PLAN
Director	30	$1,074,145	$333,545
Managing Director	45	$2,289,310	$190,000
VP, Non-Officer	14	$1,032,032	$0
Officer	12	$1,650,956	$0
Totals	**101**	**$6,046,443**	**$523,545**

These costs were applied to various Operations, Maintenance, Administrative and General (OMAG) Accounts. For UE 170, the AIP cost escalates to $6,745,351 for calendar year 2006.

Staff Recommendation:

3. Following previous established methodology, Staff should adjust the $6,745,351 ($2,054,836 – Oregon allocated) in Officer & Director AIP from OMAG accounts. *(Rate case adjustment)*

Total Annual Incentive Plan costs, excluding Officer and Senior Management Group, for fiscal year 2002 through fiscal year 2004 were:

- 2002 - $32,333,000
- 2003 - $41,976,900
- 2004 - $38,394,800

Previous Commission policy was to disallow 50 percent of merit-based bonuses, because they equally benefit shareholders and ratepayers. Audit Staff believes that the 50 percent adjustment is appropriate, based on an observation of a sample performance appraisal and a review of the components of the AIP. In UE 170, PacifiCorp removed incentive costs of international assignees and the financial related adjustment relating to the PacifiCorp Balanced Scorecard.

As a result of previous Commission merit-based bonus cost sharing methodology, PacifiCorp's current AIP policy, and a review of PacifiCorp's UE 170 submission, Audit Staff recommends that 50 percent of non-officer AIP costs be adjusted out of OMAG. This amount equals approximately $20,309,537 when escalated to calendar year 2006 (per UE 170).

Staff Recommendation

4. Staff should adjust 50 percent of non-officer AIP costs, which equals approximately $20,309,537 ($6,186,894 – Oregon allocated), from OMAG costs. *(Rate case adjustment)*

In UE 147, 100 percent of officers and 25 percent of Senior Management Group (SMG) and non-SMG were adjusted out of OMAG to share the costs and benefits of the AIP between ratepayers and shareholders. OPUC Audit Staff's recommendation differs from the UE 147 treatment based on:

- SMG personnel are on the same AIP as officers and should be adjusted in the same amount as officers;
- For non-officer exempt employees, 10 percent is focused on EBIT, only one-quarter of the Business Unit Balanced Scoreboard is focused on customers, and the Individual Performance component is not holistically focused on customers. As a result, at least 50 percent of the incentives should be assigned to shareholders; and
- Previous Commission policy on merit-based bonuses set a 50 percent share between ratepayers and shareholders.

Audit Staff's recommended total adjustment, escalated to CY 2006, for incentives and bonuses equals $8,241,730 – Oregon allocated.

In UE 170, PacifiCorp also included $3,200,00 in Long-Term Incentive Plan (LTIP) costs. This incentive is awarded to a limited population of approximately 150-160 PacifiCorp employees. The LTIP is a restricted stock incentive that will replace PacifiCorp's Stock Option Program in May 2005. Audit Staff recommends that OPUC Staff involved in the rate case, examine the LTIP in more detail and make appropriate adjustments based on the specifics of the program.

Staff Recommendation:

5. During the rate case, Staff should examine the LTIP in more detail and make appropriate adjustments based on the specifics of the program. *(Rate case adjustment)*

Uncollectible Expenses (Account 904)

The following highlights three years of PacifiCorp's *Account 904, Uncollectible accounts* (system-wide) recorded in the FERC Form No. 1:

- 2003 - $20,345,071
- 2002 - $20,912,788
- 2001 - $17,152,475

The 2003 amount is 18.6 percent higher than the 2001 amount, but slightly lower than the 2002 amount.

UE-179/PacifiCorp
April 11, 2006
OPUC Data Request 207

OPUC Data Request 207

With reference to Exhibits PPL/900, Wrigley/18 and PPL/901, pages 4.3.1 and 4.3.9, please provide the following information:

(a) Copies of each of Pacific's most current incentive plans and a discussion of the FY 2006 plan revisions referenced in Mr. Wrigley's testimony and any additional planned modifications that would affect test period incentive expenses.

(b) The number and classifications of employees that currently qualify for each plan (officer, Senior Management Group, Non-Senior management Group) and projected FY 2006 incentive payout for each plan by employee classification.

(c) Detail on how the projected test period expense of $33,648,716 was calculated by employee classification.

(d) A discussion of the ratepayer benefits of the incentive programs included in test period expense.

Response to OPUC Data Request 207

(a) See Attachments 207 a-(1 and 2) on the enclosed CD for the most current incentive plans. With regard to FY 2006 plan revisions referenced in Mr. Wrigley's testimony; the following charts illustrate plan modifications made from year-to-year, and explains the reduction in the expected amount of incentive compensation:

FY 2001/2002	FY 2002/2003 & 2003/2004	FY 2004/2005	FY 2005/2006
Measures: 50%: o Corporate EPS, Division EBIT, or Business Unit EBIT 50%: o Individual Performance	**Measures:** o 20% PacifiCorp Balanced Scorecard o 30% Business Unit Scorecard o 50% Individual Performance Group Senior Management Team had measures as follows: o 50% Group Scorecard o 50% Individual Performance	**Measures:** o 10% PacifiCorp (Financial) o 30% Business Unit Scorecard o 50% Individual Performance o 10% Key Behaviors Senior Management Group measures vary depending on the level of senior management.	**Measures:** o 10% PacifiCorp (Optimization of Availability of Power to Customers) o 30% Business Unit Scorecard, with Corporate Support groups aligned to the Average result of all Operational Scorecards. o 60% Individual Performance with Key Behaviors included. Senior Management measures vary depending on the level of senior management.

UE-179/PacifiCorp
April 11, 2006
OPUC Data Request 207

Performance Scale for Individual Performance Results:	Performance Scale for Individual Performance Results:	Performance Scale for Individual Performance Results:	Performance Scale for Individual Performance Results:
3 = 50% 3+ = 65% 4- = 80% 4 = 80% 4+ = 90% 5- = 90% 5 = 100%	2+ = 45% 3 = 60% 3+ = 70% 4 = 80% 4+ = 90% 5 = 100%	2+ = 0 – 30% 3 = 50% 3+ = 70% 4 = 80% 4+ = 90% 5 = 100%	2+ = 0 – 30% 3 = 40% 3+ = 50% 4 = 65% 4+ = 80% 5 = 100%

For FY 2005/2006; the PacifiCorp Balanced Scorecard measure for most employees is optimization of power availability to customers, with the intent of driving superior performance and line-of-sight to the customer. Corporate Support groups that had each previously based their results on individualized Business Unit Balanced Scorecards now have results based on the average scorecard achievement for the Operating Units. This change is intended to emphasize the importance and impact of the Support functions on the business. In addition; the individual performance rating scale was amended to align more favorably with the market, with 3+ representing target market (50%) for most employees. This reduction in the percentage of payout for individual performance represents further cost savings referenced in Mr. Wrigley's testimony.

At this time there are no additional planned modifications that would affect test period incentive expenses.

(b) A forecast for FY2006 has recently been prepared, and the following represents the projected incentive payouts for each plan by employee classification. This forecast assumes the same performance rating application as the previous year (if available), with "3+" (representing target) implied for those for whom ratings were not obtained in the previous year, and captures only employees eligible for incentive for FY 2006. Totals also include InterWest Mining employees who are typically reported separately since they are paid from another payroll system.

Employee Group	Count	Est. Total 2006 AIP & FO&SP Incentive Payouts
CEC & Executive	9	$2,214,846
SMG	75	$5,218,430
Active Non-SMG	2533	$35,480,434
Inactive Employees*	83	$1,710,722
Union	24	$196,436
Totals	**2724**	**$44,820,867**

*CEC, SMG, and Non-SMG included

UE-179/PacifiCorp
April 11, 2006
OPUC Data Request 207

(c) The projection for the test period expense of $33,648,716 was calculated by employee classification by reporting only Active employees in each classification and projecting target (50%) of the maximum incentive multiplied by Annual Pay. It should be noted that incentives are based on the greater of Annual Pay or Eligible Earnings (actual pay, factoring in overtime for those for whom it applies) times the Maximum Incentive Opportunity expressed as a percentage. Maximum represents 2 times Target; however, target most accurately reflects performance for most employees, and is therefore utilized as the projection for accrual of incentive.

(d) The Annual Incentive Program (AIP) and the Front Office Structure & Pricing Plans are intended to maximize availability of power to our customers and to drive performance initiatives throughout the Company. Key Behaviors and individual performance goals are aligned for all employees to support business objectives as well as customer service initiatives. For FY2006, less emphasis has been placed on financial achievement as evidenced by the PacifiCorp Balanced Scorecard goal of optimizing availability for customers for the general employee population.

UE-179/PacifiCorp
May 2, 2006
OPUC Data Request 297

OPUC Data Request 297

As a follow-up to Pacific's response to staff's Data Request (DR) No. 207(a), please provide the following:

(a) Details on the plan or plans available to officers and the senior management group (SMG) for 2005/2006 that are used as the basis for the UE 179 revenue requirement.

(b) A discussion of the bases for awarding incentives to the SMG during 2005/2006, clearly differentiating how incentives are awarded among groups within the SMG, if differences exist.

(c) A discussion of any known modifications to the SMG incentive plans that are planned for 2006/2007 and the CY 2007 test period.

Response to OPUC Data Request 297

(a) Senior Management Group (SMG) members will have their awards based on the full PacifiCorp Scorecard as well as the measures that follow:

20% PacifiCorp Scorecard
20% Business Unit Balanced Scorecard
60% Individual Performance*
* Including key behaviors tied to Customer Service and Safety

Corporate SMG with functions in the UK/US will have their awards based as follows:

20% ScottishPower Scorecard
20% Corporate Function Scorecard
60% Individual Performance*
* Including key behaviors tied to Customer Service and Safety

(b) See above.

(c) Details concerning changes that may occur to the Annual Incentive Program generally for 2006/2007 and CY 2007 test period are not yet known; however, it is known that the Senior Management Group (SMG) designation will no longer apply.

CASE: UE 179
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

Direct Testimony

July 12, 2006

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

A. My name is Michael Dougherty. I am employed by the Public Utility Commission of Oregon as Program Manager, Corporate Analysis and Water Regulation in the Economic Research and Financial Analysis section of the Utility Program. My business address is 550 Capitol Street NE, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/601, Dougherty/1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to recommend adjustments to PacifiCorp's pension expenses, benefit expenses, and non-labor Administrative & General expenses.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/602, Exhibit Staff/603, Exhibit Staff/604 and Exhibit Staff/605.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

ISSUE 1, PENSION EXPENSES ADJUSTMENT

Q. PLEASE SUMMARIZE THIS ADJUSTMENT.

A. The pension expense adjustment consists of three adjustments: FAS 87 Pension expense, IBEW 57 Pension Expense, and retirement allowance expenses. I did not make adjustments to PacifiCorp's fiscal year FAS 106 Postretirement expense or FAS 112 Postemployment expense. Based on my review, I propose the following total adjustments to PacifiCorp's calendar year 2007 test year pension expenses (Oregon Allocated):

Pension Expenses (O&M – 75.31%)	($4.33 million)
Pension Expenses (Capital – 24.69%)	($1.42 million)

This adjustment is shown in Exhibit Staff/602.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS TO PENSION EXPENSES.

A. My adjustment to the FAS 87 pension expense is based on a PacifiCorp's amount reported on PPL/901, Page 4.3.19, adjusted for a higher discount rate, higher expected rate of return on assets, and lower pay increase percent than the discount, pay increase rates, and expected rate of return on assets used by PacifiCorp.

My adjustment to IBEW 57 pension costs is based upon PacifiCorp's actual average contributions to the Plan over the past five years.

My adjustment to PacifiCorp's Retirement Allowance is based on removing Utah-specific costs.

Q. PLEASE DESCRIBE PACIFICORP'S PENSION PLAN.

A. PacifiCorp sponsors a traditional defined benefit pension plan (Plan). Participants in the Plan receive a monthly income upon retirement that is based on their years of service and their final average earnings. Assets in the Plan are secured in a trust and are guaranteed by the Pension Benefit Guaranty Corporation. PacifiCorp also sponsors a 401(k) plan that is a defined contribution plan. Adjustments to the defined contribution plan are discussed under Staff's Benefit Adjustments.

Q. SHOULD FAS 87 NET PERIODIC PENSION BENEFIT COSTS BE USED TO DETERMINE ANNUAL PENSION COSTS?

A. Yes, the Commission should use FAS 87 Net Periodic Pension Benefit Costs to determine PacifiCorp's pension costs. However, the correct level of costs should be based on updated inputs and costs should be reviewed in context of other tangible, real factors such as cash contributions to the Plan.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF FAS 87 NET PERIODIC PENSION BENEFIT COSTS.

A. FAS 87, *Employers' Accounting for Pensions*, establishes standards of financial reporting and accounting for an employer that offers pension benefits to its employees. The Accounting Standards Board issued FAS 87 in an attempt to alleviate long-standing debate on reporting for pension liability. It is a consistent measure that reflects the terms of the underlying pension plan and more accurately approximates the recognition of the cost of an employee's pension over that employee's service period.[1] The net periodic pension benefit cost of FAS 87 is a single net amount that includes various inputs concerning past, present, and future events and transactions. In addition, the Commission has previously used FAS 87 net periodic pension benefit costs in ratemaking.

Q. DOES FAS 87 ADDRESS HOW A PENSION PLAN IS FUNDED?

A. No. It is important to note that although FAS 87 establishes standards of financial accounting and reporting for employer pension plans, it does not direct how a plan is to be funded. In a response to Staff Data Request No. 305, PacifiCorp has made various cash contributions to its pension plan including $76.4 million in fiscal year 2006, $60 million in fiscal year 2005, $61.6 million in fiscal year 2004, and $26.4 million in fiscal year 2003. PacifiCorp was not required to make a contribution in fiscal year 2002.

Q. IF YOU ARE USING FAS 87 NET PERIODIC PENSION BENEFIT COSTS, WHY WOULD YOU HAVE AN ADJUSTMENT FROM PACIFICORP'S CALENDAR YEAR 2007 AMOUNT?

A. I selected a higher discount rate, higher expected rate of return on assets, and lower pay increase rate than the rates used by PacifiCorp. PacifiCorp's calendar year 2007 cost is estimated at $54.62 million, net of joint venture, and is based on various inputs including the discount rate, estimated rate of return on assets, and rate of increase in compensation levels. Other actuarial estimates include: employee turnover rates, employee mortality rates, employee compensation levels, and employee retirement ages.

[1] *Statement of Financial Accounting Standards No. 87, Employers' Accounting for Pensions,* Paragraph 6a.

The following table highlights how FAS 87 Net Periodic Pension Benefit Costs can dramatically change as a result of small adjustments to variables such as the discount rate, expected rate of return on plan assets, and pay increase rates. This information was provided by PacifiCorp in responses to Staff Data Requests Nos. 35 and 154.

Table 1 – Variations in FAS 87 Net Periodic Pension Benefit Costs

CY 2007 Costs	Discount Rate	Expected Return on Assets	Pay Increase Rate
$56.4 million (UE 179 cost)	CY 2005 – 5.75% CY 2006 – 5.50% CY 2007 – 5.75%	8.75%	4.0%
$56.1	CY 2005 – 5.75% CY 2006 – 5.75% CY 2007 – 5.75%	8.75%	4.0%
$54 million	CY 2005 – 5.75% CY 2006 – 5.75% CY 2007 – 5.75%	9.00%	4.0%
$51.6 million	CY 2005 – 5.75% CY 2006 – 5.75% CY 2007 – 6.00%	8.75%	4.0%
$49.5 million	CY 2005 – 5.75% CY 2006 – 5.75% CY 2007 – 6.00%	9.00%	4.0%
$47.1 million	CY 2005 – 5.75% CY 2006 – 5.75% CY 2007 – 6.00%	8.75%	3.0%
$45 million	CY 2005 – 5.75% CY 2006 – 5.75% CY 2007 – 5.75%	9.00%	3.0%

CY 2007 Costs	Discount Rate	Expected Return on Assets	Pay Increase Rate
$42.9 million (Alternate recommendation)	CY 2005 – 5.75% CY 2006 – 5.75% CY 2007 – 6.00%	8.75%	3.0%
$40.8 Million (Staff's recommendation)	CY 2005 – 5.75% CY 2006 – 5.75% CY 2007 – 6.00%	9.00%	3.0%

Q. HAS PACIFICORP'S NET PERIODIC PENSION COSTS VARIED SIGNIFICANTLY FROM YEAR TO YEAR?

A. Yes.

Q. CAN YOU PLEASE DEMONSTRATE HOW PACIFICORP'S FAS 87 COSTS VARIED FROM YEAR TO YEAR?

A. The following table highlights the changes in PacifiCorp's FAS 87 net periodic pension benefit costs (income) over the previous ten years. As the table indicates, costs have varied greatly, sometimes changing dramatically from one year to the next year.

Table 2 – Annual Comparison of PacifiCorp's FAS 87 Pension Expenses[2]

Year	Cost (in millions)	Increase (decrease) from previous year	Percent change from previous year
2007 (est.)	$54.4	($9.4)	-15%
2006	$63.8	$23.5	58%
2005	$40.3	$11.4	39%
2004	$28.9	$17	142%
2003	$11.9	$18.2	289%

[2] The net periodic pension benefit costs were gathered from PacifiCorp's SEC Form 10-K reports and PacifiCorp's UE 179 PPL/901, Page 4.3.19.

Year	Cost (in millions)	Increase (decrease) from previous year	Percent change from previous year
2002	($6.3)	($1.6)	-34%
2001	($4.7)	($30.7)	-118%
2000	$26	$21.8	519%
1999	$4.2	($23.6)	-85%
1998	$27.8	($13.7)	-33%
1997	$41.5	($25)	-38%

During the years of strong equity market performance of the late 1990's, PacifiCorp's pension expenses generally decreased and PacifiCorp's Plan actually achieved positive income during 2001 and 2002. Because the equity markets are recovering and bond yields are increasing, it is reasonable to expect costs to decrease at a more significant level than the calendar year 2007 amount requested by PacifiCorp.

Q. PLEASE EXPLAIN THE COMPONENTS OF NET PERIODIC PENSION BENEFIT COSTS.

A. There are six components of net periodic pension benefit costs. These are: Service Cost, Interest Cost, Expected Return on Plan Assets, Amortization of unrecognized net obligation, Amortization of prior service costs, and Amortization of unrecognized gain.

Service Cost is a calculation of the incremental increase in future benefit obligations due to an added year of service for each participant in the PacifiCorp Plan. It is only a calculation and not an actual cost to PacifiCorp.

Interest Cost is a calculation for the additional liability established because each participant is one year closer to the benefit payout. Again, this is only a calculation and not an actual cost to PacifiCorp.

The Expected Return on Plan Assets is a calculation that is determined by multiplying the market-related value of Plan assets by the expected rate of return. It is important to note that the Expected Return on Plan Assets is only an estimate and not the actual return on Plan assets.

Amortization of unrecognized net obligation, Amortization of prior service costs, and Amortization of unrecognized gain are costs or gains that result from actual pension plan performance that are different from amounts previously assumed, or from a change in an actuarial assumption. In pension accounting, amortization refers to the systematic recognition in net pension benefit cost over several periods of previously unrecognized amounts.[3] Companies are allowed to amortize asset-related gains or losses over a period not to exceed five years. Therefore, a one-time gain or loss is allowed to "smooth" out over five years for determining the accounting value of plan assets.

Q. WHAT IS THE DISCOUNT RATE?

A. The discount rate is the interest rate used for the time value of money. PacifiCorp, through its actuary, calculates its pension obligations by estimating what it will have to pay current and future retirees. Then it discounts this amount back to today's dollars. A lower discount rate will result in an increase of net periodic pension benefit costs, while a higher discount rate will result in a decrease of net periodic pension benefit costs.

Q. WHAT DISCOUNT RATE IS PACIFICORP USING FOR ITS CALENDAR YEARS 2005 AND 2006 ESTIMATES?

[3] *Wiley GAAP 2005, Interpretation and Application of Generally Accepted Accounting Principles,* Barry J. Epstein, Ralph Nach, Ervin L. Black, Patrick R. Delaney, page 747.

A. PacifiCorp is using a 5.75 percent discount rate for 2005, 5.50 percent for 2006 and a 5.75 for 2007. PacifiCorp's 2005 discount rate is 75 basis points lower than its 2004 discount rate, 150 basis points lower than its 2003 discount rate, and 175 basis points lower than its 2002 discount rate.

Q. DOES PACIFICORP EXPLAIN WHY IT IS USING A LOWER DISCOUNT RATE IN 2006 THAN IT IS IN 2005 AND 2007?

A. Yes. The Company is estimating 2006 and 2007 discount rates based on Moody's Corporate Aa bond yields of approximately 5.5 percent.[4]

Q. DO YOU AGREE THAT THE MOODY'S CORPORATE AA BOND YIELDS SHOULD BE USED AS A BASIS TO DETERMINE THE DISCOUNT RATE?

A. Yes. For pension purposes, a company's discount rate should reflect the yields of high-quality corporate bonds. However, PacifiCorp is using a recent low historical bond yield as a basis for setting pensions in the future. This results in significantly increased costs to customers. According to recent information published by Towers Perrin Capital Market Update, the March 2006 Moody's Aa Corporate bond yield was 5.84 percent, and the Benchmark Discount Rate (for pensions) was 6.09 percent. The Benchmark Discount Rate increased 43 basis points from the December 2005 benchmark of 5.66 percent.[5]

---

[4] UE 179 PPL/900, Rosborough/4.
[5] Towers Perrin, *Capital Market Update, Funded Ratio Rises 4.2% in March*, page 2.

Although bond yields will vary throughout the year and have increased steadily since the beginning of the year,[6] the discount rate used in the actuarial assumptions will stay constant during the year. So even if bond yields and interest rates increase during 2006 (which some forecasts predict),[7] PacifiCorp's pension costs will still be discounted to today's dollars using the selected discount rate of 5.50 percent for calendar year 2006 and 5.75 for calendar year 2007. These rates are 58 and 33 basis points lower than the Towers Perrin benchmark discount rate for pensions. Considering that bond yields have risen and are expected to rise at a moderate pace, the discount rates being used by PacifiCorp to determine future costs are low. As previously mentioned, a lower discount rate will result in higher FAS 87 net periodic pension costs.

Q. BASED ON YOUR EXPLANATIONS ABOVE, WHAT DISCOUNT RATES SHOULD THE COMMISSION ACCEPT TO CALCULATE CALENDAR YEAR 2007 PENSION COST?

A. I recommend that the Commission select a calendar year 2007 pension cost based on discount rates of 5.75 percent for 2005, 5.75 percent for 2006, and 6.00 percent for 2007. These are reasonable, and arguably even low, projections for discount rates to determine calendar year 2007 FAS 87 pension costs. PacifiCorp actually used a 5.75 percent rate in 2005. As previously

[6] Information based on Moody's Aaa Bond yields extracted from the Federal Reserve web-site, www.federalreserve.gov.

[7] The Financial Forecast Center, Forecast of Moody's Aaa Corporate Bond Yields, www.neatideas,com, Bank of America Business Capital, Capital Eyes*, Key Economic Factors That May Shape Your Business in 2006*, January 2006, www.bofabusinesscapital.com and Bonds Online, *S&P Sees Strength, But Risks Ahead In U.S. Corporate Bond Market*, March 23, 2006 www.bondsonline.com.

mentioned, my recommended rates for calendar year 2006 and 2007 are still lower than the Towers Perrin March 2006 benchmark discount rate for pensions of 6.08 percent.

Q. WHAT IS THE EXPECTED RATE OF RETURN ON ASSETS AND HOW IS THIS USED IN DETERMINING NET PERIODIC PENSION COSTS?

A. The expected rate of return on assets is the rate of return that PacifiCorp uses in determining the Expected Return on Plan Assets. The expected rate of return is an assumption and may not be the actual rate of return PacifiCorp earns on its Plan assets. For the 2005 and 2006 estimated costs, PacifiCorp used an expected 8.75 percent long-term rate of return on assets.

Q. HOW DOES PACIFICORP'S CALENDAR YEAR 2005 AND 2006 EXPECTED RATE OF RETURN ON PLAN ASSETS COMPARE TO PREVIOUS YEARS?

A. PacifiCorp used an 8.75 percent long-tem rate of return on assets in 2005 and 2004 and a 9.25 percent long-tem rate of return on assets in 2003, 2002, and 2001. In order to demonstrate the effect of the long-term rate of return on assets, PacifiCorp responded to Staff Data Request No. 33 that a 50 basis point increase in expected returns on assets would result in a $4.4 million reduction in pension expense.[8]

Q. HOW DOES PACIFICORP'S EXPECTED RATE OF RETURN ON PLAN ASSETS FOR CALENDAR YEAR 2006 AND 2007 COMPARE TO ITS ACTUAL FISCAL YEAR 2006, 2005, AND 2004 RATES OF RETURN?

[8] UE-179/PacifiCorp Response to Staff Data Request No. 33, dated March 29, 2006.

A. According to PacifiCorp's response to Staff's Data Request No. 31, PacifiCorp's actual rate of return on Plan assets was 21.2 percent in fiscal year 2004, 12.8 percent in fiscal year 2005, and 9.0 percent (unaudited) in 2005. For the three years ending December 31, 2005, returns have averaged 14.4 percent. This average is 5.65 percent higher than the rate PacifiCorp is using in its calculation for calendar year 2007 pension costs. Although the three-year average has been an impressive 14.4 percent, PacifiCorp points out in a supplemental data request response, that the five-year average for actual rate of return has only been 5.5 percent due to poor performing investments in 2002 and 2001.[9]

As mentioned above, the rates of return PacifiCorp used in computing the projected calendar year 2007 FAS 87 net periodic pension benefit costs do not coincide with PacifiCorp's recent actual long-term rate of return on plan assets. Based on recent market performance, one would expect equal if not better returns than the three-year average during calendar years 2006 and 2007 since overall investment returns continued their positive momentum in the first quarter of 2006, and many equity markets touched historical highs.[10]

In its SEC Form 10-K for the period ending March 31, 2006, PacifiCorp stated that it:

> "employs an investment approach whereby a mix of equities and fixed-income investments is used to *maximize long-term*

[9] UE 179/PacifiCorp supplemental response to Staff Data Request No. 31, dated April 3, 2006.

[10] Towers Perrin, *Global Capital Market Update, First Quarter 2006 Results for Defined Benefit Pension Plans in Selected Countries.*

return of plan assets for a prudent level of risk."[11] (Emphasis added.)

If PacifiCorp does what it says and says what it does, the Company would be using an estimated rate of return that would truly reflect its goal to maximize its long-term return on plan assets. Additionally, since the 8.75% is a weighted average of the returns from different asset (investment) classes, it would be possible for PacifiCorp to increase the expected return by altering the proportion invested in the higher-return classes.

Q. DOES PACIFICORP INDICATE IN DATA RESPONSES THAT THEY BELIEVE AN 8.75 PERCENT EXPECTED RATE OF RETURN ON ASSETS MAY ACTUALLY BE HIGH?

A. Yes. In response to Staff Data Request No. 157, PacifiCorp stated that the assumption of 8.75% is reasonable, even possibly on the high end of the range of reasonableness.[12]

Q. DO YOU BELIEVE THAT THE EXPECTED RATE OF RETURN SHOULD EVEN BE LOWER THAN THE REQUESTED 8.75 PERCENT?

A. No. PacifiCorp's contracted actuary does not set the level of expenses in rates. The Commission is not obliged to accept these calculations any more than it would accept the calculations on return on equity that is presented by a different contractor engaged by the Company to compute Return on Equity.

It is interesting to note that PacifiCorp's Witness Hadaway in PPL/200, Hadaway/4, points out that Standard and Poor's (S&P) forecasts that long-term

---

[11] PacifiCorp's SEC Form 10-K for the period ending March 31, 2006.
[12] UE-179/PacifiCorp Data Response 157 1st Supplemental, dated April 6, 2006.

government and corporate interest rates are expected to rise 80 to 90 basis points.[13] Additionally, PacifiCorp Witness Williams in PPL/300, Williams/3 demonstrates that PacifiCorp's rate of return should be 9.08 percent.[14] Although Staff believes that PacifiCorp's rate of return figures are inflated, it is a fragile argument to say that the expected return on pension Plan assets would be lower than PacifiCorp's rate of return. This is especially true considering that the equity portion of Plan assets was higher (65.5 percent)[15] than the equity portion of PacifiCorp's proposed capital structure (52.8 percent).[16] As PacifiCorp Witness Hadaway points out in PPL/200, Hadaway/17:

> "and generally, returns from common stocks and other more risky investment are higher."[17]

To maximize its long-term return on Plan assets, PacifiCorp's pension Plan has a target of 10 percent private equity.[18] Since private equity historically results in high returns,[19] one would expect PacifiCorp's expected rate of return to be higher than the 8.75 percent being used in calculating the calendar year 2007 FAS 87 pension expense.

When I input information on equity rates of return that were abstracted from information provided by PacifiCorp concerning return on equity into PacifiCorp's

---

[13] UE 179, PPL/200, Hadaway/3.
[14] UE 179, PPL/300, Williams/3.
[15] PacifiCorp's SEC form 10-K for the period ending March 31, 2006.
[16] UE 179, PPL/300, Williams/3.
[17] UE 179, PPL/200, Hadaway/17.
[18] Actual percent of private equity in PacifiCorp's pension Plan asset mix was 7 percent according to PacifiCorp's SEC Form 10-K for the period ending march 31, 2006.
[19] *The Risk and Return of Publicly Traded Private Equity*, Hans Zimmerman, Stephanie Bilo, Hans Christopher, and Michael Degosciu, Final Version – April 2004.

pension Plan target equity mix, I actually receive an expected rate of return of 9.50 percent (See Exhibit/Staff 603). This is 75 basis points higher than the PacifiCorp's expected rate of return. As previously mentioned, a 50 basis point increase in the expected rate of return will result in a $4.4 million reduction in pension expenses.

The three-year average of actual returns of 14.4 percent, PacifiCorp's actual asset mix to maximize long-term return on plan assets, and increasing interest rates should be a strong indicator that PacifiCorp's 8.75 percent does not reflect current market realities.

Q. BASED ON YOUR EXPLANATIONS ABOVE, WHAT EXPECTED RATE OF RETURN ON ASSETS SHOULD THE COMMISSION ACCEPT TO CALCULATE CALENDAR YEAR 2007 PENSION COSTS?

A. I recommend that the Commission accept an expected rate of return on assets of 9.00 percent for calendar years 2005, 2006, and 2007. As demonstrated above, this rate may actually be low; however, it should be in a range that would be accepted by both PacifiCorp's actuary and external auditor.

Q. WHAT PAY INCREASE RATE DID PACIFICORP USE IN ITS ACTUARIAL ASSUMPTIONS?

A. PacifiCorp used a 4.0 percent increase.

Q. DO YOU AGREE WITH THIS RATE?

A. No. Although PacifiCorp states in response to Staff Data Request No. 34 that it is not uncommon for this specific assumption to be higher than one year negotiated increases,[20] according to Exhibit PPL/901 pages 4.3.3 – 4.3.7, PacifiCorp's actual pay increases for non-IBEW 57 personnel, with the exception of fiscal year 2006 increases to UWUA 197 personnel (3.08 percent), range from less than 1.0 percent to no greater than 3.0 percent.

Additionally, according to PacifiCorp's UE 170 PPL Exhibit 801, 4.18, Labor, page 16, approximately 88 percent of PacifiCorp's non-IBEW 57 labor costs received wage increases at or lower than 3.00 percent in fiscal year 2005. Also according to pages 20 and 21 of the same exhibit, approximately 84 percent of PacifiCorp's non-IBEW 57 labor costs were subject to a 3.00 percent or less wage increase in 2006. In fact, only two groups of employees, UWUA 197 and UWUA-127 Wyoming received increases over 3.00 percent. These increases were 3.08 percent and 3.03 percent respectively.[21]

As can be seen from a three-year historical perspective, PacifiCorp's pay increases are more closely aligned to 3.0 percent rather than 4.0 percent. As a result, I believe that a 3.0 percent pay increase rate is the right level for determining FAS 87 Net Periodic Pension benefit costs.

Q. BASED ON YOUR EXPLANATIONS ABOVE, WHAT PAY INCREASE RATES SHOULD THE COMMISSION ACCEPT TO CALCULATE CALENDAR YEAR 2007 PENSION COSTS?

A. I recommend that the Commission accept a pay increase rate of 3.0 percent for calendar years 2005, 2006, and 2007.

[20] UE-179/PacifiCorp response to Staff Data Request No. 34, dated March 22, 2006.
[21] PacifiCorp UE 170 PPL Exhibit 801; Witness; Ted Weston pages 16, 20, and 21.

Q. HOW WOULD PACIFICORP'S PROJECTED CALENDAR YEAR 2007 FAS 87 NET PERIODIC PENSION BENEFIT COST CHANGE IF THE ACTUARIAL ASSUMPTIONS USED IN THE PROJECTIONS WERE REVISED TO REFLECT THE DISCOUNT RATE, EXPECTED RATE OF RETURN ON ASSETS, AND PAY INCREASE RATE THAT YOU RECOMMEND?

A. As indicated on Table 1 of this testimony, PacifiCorp's calendar year 2007 FAS 87 Net Periodic Pension Benefit cost would be $40.8 million. The net of joint venture amount would be $39.6 million. The overall Oregon-allocated FAS 87 amount would be $11.24 million and the calendar year 2007 FAS 87 Net Periodic Pension costs adjustment (Oregon-allocated) would be $4.3 million; $3.24 million for O&M costs, and $1.06 million for capital costs.

Q. YOU PREVIOUSLY MENTIONED PACIFICORP'S CASH CONTRIBUTIONS TO THE PLAN. SINCE RECENT PACIFICORP CASH CONTRIBUTIONS ARE AT OR HIGHER THAN THE PROJECTED CALENDAR YEAR 2007 FAS 87 COSTS, SHOULD THE CONTRIBUTIONS BE USED FOR RATE SETTING?

A. Although some jurisdictions have used contributions (Idaho) or included contributions to track normal levels of pension costs (Washington for some utilities), the Commission has used FAS 87 Net Periodic Pension Benefit costs for ratemaking.

PacifiCorp is legally required pursuant to Employee Retirement Income Securities Act (ERISA) to contribute enough money into its Plan to cover pension payments when they become due. Recent laws require pension plans to maintain a 90 percent funding level (although there are certain exceptions based on previous contributions and projections of Plan funding). PacifiCorp is also required to notify participants if the Plan funded status drops below 90 percent. As a result of these requirements, PacifiCorp's actuary will determine the necessary contributions for the proper Plan funding.

PacifiCorp's five-year average (fiscal years 2002 through 2006) of cash contributions to its Plan is $49.95 million, net of joint venture; however, the minimum contributions PacifiCorp was obliged to make to meet all statutory funding requirements over the same five-year time period was actually $40.7 million, net of joint venture. It is interesting to note that this minimum contribution average of $40.7 million is extremely close to my recommended FAS 87 Net Periodic Pension Benefit Cost of $39.6 million.

Q. WHAT OTHER FACTS SHOULD THE COMMISSION CONSIDER WHEN SETTING THE RIGHT LEVEL OF CALENDAR YEAR 2007 FAS 87 EXPENSE?

A. When examining Table 2 of this testimony, PacifiCorp' five-year average FAS 87 cost was $27.72 million and ten-year FAS 87 average cost was $23.34 million. Both these average costs are lower than my recommended calendar year FAS 87 Net Periodic Pension Benefit cost of $39.6 million.

As a result, the five-year minimum contribution average and historical average costs give substantial support for my recommendation of $39.6 million (system-wide) as the correct amount for calendar year 2007 pension costs.

Q. IF THE COMMISSION FOLLOWS YOUR RECOMMENDATION FOR CALENDAR YEAR 2007 FAS 87 EXPENSE, WOULD PACIFICORP NOT HAVE SUFFICIENT FUNDS TO PAY BENEFITS TO PARTICIPANTS?

A. No, PacifiCorp will continue to have sufficient funds to pay participants benefits. The following table highlights actual benefits paid to participants as compared to actual return on assets. As can be seen from the table, PacifiCorp's returns over the three-year period were actually $25 million greater than benefits paid.

Table 3 – Comparison of Benefits Paid and Actual Returns on Assets[22]

	2004	2005	2006
Actual Returns	$128.3 million	$87.5 million	$72.6 million
Benefits Paid	$107.8 million	$75.2 million	$80.3 million
Difference	**$20.5 million**	**$12.3 million**	**($7.7 million)**

Q. IF PACIFICORP IS LIMITED TO YOUR RECOMMENDED CALENDAR YEAR 2007 FAS 87 COSTS, WOULD THE ACCRUED BENEFITS OF PARTICIPANTS BE AFFECTED?

A. No. Any reduction of accrued benefits of Plan assets would be violations of the Exclusive Benefit Rule and the Anti-Assignment and Alienation Rule of ERISA. The Exclusive Benefit Rule states that the assets of a qualified pension plan must be for the exclusive benefits of its participants and beneficiaries. The Anti-Assignment and Alienation Rule provides that a person's benefit in a qualified plan cannot be assigned to anyone else, except under a qualified domestic relations order where benefits are transferred to a former spouse. These two rules prohibit PacifiCorp from reducing any accrued benefits.

[22] UE-179/PacifiCorp responses to Staff Data Request Nos. 31 and 270.

Q, EVEN THOUGH ACCRUED BENEFITS CANNOT BE REDUCED, COULD PACIFICORP ACTUALLY MAKE CHANGES TO PLAN INVESTMENTS OR BENEFITS, OR BOTH?

A. Yes. Many companies and governmental entities are faced with increasing pension costs resulting in plan reductions and curtailments. An article cited a study by SEI Investments of pension changes of midsize U. S. firms. In this study, 54 percent of responding firms plan to adjust their investment strategy, 44 percent plan to raise contributions, 22 percent plan to close their defined benefit plan, 16 percent plan to convert to a defined contribution plan, and 15 percent plan to replace their defined benefit plan.[23] A northwest utility, Cascade Natural Gas, amended its defined pension plan on October 1, 2003, and non-bargaining personnel no longer accrue benefits under the plan.[24]

Q. ARE THERE ANY OTHER FAS 87 PENSION RELATED ISSUES THAT THE COMMISSION SHOULD BE AWARE OF THAT MAY AFFECT PACIFICORP'S FAS 87 ACCOUNTING?

A. Yes, the Financial Accounting Standards Board (FASB)[25] has issued a proposal (Exposure Draft) to improve accounting for postretirement benefit plans, including pensions. The FASB rationale for the changes is that existing standards on employers' accounting for defined plans fail to produce

[23] CFO: Magazine for Senior Financial Executives, *Looking for a new benchmark – Pension Accounting – alternatives to 30-year Treasury bonds,* July, 2003.

[24] Cascade Natural Gas, SEC Form 10-K for the period ending September 30, 2004.

[25] Since 1973, the Financial Accounting Standards Board has been the designated organization in the private sector for establishing standards of financial accounting and reporting. Those standards govern the preparation of financial reports and are officially recognized as authoritative by the Securities and Exchange Commission and the American Institute of Certified Public Accountants. www.fasb.org.

representational faithful and understandable financial statements. The concern is that assets or liabilities on the books almost always differ from the funded status of the plan.[26] Because PacifiCorp's Plan is currently under-funded, the under-funded amount would be recorded as a liability on its balance sheet.

Q. WILL THIS PROPOSED CHANGE HAVE AN EFFECT ON PACIFICORP'S CAPITAL STRUCTURE?

A. It is uncertain at this time. However, previous actions by the Commission may prevent any dramatic effect on PacifiCorp's capital structure.

Q. PLEASE EXPLAIN.

A. Commission Order No. 03-233, dated April 18, 2003, (UM 1073) authorized the Company to record on an ongoing basis, as a regulatory asset, an amount equal to the pretax charge *against equity* that would otherwise be necessitated by the recognition of the Company's Additional Minimum Liability under FAS 87.[27] According to Staff's memo:

> "If the company is not allowed to create and maintain a Regulatory Asset as required by FAS 87, PacifiCorp will be obligated to record, for its fiscal year ending March 31, 2003, a $200-$240 million pretax charge to Accumulated Other Comprehensive Income less about $75-$95 million in deferred income taxes. Although this charge to equity is expected to be reversed in future periods, the charge will have the immediate effect of reducing PacifiCorp's common equity capitalization. The company claims this could have negative implications on the company's ratings and possibly increase its cost of capital.
>
> Staff does not necessarily agree that the company's cost of capital may increase without approval of the Regulatory Asset; however, Staff agrees that allowing the company to create and

---

[26] *Update on Accounting for Pension Plans and Post-Retirement Benefits and Accounting and Disclosure Guidance for Losses from Natural Disasters*, Mark LaValle, Partner, KPMG LLP.

[27] Commission Order No. 03-233 (UM 1073), dated April 18, 2003, page 1 (emphasis added).

> maintain the Regulatory Asset is the most reasonable approach in meeting FAS 87 requirements."[28]

As can be seen from Staff's statement, the Commission took the necessary actions that appear will prevent any negative impacts to PacifiCorp's equity structure based on the FASB Exposure Draft. In fact, FAS No. 71, *Accounting for the Effects of Certain Types of Regulation* states:

> "Rate actions of a regulator can provide reasonable assurance of an existence of an asset."[29]

By establishing this asset, the effect on equity would not be as dramatic as it would be for non-regulated entities because PacifiCorp is able to maintain an asset instead of charging Other Comprehensive Income. Additionally, my recommendation for calendar year 2007 would result in a smaller calendar year expense that could positively impact PacifiCorp's funded status of the Plan.

Q. WOULD YOUR ADJUSTMENT AFFECT PACIFICORP'S SEC REPORTING REQUIREMENTS?

A. No. PacifiCorp stated in its Fiscal Year 2006 SEC Form 10-K:

> "PacifiCorp has determined that costs related to SFAS No. 87, Employers' Accounting for Pensions, ("SFAS No. 87") for the Retirement Plan are currently recoverable in rates."[30]

Even after my recommended adjustments, this statement will still be true, because the Commission will be allowing PacifiCorp to recover its FAS 87 costs in rates.

---

[28] *Ibid*, Appendix A, page 2 of 3.
[29] Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation,* page 7.
[30] PacifiCorp's SEC Form 10-K for the period ending March 31, 2006.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION FOR CALENDAR YEAR 2007 FAS 87 COSTS.

A. Yes. I selected discount rates of 5.75 percent for 2005 and 2006 and 6.00 percent for 2007. I chose these rates because 5.75 percent was the actual rate PacifiCorp used in 2005. Also, there is no indication that bond yields are decreasing and the current Towers Perrin benchmark discount rate for pensions is 6.08 percent. As a result, the rates I chose are more in line with current market conditions. In fact, it could be argued that my recommended rates are borderline low.

I also selected an expected rate of return on plan assets of 9.0 percent for all years, 2005 through 2007 because as previously mentioned, PacifiCorp's three-year average actual return on plan assets have been 14.4 percent. Additionally, the stock market has shown a strong recovery in 2004 and 2005 and interest rates have been rising steadily.[31] This would likely result in continued strong returns that would not replicate the poor performing years of 2001 and 2002 that dragged down PacifiCorp's five-year average return on assets to 5.5 percent.

I also selected a 3.0 percent pay increase rate for all years, 2005 through 2007 since PacifiCorp's historical wage increases for 2005 and 2006 and projected increases for 2007 more closely align with 3.0 percent than the 4.0 percent submitted by PacifiCorp. In addition, the Congressional Budget

[31] Federal Reserve website, www.federalreserve.org.

Office forecasts Consumer Price Index percentage rates of 2.2 percent for 2007 and 2008 through 2011.[32]

As a result of my changes to these variables, PacifiCorp's calendar year 2007 FAS 87 Net Periodic Pension Benefit cost would be $40.8 million. The net of joint venture amount would be $39.6 million. The overall Oregon allocated FAS 87 amount would be $11.27 million and the calendar year 2007 FAS 87 Net Periodic Pension costs adjustment (Oregon-allocated) would be $4.30 million; $3.24 million for O&M costs, and $1.06 million for capital costs. As previously mentioned, this FAS 87 expense is also within the range of the five-year average of PacifiCorp minimum required cash contributions of $40.7 million, net of joint venture.

As an alternative, if the Commission believes that PacifiCorp's 8.75 percent expected rate of return should be maintained, then my alternative recommendation for FAS 87 pension costs would be $42.9 million. Net of joint venture, this amount would be $41.55 million. The overall Oregon allocated FAS 87 amount would be $11.82 million and the calendar year 2007 FAS 87 Net Periodic Pension costs adjustment (Oregon-allocated) would be $3.72 million; $2.80 million for O&M costs, and $0.92 million for capital costs. This alternate amount is shown on Table 1 of this testimony and associated calculations are included in Exhibit Staff/602

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE IBEW 57 PENSION COSTS?

[32] *The Budget and Economic Outlook: Fiscal Years 2007 to 2*016, Congress of the United States, Congressional Budget Office, January 2006, table 2.3.

A. PacifiCorp in PPL/800/Rosborough/2 included a $7.3 million contribution to the PacifiCorp/IBEW 57 Retirement Trust Fund. This Retirement Trust Fund is separate and distinct from the PacifiCorp Plan. PacifiCorp has previously made yearly contributions and are required to make contributions to the PacifiCorp/IBEW 57 Retirement Trust Fund equal to seven (7) percent of the eligible pay of members. However, PacifiCorp's contribution in fiscal year 2006 was $1.41 million and PacifiCorp was not required to make a contribution to the fund in fiscal year 2005 because of favorable investment returns of the fund. The five-year average contribution (fiscal years 2002 through 2006) net of joint venture was $2.26 million. As a result, I used this five-year average cost for the calendar year 2007 level.

The five-year average of contributions is a more realistic estimation of test year costs than the contractual percentage contribution that PacifiCorp has not been required to make three of the past five years.

The overall Oregon-allocated IBEW 57 contribution amount would be $0.64 million. As a result, the calendar year 2007 IBEW 57 contribution Oregon-allocated adjustment would be $1.44 million; $1.08 million for O&M costs and $0.36 million for capital costs.

Q. PLEASE DESCRIBE FAS 106 POSTRETIREMENT EXPENSES.

A. FAS 106 establishes the standard for employers' accounting for other (than pension) postretirement employee benefits (OPEB). It applies to all forms of postretirement benefits, although the most material benefit is usually postretirement health care insurance coverage.[33] PacifiCorp's calendar year 2007 cost, after net of joint venture, was estimated at $28.2 million.

FAS 106 uses the same fundamental structure as FAS 87. Components of net periodic postretirement benefit costs include the same components as the FAS 87 net periodic pension benefit costs. These components are Service Cost, Interest Cost, Expected Return on Plan Assets, Amortization of unrecognized net obligation, Amortization of prior service costs, and Amortization of unrecognized gain.

Q. DID YOU MAKE ANY ADJUSTMENTS TO PACIFICORP'S FAS 106 COSTS?

A. No.

Q. PLEASE EXPLAIN.

A. PacifiCorp's average actual benefits paid ($179.9 million) for FAS 106 for the past five years have been higher than actual returns on assets ($57.2 million). Additionally, PacifiCorp has contributed $124.7 million to the Plan over the past five years. The average annual contribution, after net joint venture, was $24.26 million. When taking in account the benefits paid, cash contributions to the Plan, and the five-year average cost for FAS 106 of $24.26 million per year ($29.9 million in fiscal year 2006), PacifiCorp's calendar year 2007 amount is a reasonable amount. As a result, I did not make any adjustment to PacifiCorp's FAS 106 costs.

[33] *Wiley GAAP 2005, Interpretation and Application of Generally Accepted Accounting Principles,* Barry J. Epstein, Ralph Nach, Ervin L. Black, Patrick R. Delaney, page 767.

Q. WHAT OTHER ISSUES DID YOU NOTE THAT WOULD AFFECT PROJECTED CALENDAR YEAR 2007 FAS 106 COSTS.

A. The Financial Accounting Standards Board (FASB) issued FASB Position SFAS No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* ("2003 Act"). According to that issuance, PacifiCorp is required to treat the effects of the 2003 Act as an actuarial experience gain. According to PacifiCorp's response to Staff Data Request No. 117, the calendar year 2007 expense includes all the forecasted financial savings for Medicare Part D subsidy receipts on a present value basis. Based on calculations from PacifiCorp's actuary, the calendar year FAS 106 costs without the subsidy would have been $39.1 million. As a result, I did not need to adjust for this amount since PacifiCorp had already accounted for this savings.

Q. PLEASE DESCRIBE FAS 112, POSTEMPLOYMENT EXPENSES.

A. FAS 112 is an accounting standard for employers who provide benefits to former or inactive employees after employment but before retirement. These benefits include, but are not limited to, salary continuation, supplemental unemployment benefits, severance benefits, disability-related benefits (including workers compensation), job training, and counseling, and continuation of benefits such as health care benefits and life insurance coverage.[34] Postemployment benefits are part of the compensation provided to an employee in exchange of service by the employee.

Q. IS THE ACCOUNTING FOR FAS 112 POSTEMPLOYMENT BENEFITS SIMILAR TO THAT OF FAS 87 AND FAS 106?

A. No. FAS 112 does not use the same type of actuarial assumptions and calculations that is used in FAS 87 and FAS 106.

Q. DID YOU MAKE ANY ADJUSTMENTS TO PACIFICORP'S FAS 112 COSTS?

A. No.

Q. PLEASE EXPLAIN.

A. PacifiCorp's calendar year 2007 costs do not differ significantly from calendar years 2003, 2004, and 2005 FAS 112 costs. In fact the calendar year 2007 costs are actually less than the fiscal year 2005 costs.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PACIFICORP'S PROJECTED CALENDAR YEAR 2007 RETIREMENT ALLOWANCE COSTS.

A. According to PacifiCorp's response to Staff Data Request No. 273, the retirement allowance amounts are obligations of PacifiCorp that are not obligations of the qualified retirement plan. My adjustment was based on removing $20,160 in costs that were specific to Utah from PacifiCorp's calendar year 2007 pension retirement allowance cost of $290,769.

---

[34] *Statement of Financial Accounting Standards No. 112, Employers' Accounting for Postemployment Benefits*, Summary paragraph.

Q. WHAT TOTAL ADJUSTMENT DID YOU MAKE TO PACIFICORP'S TOTAL CALENDAR YEAR 2007 PENSION EXPENSES?

A. I adjusted an Oregon-allocated $5.74 million in total pension-related costs from the test year expenses. The O&M portion of this adjustment is $4.33 million, and the capital portion is $1.42 million.

If the Commission accepts my alternate recommendation on FAS 87 pension expenses, my adjustment would be an Oregon-allocated $5.16 million in total pension-related costs from the test year expenses. The O&M portion of this adjustment is $3.89 million and the capital portion is $1.42 million.

Q. DOES THIS CONCLUDE YOUR TESTIMONY ON PENSION EXPENSES?

A. Yes.

ISSUE 2, BENEFIT EXPENSES ADJUSTMENT

Q. PLEASE SUMMARIZE THIS ADJUSTMENT.

A. This adjustment focuses on PacifiCorp's Benefit Expenses. I propose the following adjustments (Oregon Allocated):

Benefit Expenses (O&M – 75.31 percent)	($305,708)
Benefit Expenses (Capital – 24.69 percent)	($110,165)

This adjustment is shown in Exhibit Staff/603.

Q. PLEASE EXPLAIN YOUR ADJUSTMENTS TO BENEFIT EXPENSES.

A. I started with PacifiCorp's actual fiscal year 2006 expenses and projected calendar year expenses and escalated the costs to 2007 using the PacifiCorp escalation rates. The only exception I made to the PacifiCorp projected increases was that I used a 9 percent annual increase instead of PacifiCorp's proposed 10 percent annual increase for medical benefit expenses.

Q. WHY DID YOU USE A COMBINATION OF ACTUAL FISCAL YEAR 2006 FOR SOME COSTS AND PROJECTED CALENDAR YEAR 2006 FOR OTHER COSTS?

A. I used the most accurate, up-to-date amounts that PacifiCorp was able to provide me in response to Staff Data Request No. 38 -1st Revision. Because I had access to the most current amounts, I used these amounts for projecting forward. PacifiCorp's 2006 amounts equaled $73.77 million.

Q. PLEASE EXPLAIN WHY YOU DID NOT USE PACIFICORP'S PROJECTED ANNUAL INCREASE OF 10 PERCENT FOR MEDICAL BENEFITS.

A. I did not use PacifiCorp's projection because recent surveys conducted by Human Resources consulting firms indicate that health care costs will increase 6.4 percent to 10 percent during 2006.

A recent survey taken by Towers Perrin indicates that health care costs are expected to increase at a rate of eight percent for calendar year 2006.[35] A different survey conducted by Watson Wyatt substantiated the Towers Perrin Survey and reported an eight percent increase.[36] A third survey by Mercer Consulting reported that if employers did not make plan changes, increases would be 10 percent; however, after employers made plan changes, health care cost in 2006 would increase approximately 6.4 percent.[37]

Q, DID YOU COME ACROSS ANY STUDIES THAT INDICATE INCREASES IN MEDICAL BENEFIT COSTS THAT EQUALED PACIFICORP'S 10 PERCENT PROJECTED INCREASE?

A. Yes. A survey conducted by the Hewitt Associates indicated that average health-insurance premiums increased by 10 percent in 2006.[38] However, since PacifiCorp's actual costs increased an average of 8.7 percent per year for the

---

[35] Towers Perrin Monitor, *2006 Health Care Cost Survey,* www.towersperrin.com.

[36] Watson Wyatt Press Release, *Employer Interest in Consumer-Directed Health Plans Growing, Watson Wyatt/National Business Group on Health Survey Finds,* www.watsonwyatt.com.

[37] Mercer Consulting, *Health benefit cost growth will slow in 2006 as employers continue trimming, Employers predict average increase of 6.4%*, www.mercerhr.com.

[38] Hewitt Associates, *2006 Heath Care Expectations Survey, Executive Summary*, www.was4.hewitt.com.

past three years, I used a nine percent annual increase for escalating PacifiCorp's medical benefit costs. This nine percent was basically an average of the four surveys.

Q. DID YOU PERFORM ANY OTHER ADJUSTMENTS TO THE MEDICAL BENEFIT COST IN ADDITION TO THE LOWER PERCENT INCREASE IN HEALTH CARE COSTS?

A. No. I accepted PacifiCorp's sharing of 85 percent employer and 15 percent employee. It is interesting to note that even after my reduced escalations, my calendar year 2007 medical insurance amount is actually higher than PacifiCorp's test year amount. As a result, my Oregon-allocated medical insurance adjustment is actually in the Company's favor ($129,293).

Q. DID YOU PERFORM ANY OTHER ADJUSTMENTS OR INCLUDE ANY ADDITIONAL EXPENSES THAT WERE NOT REFLECTED IN PACIFICORP'S CALENDAR YEAR 2006 BENEFIT EXPENSES?

A. No. I did not make any additional adjustments beyond using most current costs and escalating the costs in accordance with the escalation rates provided by PacifiCorp.

Q. IF YOUR ADJUSTMENT TO MEDICAL INSURANCE WAS IN PACIFICORP'S FAVOR, WHY DO YOU HAVE AN OVERALL ADJUSTMENT REDUCING TEST YEAR COSTS?

A. The overall adjustment reducing test year costs was a result of adjustments in other benefit costs. The largest of these adjustments ($240,830) was attributed to PacifiCorp's 401(k) Plan. Exhibit Staff/603 demonstrates my adjustments.

Q. WHAT ADJUSTMENT DID YOU MAKE TO THE PACIFICORP'S TEST YEAR BENEFIT EXPENSES?

A. I adjusted an Oregon-allocated $415,873 in benefit costs from the test year expenses. The O&M portion of this adjustment is $305,708 and the capital portion is $110,165. These adjustments are shown in Exhibit Staff/603.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY CONCERNING BENEFIT EXPENSES?

A. Yes.

ISSUE 3, NON-LABOR ADMINISTRATIVE AND GENERAL EXPENSE ADJUSTMENT

Q. PLEASE SUMMARIZE THIS ADJUSTMENT.

A. I performed a thorough review of non-labor costs in PacifiCorp's Administrative and General accounts, Accounts 921 through 935. These accounts include insurance costs, corporate overhead costs, office expense, rents, and miscellaneous other costs. I did not make any membership adjustments as these adjustments were made by Staff Witness Rossow in Staff/400. After I summed all of my specific adjustments, I escalated these adjustments using PacifiCorp's escalation rates. I then took the escalated Oregon-allocated amount, $5,162,599, and subtracted from this amount, PacifiCorp's adjustment PPL/901, 4.5, A&G Expense Cap of $4,985,367, receiving an Oregon adjustment of $177,232.

Non-labor A&G Expense	($177,232)

Exhibit Staff/604 shows details of this adjustment.

Q. PLEASE EXPLAIN PACIFICORP'S ADJUSTMENT PPL/901, 4.5, A&G EXPENSE CAP.

A. During UM 1209, Commission Order No. 06-121, dated February 24, 2006, the parties to the docket agreed to Commitment O12 that established an A&G base-line stretch goal of $22.8 million that was allowed to be escalated annually.

In UE 179, PacifiCorp calculated its total Company A&G costs at $249.01 million. The difference between this amount and the escalated baseline stretch goal amount, which equaled $231.49 million is $17.52 million, $4.99 million Oregon-allocated. As a result, PacifiCorp adjusted this amount ($17.52 million system-wide, $4.99 million Oregon-allocated) from test year costs.

Q. EVEN THOUGH PACIFICORP MADE THIS SIGNIFICANT ADJUSTMENT TO A&G COSTS, DID YOU ACTUALLY DISCOVER TOTAL PROPOSED ADJUSTMENTS THAT WERE GREATER THAN PACIFICORP'S $4.99 MILLION ADJUSTMENT?

A. Yes. As previously mentioned, my line item review resulted in $5.16 million in adjustments. As Exhibit Staff/604 indicates, the majority of the adjustment resulted from adjustments in insurance, legal costs, and corporate overhead costs. It should be noted that if PacifiCorp had not agreed to the A&G stretch goal in UM 1209, my adjustments would have been $5.16 million. My thorough review of costs is appropriate since the stipulated A&G stretch goal was calculated based on my A&G adjustments in UE 170.

Q. PLEASE EXPLAIN THE CORPORATE OVERHEAD ADJUSTMENT.

A. This adjustment resulted from subtracting the MEHC corporate overhead costs of $8.8 million from the test year Scottish Power costs of $14.3 million. This resulted in a system adjustment of $5.5 million, $1.56 million Oregon-allocated. This adjustment is displayed in Staff/Exhibit/604.

As background on this issue, Commission Order No. 06-305, dated June 19, 2006, (UI 249) approved PacifiCorp's application for an Intercompany Administrative Services Agreement with Midamerican Energy Holding

Company (MEHC). The annual administrative services cost to PacifiCorp is estimated at $9.57 million.

This corporate service charge is $4.73 million less than the fiscal year 2006 Scottish Power corporate cross charge of $14.3 million. In addition, pursuant to UM 1209 Commitment O 9(b)(i), if corporate allocations from MEHC to PacifiCorp included in PacifiCorp's rates are more than $7.3 million, a rate credit to customers of up to $1.5 million will occur. Since PacifiCorp included the $1.5 million it received from previous affiliates in rates, I did not double-count the adjustment, and added the $1.5 million to the $7.3 million limit on corporate charges resulting in a total corporate cross charge of $8.8 million.

Again, all I did for this adjustment was to subtract $8.8 million from $14.3 million resulting in the adjustment of $5.5 million.

Q. PLEASE EXPLAIN THE INSURANCE ADJUSTMENT.

A. For the insurance adjustment, I examined PacifiCorp's premium costs and actual fiscal year 2006 self-insurance expenses. I totaled the premium costs and fiscal year 2006 self-insurance amounts and subtracted these amounts from PacifiCorp's test year costs. My combined adjustment was $1.685 million; however, the adjustment for property insurance benefited PacifiCorp since the Company, based on my methodology, under-estimated property insurance costs.

The premium costs included captive insurance costs that PacifiCorp has applied for in docket UI 253, dated June 16, 2006. The captive insurance costs in this docket are the same as the costs the Commission approved for

PacifiCorp when it was still owned by Scottish Power (Orders No. 04-737 and 05-146). In these dockets (UI 233 and UI 233(1)), PacifiCorp was able to demonstrate a cost savings to customers by using a captive insurance provider.

I did not escalate the insurance adjustment to calendar year 2007, since insurance premium costs are more market-driven than they are inflation-driven. Exhibit/Staff 604 displays my adjustments to insurance costs.

Q. PLEASE SUMMARIZE THE LEGAL ADJUSTMENTS.

A. Although I accepted the vast majority of PacifiCorp's legal costs, I removed certain legal costs that were extraordinary in nature and would not be repeated in the test year. These costs were associated with FERC and other wholesale power lawsuits, PUHCA reporting, and legal costs concerning PacifiCorp and the Wyoming Public Service Commission.

I also adjusted certain legal costs concerning industrial customers in other states. Since Oregon customers do not receive any benefits of the revenues received from these customers, Oregon customers should not have to share in the burden of legal expenses associated with these customers. Exhibit/Staff 604 displays my adjustments to legal costs.

Q. PLEASE SUMMARIZE THE REMAINING ADJUSTMENTS.

A. I adjusted numerous miscellaneous costs (i.e. International Assignee expenses, donations, grants, Director stock awards, celebrations, etc.) that should have been recorded below the line and not included in utility expenses. Exhibit/Staff 604 displays my adjustments to other miscellaneous costs.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 179
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualification Statement

July 12, 2006

WITNESS QUALIFICATION STATEMENT

NAME:	MICHAEL DOUGHERTY
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	PROGRAM MANAGER, CORPORATE ANALYSIS AND WATER REGULATION
ADDRESS:	550 CAPITOL ST. NE, SALEM, OR 97310-1380
EDUCATION:	Master of Science, Transportation Management, Naval Postgraduate School, Monterey CA (1987) Bachelor of Science, Biology and Physical Anthropology, City College of New York (1980)
EXPERIENCE:	Employed with the Oregon Public Utility Commission as the Program Manager, Corporate Analysis and Water Regulation. Also serve as Lead Auditor for the Commission's Audit Program. Performed a five-month job rotation as Deputy Director, Department of Geology and Mineral Industries, March through August 2004. Employed by the Oregon Employment Department as Manager - Budget, Communications, and Public Affairs from September 2000 to June 2002. Employed by Sony Disc Manufacturing, Springfield, Oregon, as Manager – Manufacturing; Manager - Quality Assurance; and Supervisor - Mastering and Manufacturing from April 1995 to September 2000. Retired as a Lieutenant Commander, United States Navy. Qualified naval engineer.

CASE: UE 179
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 602

Exhibits in Support of
Direct Testimony

July 12, 2006

Pension Adjustments

(millions)

	PacifiCorp Net of Joint Venture	Staff Before Net of Joint Venture	Staff Net of Joint Venture	Oregon Allocation	PacifiCorp Oregon Allocated	Staff Oregon Allocated	Staff System Adjustment	Staff Oregon Adjustment	O&M	Capital
Pensions - FAS 87	$54.62	$40.80	$39.51	0.28449	$15.54	$11.24	$15.11	$4.30	$3.24	$1.06
Pensions - IBEW 57	$7.33	$2.34	$2.27	0.28449	$2.09	$0.64	$5.06	$1.44	$1.08	$0.36
Retirement Allowance	$0.29	$0.27	$0.27	0.28449	$0.08	$0.08	$0.02	$0.01	$0.00	$0.00
SERP Plan	$0.00	$0.00	$0.00	0.28449	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Post Retirement Benefits FAS 106	$28.21	$29.00	$28.21	0.28449	$8.03	$8.03	$0.00	$0.00	$0.00	$0.00
Post Employment Benefits - FAS 112	$5.56	$5.75	$5.56	0.28449	$1.58	$1.58	$0.00	$0.00	$0.00	$0.00
Total	**$96.01**	**$78.16**	**$75.82**	0.28449	**$27.31**	**$21.57**	**$20.19**	**$5.74**	**$4.33**	**$1.42**
	O&M Adjustment	**$4.33**								
	Capital Adjustment	**$1.42**								
Alternate Recommendation										
Pensions - FAS 87	$54.62	$42.90	$41.55	0.28449	$15.54	$11.82	$13.07	$3.72	$2.80	$0.92
Pensions - IBEW 57	$7.33	$2.34	$2.27	0.28449	$2.09	$0.64	$5.06	$1.44	$1.08	$0.36
Retirement Allowance	$0.29	$0.27	$0.27	0.28449	$0.08	$0.08	$0.02	$0.01	$0.00	$0.00
SERP Plan	$0.00	$0.00	$0.00	0.28449	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Post Retirement Benefits FAS 106	$28.21	$29.00	$28.21	0.28449	$8.03	$8.03	$0.00	$0.00	$0.00	$0.00
Post Employment Benefits - FAS 112	$5.56	$5.75	$5.56	0.28449	$1.58	$1.58	$0.00	$0.00	$0.00	$0.00
Total	**$96.01**	**$80.26**	**$77.85**	0.28449	**$27.31**	**$22.15**	**$18.15**	**$5.16**	**$3.89**	**$1.28**
	O&M Adjustment	**$3.89**								
	Capital Adjustment	**$1.28**								

PacifiCorp
Target Asset Mix
For Pension and Post Retirement Plans
Inputted with UE 179 ROE Rates of Returns

Equity Securities	11.50%	55.0%	6.33%	
Debt Securities	5.00%	35.0%	1.75%	
Private Equity	14.20%	10.0%	1.42%	Staff maintained the same 270 basis point spread PacifiCorp originally used over the US Equity rate.
Total Expected Return		100.0%	**9.50%**	Expected Rate of Return using PacifiCorp's UE 179 assumptions for ROE
			8.75%	PacifiCorp Expected Rate of Return

Asset mix target taken from PacifiCorp's SEC Form 10-K for the period ending March 31, 2006.

CASE: UE 179
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 603

Exhibits in Support of
Direct Testimony

July 12, 2006

Benefit Adjustments

	Benefits	2006 Actual		2007 Escalated	Escalation	Staff Net of Joint Venture	Joint Venture Percent	PPL/901, 4.3.19	Adjustment	Oregon Adjustment	DR
(1)	Medical Insurance	43,851,108	FY	$50,757,657	15.75%	$50,757,657	100%	$50,303,070	-$454,587	-$129,293	38r
(2)	Dental Insurance	$2,628,529	FY	$2,858,525	8.75%	$2,858,525	100%	$3,155,596	$297,071	$84,493	38r,39
(3)	Vision Insurance	$446,031	FY	$446,031	0.0%	$446,031	100%	$498,715	$52,684	$14,984	38r,39
(4)	Stock 401K ESOP	$17,919,927	FY	$19,210,162	7.2%	$19,210,162	100%	$20,056,906	$846,744	$240,830	38r
(5)	401K Administration	$1,018,007	FY	$1,091,304	7.2%	$1,091,304	100%	$1,265,051	$173,747	$49,417	38r
	Life	$1,244,461	CY	$1,292,995	3.9%	$1,264,601	97.804%	$1,247,756	-$16,845	-$4,791	46
	L-Term Disability	$2,485,457	CY	$2,582,390	3.9%	$2,512,097	97.278%	$2,502,055	-$10,042	-$2,856	46
(6)	Accidental Death & Disability	$2,760	FY	$2,959	7.2%	$2,959	100%	$57,310	$54,351	$15,459	38r
(7)	Workers Comp/ Work	$2,220,685		$2,285,085	2.9%	$2,227,204	97.467%	$2,394,803	$167,599	$47,668	1, 16, 38r
(8)	Other Salary Overheads, Without ScottishPower I.A.s**	$1,486,279		$1,405,000	Not Escalated	$1,405,000	100%	$1,405,000	$0	$0	38r, 303
(9)	Pension Administration	$482,827	FY	$517,591	7.2%	$517,591	100%	$869,053	$351,462	$99,963	38r
	Total	**$73,786,071**		**$82,449,698**		**$82,293,130**		**$83,755,315**	**$1,462,185**	**$415,873**	
	Oregon	**$20,986,161**		**$23,450,261**		**$23,405,730**		**$23,821,603**		**$415,873**	
	O&M Costs	**$305,708**				**$17,205,552**		**$17,511,260**		**$305,708**	
	Capital Costs	**$110,165**				**$6,200,178**		**$6,310,343**		**$110,165**	

Notes:

1 Workers' Comp Oregon Adjustment taken from Staff/604.
2 Vision Plan is a 2-year plan, so there is no 2007 increase.
3 Life and L-Term Disability amounts were received from DR response 46.
4 Escalation Rates, except medical, based on PacifiCorp's revised S-7.3.
5 Medical escalation rate was 9% annual based on average of Hewitt and Towers Perrin projections and PacifiCorp three-year average of 8.7%.
6 Net of Joint Ventures percentages received from PacifiCorp's revised S-7.3.
7 Other Salary Overheads - No adjustment based on Response to Data Request No. 303.

CASE: UE 179
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 604

Exhibits in Support of Direct Testimony

July 12, 2006

Non-labor A&G Summary

Account	Oregon Adjustment	Oregon Escalated	System Adjustment	System Escalated
921	$271,618	$322,411	$954,994	$1,133,578
923	$1,200,394	$1,424,868	$4,220,514	$5,009,750
924	-$820,427	-$820,427	-$2,884,563	-$2,884,563
925	$2,505,627	$2,505,627	$8,809,603	$8,809,603
930.1	$15,821	$18,779	$55,624	$66,026
930.2 (SPUK)	$1,564,305	$1,564,305	$5,500,000	$5,500,000
930.2 (Misc)	$65,791	$78,094	$111,644	$132,521
931	$9,818	$11,653	$34,518	$40,973
935	$48,264	$57,290	$169,694	$201,427
Total A&G Adjustments	**$4,861,210**	**$5,162,599**	**$16,972,028**	**$18,009,315**
A&G Exp Cap 4.5		**$4,985,367**		**$17,523,876**
Adjustments		**$177,232**		**$485,439**

1. See Staff/604, Dougherty/2-5.
2. 930.2 (SPUK) not escalated since this is last year for SPUK costs.

Non-Labor A&G Adjustments

Account	Cost	DR	Reason	Allocation	Oregon
921	$212,214	20	International/SOE Air Travel	28.4419%	$60,358
921	$28,449	20	West Coast Coffee	28.4419%	$8,091
921	$60,000	20	Economic Development Corporation	28.4419%	$17,065
921	$64,607	20	Catering Services-Non Employees	28.4419%	$18,375
921	$38,243	20	Various Non-Oregon expenses	28.4419%	$10,877
921	$81,806	20	CWIP Translation-Pre Settlement	28.4419%	$23,267
921	$0	20	Dues & Licenses - Paul	28.4419%	$0
921	$41,779	20	Electricity	28.4419%	$11,883
921	$109,963	20	Capital Environmental Expense	28.4419%	$31,276
921	$8,000	20	Marysville Land Rights	28.4419%	$2,275
921	$36,880	20	Lodging - UK	28.4419%	$10,489
921	$36,497	20	Meals & Entertainment - Various	28.4419%	$10,380
921	$14,297	20	Wyoming Metering Expense	28.4419%	$4,066
921	$46,242	20	Misc. Material & Supplies	28.4419%	$13,152
921	$12,591	20	On-Site Meals & Refreshments	28.4419%	$3,581
921	$68,310	20	Other Employee Related Expenses	28.4419%	$19,429
921	$37,585	20	Other Ground Trans - Wyoming	28.4419%	$10,690
921	$2,095	20	Non-Business Registration	28.4419%	$596
921	$22,139	20	IAS Training (No longer under Scottish Power)	28.4419%	$6,297
921	$33,297	20	Vehicle Leasing - PERK	28.4419%	$9,470
921	**$954,994**		**Total**		**$271,618**
923	$2,967,864	20	Legal Fees - PPL V. Wyoming PSC (court found in favor of PSC - will not be a test year cost); FERC and other Wholesale cases that have wound down and will not be test year costs; PUHCA Reporting to SEC that is no longer required; Specific customer lawsuits that Oregon does not share revenue on (MAGCORP, OCI, DOES - revenues should match expenses); and civic activities (CEO Organization)	28.4419%	$844,117
923	$149,409	20	Accounting Fees - IAS, Immigration Services (CFO Organization)	28.4419%	$42,495
923	$28,300	20	Blue Sky	28.4419%	$8,049
923	$19,322	20	Ex-Pat Services (Power Delivery)	28.4419%	$5,496

Non-Labor A&G Adjustments

Account	Cost	DR	Reason	Allocation	Oregon
923	$1,356	20	Specific State Rate Case Services (External Regulatory Affairs)	28.4419%	$386
923	$567,556	20	MSP - Phase 3, RTO - Phase - 4, SP Tax (SM&P/CBS Exec), Canopy Botanicals	28.4419%	$161,424
923	$2,341	20	IA Tax Services (Economic Devel.)	28.4419%	$666
923	$50,677	20	Donations, Grants (Economic Devel.)	28.4419%	$14,414
923	$4,402	20	IA Tax Services (HR)	28.4419%	$1,252
923	$3,748	20	IA Tax Services (Internal Audit)	28.4419%	$1,066
923	$49,604	20	IA Tax Services, MSP - Phase 3, RTO (Major Projects)	28.4419%	$14,108
923	$333,820	20	Legal fees (MSP, RTO - Phase 4, Immigration - Major Projects)	28.4419%	$94,945
923	$36,491	339	Compensation Reduction Plan	28.4419%	$10,379
923	$89,549	339	Admin & Record Keeper - NQ Plans	28.4419%	$25,469
923	-$83,925		Add Back PPL/901/4.4.2	28.4419%	-$23,870
923	**$4,220,514**		**Total**		**$1,200,394**
924	**-$2,884,563**		**Property**[1]	28.4419%	**-$820,427**
925	**$8,809,603**		**Liability**	28.4419%	**$2,505,627**
930.1	$29,865	20	Utah Blue Sky	28.4419%	$8,494
930.1	$1,000	20	Carbon 50 Year Celebration	28.4419%	$284
930.1	$7,108	20	Spirit of Excellence Advertsing	28.4419%	$2,022
930.1	$29,423	20	Blue Sky Add (Melvin Marks) - $29,423	28.4419%	$8,368
930.1	$8,836	20	Nonutility (Arbor Day, WY HS, WSJ SOX, Big Game)	28.4419%	$2,513
930.1	-$20,608		Blue Sky Adjustment 4,1	28.4419%	-$5,861
930.1	**$55,624**		**Total**	**28.4419%**	**$15,821**
930.2	$5,500,000	111	SPUK ($14,300,000) - MEHC ($8,800,000)[2]	28.4419%	$1,564,305
930.2	$111,644	20	Challenge Grants, Promotions	28.4419%	$31,754
930.2	$166,020	20	Director Deferred Stock Awards	28.4419%	$47,219
930	-$46,348	20	Y2k Double Count	28.4419%	-$13,182
930.2	**$5,611,644**		**Total**	**28.4419%**	**$65,791**

Non-Labor A&G Adjustments

Account	Cost	DR	Reason	Allocation	Oregon
931	$2,083	20	Rent - Utah Sports	28.4419%	$592
931	$16,667	20	Rent - Econ Development	28.4419%	$4,740
931	$15,768	20	IBEW	28.4419%	$4,485
931	**$34,518**	20	**Total**	**28.4419%**	**$9,818**
935	$5,920	20	Unused Leave (To prevent double counting)	28.4419%	$1,684
935	$25,000	20	EDCU Contribution Agreement	28.4419%	$7,110
935	$1,702	20	Holiday Wreaths	28.4419%	$484
935	$2,485	20	Holiday Decorations	28.4419%	$707
935	$6,250	20	Utah Sports	28.4419%	$1,778
935	**$169,694**		**Total**	**28.4419%**	**$48,264**
A&G	**$11,046,988**		**Total**		**$4,861,210**

Note:
1. Insurance adjustment from Staff Work papers page 8.
2. UM 1209 Commitment O9(b)(i) "to the Commission's satisfaction, in the context of a general rate case, that corporate allocations from MEHC to PacifiCorp included in PacifiCorp's rates are less than $7.3 million."

Insurance Adjustments

Worker's Comp

Premium	Amount	DR	Oregon Allocation		Oregon Expense
Oregon Standard	$1,840,496	253	28.4419%	SO	$523,472
Total	**$1,840,496**				**$523,472**

Liability

Premium					
Foreign Liability	$1,000	19	28.4419%	SO	$284
Transportation	$5,000	19	28.4419%	SO	$1,422
Crime	$24,475	253	28.4419%	SO	$6,961
D&O	$97,700	253	28.4419%	SO	$27,788
General Liability	$2,522,000	19	28.4419%	SO	$717,305
Captive Liability	$1,637,000	255	28.4419%	SO	$465,594
Special Liability	$3,000	19	28.4419%	SO	$853
Total	**$4,290,175**				**$1,219,354**

Property

Property	$15,811,590	254	28.4419%	SO	$4,497,117
Total	**$15,811,590**				**$4,497,117**

Total Uninsured Property Losses Losses	$7,531,254	13	28.4419%	$2,142,032
Total Unisured Liability Losses	$297,838	14	28.4419%	$84,711

			Self	Premium	Total	Page 4.7.1 Oregon	Adjustment
Property	924		$2,142,032	$4,497,117	$6,639,148	$5,818,721	($820,427)
Liability	925		$84,711	$1,219,354	$1,304,065	$3,809,692	$2,505,627
						Page 4.3.19 Oregon	
Workers Comp	Benefits	16	$108,133	$523,472	$631,605	$681,130	$49,525

CASE: UE 179
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 605

Exhibits in Support of
Direct Testimony

July 12, 2006

UE-179/PacifiCorp
March 31, 2006
OPUC Data Request 35

OPUC Data Request 35

Please provide an analysis of PPL/802, Rosborough 1 inputting:

a. A 5.75% discount rate for CY 2006 and a salary increase of 3% for CYs 2006 and 2007; and
b. A 5.75% discount rate for CY 2006, a 6.00% discount rate for CY 2007 and a salary increase of 3% for CYs 2006 and 2007.

Response to OPUC Data Request 35

This information is currently being prepared by Hewitt & Associates and will be provided in response to OPUC 154.

UE-179/PacifiCorp
May 8, 2006
OPUC Data Request 154 2nd Supplemental

OPUC Data Request 154

Using the format in Staff Data Request 35, please provide an analysis of PPL/802, Rosborough 1, inputting:

a. A 5.75% discount rate for CY 2006; salary increases of 3% for CYs 2006 and 2007, and Expected Rate of Return of 9.0% in CYs 2006 and 2007; and
b. A 5.75% discount rate for CY 2006, a 6.00% discount rate for CY 2007, salary increases of 3% for CYs 2006 and 200, and Expected Rate of Return of 9.0% in CYs 2006 and 2007.

2nd Supplemental Response to OPUC Data Request 154

Studies reflecting all requested assumptions – including 3% salary increases - are provided as 2nd Supplemental Attachment OPUC 154 on the enclosed CD. The first two tabs of the attachment respond to OPUC request 35; the remaining two tabs respond to OPUC request 154.

PacifiCorp Retirement Plan
Electric Operations

Reconciliation of Projected CY 2006 Expense from Actual CY 2005 and Projected CY 2007 from Projected CY 2006

(in millions)

Actual Calendar Year 2005 Expense	$49.9
Increase in interest cost due to additional benefit accruals during CY 2005	1.5
Impact of change in mortality table*	2.4
Increase in service cost due to demographics (e.g., new participants and increasing age of the population)	0.9
Impact on expected return on assets due to the expected change in the market related value of assets (before reflection of deferred asset losses)	(5.0)
Impact on expected return on assets due to scheduled recognition of a portion of the deferred asset losses	6.1
Decrease in amortization payments due to payoff of transition obligation	(5.6)
Increase in unrecognized net loss amortization due to scheduled recognition of a portion of the deferred asset losses	5.7
Projected Calendar Year 2006 Expense	$55.9
Increase in interest cost due to additional benefit accruals during CY 2006	0.8
Increase in service cost due to demographics (e.g., new participants and increasing age of the population)	0.9
Impact on expected return on assets due to the expected change in the market related value of assets (before reflection of deferred asset losses)	(5.8)
Impact on expected return on assets due to scheduled recognition of a portion of the deferred asset losses	1.9
Decrease in amortization payments due to payoff of transition obligation	(0.1)
Increase in unrecognized net loss amortization due to scheduled recognition of a portion of the deferred asset losses	2.5
Projected Calendar Year 2007 Expense	$56.1

* Change is necessary to stay within Hewitt Associates' Actuarial Assumption Guidelines

Projection Assumptions
- Discount rate: 5.75% for CY 2005, 5.75% for CY 2006, 5.75% for CY 2007
- Expected return on assets: 8.75% for all years
- Active participant increase of 119 during 2005, based on actual 2004 hires; constant thereafter
- Pay increases of 4%
- 8.75% rate of return on market value of assets during 2005 and 2006

PacifiCorp Retirement Plan
Electric Operations

Reconciliation of Projected CY 2006 Expense from Actual CY 2005 and Projected CY 2007 from Projected CY 2006

(in millions)

Actual Calendar Year 2005 Expense	$49.9
Increase in interest cost due to additional benefit accruals during CY 2005	1.5
Impact of change in mortality table*	2.4
Increase in service cost due to demographics (e.g., new participants and increasing age of the population)	0.9
Impact on expected return on assets due to the expected change in the market related value of assets (before reflection of deferred asset losses)	(5.0)
Impact on expected return on assets due to scheduled recognition of a portion of the deferred asset losses	6.1
Impact of change in expected return on assets assumption	(2.1)
Decrease in amortization payments due to payoff of transition obligation	(5.6)
Increase in unrecognized net loss amortization due to scheduled recognition of a portion of the deferred asset losses	5.7
Projected Calendar Year 2006 Expense	$53.8
Increase in interest cost due to additional benefit accruals during CY 2006	0.8
Increase in service cost due to demographics (e.g., new participants and increasing age of the population)	0.9
Impact on expected return on assets due to the expected change in the market related value of assets (before reflection of deferred asset losses)	(5.8)
Impact on expected return on assets due to scheduled recognition of a portion of the deferred asset losses	1.9
Decrease in amortization payments due to payoff of transition obligation	(0.1)
Increase in unrecognized net loss amortization due to scheduled recognition of a portion of the deferred asset losses	2.5
Projected Calendar Year 2007 Expense	$54.0

* Change is necessary to stay within Hewitt Associates' Actuarial Assumption Guidelines

Projection Assumptions
- Discount rate: 5.75% for CY 2005, 5.75% for CY 2006, 5.75% for CY 2007
- Expected return on assets: 9.00% for all years
- Active participant increase of 119 during 2005, based on actual 2004 hires; constant thereafter
- Pay increases of 4%
- 8.75% rate of return on market value of assets during 2005 and 2006

PacifiCorp Retirement Plan
Electric Operations

Reconciliation of Projected CY 2006 Expense from Actual CY 2005 and Projected CY 2007 from Projected CY 2006

(in millions)

Actual Calendar Year 2005 Expense	$49.9
Increase in interest cost due to additional benefit accruals during CY 2005	1.5
Impact of change in mortality table*	2.4
Increase in service cost due to demographics (e.g., new participants and increasing age of the population)	0.9
Impact on expected return on assets due to the expected change in the market related value of assets (before reflection of deferred asset losses)	(5.0)
Impact on expected return on assets due to scheduled recognition of a portion of the deferred asset losses	6.1
Decrease in amortization payments due to payoff of transition obligation	(5.6)
Increase in unrecognized net loss amortization due to scheduled recognition of a portion of the deferred asset losses	5.7
Projected Calendar Year 2006 Expense	$55.9
Increase in interest cost due to additional benefit accruals during CY 2006	0.8
Impact of change in discount rate	(4.5)
Increase in service cost due to demographics (e.g., new participants and increasing age of the population)	0.9
Impact on expected return on assets due to the expected change in the market related value of assets (before reflection of deferred asset losses)	(5.8)
Impact on expected return on assets due to scheduled recognition of a portion of the deferred asset losses	1.9
Decrease in amortization payments due to payoff of transition obligation	(0.1)
Increase in unrecognized net loss amortization due to scheduled recognition of a portion of the deferred asset losses	2.5
Projected Calendar Year 2007 Expense	$51.6

* Change is necessary to stay within Hewitt Associates' Actuarial Assumption Guidelines

Projection Assumptions
- Discount rate: 5.75% for CY 2005, 5.75% for CY 2006, 6.00% for CY 2007
- Expected return on assets: 8.75% for all years
- Active participant increase of 119 during 2005, based on actual 2004 hires; constant thereafter
- Pay increases of 4%
- 8.75% rate of return on market value of assets during 2005 and 2006

PacifiCorp Retirement Plan
Electric Operations

Reconciliation of Projected CY 2006 Expense from Actual CY 2005 and Projected CY 2007 from Projected CY 2006

(in millions)

Actual Calendar Year 2005 Expense	$49.9
Increase in interest cost due to additional benefit accruals during CY 2005	1.5
Impact of change in mortality table*	2.4
Increase in service cost due to demographics (e.g., new participants and increasing age of the population)	0.9
Impact on expected return on assets due to the expected change in the market related value of assets (before reflection of deferred asset losses)	(5.0)
Impact on expected return on assets due to scheduled recognition of a portion of the deferred asset losses	6.1
Impact of change in expected return on assets assumption	(2.1)
Decrease in amortization payments due to payoff of transition obligation	(5.6)
Increase in unrecognized net loss amortization due to scheduled recognition of a portion of the deferred asset losses	5.7
Projected Calendar Year 2006 Expense	$53.8
Increase in interest cost due to additional benefit accruals during CY 2006	0.8
Impact of change in discount rate	(4.5)
Increase in service cost due to demographics (e.g., new participants and increasing age of the population)	0.9
Impact on expected return on assets due to the expected change in the market related value of assets (before reflection of deferred asset losses)	(5.8)
Impact on expected return on assets due to scheduled recognition of a portion of the deferred asset losses	1.9
Decrease in amortization payments due to payoff of transition obligation	(0.1)
Increase in unrecognized net loss amortization due to scheduled recognition of a portion of the deferred asset losses	2.5
Projected Calendar Year 2007 Expense	$49.5

* Change is necessary to stay within Hewitt Associates' Actuarial Assumption Guidelines

Projection Assumptions
- Discount rate: 5.75% for CY 2005, 5.75% for CY 2006, 6.00% for CY 2007
- Expected return on assets: 9.00% for all years
- Active participant increase of 119 during 2005, based on actual 2004 hires; constant thereafter
- Pay increases of 4%
- 8.75% rate of return on market value of assets during 2005 and 2006

PacifiCorp Retirement Plan
Electric Operations

Reconciliation of Projected CY 2006 Expense from Actual CY 2005 and Projected CY 2007 from Projected CY 2006

(in millions)

Actual Calendar Year 2005 Expense	$49.9
Increase in interest cost due to additional benefit accruals during CY 2005	1.5
Impact of change in mortality table*	2.4
Impact of decrease in salary scale from 4% to 3%	(8.0)
Increase in service cost due to demographics (e.g., new participants and increasing age of the population)	0.9
Impact on expected return on assets due to the expected change in the market related value of assets (before reflection of deferred asset losses)	(5.0)
Impact on expected return on assets due to scheduled recognition of a portion of the deferred asset losses	6.1
Decrease in amortization payments due to payoff of transition obligation	(5.6)
Increase in unrecognized net loss amortization due to scheduled recognition of a portion of the deferred asset losses	5.7
Projected Calendar Year 2006 Expense	$47.9
Increase in interest cost due to additional benefit accruals during CY 2006	0.6
Increase in service cost due to demographics (e.g., new participants and increasing age of the population)	0.9
Impact on expected return on assets due to the expected change in the market related value of assets (before reflection of deferred asset losses)	(5.8)
Impact on expected return on assets due to scheduled recognition of a portion of the deferred asset losses	1.9
Decrease in amortization payments due to payoff of transition obligation	(0.1)
Increase in unrecognized net loss amortization due to scheduled recognition of a portion of the deferred asset losses	2.5
Decrease in unrecognized net loss amortization due to lower pay increases	(0.8)
Projected Calendar Year 2007 Expense	$47.1

* Change is necessary to stay within Hewitt Associates' Actuarial Assumption Guidelines

Projection Assumptions
- Discount rate: 5.75% for CY 2005, 5.75% for CY 2006, 5.75% for CY 2007
- Expected return on assets: 8.75% for all years
- Active participant increase of 119 during 2005, based on actual 2004 hires; constant thereafter
- Pay increases of 3%
- 8.75% rate of return on market value of assets during 2005 and 2006

PacifiCorp Retirement Plan
Electric Operations

Reconciliation of Projected CY 2006 Expense from Actual CY 2005 and Projected CY 2007 from Projected CY 2006

(in millions)

Actual Calendar Year 2005 Expense	$49.9
Increase in interest cost due to additional benefit accruals during CY 2005	1.5
Impact of change in mortality table*	2.4
Impact of decrease in salary scale from 4% to 3%	(8.0)
Increase in service cost due to demographics (e.g., new participants and increasing age of the population)	0.9
Impact on expected return on assets due to the expected change in the market related value of assets (before reflection of deferred asset losses)	(5.0)
Impact on expected return on assets due to scheduled recognition of a portion of the deferred asset losses	6.1
Impact of change in expected return on assets assumption	(2.1)
Decrease in amortization payments due to payoff of transition obligation	(5.6)
Increase in unrecognized net loss amortization due to scheduled recognition of a portion of the deferred asset losses	5.7
Projected Calendar Year 2006 Expense	$45.8
Increase in interest cost due to additional benefit accruals during CY 2006	0.6
Increase in service cost due to demographics (e.g., new participants and increasing age of the population)	0.9
Impact on expected return on assets due to the expected change in the market related value of assets (before reflection of deferred asset losses)	(5.8)
Impact on expected return on assets due to scheduled recognition of a portion of the deferred asset losses	1.9
Decrease in amortization payments due to payoff of transition obligation	(0.1)
Increase in unrecognized net loss amortization due to scheduled recognition of a portion of the deferred asset losses	2.5
Decrease in unrecognized net loss amortization due to lower pay increases	(0.8)
Projected Calendar Year 2007 Expense	$45.0

* Change is necessary to stay within Hewitt Associates' Actuarial Assumption Guidelines

Projection Assumptions
- Discount rate: 5.75% for CY 2005, 5.75% for CY 2006, 5.75% for CY 2007
- Expected return on assets: 9.00% for all years
- Active participant increase of 119 during 2005, based on actual 2004 hires; constant thereafter
- Pay increases of 3%
- 8.75% rate of return on market value of assets during 2005 and 2006

PacifiCorp Retirement Plan
Electric Operations

Reconciliation of Projected CY 2006 Expense from Actual CY 2005 and Projected CY 2007 from Projected CY 2006

(in millions)

Actual Calendar Year 2005 Expense	$49.9
Increase in interest cost due to additional benefit accruals during CY 2005	1.5
Impact of change in mortality table*	2.4
Impact of decrease in salary scale from 4% to 3%	(8.0)
Increase in service cost due to demographics (e.g., new participants and increasing age of the population)	0.9
Impact on expected return on assets due to the expected change in the market related value of assets (before reflection of deferred asset losses)	(5.0)
Impact on expected return on assets due to scheduled recognition of a portion of the deferred asset losses	6.1
Decrease in amortization payments due to payoff of transition obligation	(5.6)
Increase in unrecognized net loss amortization due to scheduled recognition of a portion of the deferred asset losses	5.7
Projected Calendar Year 2006 Expense	$47.9
Increase in interest cost due to additional benefit accruals during CY 2006	0.6
Impact of change in discount rate	(4.2)
Increase in service cost due to demographics (e.g., new participants and increasing age of the population)	0.9
Impact on expected return on assets due to the expected change in the market related value of assets (before reflection of deferred asset losses)	(5.8)
Impact on expected return on assets due to scheduled recognition of a portion of the deferred asset losses	1.9
Decrease in amortization payments due to payoff of transition obligation	(0.1)
Increase in unrecognized net loss amortization due to scheduled recognition of a portion of the deferred asset losses	2.5
Decrease in unrecognized net loss amortization due to lower pay increases	(0.8)
Projected Calendar Year 2007 Expense	$42.9

* Change is necessary to stay within Hewitt Associates' Actuarial Assumption Guidelines

Projection Assumptions
- Discount rate: 5.75% for CY 2005, 5.75% for CY 2006, 6.00% for CY 2007
- Expected return on assets: 8.75% for all years
- Active participant increase of 119 during 2005, based on actual 2004 hires; constant thereafter
- Pay increases of 3%
- 8.75% rate of return on market value of assets during 2005 and 2006

PacifiCorp Retirement Plan
Electric Operations

Reconciliation of Projected CY 2006 Expense from Actual CY 2005 and Projected CY 2007 from Projected CY 2006

(in millions)

Actual Calendar Year 2005 Expense	$49.9
Increase in interest cost due to additional benefit accruals during CY 2005	1.5
Impact of change in mortality table*	2.4
Impact of decrease in salary scale from 4% to 3%	(8.0)
Increase in service cost due to demographics (e.g., new participants and increasing age of the population)	0.9
Impact on expected return on assets due to the expected change in the market related value of assets (before reflection of deferred asset losses)	(5.0)
Impact on expected return on assets due to scheduled recognition of a portion of the deferred asset losses	6.1
Impact of change in expected return on assets assumption	(2.1)
Decrease in amortization payments due to payoff of transition obligation	(5.6)
Increase in unrecognized net loss amortization due to scheduled recognition of a portion of the deferred asset losses	5.7
Projected Calendar Year 2006 Expense	$45.8
Increase in interest cost due to additional benefit accruals during CY 2006	0.6
Impact of change in discount rate	(4.2)
Increase in service cost due to demographics (e.g., new participants and increasing age of the population)	0.9
Impact on expected return on assets due to the expected change in the market related value of assets (before reflection of deferred asset losses)	(5.8)
Impact on expected return on assets due to scheduled recognition of a portion of the deferred asset losses	1.9
Decrease in amortization payments due to payoff of transition obligation	(0.1)
Increase in unrecognized net loss amortization due to scheduled recognition of a portion of the deferred asset losses	2.5
Decrease in unrecognized net loss amortization due to lower pay increases	(0.8)
Projected Calendar Year 2007 Expense	$40.8

* Change is necessary to stay within Hewitt Associates' Actuarial Assumption Guidelines

Projection Assumptions
- Discount rate: 5.75% for CY 2005, 5.75% for CY 2006, 6.00% for CY 2007
- Expected return on assets: 9.00% for all years
- Active participant increase of 119 during 2005, based on actual 2004 hires; constant thereafter
- Pay increases of 3%
- 8.75% rate of return on market value of assets during 2005 and 2006

UE-179/PacifiCorp
March 31, 2006
OPUC Data Request 31

OPUC Data Request 31

(a) Please provide in the following table format, the following pension information for years ending March 31, from 2003 through 2005, and estimated for 2006. (b) Please explain any variation between Long-term Rate of Return on Assets, and Actual Rate of Return on Assets.

	2003	**2004**	**2005**	**2006**
Obligation at March 31				
Fair Value of Plan				
Actual Return on Assets				
Funded Status				
Accumulated Benefit Obligation				
Funded Ratio				
Service Cost				
Interest Cost				
Expected Return on Assets				
Amortization Of Transition Asset				
Amortization Of Prior Service Cost				
Recognized (Gain) Loss				
Net Periodic Pension Cost (Income)				
PacifiCorp's Contribution to Plan				
Discount Rate				
Long-term Rate of Return on Assets				
Actual Rate of Return on Assets				
PacifiCorp's Return on Common Equity				

Response to OPUC Data Request 31

(a)

($ millions)	2003	2004	2005	2006
Obligation at March 31	1,107.6	1,181.7	1,287.0	1,374.5
Fair Value of Plan	681.2	733.2	806.5	860.6
Actual Return on Assets	(60.0)	128.3	87.5	72.6
Funded Status	(426.4)	(448.5)	(480.5)	(513.9)
Accumulated Benefit Obligation	1,020.3	1,047.9	1,141.2	1,196.6
Funded Ratio	67%	70%	71%	72%
Service Cost	16.0	19.3	24.9	29.7
Interest Cost	73.9	71.0	70.9	71.5
Expected Return on Assets	(92.8)	(80.7)	(77.7)	(76.9)
Amortization Of Transition Asset	8.4	8.4	8.4	8.4
Amortization Of Prior Service Cost	0.9	0.9	0.9	1.1
Recognized (Gain) Loss	(4.3)	0	8.4	21.2
Net Periodic Pension Cost (Income)	2.1	18.9	35.8	55.0
PacifiCorp's Contribution to Plan	26.4	33.4	61.6	63.7
Discount Rate	7.50%	6.75%	6.25%	5.75%
Long-term Rate of Return on Assets	9.25%	8.75%	8.75%	8.75%
Actual Rate of Return on Assets	-7.5%	21.2%	12.8%	9.0% (unaudited)
PacifiCorp's Return on Common Equity	See below	See below	See below	See below

Allowed Return on Common Equity in Oregon was 10.75% from April 2, 2002 through September 1, 2003. From that date through October 4, 2005, it was 10.5%. It is presently 10.0%.

UE-179/PacifiCorp
March 29, 2006
OPUC Data Request 33

OPUC Data Request 33

Please provide the estimated effect on 2006 Net periodic pension cost (income) if the discount rate is changed 25 basis points in both directions and expected rate of return is changed 50 basis points in both directions.

Response to OPUC Data Request 33

The fiscal year 2006 net periodic pension cost increases $4.4 million if the discount rate is lowered by 25 basis points. The fiscal year 2006 net periodic pension cost decreases $4.1 million if the discount rate is raised by 25 basis points. The fiscal year 2006 net periodic pension cost increases (or decreases) $4.4 million if the expected rate of return is lowered (or raised) by 50 basis points.

UE-179/PacifiCorp
April 3, 2006
OPUC Data Request 31 1st Supplemental

1st Supplemental Response to OPUC Data Request 31

(b) Over this short term period from 2003 through 2005, the returns on both the retirement trust and retiree welfare trusts have exceeded the assumed Long term Return on Assets since during this period investment markets have been favorable relative to study assumptions. Returns for these trust assets, for the three years ending 12/31/05 returns have averaged 14.4%. Taking a longer retrospective look however, over the five years ending 12/31/05, the average return was only 5.5%. The welfare trust has seen average returns over those same periods of 13.5% and 5.1% respectively. The assumption used in the study is intended to be an average expected return over a future period expected to be much longer than either a three or five year period such as those discussed above. The Company believes that the 8.75% assumption included in this filing is reasonable and even optimistic in customers' favor in the current environment. In a national survey conducted by Hewitt Associates of Fortune 500 companies, at year end 2004, an 8.75% assumption was at the higher end of the range (75th percentile). When the Company completes its year end 2005 assumptions, expected return may be reduced to 8.5%, thus increasing future pension expense. Thus, use of 8.75% has a mitigating effect on the level of pension expense in the test year.

UE-179/PacifiCorp
April 6, 2006
OPUC Data Request 157 1st Supplemental

OPUC Data Request 157

Please provide all supporting documentation and analysis that was used to determine the CYs 2006 and 2007 discount rate and expected rate of return.

Supplemental Response to OPUC Data Request 157

Provided as 1st Supplemental Attachment OPUC 157 on the enclosed CD is a summary of the rationale for the year end Discount Rate and Expected Return on Plan Asset assumptions for December 31, 2005. December 31, 2005 is the Measurement Date for determining FAS 87 expense for the calendar year 2006. While calendar year 2007 assumptions cannot be finalized until December 31, 2006, the Company believes the Expected Return on Plan Asset assumption of 8.75% is reasonable, even possibly on the high end of the range of reasonableness – to the benefit of ratepayers. The projected calendar 2007 expense was calculated assuming that discount rates will rise slightly over the year and a 5.75% rate will be reasonable for year end 2006.

UE-179/PacifiCorp
March 22, 2006
OPUC Data Request 34

OPUC Data Request 34

Please explain why a 4% increase is used in the actuarial projections when actual pay increases for non-IBEW 57 employees (Exhibit PPL/901 pages 4.3.5 – 4.3.7) range from less than 1 percent to no greater than 3 percent.

Response to OPUC Data Request 34

The salary increase assumption is intended to be a long-term assumption, not a one year assumption. Further, it is intended to reflect the reasonable change from one year to the next, which would also include all salary increases, to include salary changes associated with promotional changes and starting salaries for new employees (which can be higher or lower than the employee being replaced). It is not uncommon for this specific assumption to be higher than one year negotiated increases or expected general merit increases for non-union personnel.

OPUC Data Request 34

Please explain why a 4% increase is used in the actuarial projections when actual pay increases for non-IBEW 57 employees (Exhibit PPL/901 pages 4.3.5 – 4.3.7) range from less than 1 percent to no greater than 3 percent.

Response to OPUC Data Request 34

The salary increase assumption is intended to be a long-term assumption, not a one year assumption. Further, it is intended to reflect the reasonable change from one year to the next, which would also include all salary increases, to include salary changes associated with promotional changes and starting salaries for new employees (which can be higher or lower than the employee being replaced). It is not uncommon for this specific assumption to be higher than one year negotiated increases or expected general merit increases for non-union personnel.

UE-179/PacifiCorp
April 26, 2006
OPUC Data Request 270

OPUC Data Request 270

As a follow-up to PacifiCorp's responses to Staff Data Requests No. 31 and No. 32, please provide the pension and postretirement benefits paid for fiscal years 2002 through 2006.

Response to OPUC Data Request 270

The pension and post-retirement benefit plans operate on calendar years. Pension and post retirement benefits for calendar years 2002 -2005 are shown below.

Year	Pension	Post-Retirement
2002	$111,383,000	$33,751,000
2003	$107,795,000	$37,736,000
2004	$75,738,000	$40,068,000
2005	$80,352,000	$41,542,000

Data is for Calendar Years

The benefits paid for calendar year 2006 will not be known until after year end.

CASE: UE 179
WITNESS: Bryan Conway

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

Direct Testimony

<u>REDACTED VERSION</u>

July 12, 2006

STAFF EXHIBIT 702

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 06-125. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 179 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

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

A. My name is Bryan Conway. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551. I am employed by the Public Utility Commission of Oregon (OPUC) as the Program Manager of the Economic and Policy Analysis Section in the Economic Research and Financial Analysis Division.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. My Witness Qualifications Statement is found on Exhibit Staff/701, Conway/1.

Q. HAVE YOU PREPARED AN EXHIBIT?

A. Yes, I have prepared Staff Exhibit 701 consisting of 13 pages and Staff Exhibit 702 consisting of 5 confidential pages.

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. The purpose of my testimony is to review the costs of preferred stock and long-term debt for PacifiCorp.

Summary Recommendation

Q. WHAT IS YOUR SUMMARY RECOMMENDATION?

A. I recommend the Commission reject the Company's proposed cost of long-term debt and adopt Staff's recommendation of 6.33%. I recommend the Commission reject the Company's proposed cost of preferred stock and adopt Staff's recommendation of 6.30%.

Q. HAVE YOU PREPARED TABLES THAT SUMMARIZES STAFF'S RECOMMENDATION?

A. Yes, Table 1 summarizes Staff's and the Company's recommendations on the cost of long-term debt and the cost of preferred stock.

Table 1:

Issue	Company Proposal	Staff Proposal
Cost of Preferred Stock	6.54%	6.30%
Cost of Long-Term Debt	6.37%	6.33%

<u>Embedded Cost of Preferred Stock</u>

Q. WHAT IS PACIFICORP'S RECOMMENDED COST OF PREFERRED STOCK?

A. In Exhibit PPL/304, PacifiCorp proposed embedded cost of preferred stock is 6.54%.

Q. HOW DID PACIFICORP ARRIVE AT THE 6.54% FIGURE?

A. PacifiCorp first determined the cost of money for each preferred stock issuance. The cost of money for each preferred stock series was then multiplied by the principal amount outstanding for each issue to yield the annualized cost for each issue. The sum of the annualized costs for each preferred stock issue, divided by the total amount of preferred stock outstanding, equates to the weighted average cost of all issues, or the Company's embedded cost of preferred stock. PacifiCorp further included unamortized costs associated with two Quarterly Income Debt Securities (QUIDS) that PacifiCorp redeemed using cash proceeds from the sale of property.

Q. WHAT IS STAFF'S RECOMMENDED COST OF PREFERRED STOCK?

A. I recommend PacifiCorp's embedded cost of preferred stock be 6.30%.

Q. WHAT ADJUSTMENTS DID YOU MAKE TO PACIFICORP'S EMBEDDED COST OF PREFERRED STOCK?

A. I made two adjustments to PacifiCorp's embedded cost of preferred stock. First, I removed $151,974 of costs labeled as unamortized expenses associated with the QUIDS. Second, I accounted for the mandatory sinking fund payment due June 15, 2007. (*See* Staff/701, Conway/2.)

Q. WHY DID YOU REMOVE THE UNAMORTIZED EXPENSES ASSOCIATED WITH THE QUIDS FROM YOUR CALCULATION OF THE EMBEDDED COST OF PREFERRED STOCK?

A. There are several reasons for excluding the cost of the QUIDS. First, the unamortized expense associated with the QUIDS should not be reflected in rates because the QUIDS are no longer outstanding and no replacement debt has been identified. Second, the expenses are non-recurring in nature, and as such should not be included in rates. Third, because PacifiCorp did not identify in previous rate cases new debt issuances used to fund the QUIDS redemption, PacifiCorp did not show that customers were best served by the early redemption. In other words, there is no reliable evidence that customers benefited from the early redemption of the QUIDS. If one assumes that equity was used to refund the QUIDS, then it would appear that PacifiCorp substituted QUIDS with an interest rate of approximately 8.5% for equity which is a higher cost.

Q. HAS THE COMMISSION PREVIOUSLY RULED ON THE INCLUSION OF THE UNAMORTIZED EXPENSES ASSOCIATED WITH THESE SAME QUIDS?

A. Yes. The last time the issue was litigated before the Commission, it excluded the unamortized expense associated with the QUIDS. See Order 01-787 at 19. The Commission decision in that case remains sound and should be applied in this case.

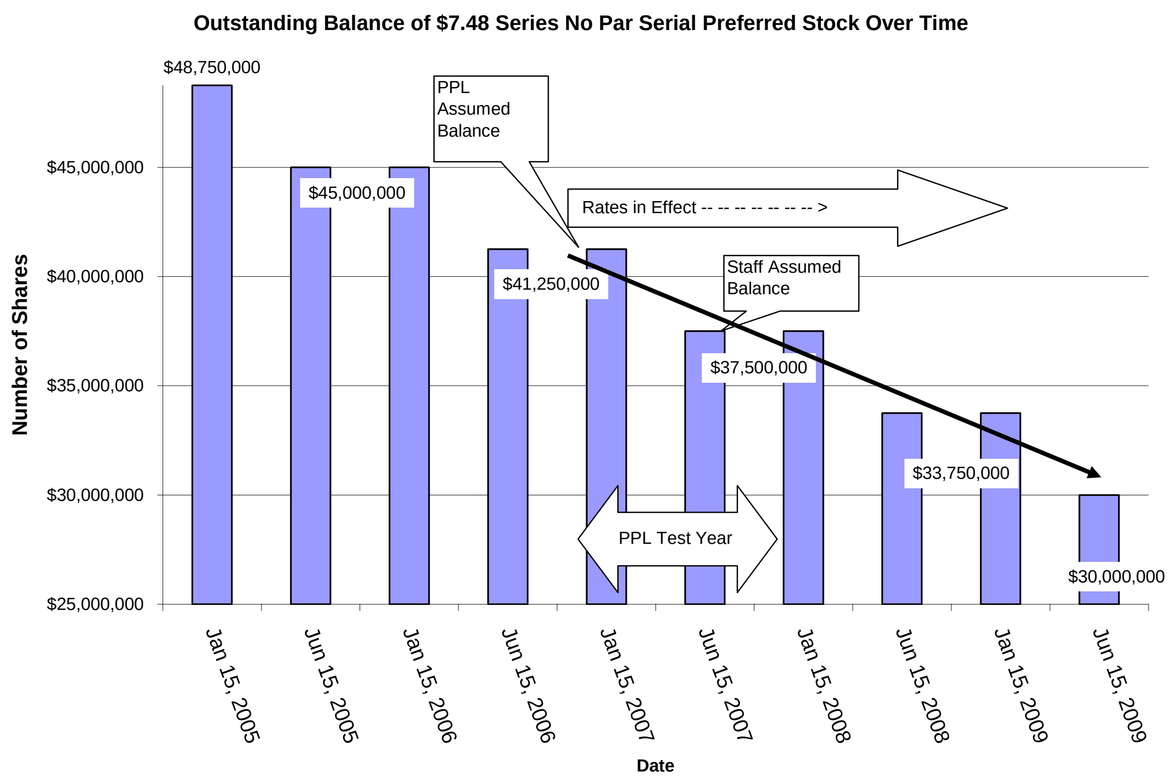
Q. PLEASE EXPLAIN HOW YOU ACCOUNTED FOR THE MANDATORY SINKING FUND PAYMENT DUE JUNE 15, 2007.

A. I assume the preferred stock balance as of the midpoint of the test year, which is July 1, 2007. The effect of this assumption was to remove an additional 5 percent payment, associated with retired preferred stock, which is due on June 15, 2007. This adjustment takes into account the reduction in the number of outstanding shares of PacifiCorp's $7.48 No Par Serial Preferred Stock series and reduces the embedded cost of PacifiCorp's preferred stock.

Q. WHY IS THIS ADJUSTMENT APPROPRIATE?

A. Accounting for the June 15, 2007, payment helps ensure that the cost of preferred stock is most reflective of rates on a going forward basis. Because the five percent payments are mandatory and occur annually, it is known and measurable. Chart 1 illustrates the effect of the mandatory sinking fund on PacifiCorp's $7.48 No Par Serial Preferred Stock series and the relationship between the test year, the mandatory payment, and the period rates are anticipated to be in effect.

Chart 1:



Embedded Cost of Long-Term Debt

Q. WHAT IS LONG-TERM DEBT?

A. Long-term debt as debt with a maturity of more than one year.

Q. WHAT IS PACIFICORP'S PROPOSED COST OF LONG-TERM DEBT?

A. In Exhibit PPL/301, PacifiCorp proposes its embedded cost of long-term debt be 6.371%.

Q. HOW DID PACIFICORP ARRIVE AT THE 6.371% FIGURE?

A. PacifiCorp follows the same process it used to calculate the embedded cost of preferred stock except it assumed a new debt issuance (i.e., pro forma debt).

Q. WHAT IS STAFF'S FORECAST OF PACIFICORP'S EMBEDDED COST OF LONG-TERM DEBT?

A. I recommend an embedded cost of long-term debt of 6.33%. (*See* Staff/701, Conway/3-7.)

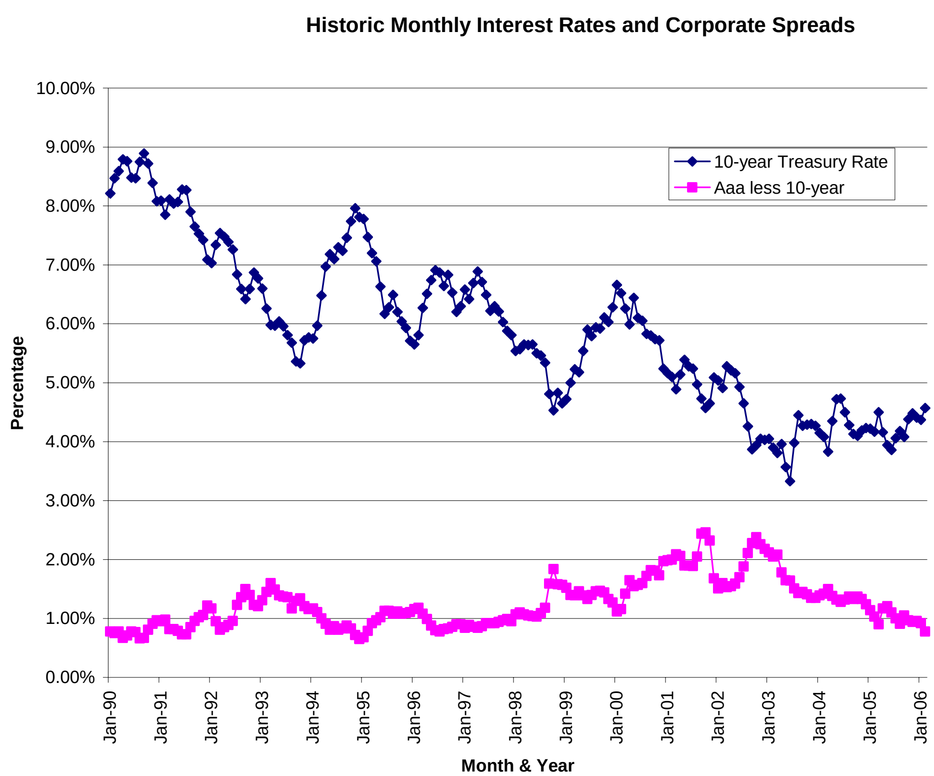
Q. WHAT ADJUSTMENTS DO YOU MAKE TO PACIFICORP'S EMBEDDED COST OF LONG-TERM DEBT?

A. I made three adjustments to PacifiCorp's forecast of its long-term cost of debt. First, I used a contemporaneous interest rates and spreads rather than matching November 2005 spreads with forward twenty-year Treasury rates as of March 31, 2007. Second, I assumed a 10-year maturity term for the pro-forma debt. Third, I used contemporaneous London Interbank Offered Rate (LIBOR) interest rates and the average relationship between LIBOR and PacifiCorp's Pollution Control Bond (PCRB) rates from January 2005 through March 2006 to reset the rates for the PCRBs found on lines 10-28 of PPL/301, Williams/5 rather than forward LIBOR rates as of March 31, 2007.

Q. WHY SHOULD CONTEMPORANEOUS INTEREST RATES AND SPREADS BE USED?

A. Spreads and interest rates are not independent. Historically, spreads decline as interest rates rise. This phenomenon is demonstrated by Chart 2. Further, many other factors can impact spreads, such as the credit quality of the utility, its parent's credit quality, and the credit industries comfort with management's direction, and the energy industry as a whole. Assuming spreads from 2005 with projected interest rates from 2007 likely results in a mismatch between spreads and interest rates.

Chart 2:



Q. PLEASE EXPLAIN YOUR CHOICE TO USE CONTEMPORANEOUS INTEREST RATES RATHER THAN PACIFICORP'S FORWARD 20-YEAR TREASURY RATES OR PACIFICORP'S FORWARD LIBOR ESTIMATES.

A. First, the long-standing practice of the Commission is to use current interest rates. Second, the utility has the flexibility to issue debt earlier than anticipated and so it is not prejudicial to use current interest rates. Third the utility can enter into financial agreements that lock in current interest rates if, in the utility's judgment, interest rates will rise and it is cost-effective to do so. Finally, consistently using the current rates should result in fairer rates over the long run. It is more equitable for the Commission to use a consistent basis for establishing rates for new issuances rather than choosing forward (current) rates when rates are forecasted to fall and current (forward) rates when interest rates are forecasted to rise.

Q. PLEASE EXPLAIN YOUR DECISION TO ASSUME A 10-YEAR MATURITY FOR THE PRO-FORMA DEBT SERIES.

A. Staff generally advocates for a 5-, 7-, and 10-year maturity assumption when estimating the cost of debt for a utility. In this case, Staff is assuming a 5-, 12- and 13-year maturity (average maturity of 10 years) based partially on the current interest rate environment and relatively flat yield curve. If the Commission were to determine that a forward interest rate should be applied in this case, then Staff would support a shorter average maturity assumption unless the Commission also finds that the current interest rate environment will persist and the yield curve will remain flat.

There are two principle reasons for assuming a 10-year maturity for purposes of determining the cost of PacifiCorp's incremental debt.

First, the Commission is setting a price for incremental debt, not a maturity schedule. If the Company is able to issue lower-cost debt, then shareholders benefit. Because the Company can choose to issue debt of a shorter maturity, and therefore save on interest expense, assuming too long of a maturity for replacement debt only increases the potential gains to shareholders at the expense of customers. Given the relatively flat yield curve in today's rates, Staff supports the longer-term maturity assumption of 10 years.

Second, the Company has a substantial amount of long-term debt maturing in 2011. If the Company's projections of higher interest rates occur in the future, it will be important to provide the flexibility to issue long-term debt at that time. As Chart 3 illustrates, Staff's assumption of a 10-year average maturity fits well with the Company's current maturity schedule. The years Staff assumed PacifiCorp's refinanced debt would mature do not leave the Company open to a large refinancing requirement over the foreseeable future and allow flexibility for a mix of short- and long-term debt issuances once the $577 million in debt, maturing in 2001, comes due.

Q. WHAT IS STAFF'S RESULTING ESTIMATED INTEREST RATE FOR THE PRO FORMA DEBT?

A. The Company's estimated March 7, 2006, credit spread for ten-year notes ranged from 80-95 basis points. (*See* PacifiCorp's response to Staff Data Request No. 5 attached as Staff/702, Conway/3-5.) The reference 10-year Treasury bond's yield on June 29, 2006, was 5.189% (*See* Staff/701, Conway/8.) Assuming PacifiCorp's estimate for issuance costs of approximately 9 basis points and averaging the midpoints of PacifiCorp's estimated spreads, Staff's projected cost of pro forma debt is (0.85 + 5.189 + .09) = 6.13%.

Q. PLEASE EXPLAIN YOUR RECOMMENDATION TO BASE THE RELATIONSHIP BETWEEN THE PCRB RATES AND LIBOR FROM JANUARY 2005 THROUGH MARCH 2006 TO ESTABLISH THE INTEREST RATE FOR THE PCRB DEBT.

A. The PCRBs are variable rate debt that has its interest rate reset via a monthly auction process. Staff and the Company both projected PCRB rates based on the historic relationship between the LIBOR rates and the PCRB rates. (*See* PacifiCorp's response to Staff Data Request No. 371 attached as Staff/701, Conway/10-11.) PacifiCorp sets its PCRB rate assuming the average relationship between the PCRB rates and LIBOR from December 1999 through March 2006.

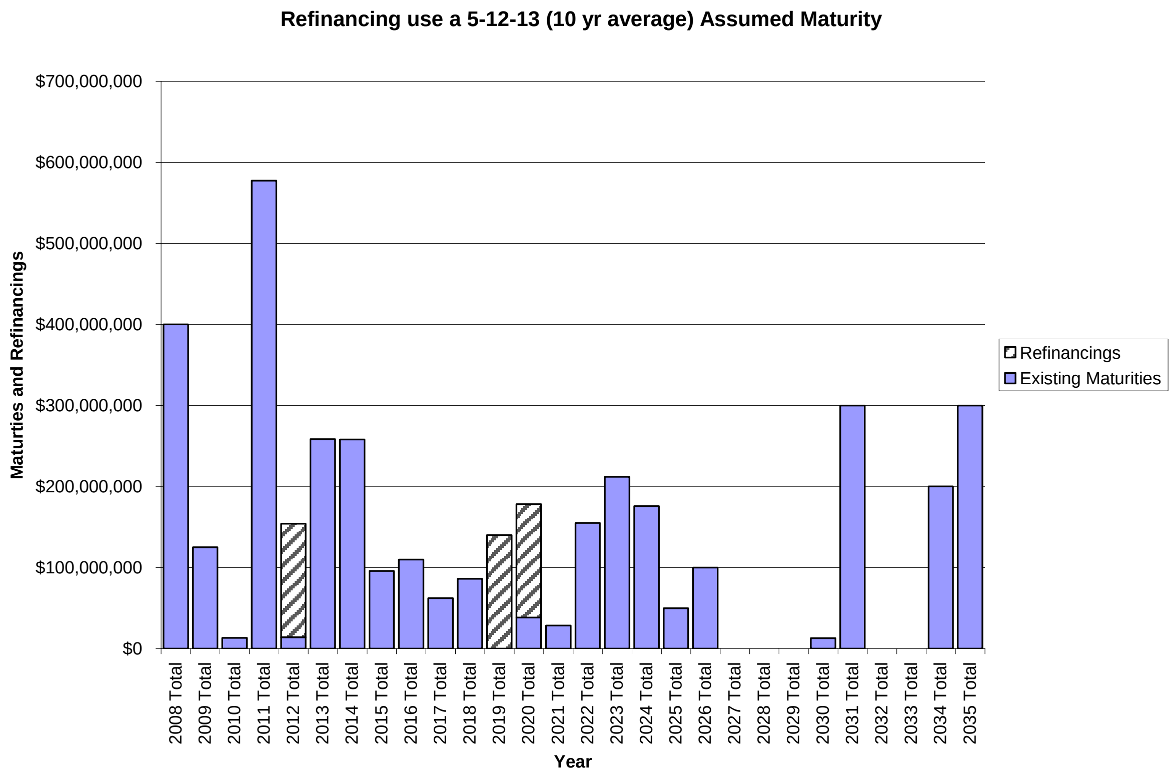
Q. DO YOU AGREE WITH THIS CHOICE OF TIME PERIOD?

A. No. During the period from January 2002 through December 2004, LIBOR rates averaged only 1.5% but the PCRB rates did not see as dramatic of a drop. Since 1999, the PCRB rates have, on average, been lower than the LIBOR rates. However during the January 2002 through December 2004 time period, PCRB rates were actually higher than LIBOR rates. The average PCRB to LIBOR ratio was 104%. Today, LIBOR rates today stand at around 3.5% and are not currently expected to drop back to the lows experienced between 2002 and 2004.

Q. WHAT TIME PERIOD DOES STAFF RECOMMEND BE USED?

A. Staff recommends a more recent history of January 2005 through March 2006. This time period better represents the expected relationship between LIBOR and the PCRB rates for the test period. During the time period chosen by Staff, the LIBOR rate averaged 3.63% and the average PCRB to LIBOR ratio was 71%. Using the entire time period, but excluding the years 2002 through 2004, results in an average PCRB to LIBOR ratio of 70% and an average LIBOR rate of 4.61%. As of June 28, 2006, the LIBOR rate was 5.35%. (*See* Exhibit Staff/701, Conway/12.) Staff multiplied the LIBOR rate of 5.35% and the average PCRB to LIBOR ratio of 71% to obtain its projected PCRB rate of 3.78%. As of March 2006, the LIBOR rate was 4.76%, the PCRB rate was 3.11%, and the PCRB to LIBOR relationship was 65%.

Chart 3:



Q. DID YOU USE ANY OTHER INFORMATION TO GAUGE THE REASONABLENESS OF YOUR ASSUMED PRO FORMA DEBT?

A. Yes. I also checked my assumed pro forma debt against the current yield to maturity of PacifiCorp's long-term debt offered on the secondary market as of June 27, 2006, with a bond rating equal to PacifiCorp's current senior secured debt rating. (*See* Staff/701, Conway/ 13.) I assume these seasoned securities traded in the secondary market reflect the same credit risks associated with contemporaneous senior secured debt offered in the primary market of the same maturity.

Q. WHAT IS THE SECONDARY MARKET?

A. The secondary market is the market where securities are traded after they are initially offered in the primary market.

Q. HOW DOES YOUR ASSUMED PRO FORMA DEBT COSTS COMPARE TO THE YIELD TO MATURITIES IN THE SECONDARY MARKET?

A. I assumed PacifiCorp placed secured debt with an A- rating that matures in March of 2007, with a coupon rate of 6.04%. After issuance expenses and fees the resulting internal rate of return is 6.13%. I compare these assumptions to three of PacifiCorp's bond securities available on the secondary market with equivalent bond ratings. The three issuances mature in November 2011, September 2013, and June 2035 and have a yield to maturity of 5.64%, 5.68%, and 6.11%, respectively. The average yield to maturity is 5.81%.

Q. WHAT DO YOU CONCLUDE FROM YOUR ANALYSIS OF THE SECONDARY MARKET FOR PACIFICORP'S DEBT SECURITIES?

A. I conclude that the average yield to maturity of 5.81% with a corresponding 13-year maturity schedule supports the reasonableness of my assumption of 6.04% pro forma debt with a 10-year maturity. The analysis also indicates that a 6.04% assumption would also be supportable if Staff had assumed a longer time to maturity of approximately 20 years.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 179
WITNESS: Bryan Conway

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Exhibits in Support of
Direct Testimony

July 12, 2006

WITNESS QUALIFICATION STATEMENT

NAME:	Bryan A. Conway
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Program Manager, Economic & Policy Analysis Section
ADDRESS:	550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.

EDUCATION:

B.S. University of Oregon, Eugene, Oregon
Major: Economics; 1991

M.S. Oregon State University, Corvallis, Oregon
Major: Economics; 1994

In addition, I have completed all of the required and elective coursework for a Ph.D. in economics from Oregon State University. My fields of study were Industrial Organization and Applied Econometrics.

EXPERIENCE:

Starting in October 1998, I have been employed by the Public Utility Commission of Oregon. I am currently the Program Manager of the Economic & Policy Analysis Section. My responsibilities include leading research and providing technical support on a wide range of policy issues for electric, telecommunications, and gas utilities. I have testified before the Commission on policy and technical issues in UG 132, UE 115, UE 116, UE 170 and have been the Summary Staff Witness in UP 158, UP 168, UP 165/170, UX 27, UX 28, UM 967, UM 1041, UM 1045, UM 1121, UM 1206, and UM 1209.

From December 1994 to October 1998, I worked for the Oregon Employment Department as a Research Analyst in their Research Section. Duties included leading research projects on various policy issues involving labor economics and information systems.

OTHER EXPERIENCE: I am currently a faculty member of the University of Phoenix teaching economics.

From January 1998 through September 2000, I was a part time instructor at Linn-Benton Community College teaching principles of economics.

From July 1992 through June 1994, I was a graduate teaching assistant at Oregon State University teaching introductory principles of economics.

PACIFICORP
Electric Operations
Cost of Preferred Stock
March 31, 2007
Pro-Forma

Line No.	Description of Issue	Issuance Date	Shares Issued and Outstanding	Total Book Value	Net Premium and (Expense)	Net Proceeds to Company	Annual Dividend Requirement	Cost of Money to Company	Annualized Cost	Line No.
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**5% Preferred Stock, $100 Par Value**	(a)	126,243	$12,624,300	($98,049)	$12,526,251	$631,215	5.04%	636,156	1
2										2
3	**Serial Preferred, $100 Par Value**									3
4	4.52% Series	Nov-55	2,065	$206,500	($9,676)	$196,824	$9,334	4.74%	9,793	4
5	7.00% Series	(b)	18,046	$1,804,600	(c)	$1,804,600	$126,322	7.00%	126,322	5
6	6.00% Series	(b)	5,930	$593,000	(c)	$593,000	$35,580	6.00%	35,580	6
7	5.00% Series	(b)	41,908	$4,190,800	(c)	$4,190,800	$209,540	5.00%	209,540	7
8	5.40% Series	(b)	65,959	$6,595,900	(c)	$6,595,900	$356,179	5.40%	356,179	8
9	4.72% Series	Aug-63	69,890	$6,989,000	($30,349)	$6,958,651	$329,881	4.74%	331,320	9
10	4.56% Series	Feb-65	84,592	$8,459,200	($49,071)	$8,410,129	$385,740	4.59%	387,990	10
11										11
12	**No Par Serial Preferred, $100 Stated Value**									12
13	$7.48 Series (d)	Jun-92	375,000	37,500,000	(462,238)	$37,037,762	$2,805,000	7.69%	2,884,734	13
14										14
15	**No Par Serial Preferred, $25 Stated Value**									15
16	Unamortized expense (e)	May-95		Note: Included in cost of debt					-	16
17	Unamortized expense (f)	1995		Note: Included in cost of debt					-	17
18										18
19	TOTAL			$78,963,300	($649,383)	$78,313,917	$4,888,790		4,977,613	19
20										20
21										21
22						Cost of Preferred Stock =		6.304%		22
23										23
24										24

25 (a) Issue replaced 6% and 7% preferred stock of Pacific Power & Light Company and Northwestern Electric Company
26 and 5% preferred stock of Mountain States Power Company, most of which sold in the 1920's and 1930's.
27 (b) These issues replaced an issue of The California Oregon Power Company as a result of the merger of that Company into Pacific Power & Light Co.
28 (c) Original issue expense/premium has been fully amortized or expensed.
29 (d) Annual 5% sinking fund begins June 15, 2002.
30 (e) Column 10 is the after-tax annual unamortized debt expense related to the 8.375% QUIDS due 6/30/35 which were redeemed November 2000.
31 (f) Column 10 is the after-tax annual unamortized debt expense related to the 8.55% QUIDS due 12/31/25 which were redeemed November 2000.
32

Pro Forma Cost of Debt Summary -adjusted to current forward rates (confidential)

As of March 31, 2007

DESCRIPTION	AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY	ANNUAL DEBT SERVICE COST	SEGMENT	Coupon*	Weighted Average Maturity
Subtotal - First Mortgage Bonds	$2,413,778,000	($23,809,875)	($13,231,634)	$2,376,736,491	[redacted]	[redacted]	[redacted]	13.09
Subtotal - Medium-Term Notes	$841,000,000	($8,745,555)	($24,913,962)	$807,340,483	$64,632,520	7.685%	7.273%	9.45
Total First Mortgage Bonds	$3,254,778,000	($32,555,430)	($38,145,597)	$3,184,076,974	$217,519,302	6.683%	6.422%	12.15
Subtotal - Pollution Control Obligations secured by First Mortgage Bonds	$398,329,151	($10,560,810)	($9,550,194)	$378,218,147	[redacted]	[redacted]	[redacted]	14.78
Subtotal - Pollution Control Revenue Bonds	$337,900,000	($4,231,330)	($7,621,229)	$326,047,441	[redacted]	[redacted]	[redacted]	11.06
Total PCRB	$736,229,151	($14,792,139)	($17,171,423)	$704,265,589	$35,100,307	4.768%	3.999%	13.07
Total Cost of Long Term Debt	$3,991,007,151	($47,347,569)	($55,317,020)	$3,888,342,562	$252,619,609	6.330%	5.975%	12.32

UE 179

Staff/701
Conway/4

PACIFICORP
Electric Operations
Cost of Long-Term Debt
March 31, 2007
Pro-Forma (confidential)

LINE NO.	BOND INTEREST RATE	DESCRIPTION	MATURITY DATE	ORIGINAL LIFE	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	COST OF MONEY TO COMPANY (BOND TABLE BASIS)	ANNUAL DEBT SERVICE COST	LINE NO.
	(1)	(2)		(3)	(4)	(5)	(6)		(7)	(8)	(9)	(10)	
		First Mortgage Bonds											
1	4.300%	Series due Sep 2008	09/15/08	5	$200,000,000	$200,000,000	($1,610,660)	($5,967,819)	$192,421,521	96.211%	5.170%	$10,340,000	1
2	6.900%	Series due Nov 2011	11/15/11	10	$500,000,000	$500,000,000	($5,338,849)	$0	$494,661,151	98.932%	7.051%	$35,255,000	2
3	5.450%	Series due Sep 2013	09/15/13	10	$200,000,000	$200,000,000	($1,654,660)	($5,967,819)	$192,377,521	96.189%	5.961%	$11,922,000	3
4	4.950%	Series due Aug 2014	08/15/14	10	$200,000,000	$200,000,000	($2,170,365)	$0	$197,829,635	98.915%	5.090%	$10,180,000	4
5	7.700%	Series due Nov 2031	11/15/31	30	$300,000,000	$300,000,000	($3,701,310)	$0	$296,298,690	98.766%	7.807%	$23,421,000	5
6	5.900%	Series due Aug 2034	08/15/34	30	$200,000,000	$200,000,000	($2,614,365)	$0	$197,385,635	98.693%	5.994%	$11,988,000	6
7	5.250%	Series due Jun 2035	06/15/35	30	$300,000,000	$300,000,000	($3,990,037)	($1,295,995)	$294,713,968	98.238%	5.369%	$16,107,000	7
8	6.037%	Pro Forma Series	03/31/17	10	$419,943,000	$419,943,000	($2,729,630)	$0	$417,213,371	99.350%	6.125%	$25,721,609	8
9	8.271%	C-U Series due Oct 2010 (a)	10/01/10	18	$48,972,000	$13,200,000	$0	$0	$13,200,000	100.000%	8.271%	$1,091,772	9
10	7.978%	C-U Series due Oct 2011 (a)	10/01/11	19	$4,422,000	$1,469,000	$0	$0	$1,469,000	100.000%	7.978%	$117,197	10
11	8.493%	C-U Series due Oct 2012 (a)	10/01/12	20	$19,772,000	$7,988,000	$0	$0	$7,988,000	100.000%	8.493%	$678,421	11
12	8.797%	C-U Series due Oct 2013 (a)	10/01/13	21	$16,203,000	$7,542,000	$0	$0	$7,542,000	100.000%	8.797%	$663,470	12
13	8.734%	C-U Series due Oct 2014 (a)	10/01/14	22	$28,218,000	$14,492,000	$0	$0	$14,492,000	100.000%	8.734%	$1,265,731	13
14	8.294%	C-U Series due Oct 2015 (a)	10/01/15	23	$46,946,000	$25,697,000	$0	$0	$25,697,000	100.000%	8.294%	$2,131,309	14
15	8.635%	C-U Series due Oct 2016 (a)	10/01/16	24	$18,750,000	$11,159,000	$0	$0	$11,159,000	100.000%	8.635%	$963,580	15
16	8.470%	C-U Series due Oct 2017 (a)	10/01/17	25	$19,609,000	$12,288,000	$0	$0	$12,288,000	100.000%	8.470%	$1,040,794	16
17	6.125%	Subtotal - First Mortgage Bonds				$2,413,778,000	($23,809,875)	($13,231,634)	$2,376,736,491			$152,886,782	17

(a) Debt assumed in connection with asset purchase from Colorado-Ute. Principal amortizes every October.

PACIFICORP
Electric Operations
Cost of Long-Term Debt
March 31, 2007
Pro-Forma (confidential)

LINE NO.	BOND INTEREST RATE (1)	DESCRIPTION (2)	MATURITY DATE	ORIGINAL LIFE (3)	PRINCIPAL AMOUNT ORIGINAL ISSUE (4)	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING (5)	ISSUANCE EXPENSES (6)	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT (7)	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT (8)	COST OF MONEY TO COMPANY (BOND TABLE BASIS) (9)	ANNUAL DEBT SERVICE COST (10)	LINE NO.
1		**Series C MTNs**											1
2	9.150%	Series C due Aug 2011	08/09/11	20	$8,000,000	$8,000,000	($75,327)	$0	$7,924,673	99.058%	9.254%	$740,320	2
3	8.950%	Series C due Sep 2011	09/01/11	20	$20,000,000	$20,000,000	($132,118)	$0	$19,867,882	99.339%	9.022%	$1,804,400	3
4	8.920%	Series C due Sep 2011	09/01/11	20	$20,000,000	$20,000,000	($188,318)	$0	$19,811,682	99.058%	9.023%	$1,804,600	4
5	8.950%	Series C due Sep 2011	09/01/11	20	$25,000,000	$25,000,000	($175,398)	$0	$24,824,602	99.298%	9.026%	$2,256,500	5
6	8.290%	Series C due Dec 2011	12/30/11	20	$3,000,000	$3,000,000	($23,040)	($410,784)	$2,566,175	85.539%	9.972%	$299,160	6
7	8.260%	Series C due Jan 2012	01/10/12	20	$1,000,000	$1,000,000	($7,649)	($136,928)	$855,423	85.542%	9.938%	$99,380	7
8	8.280%	Series C due Jan 2012	01/10/12	20	$2,000,000	$2,000,000	($13,297)	($273,856)	$1,712,847	85.642%	9.947%	$198,940	8
9	8.250%	Series C due Feb 2012	02/01/12	20	$3,000,000	$3,000,000	($22,946)	($410,784)	$2,566,270	85.542%	9.927%	$297,810	9
10	8.530%	Series C due Dec 2021	12/16/21	30	$15,000,000	$15,000,000	($115,202)	($2,053,922)	$12,830,877	85.539%	10.066%	$1,509,900	10
11	8.375%	Series C due Dec 2021	12/31/21	30	$5,000,000	$5,000,000	($38,400)	($684,641)	$4,276,959	85.539%	9.889%	$494,450	11
12	8.260%	Series C due Jan 2022	01/07/22	30	$5,000,000	$5,000,000	($33,243)	($684,641)	$4,282,117	85.642%	9.745%	$487,250	12
13	8.270%	Series C due Jan 2022	01/10/22	30	$4,000,000	$4,000,000	($30,594)	($547,712)	$3,421,693	85.542%	9.768%	$390,720	13
14		**Sub-Total Series C**				$111,000,000	($855,533)	($5,203,268)	$104,941,200			$10,383,430	14
15													15
16		**Series E MTNs**											16
17	8.130%	Series E due Jan 2013	01/22/13	20	$10,000,000	$10,000,000	($75,827)	($671,687)	$9,252,486	92.525%	8.939%	$893,900	17
18	8.050%	Series E due Sep 2022	09/01/22	30	$15,000,000	$15,000,000	($131,471)	($1,695,566)	$13,172,963	87.820%	9.258%	$1,388,700	18
19	8.070%	Series E due Sep 2022	09/09/22	30	$8,000,000	$8,000,000	($70,118)	($904,302)	$7,025,580	87.820%	9.280%	$742,400	19
20	8.110%	Series E due Sep 2022	09/09/22	30	$12,000,000	$12,000,000	($105,177)	($1,356,453)	$10,538,370	87.820%	9.325%	$1,119,000	20
21	8.120%	Series E due Sep 2022	09/09/22	30	$50,000,000	$50,000,000	($438,238)	($5,651,887)	$43,909,875	87.820%	9.336%	$4,668,000	21
22	8.050%	Series E due Sep 2022	09/14/22	30	$10,000,000	$10,000,000	($87,648)	($1,130,377)	$8,781,975	87.820%	9.258%	$925,800	22
23	8.080%	Series E due Oct 2022	10/14/22	30	$25,000,000	$25,000,000	($200,190)	($2,061,627)	$22,738,182	90.953%	8.953%	$2,238,250	23
24	8.080%	Series E due Oct 2022	10/14/22	30	$26,000,000	$26,000,000	($208,198)	($2,938,981)	$22,852,821	87.895%	9.283%	$2,413,580	24
25	8.230%	Series E due Jan 2023	01/20/23	30	$4,000,000	$4,000,000	$51,229	($88,989)	$3,962,241	99.056%	8.316%	$332,640	25
26	8.230%	Series E due Jan 2023	01/20/23	30	$5,000,000	$5,000,000	($37,914)	($335,843)	$4,626,243	92.525%	8.951%	$447,550	26
27		**Sub-Total Series E**				$165,000,000	($1,303,552)	($16,835,712)	$146,860,736			$15,169,820	27
28													28
29		**Series F MTNs**											29
30	7.260%	Series F due Jul 2023	07/21/23	30	$11,000,000	$11,000,000	($100,622)	($589,062)	$10,310,316	93.730%	7.804%	$858,440	30
31	7.260%	Series F due Jul 2023	07/21/23	30	$27,000,000	$27,000,000	($246,981)	($1,445,880)	$25,307,139	93.730%	7.804%	$2,107,080	31
32	7.230%	Series F due Aug 2023	08/16/23	30	$15,000,000	$15,000,000	($137,211)	($268,624)	$14,594,165	97.294%	7.457%	$1,118,550	32
33	7.240%	Series F due Aug 2023	08/16/23	30	$30,000,000	$30,000,000	($274,423)	($537,248)	$29,188,329	97.294%	7.467%	$2,240,100	33
34	6.750%	Series F due Sep 2023	09/14/23	30	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	99.235%	6.810%	$136,200	34
35	6.720%	Series F due Sep 2023	09/14/23	30	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	99.235%	6.780%	$135,600	35
36	6.750%	Series F due Sep 2023	09/14/23	30	$5,000,000	$5,000,000	($38,250)	($34,169)	$4,927,581	98.552%	6.865%	$343,250	36
37	6.750%	Series F due Oct 2023	10/26/23	30	$12,000,000	$12,000,000	($91,396)	$0	$11,908,604	99.238%	6.810%	$817,200	37
38	6.750%	Series F due Oct 2023	10/26/23	30	$16,000,000	$16,000,000	($121,861)	$0	$15,878,139	99.238%	6.810%	$1,089,600	38
39	6.750%	Series F due Oct 2023	10/26/23	30	$20,000,000	$20,000,000	($152,326)	$0	$19,847,674	99.238%	6.810%	$1,362,000	39
40		**Sub-Total Series F**				$140,000,000	($1,193,670)	($2,874,983)	$135,931,347			$10,208,020	40
41													41

PACIFICORP
Electric Operations
Cost of Long-Term Debt
March 31, 2007
Pro-Forma (confidential)

LINE NO.	BOND INTEREST RATE	DESCRIPTION	MATURITY DATE	ORIGINAL LIFE	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	COST OF MONEY TO COMPANY (BOND TABLE BASIS)	ANNUAL DEBT SERVICE COST	LINE NO.
	(1)	(2)		(3)	(4)	(5)	(6)		(7)	(8)	(9)	(10)	
42		Series G MTNs											42
43	6.710%	Series G due Jan 2026	01/15/26	30	$100,000,000	$100,000,000	($904,467)	$0	$99,095,533	99.096%	6.781%	$6,781,000	43
44		Sub-Total Series G				$100,000,000	($904,467)	$0	$99,095,533			$6,781,000	44
45													45
46		Series H MTNs											46
47	6.375%	Series H due May 2008	05/15/08	10	$200,000,000	$200,000,000	($2,060,179)	$0	$197,939,821	98.970%	6.517%	$13,034,000	47
48	7.000%	Series H due Jul 2009	07/15/09	12	$125,000,000	$125,000,000	($2,428,154)	$0	$122,571,846	98.057%	7.245%	$9,056,250	48
49		Sub-Total Series H				$325,000,000	($4,488,333)	$0	$320,511,667			$22,090,250	49
50													50
51													51

PACIFICORP
Electric Operations
Cost of Long-Term Debt
March 31, 2007
Pro-Forma (confidential)

LINE NO.	BOND INTEREST RATE (1)	DESCRIPTION (2)	ISSUE DATE	MATURITY DATE	ORIGINAL LIFE (3)	PRINCIPAL AMOUNT ORIGINAL ISSUE (4)	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING (5)	ISSUANCE EXPENSES (6)	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT (7)	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT (8)	COST OF MONEY TO COMPANY (BOND TABLE BASIS) (9)	ANNUAL DEBT SERVICE COST (10)	LINE NO.
		SECURED POLLUTION CONTROL REVENUE BONDS												
1	5.650%	Emery County due Nov 2023	11/15/93	11/01/23	30	$46,500,000	$46,500,000	($1,624,793)	($2,842,053)	$42,033,154	90.394%	6.501%	$3,022,965	1
2	5.625%	Emery County due Nov 2023	11/15/93	11/01/23	30	$16,400,000	$16,400,000	($1,015,051)	($819,557)	$14,565,392	88.813%	6.606%	$1,083,384	2
3	5.625%	Lincoln County due Nov 2021	11/15/93	11/01/21	28	$8,300,000	$8,300,000	($426,105)	($414,778)	$7,459,117	89.869%	6.538%	$542,654	3
4	3.900%	Converse 88 due Jan 2014	01/01/88	01/01/14	30	$17,000,000	$17,000,000	($155,970)	($579,849)	$16,264,181	95.672%	4.258%	$723,860	4
5	3.900%	Sweetwater 84C due Dec 2014	12/12/84	12/01/14	30	$15,000,000	$15,000,000	($227,887)	$0	$14,772,113	98.481%	4.090%	$613,500	5
6	3.400%	Lincoln 91 due Jan 2016	01/17/91	01/01/16	25	$45,000,000	$45,000,000	($771,836)	($2,578,602)	$41,649,562	92.555%	4.121%	$1,854,450	6
7	4.125%	Forsyth 86A due Dec 2016 (a)	12/29/86	12/01/16	30	$8,500,000	$8,500,000	($304,824)	$0	$8,195,176	96.414%	4.446%	$377,910	7
8	4.125%	Converse 95 due Nov 2025 (a)	11/17/95	11/01/25	30	$5,300,000	$5,300,000	($132,043)	$0	$5,167,957	97.509%	4.380%	$232,140	8
9	4.125%	Lincoln 95 due Nov 2025 (a) (b)	11/17/95	11/01/25	30	$22,000,000	$19,859,151	($404,262)	$0	$19,454,889	97.964%	4.458%	$885,321	9
10	[redacted]	Carbon County due Nov 2024	11/17/94	11/01/24	30	$9,365,000	$9,365,000	($206,519)	($58,574)	$9,099,907	97.169%	4.240%	$397,076	10
11	[redacted]	Converse County due Nov 2024	11/17/94	11/01/24	30	$8,190,000	$8,190,000	($209,778)	($86,323)	$7,893,899	96.385%	4.288%	$351,187	11
12	[redacted]	Emery County due Nov 2024	11/17/94	11/01/24	30	$121,940,000	$121,940,000	($3,274,246)	($1,925,767)	$116,739,987	95.736%	4.546%	$5,543,392	12
13	[redacted]	Lincoln County due Nov 2024	11/17/94	11/01/24	30	$15,060,000	$15,060,000	($422,858)	($81,427)	$14,555,715	96.651%	4.363%	$657,068	13
14	[redacted]	Moffat County due May 2013	11/17/94	05/01/13	19	$40,655,000	$40,655,000	($874,159)	($74,912)	$39,705,929	97.666%	4.254%	$1,729,464	14
15	[redacted]	Sweetwater County due Nov 2024	11/17/94	11/01/24	30	$21,260,000	$21,260,000	($510,479)	($88,352)	$20,661,169	97.183%	4.240%	$901,424	15
16	4.109%	**Total - Secured Pollution Control Revenue Bonds**				$400,470,000	$398,329,151	($10,560,810)	($9,550,194)	$378,218,147			$18,915,795	16
17														17
18		**UNSECURED POLLUTION CONTROL REVENUE BONDS**												18
19	[redacted]	Sweetwater 88B due Jan 2014	01/01/88	01/01/14	30	$11,500,000	$11,500,000	($84,822)	($392,250)	$11,022,928	95.852%	4.803%	$552,345	19
20	[redacted]	Sweetwater 90A due Jul 2015	07/24/90	07/01/15	25	$70,000,000	$70,000,000	($660,750)	($795,122)	$68,544,128	97.920%	4.680%	$3,276,000	20
21	[redacted]	Emery 91 due Jan 2015	05/22/91	01/01/16	25	$45,000,000	$45,000,000	($872,505)	($2,568,859)	$41,558,636	92.353%	5.160%	$2,322,000	21
22	[redacted]	Sweetwater 88A due Jan 2017	01/01/88	01/01/17	30	$50,000,000	$50,000,000	($422,443)	($882,101)	$48,695,456	97.391%	4.754%	$2,377,000	22
23	[redacted]	Forsyth 88B due Jan 2018	01/01/88	01/01/18	30	$45,000,000	$45,000,000	($380,198)	($1,013,283)	$43,606,519	96.903%	4.735%	$2,130,750	23
24	[redacted]	Gillette 88 due Jan 2018	01/01/88	01/01/18	30	$63,000,000	$41,200,000	($351,905)	($1,006,013)	$39,842,082	96.704%	4.748%	$1,956,176	24
25	[redacted]	Converse 92 due Jul 2006	09/29/92	12/01/20	28	$22,485,000	$22,485,000	($205,066)	($303,303)	$21,976,631	97.739%	4.138%	$930,429	25
26	[redacted]	Sweetwater 92A due Apr 2005	09/29/92	12/01/20	28	$9,335,000	$9,335,000	($152,122)	($134,094)	$9,048,784	96.934%	4.188%	$390,950	26
27	[redacted]	Sweetwater 92B due Dec 2005	09/29/92	12/01/20	28	$6,305,000	$6,305,000	($141,505)	($97,735)	$6,065,760	96.206%	4.234%	$266,954	27
28	[redacted]	Sweetwater 95 due Nov 2025 (a)	11/17/95	11/01/25	30	$24,400,000	$24,400,000	($225,000)	($428,469)	$23,746,531	97.322%	4.705%	$1,148,020	28
29	6.150%	Emery 96 due Sep 2030	09/24/96	09/30/30	34	$12,675,000	$12,675,000	($735,013)	$0	$11,939,987	94.201%	6.579%	$833,888	29
30	3.869%	**Total - Unsecured Pollution Control Revenue Bonds**				$359,700,000	$337,900,000	($4,231,330)	($7,621,229)	$326,047,441			$16,184,512	30
31														31
32		(a) Subject to Alternative Minimum Tax.												32
33		Annual Debt Service (column 10) includes remarketing fees and credit enhancement fees.												33
34		(b) Currently outstanding amounts are shown net of construction fund balances.												34
35														35

UE 179

Staff/701
Conway/8
June 29, 2006

Source: Scottrade.com

Qty	Issue	Customer Price	YTM	Coupon	Maturity	Min. Qty	Payment Months	Notes
10001	T-NOTE	98.226	5.196	2.25	2/15/2007	10	Feb,Aug	Non Callable
10001	T-NOTE	100.679	5.109	6.25	2/15/2007	10	Feb,Aug	Non Callable
10001	T-NOTE	98.847	5.166	3.375	2/28/2007	10	Feb,Aug	Non Callable
10001	T-NOTE	97.366	5.201	2.75	8/15/2007	10	Feb,Aug	Non Callable
10001	T-NOTE	97.917	5.187	3.25	8/15/2007	10	Feb,Aug	Non Callable
10001	T-NOTE	101.007	5.18	6.125	8/15/2007	10	Feb,Aug	Non Callable
10001	T-NOTE	98.675	5.186	4	8/31/2007	10	Feb,Aug	Non Callable
10001	T-NOTE	96.667	5.171	3	2/15/2008	10	Feb,Aug	Non Callable
10001	T-NOTE	100.593	5.11	5.5	2/15/2008	10	Feb,Aug	Non Callable
10001	T-NOTE	97.249	5.166	3.375	2/15/2008	10	Feb,Aug	Non Callable
10001	T-NOTE (2YR)	99.144	5.166	4.625	2/29/2008	10	Feb,Aug	Non Callable
10001	T-NOTE	96.241	5.143	3.25	8/15/2008	10	Feb,Aug	Non Callable
10001	T-NOTE (DBL OLD 3YR)	98.062	5.099	4.125	8/15/2008	10	Feb,Aug	Non Callable
10001	T-NOTE	94.784	5.153	3	2/15/2009	10	Feb,Aug	Non Callable
10001	T-NOTE (3YR)	98.421	5.15	4.5	2/15/2009	10	Feb,Aug	Non Callable
10001	T-NOTE	95.339	5.135	3.5	8/15/2009	10	Feb,Aug	Non Callable
10001	T-NOTE	102.445	5.139	6	8/15/2009	10	Feb,Aug	Non Callable
10001	T-NOTE	104.421	5.143	6.5	2/15/2010	10	Feb,Aug	Non Callable
10001	T-NOTE	94.648	5.138	3.5	2/15/2010	10	Feb,Aug	Non Callable
10001	T-NOTE	102.37	5.103	5.75	8/15/2010	10	Feb,Aug	Non Callable
10001	T-NOTE	96.331	5.123	4.125	8/15/2010	10	Feb,Aug	Non Callable
10001	T-NOTE	99.64	5.087	5	2/15/2011	10	Feb,Aug	Non Callable
10001	T-NOTE (OLD 5YR)	97.382	5.137	4.5	2/28/2011	10	Feb,Aug	Non Callable
10001	T-NOTE	99.578	5.093	5	8/15/2011	10	Feb,Aug	Non Callable
10001	T-NOTE	98.703	5.143	4.875	2/15/2012	10	Feb,Aug	Non Callable
10001	T-NOTE	96.008	5.143	4.375	8/15/2012	10	Feb,Aug	Non Callable
10001	T-NOTE	92.86	5.161	3.875	2/15/2013	10	Feb,Aug	Non Callable
5001	T-BOND	113.731	9.314	12	08-15-	10	Feb,Aug	Callable
10001	T-NOTE	94.625	5.161	4.25	8/15/2013	10	Feb,Aug	Non Callable
10001	T-NOTE	92.594	5.188	4	2/15/2014	10	Feb,Aug	Non Callable
5001	T-BOND	121.129	8.799	12.5	08-15-	10	Feb,Aug	Callable
5001	T-NOTE	93.883	5.182	4.25	8/15/2014	10	Feb,Aug	Non Callable
5001	T-BOND	141.625	5.195	11.25	2/15/2015	10	Feb,Aug	Non Callable
5001	T-NOTE	91.848	5.184	4	2/15/2015	10	Feb,Aug	Non Callable
5001	T-BOND	138.953	5.204	10.625	8/15/2015	10	Feb,Aug	Non Callable
5001	T-NOTE (DBL OLD	93.258	5.187	4.25	8/15/2015	10	Feb,Aug	Non Callable
5001	T-BOND	130.114	5.225	9.25	2/15/2016	10	Feb,Aug	Non Callable
5001	T-NOTE (10YR)	94.832	5.189	4.5	2/15/2016	10	Feb,Aug	Non Callable
5001	T-BOND	129.998	5.274	8.875	8/15/2017	10	Feb,Aug	Non Callable
5001	T-BOND	132.287	5.327	8.875	2/15/2019	10	Feb,Aug	Non Callable
5001	T-BOND	126.029	5.339	8.125	8/15/2019	10	Feb,Aug	Non Callable
5001	T-BOND	130.173	5.351	8.5	2/15/2020	10	Feb,Aug	Non Callable
5001	T-BOND	133.294	5.358	8.75	8/15/2020	10	Feb,Aug	Non Callable
5001	T-BOND	125.185	5.366	7.875	2/15/2021	10	Feb,Aug	Non Callable
5001	T-BOND	128.277	5.369	8.125	8/15/2021	10	Feb,Aug	Non Callable
5001	T-BOND	119.961	5.381	7.25	8/15/2022	10	Feb,Aug	Non Callable
5001	T-BOND	118.953	5.384	7.125	2/15/2023	10	Feb,Aug	Non Callable
5001	T-BOND	109.617	5.383	6.25	8/15/2023	10	Feb,Aug	Non Callable

Source: Scottrade.com

5001 T-BOND	126.207	5.379	7.625	2/15/2025	10 Feb,Aug	Non Callable
5001 T-BOND	117.812	5.372	6.875	8/15/2025	10 Feb,Aug	Non Callable
5001 T-BOND	107.601	5.368	6	2/15/2026	10 Feb,Aug	Non Callable
5001 T-BOND	116.867	5.368	6.75	8/15/2026	10 Feb,Aug	Non Callable
5001 T-BOND	115.64	5.362	6.625	2/15/2027	10 Feb,Aug	Non Callable
5001 T-BOND	112.711	5.362	6.375	8/15/2027	10 Feb,Aug	Non Callable
5001 T-BOND	102.027	5.342	5.5	8/15/2028	10 Feb,Aug	Non Callable
5001 T-BOND	98.828	5.339	5.25	2/15/2029	10 Feb,Aug	Non Callable
5001 T-BOND	110.375	5.338	6.125	8/15/2029	10 Feb,Aug	Non Callable
5001 T-BOND (OLD 30YR)	100.953	5.305	5.375	2/15/2031	10 Feb,Aug	Non Callable
5001 T-BOND (30YR)	88.953	5.238	4.5	2/15/2036	10 Feb,Aug	Non Callable

Attachment OPUC 371

Oregon General Rate Case
Indicative Forward PCRB Variable Rates
(rates updated)
For March 31, 2007

	30 Day LIBOR (a)	Floating Rate PCRBs (b)	PCRB / LIBOR (b)/(a)
Dec-99	6.41%	3.77%	59%
Jan-00	5.81%	3.27%	56%
Feb-00	5.89%	3.64%	62%
Mar-00	6.05%	3.70%	61%
Apr-00	6.16%	3.95%	64%
May-00	6.54%	4.90%	75%
Jun-00	6.65%	4.39%	66%
Jul-00	6.63%	3.77%	57%
Aug-00	6.62%	4.12%	62%
Sep-00	6.62%	4.53%	68%
Oct-00	6.62%	4.23%	64%
Nov-00	6.64%	4.36%	66%
Dec-00	6.69%	4.18%	62%
Jan-01	5.87%	3.03%	52%
Feb-01	5.52%	3.70%	67%
Mar-01	5.13%	3.29%	64%
Apr-01	4.80%	3.85%	80%
May-01	4.16%	3.49%	84%
Jun-01	3.91%	3.13%	80%
Jul-01	3.82%	2.74%	72%
Aug-01	3.64%	2.46%	67%
Sep-01	3.15%	2.50%	79%
Oct-01	2.48%	2.27%	91%
Nov-01	2.13%	1.89%	89%
Dec-01	1.95%	1.79%	92%
Jan-02	1.80%	1.69%	94%
Feb-02	1.85%	1.57%	85%
Mar-02	1.89%	1.69%	90%
Apr-02	1.86%	1.83%	98%
May-02	1.84%	1.86%	101%
Jun-02	1.84%	1.77%	96%
Jul-02	1.83%	1.70%	93%
Aug-02	1.80%	1.70%	95%
Sep-02	1.82%	1.87%	102%
Oct-02	1.80%	2.02%	112%
Nov-02	1.44%	1.86%	129%
Dec-02	1.42%	1.75%	123%
Jan-03	1.36%	1.59%	117%
Feb-03	1.34%	1.61%	120%
Mar-03	1.30%	1.53%	118%
Apr-03	1.31%	1.68%	128%
May-03	1.32%	1.72%	130%
Jun-03	1.16%	1.38%	119%
Jul-03	1.11%	1.12%	101%
Aug-03	1.11%	1.16%	105%
Sep-03	1.12%	1.21%	108%
Oct-03	1.12%	1.24%	111%

Oregon General Rate Case
Indicative Forward PCRB Variable Rates
(rates updated)
For March 31, 2007

	30 Day LIBOR (a)	Floating Rate PCRBs (b)	PCRB / LIBOR (b)/(a)
Nov-03	1.13%	1.28%	114%
Dec-03	1.15%	1.32%	114%
Jan-04	1.11%	1.17%	106%
Feb-04	1.10%	1.17%	107%
Mar-04	1.09%	1.20%	110%
Apr-04	1.10%	1.27%	115%
May-04	1.10%	1.22%	111%
Jun-04	1.25%	1.28%	102%
Jul-04	1.41%	1.26%	89%
Aug-04	1.60%	1.37%	86%
Sep-04	1.78%	1.49%	83%
Oct-04	1.90%	1.72%	91%
Nov-04	2.19%	1.65%	75%
Dec-04	2.39%	1.67%	70%
Jan-05	2.49%	1.67%	67%
Feb-05	2.61%	1.88%	72%
Mar-05	2.81%	1.95%	69%
Apr-05	2.97%	2.50%	84%
May-05	3.09%	2.85%	92%
Jun-05	3.25%	2.39%	74%
Jul-05	3.43%	2.28%	66%
Aug-05	3.69%	2.44%	66%
Sep-05	3.78%	2.55%	68%
Oct-05	3.99%	2.51%	63%
Nov-05	4.15%	2.93%	71%
Dec-05	4.36%	3.10%	71%
Jan-06	4.48%	2.83%	63%
Feb-06	4.58%	3.12%	68%
Mar-06	4.76%	3.11%	65%
Average			86%

	Forward 30 Day LIBOR* (1)	Historical Floating Rate PCRB / 30 Day LIBOR (2)	Forecast Floating Rate PCRB (1) * (2)
3/31/2007	5.35%	86%	4.60%

* Source: Bloomberg L.P.

Bank of America

Current Prime Rate is **8.25000**. Effective **06/29/06**

Rates last updated on **06/29/06**

LIBOR Value Date as of **07/03/06**

Standard Rate Table

L07	LIBOR - 7 DAY DAILY RATE	5.33875
L14	LIBOR - 14 DAY - DAILY CHG	5.33375
L30	LIBOR - 30 DAY - DAILY CHG	5.34625
L60	LIBOR - 60 DAY - DAILY CHG	5.44063
L90	LIBOR - 90 DAY - DAILY CHG	5.50813
L20	LIBOR - 120 DAY - DAILY CHG	5.55000
L99	LIBOR - 180 DAY - DAILY CHG	5.64000
L27	LIBOR - 270 DAY - DAILY CHG	5.71063
L36	LIBOR - 360 DAY	5.76625
EM1	Overnight Money Market - 360	5.12500
EM7	7-Day Money Market - 360	5.32000
E30	30-Day EuroDollar	5.33000
E60	60-Day EuroDollar	5.44000
E90	90-Day EuroDollar	5.49000

Rounded Rate Table

L73	7 DAY - ROUNDED UP 2 DIGITS	5.34000
L13	14 DAY - ROUNDED UP 2 DIGITS	5.34000
L33	30 DAY - ROUNDED UP 2 DIGITS	5.35000
L63	60 DAY - ROUNDED UP 2 DIGITS	5.45000
L93	90 DAY - ROUNDED UP 2 DIGITS	5.51000
L43	120 DAY - ROUNDED UP 2 DIGITS	5.55000
L83	180 DAY - ROUNDED UP 2 DIGITS	5.64000
L03	270 DAY - ROUNDED UP 2 DIGITS	5.72000
L37	360 DAY - ROUNDED UP 2 DIGITS	5.77000
L72	7 DAYS ROUNDED TO 2 PLACES	5.34000
L24	14 DAYS ROUNDED TO 2 PLACES	5.33000
L32	30 DAYS ROUNDED TO 2 PLACES	5.35000
L62	60 DAYS ROUNDED TO 2 PLACES	5.44000
L92	90 DAYS ROUNDED TO 2 PLACES	5.51000
L42	120 DAYS ROUNDED TO 2 PLACES	5.55000
L82	180 DAYS ROUNDED TO 2 PLACES	5.64000
L02	270 DAYS ROUNDED TO 2 PLACES	5.71000
L35	360 DAYS ROUNDED TO 2 PLACES	5.77000
LR6	LIBOR 7 DAY ROUNDED 1/8	5.37500
L48	LIBOR 14 DAY ROUNDED 1/8	5.37500
L98	LIBOR 30 DAY ROUNDED 1/8	5.37500
LR4	LIBOR 60 DAY ROUNDED 1/8	5.50000
LR5	LIBOR 90 DAY ROUNDED 1/8	5.62500
L18	LIBOR 120 DAY ROUNDED 1/8	5.62500
L88	LIBOR 180 DAY ROUNDED 1/8	5.75000
LR8	LIBOR 270 DAT ROUNDED 1/8	5.75000
L38	LIBOR 360 DAY ROUNDED 1/8	5.87500
L76	LIBOR 7 DAY ROUNDED 1/16	5.37500
L46	LIBOR 14 DAY ROUNDED 1/16	5.37500
LR1	LIBOR 30 DAY ROUNDED 1/16	5.37500
LR2	LIBOR 60 DAY ROUNDED 1/16	5.50000
LR3	LIBOR 90 DAY ROUNDED 1/16	5.56250
L16	LIBOR 120 DAY ROUNDED 1/16	5.56250
L86	LIBOR 180 DAY ROUNDED 1/16	5.68750
L06	LIBOR 270 DAY ROUNDED 1/16	5.75000
L31	LIBOR 360 DAY ROUNDED 1/16	5.81250
L22	7 DAY ROUNDED UP-NEAREST 1/32	5.34375
L21	14 DAY ROUNDED UP-NEAREST 1/32	5.34375
L23	30 DAY ROUNDED UP-NEAREST 1/32	5.37500
L26	60 DAY ROUNDED UP-NEAREST 1/32	5.46875
L29	90 DAY ROUNDED UP-NEAREST 1/32	5.53125
L12	120DAY ROUNDED UP-NEAREST 1/32	5.56250
L28	180DAY ROUNDED UP-NEAREST 1/32	5.65625
L09	270DAY ROUNDED UP-NEAREST 1/32	5.71875
L34	360DAY ROUNDED UP-NEAREST 1/32	5.78125

27-Jun-06

Qty	CUSIP	Issue	Industry	Ratings	Customer Price	YTM	YTW	Coupon	Maturity	Min. Qty	Payment Months	Notes
50	695114BM9	Pacificorp	Utility	A3/A-	100.549	3.958	3.958	5.65	11/1/2006	50	Nov	Non Callable
332	69512EGN9	Pacificorp Secd Mtn-Book Entry	Utility	A3/A-	101.632	5.443	5.443	6.375	5/15/2008	10	May,Nov	Non Callable, Make Whole Calls
340	695114BV9	Pacificorp	Utility	A3/A-	97.626	5.452	5.452	4.3	9/15/2008	10	Mar,Sep	Non Callable, Make Whole Calls
250	695114BU1	Pacificorp	Utility	A3/A-	105.767	5.639	5.639	6.9	11/15/2011	10	May,Nov	Non Callable, Make Whole Calls
28	695114BW7	Pacificorp	Utility	A3/A-	98.671	5.676	5.676	5.45	9/15/2013	10	Mar,Sep	Non Callable, Make Whole Calls
400	695114BZ0	Pacificorp	Utility	A3/A-	88.427	6.107	6.107	5.25	6/15/2035	10	Jun,Dec	Non Callable, Make Whole Calls

Source: Scottrade.com

CASE: UE 179
WITNESS: Bryan Conway

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 702

Exhibits in Support of Direct Testimony

<u>REDACTED VERSION</u>

July 12, 2006

STAFF EXHIBIT 702

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 06-125. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 179 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UE 179
WITNESS: Thomas D. Morgan

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

Direct Testimony

July 12, 2006

Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Thomas D. Morgan and my business address is 550 Capitol Street NE, Salem, Oregon 97310-1380.[1]

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

A. I am employed as a Financial Economist by the Public Utility Commission of Oregon ("Commission") in the Finance/Policy Analysis Division. I have been employed by the Commission since August 2001 (excluding July through December 2005.)

Q. HAVE YOU PREPARED ANY EXHIBITS?

A. Yes. My Witness Qualifications Statement is included as Staff/801. The results of my analyses are included as Staff/802. I have also prepared an Appendix marked as Staff/803, which includes 397 pages of additional testimony and supporting reports.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to develop the cost of capital estimates for the rate-regulated property operated by PacifiCorp, dba Pacific Power and Light ("Company").[2] In addition, I provide Staff's overall recommended required rate of return (ROR) for the Company.

Q. WHAT IS YOUR RECOMMENDED RETURN ON EQUITY?

A. I recommend that the Commission adopt a 9.5 percent return on equity.

Q. HOW DID YOU DEVELOP YOUR RECOMMENDED RETURN ON EQUITY?

---

[1] My telephone number is (503) 378-4629 and my e-mail address is thomas.d.morgan@state.or.us.
[2] PacifiCorp is a wholly owned subsidiary of Mid-American Electric Holding Company (MEHC). PacifCorp's equity is owned by its parent and does not have publicly-traded common stock.

A. My recommendation is based upon review of single and multi-stage discounted cash flow ("DCF") model results and sensitivity analyses. The use of DCF models is consistent with Commission's most recent return on equity decisions in Dockets UE 115[3] and UE 116.[4] I detail the underlying theory of the DCF model beginning at Staff/803, Morgan/41.

Q. DOES YOUR DCF ANALYSIS ALSO PRODUCE A RANGE OF COST OF EQUITY ESTIMATES?

A. Yes. The following table illustrates the range of results produced by the DCF models:

Table 1 – Cost of Equity Summary Results

	Range of Results
Single-stage DCF	9.0 percent to 9.9 percent
2-stage 150-year DCF	8.1 percent to 9.8 percent
3-Stage 40-year DCF	8.6 percent to 9.6 percent

Consistent with the Commission's internal operating guidelines, this range provides the Commission with information related to the upper and lower ends of a reasonable cost of equity estimate.

Q. PLEASE SUMMARIZE YOU COST OF EQUITY RECOMMENDATION?

A. I recommend that a cost of equity of 9.5 percent. The range of my cost of equity estimates is 9.0 to 9.75 percent. Although the range produced from the models is wider than my recommended range, the results are due to the sensitivity analyses that include assumptions of growth rates that are higher than my recommendations. Similarly, I excluded the results lower than my recommended range.

---

[3] Order 01-777, August, 2001. http://apps.puc.state.or.us/orders/2001ords/01-777.pdf
[4] Order 01-787, September, 2001. http://apps.puc.state.or.us/orders/2001ords/01-787.pdf

Q. WHAT IS YOUR RECOMMENDED OVERALL ROR FOR THE COMPANY?

A. My recommendation of a 9.5 percent return on equity in conjunction with Staff Witness Conway's recommendations for the embedded costs of long-term debt and preferred stock, results in a 7.87 percent overall ROR. The following table summarizes the components of Staff's recommended ROR and compares it to the Company's request:

Table 2 – Cost of Capital Results

	Company Requested			Staff Recommended			Difference
Capital Component	**Cost**	**Ratio**	**Weighted Cost**	**Cost**	**Ratio**	**Weighted Cost**	
Long-Term Debt	6.37%	46.20%	2.94%	6.33%	50.50%	3.20%	0.24%
Preferred Stock	6.54%	1.00%	0.07%	6.30%	1.00%	0.06%	0.00%
Common Equity	11.50%	52.80%	6.07%	9.50%	48.50%	4.61%	-1.46%
TOTAL		100.00%	9.08%		100.00%	7.87%	-1.22%

Q. WHY DID YOU APPLY THE DCF MODELS TO A SAMPLE OF COMPANIES RATHER THAN TO COMPANY ITSELF?

A. I applied the DCF models to a representative sample of companies because the Company is not publicly-traded and the market's impact on the Company's share activity cannot be readily observed.

Q. WHAT SAMPLE OF COMPANIES DID YOU ADOPT TO DETERMINE THE COST OF EQUITY?

A. My sample selection includes fourteen companies,[5] nine of which are the same companies included Company's sample selection. Like the Company, I also

[5] The company name and ticker symbol (in parenthesis) of my sample companies are as follows: Alliant Energy (LNT); American Electric Power (AEP); Consolidated Edison, Inc. (ED); Empire District Electric Co. (EDE); Energy East Corporation (EAS); IDACORP, Inc. (IDA); MGE Energy (MGEE); NSTAR (NST); OGE Energy (OGE); Progress Energy (PGN); Southern Co. (SO); Wisconsin Energy (WES); WPS Resources (WPS); Xcel Energy, Inc. (XEL).

limited my selection to companies covered by Value Line. However, my sample selection is slightly different than the Company's because I considered the overall contribution to earnings (profitability) and the underlying asset base of the companies in addition to revenues. Because revenues are only one financial metric, consideration of additional financial metrics - profitability and the asset base - provide a more representative sample.

Therefore, my primary selection process was to exclude companies that have a large amount of revenues, assets, or earnings focused on unregulated operations. In addition, I selected companies that were rated BBB or better by Standard & Poor's. Because the financial metrics used to select companies are not static, the final selection process required final judgment pertaining to the anticipated future state of the companies' business.

While my sample selection is slightly different the Company's, I also analyzed the DCF models using the Company's sample selection. The results of my DCF analysis are largely independent of the sample used in the models. Instead, the main driver of the differences in DCF results are related to the input assumptions related to growth rates, which will be discussed later in my testimony. The difference between Staff's and the Company's sample selections does not have a notable impact in this particular proceeding

Q. IS THE APPROPRIATE COST OF EQUITY LINKED TO THE CAPITAL STRUCTURE?

A. Yes. The cost of equity is inextricably linked to the capital structure. For example, if a company was going to use less debt and more equity in its capital structure than the sample companies used in the DCF models, all else being equal, it is a less risky investment and would result in investors requiring a lower return.

My recommended return on equity is based upon the average capital level of equity of the sample of comparable companies used in the DCF models. If we were to assume a higher level of equity in the capital structure than the comparable companies, as the Company does, the DCF results are inaccurate. The results would be inaccurate because the DCF models return on equity is based upon the capital structure of the sample selection and does not take into account that a more equity-rich capital structure would lower risk and, therefore, investors required rate of return.

The Company's proposed capital structure is not reasonable based on its proposed cost of equity derivation. Adopting a capital structure that is different than the Company's actual capital structure does not impact the ability of the Company to manage its capital structure. Rather, it simply recognizes that the DCF results related to return on equity are a reflection of the capital structure of the sample selection or comparable companies.

Q. HAS THE COMMISSION RECOGNIZED THIS COST OF EQUITY AND CAPITAL STRUCTURE RELATIONSHIP IN THE PAST?

A. Yes. In Order No. 01-777 at 36, the Commission stated:

> "It is well understood by finance practitioners and theoreticians that the cost of equity drops as the percentage of common equity in the capital structure increases. Because the average amount of common equity in the capital structure of the comparable group of electric companies was 45.14 percent compared to 52.16 percent for PGE, it necessarily follows that PGE has a lower cost of equity. PGE's capital structure is therefore less risky, and its cost of common equity should be adjusted accordingly."

Q. IS THE APPROPRIATE LONG-TERM GROWTH RATE AN IMPORTANT ISSUE IN THIS DOCKET?

A. Yes, the disparity between the cost of equity estimates provided by Company and staff is largely due to differences in the appropriate long-term growth rates used in the DCF models. My long-term growth rates are based upon analysis and review of growth rates in the regulated utility industry, financial analysts' estimates of future growth, and sustainable growth rates estimates.

In contrast, the Company's long-term growth rates are based largely on a selective average of historical GDP growth as a proxy for future growth in the regulated utility industry. The Company's long-term growth rate (it recommends a terminal growth rate of 6.6 percent) is much higher than my analysis and review supports (4.0 to 5.0 percent), and underlies the Company's inflated recommendation for the cost of equity. For these reasons discussed in more detail below, the Commission should reject the Company's cost of equity estimate, which is largely predicated on the use of an unreasonable long-term growth rate.

Q. WHAT ARE THE METHODS YOU USED TO ESTIMATE LONG-TERM GROWTH?

A. My growth rate analysis is supported by using separate supporting methods and available market expectations. Specifically, I considered the following:

1. Market Consensus Growth Rates (Financial Analysts' Forecasts);
2. Sustainable Growth; and
3. Historical Utility Growth Rates

Q. WHAT INPUTS ARE REQUIRED FOR A SINGLE-STAGE DCF MODEL?

A. The single-stage DCF model, which is also know as a perpetuity model, requires a dividend growth estimate, current stock price, and an initial dividend.

Q. HOW ARE YOUR MULTI-STAGE DCF MODELS DIFFERENT THAN THE SINGLE-STAGE DCF MODEL?

A. A multi-stage DCF model also requires a current stock price and initial dividend but separates dividend growth into two or more stages. While a single-stage model assumes that growth is steady and stable, the multi-stage models allow the growth rate to change over a period of time before making the final (also called “terminal” or horizon”) constant growth rate assumption.

Q. WHAT MULTI-STAGE DCF MODELS DID YOU DEVELOP?

A. I developed a two-stage DCF model that uses the current dividend yields and Value Line’s Investment Survey (“Value Line”) estimates of growth for the next few years. Then, I applied long-term growth forecasts for another 150 years.

I also utilized the three-stage DCF model that the Commission has relied on in the last two contested cases involving return on equity, UE 115 and UE 116. This model has three-stages over a 40-year period. In the first stage, estimates from Value Line are used. The second stage uses implicit growth rates from two primary input assumptions. The third stage is the “reversionary” stage where an explicit estimation of the stock price is produced at year 40.

Q. WHAT DID YOU USE FOR THE CURRENT STOCK PRICE IN YOUR DCF MODELS?

A. I used the current stock price (P_o) from Microsoft Network Money as of June 28, 2006.[6] The most current spot prices are the correct prices to use for P_o

[6] http://moneycentral.msn.com/investor/home.asp: Supplied by Standard & Poor’s ComStock, Inc.

because, based upon the efficient market hypothesis, current spot prices include all current and past information.

Q. WHAT DID YOU USE FOR THE INITIAL DIVIDEND, D_1, IN YOUR DCF MODELS?

A. I used the estimates of D_1 (the expected dividend per share over the next twelve months) from the June 23, 2006, Value Line Summary and Index.

Q. DO YOU AND THE COMPANY AGREE ON THE GROWTH RATES TO BE USED OVER THE NEXT FEW YEARS?

A. Yes, we generally agree on the growth rates that should be applied in the near term. We disagree, however, regarding the perpetual, long-term growth rate to be used in the DCF models.

Q. WHAT IS THE APPROPRIATE PERPETUAL, LONG-TERM GROWTH RATE TO BE USED IN THE DCF MODELS?

A. I conclude that the appropriate growth rate ranges from 4.0 to no more than 5.0 percent. My perpetual growth rate analysis is supported by separate supporting methods and available market expectations.

Further, because the Company inputs an estimate of overall growth rate in the economy as measured by historic Gross Domestic Product ("GDP"), I provide an analysis of historic GDP growth rates and why they should not be used as an input in a DCF model at Staff/803, Morgan/18.

Market Consensus (Analyst) Growth Rates

Q. WHAT DID YOU USE FOR THE ESTIMATES OF GROWTH?

A. I began by reviewing the actual growth rates achieved by the comparable companies. Then, I considered current forecasts of growth. In order to estimate reasonable future growth rates, I reviewed estimates from the following five major financial analysis services: Kiplinger's; Firstcall; Zack's; Reuters; and Value Line. Using the analysts' minimum and maximum estimates of 3.8 to 5.3 percent, I created a sensitivity analysis in the single and two-stage DCF models. In Staff/802, Morgan/16, I provide a table illustrating analysts' future growth estimates. In the three-stage model, I also provide a sensitivity analysis with implicit growth rates that range up to five percent.

Q. HOW DID YOU ESTIMATE DIVIDEND GROWTH?

A. Consistent with Staff's past approach to the DCF method, I viewed past dividend growth as an indicator of the marginal investor's expectations of future growth. I analyzed the historical dividend growth of the comparable companies by looking at both the arithmetic and geometric means.[7]

In addition, I considered the historic growth rate in both earnings per share and book value. Over time, a convergence among these two measures is expected. For a more detailed explanation of the convergence issue, please see Staff/803, Morgan/48.

Q. IS IT APPROPRIATE TO CONSIDER ANALYST'S FORECASTS OF GROWTH WITHIN THE DCF MODEL?

A. Yes. While the Company and I both incorporate analysts' forecasts, they are not generally supportable assumptions for perpetual growth. Because analyst estimates are explicitly designed to cover a more limited amount of time, I do not rely on them exclusively. Also, analysts may expect higher than sustainable growth rates at times, such as during a recession or major industry restructuring. Thus, such estimates should not necessarily be used for the indefinite future. Nonetheless, in the broad prospective they provide relevant information to consider in conducting a DCF analysis.

[7] A discussion of geometric and arithmetic averages can be found at Staff/803, Morgan/25.

Q. HAS THIS ISSUE BEEN DISCUSSED IN SCHOLARLY ARTICLES?

A. Yes. A recent publication, entitled "Prophets and Profits," written by McKinsey & Company concluded that analysts tend to provide inflated (as much as 20 percent for five year forecasts) growth estimates. A copy of the publication can be found at Staff/803, Morgan/244. Another article from the Journal of Finance, entitled "The Level & Persistence of Growth Rates," indicates that, while analyst forecasts are not appropriate for perpetual use, they are useful when combined with historic results and reasonable future expectations. The article also explains that actual growth results have generally been lower, on average, than expected from analyst long-term forecasts. A copy of this article can be found at Staff/803, Morgan/248.

Q. WHAT DO YOU CONCLUDE THE MARKET EXPECTS FOR GROWTH RATES?

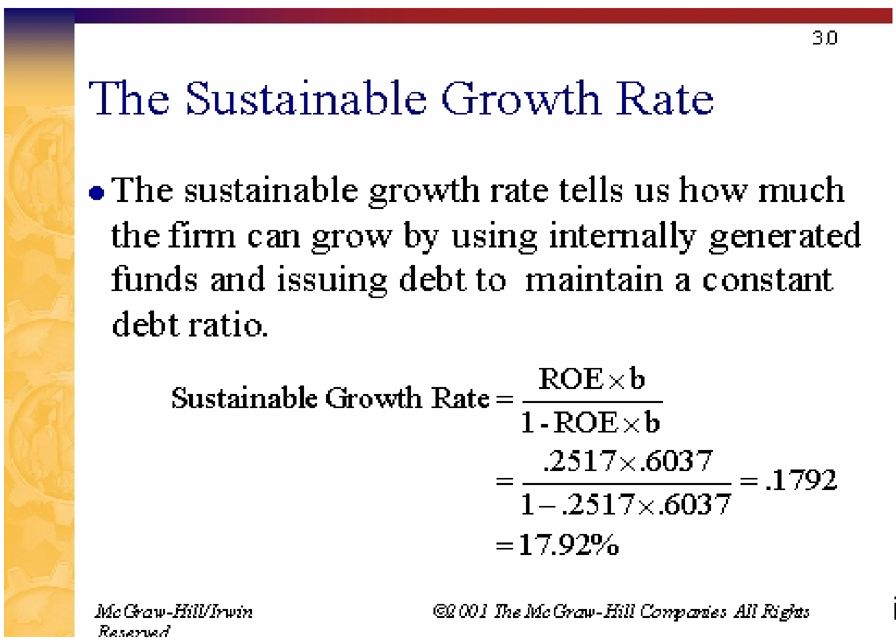
A. I conclude that all the actual growth rates and analysts' forecasts for the next five years provide significant support for a growth rate of less than five percent. While these growth rates are in line with Dr. Hadaway's own analysts' estimates, he continues to inappropriately rely on a historic, long-term average GDP to result in higher cost of equity estimates.

Sustainable Growth

Q. PLEASE DESCRIBE THE SUSTAINABLE GROWTH METHOD?

A. The sustainable growth method is a minor variation of the "retention growth" method. The retention growth is calculated by taking the product of the percentage of retained earnings and the rate of return on book equity. The percentage of earnings retained (b), multiplied by the rate of return on equity (ROE), creates a long-horizon future growth estimate (g) [g = b x ROE]. The retention growth rate provides a useful check on the supportability of growth rates because it requires an explicit expectation regarding the sustainability of both ROEs and reinvestment rates (or, as the complementary factor, dividend payouts). The combination of retention rates and ROEs necessary to produce a particular growth rate can be determined.

The sustainable growth rate can be estimated by the “b x ROE” formula described above. A variation on the model, designed with the assumption of on-going debt issuances to maintain a “balanced” capital structure while reinvesting a portion of the earnings (“plowback) is described below:



is expected as a long-

sensitivity analysis, we might assume a 10 percent ROE and a 30 percent retention, which would result in a growth indication of just less than 3.10 percent. The following table presents a summary of the calculations described above:

SUSTAINABLE GROWTH RATE

ROE	Dividend Payout, “d”	Retention Rate “b” = (1-“d”)	ROE x “b”	[1- ROE x “b”]	Expected Growth
10.00%	**70%**	**30%**	3.00%	97.00%	**3.09%**
10.50%	**70%**	**30%**	3.15%	96.85%	**3.25%**
11.00%	**65%**	**40%**	4.40%	95.60%	**4.60%**
12.00%	**60%**	**40%**	4.80%	95.20%	**5.04%**

Q. DO YOU HAVE ANYTHING ELSE TO ADD?

A. Yes. The expectations of Value Line for “earned” ROEs are readily available and are closer to the credible long-run estimates for the earnings that might be expected to accrue to the companies within the industry. Using Value Line’s estimate of future “earned” ROEs at about 11 percent, along with a 40 percent retention rate, provides a growth rate estimate of 4.4 percent. This forecasted growth rate is more reasonable than the Company’s because it is based upon the future expectations for the specific industry.

<u>Historic Utility Growth Rates</u>

Q. IS THERE HISTORIC INFORMATION AVAILABLE REGARDING THE ACTUAL GROWTH RATES OF THE COMPARABLE COMPANIES?

A. Yes. Over the past fifteen years, the comparable electric companies have achieved a median growth in book value, earnings per share, and dividends of less than 3.0 percent.

Q. SHOULD THE COMMISSION GIVE ANY WEIGHT TO THE HISTORIC GROWTH IN THIS CASE?

A. Yes. Because there is no evidence that this historic period was the result of unfair earnings performance, it could be guidance upon which to judge future growth expectations. The historic dividend growth reflects the comparable companies' economic performance and dividend policies. If historic dividend growth is relatively stable, one would assume that the historic dividend growth would continue all else being equal.

While the Company forecasts that future dividend growth will significantly increase, it offers no explanation or support for its contention. In fact, Dr. Hadaway provides no economic analysis that would support a significant change in growth rates from what has occurred in the past. Neither actual past performance nor the views of independent analysts' future expectations support Dr. Hadaway's contention that dividend growth will significantly increase.

Considering the comparable companies' historic growth, and coupling the historic results with Value Line's forecasts of 4.17 percent average growth in earnings over the next five-year period, supports an expected long-term growth rate somewhere in the range of 3.0 to 4.5 percent.

Q. IF THE DCF MODELS USE DIVIDEND GROWTH, WHY WOULD ONE CONSIDER GROWTH IN BOOK VALUE OR GROWTH IN EARNINGS?

A. Over the long run, there can be no growth in dividends per share without growth in earnings per share unless companies have higher payout ratios. Both earnings and dividend expectations have a significant influence on the market prices. By considering earnings growth rates in the DCF analysis, a link is provided between investors' market appreciation expectations and the growth rate component of the DCF models. Over the long run, a convergence among these measures of growth is to be expected.

Q. DO YOU HAVE ADDITIONAL INFORMATION ON THE HISTORIC GROWTH RATES FROM THE COHORT SAMPLE YOU HAVE SELECTED?

A. Yes, based upon Value Line's most current data, the following tables detail historic growth in cash flow, earnings per share, dividends, and book value. The last table provides Value Line's forecasts for these same financial metrics.

From this data, the growth rates over the past five and ten year periods have averaged less than four percent.

HISTORIC 10-YEAR GROWTH RATES

Company	Book Value	Dividends	Earnings
Alliant Energy	1.00%	-3.50%	-3.50%
Amer. Elec. Power	-1.00%	-2.50%	N/A
Consol. Edison	2.50%	1.50%	N/A
Empire Dist. Elec.	2.00%	N/A	-1.00%
Energy East Corp.	4.50%	-0.50%	3.00%
IDACORP, Inc.	3.00%	-0.50%	1.50%
MGE Energy	2.50%	1.00%	1.50%
NSTAR	3.00%	2.50%	4.50%
OGE Energy	2.00%	N/A	2.00%
Progress Energy	6.50%	3.00%	4.50%
Southern Co.	1.00%	2.00%	2.50%
Wisconsin Energy	2.50%	-5.00%	2.00%
WPS Resources	4.00%	2.00%	3.00%
Xcel Energy Inc.	-1.00%	-3.50%	-4.00%
Average	2.32%	-0.29%	1.33%
Median	2.50%	0.25%	2.00%
Maximum Value	6.50%	3.00%	4.50%
Minimum Value	-1.00%	-5.00%	-4.00%

HISTORIC 5-YEAR GROWTH RATES

Company	Book Value	Dividends	Earnings
Alliant Energy	-1.50%	-7.50%	-3.00%
Amer. Elec. Power	-4.00%	-5.50%	-2.00%
Consol. Edison	2.00%	1.00%	-2.00%
Empire Dist. Elec.	2.00%	N/A	-3.50%
Energy East Corp.	5.50%	5.50%	-0.50%
IDACORP, Inc.	4.00%	-0.50%	-3.00%
MGE Energy	5.00%	1.00%	4.00%
NSTAR	1.50%	2.50%	5.00%
OGE Energy	1.00%	N/A	-2.50%
Progress Energy	8.50%	3.00%	5.50%
Southern Co.	-1.50%	1.00%	2.50%
Wisconsin Energy	3.50%	-12.00%	9.50%
WPS Resources	6.50%	2.00%	9.50%
Xcel Energy Inc.	-5.00%	-9.00%	-9.50%
Average	1.96%	-1.54%	0.71%
Median	2.00%	1.00%	-1.25%
Maximum Value	8.50%	5.50%	9.50%
Minimum Value	-5.00%	-12.00%	-9.50%

FORECAST (EX-ANTE) 5-YEAR GROWTH RATES

The following table provides Value Line's current growth rate forecasts. A reasonable earnings growth rate estimate for the group is approximately 4.5 percent.

Company	Book Value	Dividends	Earnings
Alliant Energy	4.50%	-2.50%	6.50%
Amer. Elec. Power	4.50%	N/A	2.00%
Consol. Edison	2.50%	1.00%	1.50%
Empire Dist. Elec.	1.50%	N/A	5.00%
Energy East Corp.	3.00%	5.00%	4.50%
IDACORP, Inc.	3.00%	-4.50%	4.50%
MGE Energy	4.00%	1.00%	6.00%
NSTAR	5.50%	3.00%	2.50%
OGE Energy	5.00%	3.00%	5.50%
Progress Energy	2.50%	1.50%	N/A
Southern Co.	5.50%	3.50%	4.00%
Wisconsin Energy	5.50%	4.50%	4.00%
WPS Resources	7.50%	2.00%	5.00%
Xcel Energy Inc.	3.00%	2.50%	7.50%
Average	4.11%	1.67%	4.50%
Median	4.25%	2.25%	4.50%
Maximum Value	7.50%	5.00%	7.50%
Minimum Value	1.50%	-4.50%	1.50%

Q. PLEASE SUMMARIZE THE COMPANY'S RECOMMENDATIONS.

A. The Company recommends:

- A capital structure of 46.2 percent long-term debt, 1.0 percent preferred stock, and 52.8 percent common equity. *See* PPL/300, Williams/3.
- A cost of preferred stock of 6.54 percent. *See* PPL/304, Williams/1.
- A cost of equity of 11.50 percent. *See* PPL/200, Hadaway/5
- A rate of return of 9.08 percent. *See* PPL/300, Williams/3.

Q. SHOULD THE COMMISSION GIVE THE COMPANY'S 11.50 PERCENT RECOMMENDED RETURN ON EQUITY ANY WEIGHT?

A. No. Dr. Hadaway's analysis presumes a growth rate that is greater than the company or the electric industry has experienced on average. His growth rate estimate is based exclusively on historic growth in nominal GDP and disregards analyst estimates, sustainable growth rates, and historic growth rates. In addition, the Company's own internal financial planning does not support Dr. Hadaway's growth rates.

Q. WHICH DCF MODELS ARE USED BY DR. HADAWAY?

A. Dr. Hadaway used three versions of the DCF models. He places little reliance on the results of one of his versions, asserting that it produced results that were "too low." *See* PPL/200, Hadaway/39. The two models on which he relies, and which I discuss below, are a constant growth model and a low near-term growth two-stage growth model. As already noted, Dr. Hadaway applied the models to a sample of 13 integrated electric companies.

Q. WOULD YOU PLEASE DESCRIBE THE TWO DCF MODELS USED BY DR. HADAWAY?

A. Yes. Dr. Hadaway uses a constant growth (single-stage) DCF model based upon current dividend yields and assumptions of perpetual growth. This model uses the most current three-month average share price coupled with the expected dividend per share for the ensuring 12-month period, as estimated by Value Line. As I discussed above, the current stock price should be used rather than an average of historic prices.

Dr. Hadaway also uses a two-stage model in which dividends are explicitly forecast for the remainder of a 150-year forecast period. His explicit forecast replaces the terminal price expectations. The growth rate applied from years 5 to 150 is based solely upon Dr. Hadaway's historic GDP calculation of 6.6 percent.

Q. HOW DOES DR. HADAWAY ESTIMATE PERPETUAL GROWTH?

A. Dr. Hadaway's estimate of long-term growth is based on the average of (1) a five year forecast provided by Zack's; (2) Value Line's estimates for the ensuing three to five years; (3) the "b x r" sustainable growth model, and (4) a calculation of historic growth of GDP. Ultimately, Dr. Hadaway only uses his historic GDP growth calculation of 6.6 percent.

Q. ARE HIS ESTIMATION TECHNIQUES APPROPRIATE?

A. No. Dr. Hadaway seems to imply that long run nominal GDP growth is a useful estimate of perpetual or terminal growth in any DCF model. He makes this assertion notwithstanding the fact that compared to other growth estimates his GDP calculation overstates expected industry growth rates by fifty percent. I discuss GDP growth rates at Staff/803, Morgan/18.

Dr. Hadaway uses analyst forecasts of growth (from Value Line and Zack's) and equally weighs them with the b x r sustainable growth rate calculation. The sustainable growth rate relies upon the ability of retained earnings to grow the future earnings of the company. This earnings growth depends upon normalized ex-ante earnings (*e.g.* forward-looking expectations). The "r" variable represents the long-run anticipated ROE and is applied by multiplying it with the ratio of the long run forecast of retained earnings.

The Company's model, however, assumes that the current, simple average, of the expected ROEs over a single period of time is appropriate to forecast for the indefinite future. Specifically, Dr. Hadaway has used the net book value per share and expected earnings per share in the 2008-2010 period[8] to calculate the expected ROE for that period. He then assumes that this ROE figure is the best estimate for the future. Because the projected ROE results should reflect the long-run normalized returns for each company, his reliance on a single-period's expected figures projected perpetually into the future is not theoretically sound.

In addition, Dr. Hadaway relies on Value Line's forecast short-to-near-term retention ratios as his proxy for perpetual retention rates to calculate his "br" sustainable growth figure. However, those forecasts are short term and require more consideration before they are accepted as reasonable proxies for long-term perpetual growth.

While I do not agree with Dr. Hadaway's averaging of a historic GDP with the "br" and the "long-term" earnings growth estimates by Value Line and Zacks, he ultimately throws out all of these figures and relies exclusively on his GDP calculation of 6.6 percent. While he does not provide supporting documentation for his claims, he did provide a table (PPL/204, Hadaway/1) that provides some data relative to GDP for the 1947-2004 periods. The table, however, is problematic because it implies that the average of the nominal

[8] As of the date of the Company's testimony, Value Line had not released its forecast for 2009-2011.

growth rates for six overlapping periods provides a reasonable forecast for the future.

The following table identifies the six periods that are calculated and the overall average of each period. Notably, this method gives a large amount of weight to high inflationary periods (1970-1985).

Dr. Hadaway's Historic GDP Growth Calculations

10-year nominal average	5.20%
20-year nominal average	5.60%
30-year nominal average	7.10%
40-year nominal average	7.50%
50-year nominal average	7.10%
57-year nominal average	7.10%
Six-period Average	**6.60%**

Q. HAS DR. HADAWAY CONSISTENTLY APPLIED HIS GDP ESTIMATE?

A. No. In 2003, Dr. Hadaway filed testimony in which he employed a simple 20-year average for GDP growth for his long-term earnings growth proxy, which indicated a 6.0 percent growth estimate. In Docket UE 170, he changed is methodology and began using four different periods to calculate the average GDP growth. In that docket, he averaged the four historical overlapping GDP growth period averages, the result of which increased his long-term growth estimate to 6.6 percent, which is identical to the results from the six-period average he employs in this docket.

Q. ARE THERE OTHER METHODS FOR CALCULATING LONG-TERM GDP GROWTH?

A. Yes. The impact of inflation can be removed from the historic data. Since real growth has been actually declining over the historic period, it is reasonable to remove inflation and simply consider real growth rates rather than nominal growth rates. Then, forward-looking forecasts for inflation can be directly applied to the historic results to reflect a reasonable forward-looking estimate of nominal GDP growth.

The following table removes the impact of inflation and provides an average rate of real growth of 2.8 percent. If we assume that inflation is 2.5 percent, the long-run expectation of nominal growth is still only 5.3 percent.[9]

Period	GDP Growth	Inflation	Real Growth
10-year GDP nominal average	5.20%	2.50%	2.70%
20-year GDP nominal average	5.60%	3.00%	2.60%
30-year GDP nominal average	7.10%	4.60%	2.50%
40-year GDP nominal average	7.50%	4.70%	2.80%
50-year GDP nominal average	7.10%	4.00%	3.10%
57-year GDP nominal average	7.10%	3.80%	3.30%
Six-period Average	**6.60%**	**3.80%**	**2.80%**

Q. DO YOU AGREE WITH THE COMPANY'S ASSUMPTION THAT GDP GROWTH IS THE CORRECT LONG-TERM PROXY FOR UTILITY-SPECIFIC COMPANIES?

A. No. The Company's support for this proposition is based upon a short excerpt from a basic finance book that states: "One might expect the dividend of an 'average' or 'normal' company to grow at the nominal growth rate in the economy." *See* PPL/200, Hadaway/37. Of course, this completely ignores that pubic utilities are not the "average" or "normal" company referenced in the excerpt. Rather, public utilities are less risky than the average company due to

[9] Although there are also independent sources of forecast data readily available, Dr. Hadaway failed to consider any forward looking expectations. While I do not support the use of GDP growth as a proxy for long-term utility growth, if Dr. Hadaway had considered these readily available projections of GDP growth rates he would likely produce results only slightly higher than the highest analyst forecast for the industry.

regulation. In addition, they also pay out a higher portion of their earnings in dividends, which tempers their growth rate potential downward from that of the overall economy.

Q. CAN YOU PROVIDE AN EXAMPLE THAT ILLUSTRATES THE ILLOGICAL EFFECTS OF USING GDP AS A PROXY FOR GROWTH IN EACH SECTOR OF THE ECONOMY?

A. Yes. The following table[10] reflects what the effects would be if we applied the Company's 6.6 percent GDP growth rate assumption to several S&P industry sections:

S&P 500 Industry Group Dividend Yields	Yield	+ Hadaway's GDP growth calculation	ROE
Real Estate	7.09%	6.60%	13.69%
Utilities	4.95%	6.60%	11.55%
Automobiles & Components	3.30%	6.60%	9.90%
Banks	3.14%	6.60%	9.74%
Telecommunication Services	3.06%	6.60%	9.66%
Food, Beverage & Tobacco	2.86%	6.60%	9.46%
Materials	2.64%	6.60%	9.24%
Energy	2.58%	6.60%	9.18%
Capital Goods	2.20%	6.60%	8.80%
Consumer Durables & Apparel	1.98%	6.60%	8.58%
Household & Personal Products	1.90%	6.60%	8.50%
Diversified Financials	1.87%	6.60%	8.47%
Pharmaceuticals & Biotechnology	1.81%	6.60%	8.41%
Insurance	1.20%	6.60%	7.80%
Transportation	1.09%	6.60%	7.69%
Food and Drug Retailing	0.99%	6.60%	7.59%
Hotels, Restaurants and Leisure	0.96%	6.60%	7.56%
Commercial Services and Supplies	0.84%	6.60%	7.44%
Retailing	0.68%	6.60%	7.28%
Media	0.52%	6.60%	7.12%
Health Care Equipment & Services	0.44%	6.60%	7.04%
Technology Hardware and Equipment	0.40%	6.60%	7.00%
Software and Services	0.08%	6.60%	6.68%

[10] The table is based upon the framework of Wachovia Securities, Outlook 2003, "Pursuing Total Returns." Notably, these figures do not reflect the impact of the recent dividend tax changes. This may decrease the required dividend yield from utilities by more than 50 basis points.

Q. CAN YOU EXPLAIN WHAT THESE RESULTS IMPLY?

A. These results imply that public utilities would have the highest required returns of any sector other than the real estate investment trusts. On the other hand, these results imply that investors would expect the lowest returns from technology, software, food and drug, and biotechnical stocks.

These perverse results demonstrate that an economy wide growth rate is an inappropriate proxy in earnings per share growth rates. Some sectors are expected to grow faster than the economy, such as those that do not pay dividends, while others sectors, such as regulated utilities that pay out large portions of their earnings as dividends are expected to grow a slower rate.

Q. DO YOU RECOMMEND THAT THE COMMISSION USE DR. HADAWAY'S LONG-TERM GROWTH ESTIMATE?

A. No. Dr. Hadaway initially estimates that investment analysts expect sustainable growth be 4.76 percent for the average of his comparable companies. *See* PPL/205, Hadaway/2, Column 13. However, he throws out his own numbers because he finds them "pessimistic." Instead, he relies exclusively on his unsupported historic GDP calculation of 6.6 percent.

I cannot contemplate an economic, theoretical, or mathematical reason to employ an average of six separate period averages to GDP growth. In addition, if GDP data was going to be used in the growth rate estimates, it should include forward-looking estimates of inflation and real growth and be tempered to reflect the lower growth rates for earnings for public utilities. The Commission should adopt my range of long-term growth rates of 4.0 to 5.0 percent, which is based upon a principled review of analysts' forecasts, sustainable growth, and historic growth.

Q. DO YOU RECOMMEND THAT THE COMMISSION ADOPT DR. HADAWAY'S DCF RESULTS?

No. Dr. Hadaway's DCF results are all driven by his unsupported use of his historic GDP growth estimate as a proxy for long-term growth for public utilities. As a result, his DCF results substantially overstate the required return on equity.

Q. DO YOU WISH TO DISCUSS DR. HADAWAY'S RISK-PREMIUM REGRESSION ANALYSIS OF ROES APPROVED IN OTHER JURISDICTIONS?

A. Yes. Dr. Hadaway uses a regression analysis of ROEs approved in other jurisdictions to estimate the Company's cost of equity.

Q. DO YOU BELIEVE THAT THIS IS AN APPROPRIATE APPROACH?

A. No, I do not. First, the ROE is only one component involved in establishing an overall revenue requirement. Requesting the Commission to base its ROE decision on ROEs of other jurisdictions is equivalent to taking one cost element in isolation out of another states' rates and putting it into Oregon rates. In addition, cost of equity is just one of many rate-making issues and return on equity is not independent of all of these issues. For example, the use of power costs adjustments, deferred accounting, and the use of future test periods could result in lower costs of equity required by investors when compared to states that have different practices.

Second, Dr. Hadaway's reasoning is circular. As an author of a text focusing on the utility industry has stated: "It would be hopelessly circular to set a fair return based on the past actions of other regulators, much like observing a series of duplicate images in multiple mirrors."[11] For example, if all

[11] Morin, Roger, Regulatory Finance - Utilities' Cost of Capital, Public Utility Reports, 1994, p. 395.

regulators adopted this practice then no Commission would be free to update ROE and their decisions would always be based upon outdated information.

Third, it is notable that this model includes data spanning a period where interest rates were the highest in history. If the model were applied using current and forecast data, it would likely indicate a lagging effect and demonstrate that the average ROE is lower than indicated in Dr. Hadaway's regression analysis.

Q. HAS THE COMMISSION DISCUSSED THE USE OF THESE MODELS IN THE PAST?

A. Yes, the Commission rejected this as an independent model in the past. In UE 116, the Commission stated that:

> Capital market conditions, not regulatory decisions, determine a utility's cost of equity. While we agree that regulatory agencies generally make every effort to capture those market conditions, a review of past decisions cannot replace an independent analysis of current market conditions and how they affect the particular utility. Moreover, ROE determinations are made not just in the traditional rate cases, but also in a range of other proceedings, such as industry restructuring plans, merger approval cases, or performance-based regulatory plans. Thus, the ROE awards may have been based, in part, on other unknown parameters relevant in that particular docket.

The Commission correctly rejected the generic analysis of determining ROE based upon other state commission rulings and they should again reject the Company's request to establish circular ROE decisions that do not consider current market conditions.

Q. PLEASE DESCRIBE DR. HADAWAY'S RISK-PREMIUM MODEL?

A. Dr. Hadaway's first risk premium model is utility debt + risk premium. The model appears to be unique to Dr. Hadaway and to my knowledge has not been subjected to peer-review. His model purports to relate Authorized Equity Rates of Return from 1980-2005 to some average interest rate for bonds as reported by Moody's Investors Service. Over the period included the model, the allowed returns ranged from a high of 15.78 percent and a low of 10.77 percent. The yield on debt ranged from a low of 6.61 percent to a high of 15.62 percent.

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING THIS RISK-PREMIUM MODEL?

Yes, I do. First, the results on his model include the early 1980's when interest rates were extremely high. This is notable because his model suggests that the relevant historic time-period (*e.g.* early 1980's) he uses is assumed to apply to the future. This is clearly problematic considering that interest rates are and are expected to remain at much lower levels then much of the period analyzed by this model.

Second, because there are no other independent variables in his model, it assumes that the "average" cost of debt in a wide-range of companies is the other relevant variable that affects allowed rates of return. As mentioned above, the model does not consider other issues that may be directly relevant such as leverage, overall rate base, performance-based regulation or other regulatory approaches. Because of these issues and the fact that the only dependent variable in this unique regression was developed by the witness and has not been subject to peer-review, the model should be disregarded as an unreliable measure of capital market decisions.

Q. WHAT OTHER RISK-POSITIONING-TYPE MODELS DOES DR. HADAWAY DISCUSS?

A. Dr. Hadaway references two studies. *See* PPL/200, Hadaway/40-42. The first study uses the long-term historic data related to stock market returns and corporate bond returns. The second study uses stock market returns for approximately one decade in the 1980s.

Q. PLEASE DISCUSS THE FIRST STUDY REFERENCED BY DR. HADAWAY.

A. The first study referenced by Dr. Hadaway uses the achieved stock market returns as reported by Ibbotson's & Associates, who aggregated the data for a period from 1926-2004. He uses the historic return data from the stock market and "corporate bond" rates. The difference between these data represent the return "premium" investors have achieved from holding common equity over the return they would have achieved by investing only in corporate bonds. Dr. Hadaway then calculated the arithmetic and geometric common risk premium from the data set (6.2 and 4.5 percent, respectively) and applied it to his current forecast of debt interest rates of 6.3 percent. The result is a wide-range of estimates from 10.8 to 12.5 percent.

Q. IS THIS METHOD APPLICABLE TO PUBLIC UTILITIES?

A. No. The data applies to the overall stock market and not specifically to the public utility sector. In addition, it is unclear whether the earned results over the historic timeframe reasonably predict the current expectations of investors for the overall stock market; much less whether his calculations are representative and consistent with public utility return forecasts. Finally, as a new model not previously adopted by the Commission, Dr. Hadaway fails to adequately explain how this technique is reliable as applied to rate-regulated public utilities. For these reasons, the Commission should reject this analysis.

Q. PLEASE DISCUSS THE SECOND STUDY REFERENCED BY DR. HADAWAY.

A. Dr. Hadaway references the Harris and Marston study, published in 1991. This study calculates the value-weighted sum of annual returns for the overall market, in order to calculate the market returns for each year. The average market return is then subtracted from the prevailing bond yield to create an estimate for the equity risk premium. The study uses analysts' forecasts of the earnings growth rate as a proxy for the dividend growth rate and then estimates the expected return by using this relationship for each company in the S&P 500 for the period from 1982-1991. Dr. Hadaway uses the results of this study,[12] which reflects a 6.4 percent annual premium over government bond yields and 5.13 percent over corporate bonds, on average.

Q. DO YOU BELIEVE THAT THIS STUDY PROVIDES SUPPORTABLE RESULTS FOR THE REGULATED UTILITY INDUSTRY?

A. No, I do not. Similar to the previous study, this model is designed to reflect returns for the overall stock market and is not useful in estimating ROEs for public utility companies. Another difficulty is that the aggregated earnings growth forecasts are around 12 percent per year. A dividend growth rate of 12 percent is not sustainable in perpetuity.[13] The study's updated calculations reflect a risk premium over 50 basis points higher than the earlier study. The volatility of the results is based on overall market returns, and not returns required by public utility investors. Therefore, the results are not reasonably

[12] Harris and Marston updated their calculations in 1999, using data from 1982-1998, concluding that the average equity risk premium was 7.1 percent, with a range in any year of 5.2 to 9.2 percent. This is relatively close to the historical results provided in the Ibbotson Associates study. Harris, Robert and Marston, Felicia, "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts" (1999). Darden Business School Working Paper No. 99-08.

[13] This is consistent with the findings of Chan, Karceski and Lakonishok (2001), who demonstrate that analysts' forecasts are optimistic.

reliable for forecasting the risk premium for public utilities and the Commission should reject them. Dr. Hadaway also advises against the use of the results for public utilities. *See* PPL/200, Hadaway/42, line 15.

Q. ARE THERE MACROECONOMIC FACTORS, OTHER THAN CHANGES IN INTEREST RATES,[14] THAT WERE OMITTED IN THE COMPANY'S ANALYSIS?

A. Yes. The Company failed to discuss the implications of the tax cut program enacted in 2003. The tax changes lowered dividend taxes, which is especially relevant for public utilities, which generally pay a large amount of dividends. With this reduction, the equity investor would be expected to bid up the price all else being equal. This change would be expected to significantly contribute to the price of shares in high-dividend paying companies; thereby, reducing the required rate of return.

Sensitivity Analysis

Q. WHAT IS THE RANGE OF COST OF EQUITY RESULTS THAT CAN BE INDICATED BY THE 40-YEAR DCF MODEL PREVIOUSLY ADOPTED BY THIS COMMISSION?[15]

A. The following table provides a range of results, indicating the cost of equity that could be generated in the 3-stage, 40-year DCF.

SENSITIVITY ANALYSIS, EXPECTED COST OF EQUITY

Growth Rate	3.50%	4.00%	4.50%	5.00%	5.50%
Cost of Equity	7.21%	7.97%	8.70%	9.42%	10.12%

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

---

[14] Expected changes in interest rates are included in my analysis. For more information on interest rates, please refer to Staff/803, Morgan/3.

[15] Orders 01-777 and 01-787.

CASE: UE 179
WITNESS: Thomas D. Morgan

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Witness Qualification Statement

July 12, 2006

WITNESS QUALIFICATIONS STATEMENT

NAME:	Thomas D. Morgan
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Financial Economist, Economic & Policy Analysis
ADDRESS:	550 Capitol St NE Suite 215, Salem, Oregon 97301-2551.
EDUCATION:	Bachelor of Science in Business Administration, Finance; 1993, University of Oregon, Eugene, Oregon *summa cum laude*. I am enrolled in Master of Science in Finance program through the University of Leicester (UK).

RELEVANT WORK EXPERIENCE:

Since August 2001, I have been employed by the Public Utility Commission of Oregon as a financial analyst in the Economic Research & Financial/Policy Analysis Division. Current responsibilities include conducting research and providing technical support for cost of equity issues for electric, telecommunications, and gas utilities.

From October 1997 to August 2001, I worked for the Oregon Department of Revenue as a Senior Appraiser Analyst in the Utility Program, Valuation Section of the Property Tax Division. Duties included appraising a variety of public utility and transportation properties. The valuation process included developing cost of capital studies for use in the discounting of cash flows in the Income Capitalization Approach to value. Duties included valuation of the property owned by gas, electric, telecommunication and airline companies.

I am a certified general property appraiser and have been involved in the valuation of commercial properties since 1993.

CASE: UE 179
WITNESS: Thomas D. Morgan

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 802

Analysis Workpapers

July 12, 2006

Single-Stage DCF Model Results

UE 179

Schedule 1 - Single Stage Model

COMPANY	TICKER	[A] Next 12-months Dividend	[B] Current Price	[C] Dividend Yield	[D] Growth Rate	[E] Selected Companies
Alliant Energy	LNT	$1.18	$33.51	3.52%	4.40%	7.92%
Amer. Elec. Power	AEP	$1.51	$33.90	4.45%	3.51%	7.97%
Consol. Edison	ED	$2.31	$43.55	5.30%	3.41%	8.72%
Empire Dist. Elec.	EDE	$1.28	$20.49	6.25%	3.38%	9.62%
Energy East Corp.	EAS	$1.21	$23.58	5.13%	4.27%	9.40%
IDACORP, Inc.	IDA	$1.20	$33.61	3.57%	4.79%	8.36%
MGE Energy	MGEE	$1.38	$29.59	4.66%	6.00%	10.66%
NSTAR	NST	$1.24	$28.20	4.40%	4.50%	8.90%
OGE Energy	OGE	$1.33	$33.98	3.91%	3.50%	7.41%
Progress Energy	PGN	$2.46	$42.14	5.84%	3.49%	9.33%
Southern Co.	SO	$1.56	$31.85	4.90%	4.70%	9.60%
Wisconsin Energy	WEC	$0.93	$39.17	2.37%	6.80%	9.17%
WPS Resources	WPS	$2.29	$48.67	4.71%	4.80%	9.51%
Xcel Energy Inc.	XEL	$0.89	$19.00	4.68%	4.86%	9.54%
AVERAGE		**$1.48**	**$32.95**	**4.55%**	**4.46%**	**9.01%**
MEDIAN		**$1.31**	**$33.56**	**4.67%**	**4.45%**	**9.25%**

[A] Value Line Summary and Index, June 30, 2006
[B] Most current stock quotes provided by MSN Money, www.moneycentral.msn.com
[C] Dividend rate divided by market price [C] / [B]
[D] Growth Rates from average of Kiplinger's; Firstcall; Zack's; Reuters; Value Line
[E] Dividend Yield + Growth [C] + [D]

Single-Stage DCF Model, Sensitivity Analysis

UE 179

Schedule 1A - Sensitivity Analysis

COMPANY	TICKER	Next 12-months Dividend	Current price	Div Yield	Minimum Analyst Estimate	COE Results	Maximum Analyst Estimate	COE Results
Alliant Energy	LNT	$1.18	$33.51	3.52%	2.50%	6.02%	6.50%	10.02%
Amer. Elec. Power	AEP	$1.51	$33.90	4.45%	2.00%	6.45%	6.00%	10.45%
Consol. Edison	ED	$2.31	$43.55	5.30%	1.50%	6.80%	4.00%	9.30%
Empire Dist. Elec.	EDE	$1.28	$20.49	6.25%	2.50%	8.75%	5.00%	11.25%
Energy East Corp.	EAS	$1.21	$23.58	5.13%	4.00%	9.13%	4.50%	9.63%
IDACORP, Inc.	IDA	$1.20	$33.61	3.57%	4.50%	8.07%	5.00%	8.57%
MGE Energy	MGEE	$1.38	$29.59	4.66%	6.00%	10.66%	6.00%	10.66%
NSTAR	NST	$1.24	$28.20	4.40%	2.50%	6.90%	5.00%	9.40%
OGE Energy	OGE	$1.33	$33.98	3.91%	3.00%	6.91%	5.50%	9.41%
Progress Energy	PGN	$2.46	$42.14	5.84%	2.87%	8.71%	4.00%	9.84%
Southern Co.	SO	$1.56	$31.85	4.90%	4.00%	8.90%	5.00%	9.90%
Wisconsin Energy	WEC	$0.93	$39.17	2.37%	4.00%	6.37%	8.00%	10.37%
WPS Resources	WPS	$2.29	$48.67	4.71%	4.50%	9.21%	5.00%	9.71%
Xcel Energy Inc.	XEL	$0.89	$19.00	4.68%	4.00%	8.68%	5.00%	9.68%
AVERAGE		**$1.48**	**$32.95**	**4.55%**	**3.42%**	**7.97%**	**5.32%**	**9.87%**
MEDIAN		**$1.31**	**$33.56**	**4.67%**	**3.50%**	**8.38%**	**5.00%**	**9.77%**

150-Year Horizon DCF | UE 179 | **Schedule 2 - Sensitivity Range Analysis - Low** | ===> to year 150

HADAWAY COMPANIES	(ticker)	IRR	[1] Current Price [A]	[2] Dividend EOY 1 [B]	[3] Dividend EOY 2 [B]	[4] Dividend EOY 3 [B]	[5] Dividend EOY 4 [B]	LT Growth Dividend EOY 5 [C]	Dividend EOY 6	Dividend EOY 7	Dividend EOY 8	Dividend EOY 9	Dividend EOY 10
Alliant Energy	LNT	6.46%	($33.51)	$1.19	$1.28	$1.36	$1.44	$1.48	$1.52	$1.55	$1.59	$1.63	$1.67
Amer. Elec. Power	AEP	7.06%	($33.90)	$1.53	$1.64	$1.74	$1.84	$1.88	$1.92	$1.95	$1.99	$2.03	$2.07
Consol. Edison	ED	6.71%	($43.55)	$2.31	$2.33	$2.35	$2.37	$2.40	$2.44	$2.48	$2.51	$2.55	$2.59
Empire Dist. Elec.	EDE	8.35%	($20.49)	$1.28	$1.28	$1.28	$1.28	$1.31	$1.34	$1.38	$1.41	$1.45	$1.48
Energy East Corp.	EAS	9.15%	($23.58)	$1.21	$1.26	$1.32	$1.37	$1.42	$1.48	$1.54	$1.60	$1.67	$1.73
IDACORP, Inc.	IDA	7.62%	($33.61)	$1.20	$1.20	$1.20	$1.20	$1.25	$1.31	$1.37	$1.43	$1.50	$1.56
MGE Energy	MGEE	10.09%	($29.59)	$1.38	$1.40	$1.41	$1.43	$1.52	$1.61	$1.70	$1.81	$1.91	$2.03
NSTAR	NST	7.12%	($28.20)	$1.23	$1.29	$1.35	$1.41	$1.45	$1.48	$1.52	$1.56	$1.60	$1.64
OGE Energy	OGE	6.95%	($33.98)	$1.34	$1.38	$1.43	$1.47	$1.52	$1.56	$1.61	$1.66	$1.71	$1.76
Progress Energy	PGN	8.55%	($42.14)	$2.47	$2.52	$2.56	$2.60	$2.67	$2.75	$2.83	$2.91	$2.99	$3.08
Southern Co.	SO	8.90%	($31.85)	$1.56	$1.62	$1.69	$1.76	$1.83	$1.90	$1.98	$2.06	$2.14	$2.23
Wisconsin Energy	WEC	6.35%	($39.17)	$0.94	$0.98	$1.03	$1.07	$1.12	$1.16	$1.21	$1.25	$1.31	$1.36
WPS Resources	WPS	8.87%	($48.67)	$2.30	$2.34	$2.38	$2.42	$2.53	$2.64	$2.76	$2.88	$3.01	$3.15
Xcel Energy Inc.	XEL	8.97%	($19.00)	$0.90	$0.95	$1.01	$1.07	$1.11	$1.15	$1.20	$1.25	$1.30	$1.35
AGGREGATE		8.08%	($461.24)	$20.83	$21.46	$22.10	$22.73	$23.48	$24.27	$25.08	$25.92	$26.79	$27.70
Average		7.94%											
Stdev		1.18%						3.32%					
Min		6.35%											
Max		10.09%											
Median		7.98%											
25 percentile		6.98%											
75 percentile		8.89%											

Sources:

[A] Most current stock quotes provided by MSN Money, www.moneycentral.msn.com
[B] Value Line Data (See Schedule 3)
[C] Long-term growth is the input variable, based on consensus analyst growth expectations.

150-Year Horizon DCF **UE 179**

Schedule 2A - Sensitivity Range Analysis - High

COHORT COMPANY DATA

SELECTED FINANCIAL DATA

HADAWAY COMPANIES	(ticker)	**IRR**	[1] Current Price	[2] Dividend EOY 1	[3] Dividend EOY 2	[4] Dividend EOY 3	[5] Dividend EOY 4	LT Growth Dividend EOY 5	Dividend EOY 6	Dividend EOY 7	Dividend EOY 8	Dividend EOY 9	===> to year 150 Dividend EOY 10
			[A]	[B]	[B]	[B]	[B]	[C]					
Alliant Energy	LNT	10.04%	($33.51)	$1.19	$1.28	$1.36	$1.44	$1.54	$1.64	$1.74	$1.86	$1.98	$2.11
Amer. Elec. Power	AEP	10.55%	($33.90)	$1.53	$1.64	$1.74	$1.84	$1.95	$2.07	$2.19	$2.33	$2.46	$2.61
Consol. Edison	ED	8.87%	($43.55)	$2.31	$2.33	$2.35	$2.37	$2.46	$2.56	$2.66	$2.77	$2.88	$3.00
Empire Dist. Elec.	EDE	10.47%	($20.49)	$1.28	$1.28	$1.28	$1.28	$1.34	$1.41	$1.48	$1.56	$1.63	$1.72
Energy East Corp.	EAS	9.59%	($23.58)	$1.21	$1.26	$1.32	$1.37	$1.43	$1.49	$1.56	$1.63	$1.71	$1.78
IDACORP, Inc.	IDA	8.07%	($33.61)	$1.20	$1.20	$1.20	$1.20	$1.26	$1.32	$1.39	$1.46	$1.53	$1.61
MGE Energy	MGEE	10.09%	($29.59)	$1.38	$1.40	$1.41	$1.43	$1.52	$1.61	$1.70	$1.81	$1.91	$2.03
NSTAR	NST	9.32%	($28.20)	$1.23	$1.29	$1.35	$1.41	$1.48	$1.56	$1.64	$1.72	$1.80	$1.89
OGE Energy	OGE	9.19%	($33.98)	$1.34	$1.38	$1.43	$1.47	$1.55	$1.64	$1.73	$1.82	$1.92	$2.03
Progress Energy	PGN	9.51%	($42.14)	$2.47	$2.52	$2.56	$2.60	$2.70	$2.81	$2.92	$3.04	$3.16	$3.29
Southern Co.	SO	9.77%	($31.85)	$1.56	$1.62	$1.69	$1.76	$1.85	$1.94	$2.04	$2.14	$2.25	$2.36
Wisconsin Energy	WEC	10.05%	($39.17)	$0.94	$0.98	$1.03	$1.07	$1.16	$1.25	$1.35	$1.46	$1.58	$1.70
WPS Resources	WPS	9.31%	($48.67)	$2.30	$2.34	$2.38	$2.42	$2.54	$2.66	$2.80	$2.94	$3.08	$3.24
Xcel Energy Inc.	XEL	12.03%	($19.00)	$0.90	$0.95	$1.01	$1.07	$1.15	$1.23	$1.33	$1.42	$1.53	$1.65
AGGREGATE		9.81%	(461.24)	20.83	21.46	22.10	22.73	23.93	25.20	26.53	27.94	29.43	31.01
Average		9.78%											
Stdev		0.89%											
Min		8.07%											
Max		12.03%											
Median		9.68%											
25 percentile		9.31%											
75 percentile		10.08%											

[A] Most current stock quotes provided by MSN Money, www.moneycentral.msn.com
[B] Value Line Data (See Schedule 3)
[C] Long-term growth is the input variable, based on consensus analyst growth expectations.

150-Year Horizon DCF **UE 179**

COHORT COMPANY DATA

SELECTED FINANCIAL DATA

Schedule 2B - Analyst Growth Estimates Consensus

LT Growth ===> to year 150
Based on Analysts' Estimates *(See Schedule 8)*

GAS COMPANIES	(ticker)	IRR	[1] Current Price	[2] Dividend EOY 1	[3] Dividend EOY 2	[4] Dividend EOY 3	[5] Dividend EOY 4	Dividend EOY 5	Dividend EOY 6	Dividend EOY 7	Dividend EOY 8	Dividend EOY 9	Dividend EOY 10
			[A]	[B]	[B]	[B]	[B]	[B]	[C]				
Alliant Energy	LNT	8.15%	($33.51)	$1.19	$1.28	$1.36	$1.44	$1.51	$1.57	$1.64	$1.71	$1.79	$1.87
Amer. Elec. Power	AEP	8.38%	($33.90)	$1.53	$1.64	$1.74	$1.84	$1.91	$1.97	$2.04	$2.11	$2.19	$2.27
Consol. Edison	ED	8.36%	($43.55)	$2.31	$2.33	$2.35	$2.37	$2.45	$2.53	$2.62	$2.71	$2.80	$2.90
Empire Dist. Elec.	EDE	9.09%	($20.49)	$1.28	$1.28	$1.28	$1.28	$1.32	$1.37	$1.41	$1.46	$1.51	$1.56
Energy East Corp.	EAS	9.38%	($23.58)	$1.21	$1.26	$1.32	$1.37	$1.43	$1.49	$1.55	$1.62	$1.69	$1.76
IDACORP, Inc.	IDA	7.88%	($33.61)	$1.20	$1.20	$1.20	$1.20	$1.26	$1.32	$1.38	$1.45	$1.52	$1.59
MGE Energy	MGEE	10.09%	($29.59)	$1.38	$1.40	$1.41	$1.43	$1.52	$1.61	$1.70	$1.81	$1.91	$2.03
NSTAR	NST	8.88%	($28.20)	$1.23	$1.29	$1.35	$1.41	$1.48	$1.54	$1.61	$1.69	$1.76	$1.84
OGE Energy	OGE	7.40%	($33.98)	$1.34	$1.38	$1.43	$1.47	$1.52	$1.58	$1.63	$1.69	$1.75	$1.81
Progress Energy	PGN	9.08%	($42.14)	$2.47	$2.52	$2.56	$2.60	$2.69	$2.78	$2.88	$2.98	$3.08	$3.19
Southern Co.	SO	9.51%	($31.85)	$1.56	$1.62	$1.69	$1.76	$1.84	$1.93	$2.02	$2.11	$2.21	$2.32
Wisconsin Energy	WEC	8.94%	($39.17)	$0.94	$0.98	$1.03	$1.07	$1.15	$1.22	$1.31	$1.40	$1.49	$1.59
WPS Resources	WPS	9.14%	($48.67)	$2.30	$2.34	$2.38	$2.42	$2.53	$2.65	$2.78	$2.92	$3.06	$3.20
Xcel Energy Inc.	XEL	9.71%	($19.00)	$0.90	$0.95	$1.01	$1.07	$1.12	$1.17	$1.23	$1.29	$1.35	$1.42
AGGREGATE		8.87%	($461.24)	$20.83	$21.46	$22.10	$22.73	$23.71	$24.74	$25.82	$26.94	$28.11	$29.34
Average		8.86%											
Stdev		0.72%											
Min		7.40%											
Max		10.09%											
Median		9.01%											
25 percentile		8.36%											

[A] Most current stock quotes provided by MSN Money, www.moneycentral.msn.com
[B] Value Line Data (See Schedule 3)
[C] Long-term growth is the input variable, based on consensus analyst growth expectations.

Value Line Data

Schedule 3

COHORT ELECTRIC COMPANIES UE 179

VALUE LINE'S EARNINGS PER SHARE PROJECTIONS

	2006	2007	2008	2009	2010
Alliant Energy	$2.15	$2.20	$2.23	$2.27	$2.30
Amer. Elec. Power	$2.60	$2.65	$2.77	$2.88	$3.00
Consol. Edison	$3.05	$3.15	$3.18	$3.22	$3.25
Empire Dist. Elec.	$1.05	$1.40	$1.43	$1.47	$1.50
Energy East Corp.	$1.75	$1.65	$1.77	$1.88	$2.00
IDACORP, Inc.	$1.85	$1.90	$1.93	$1.97	$2.00
MGE Energy	$2.00	$2.10	$2.22	$2.33	$2.45
NSTAR	$1.90	$2.05	$2.12	$2.18	$2.25
OGE Energy	$1.80	$1.90	$2.02	$2.13	$2.25
Progress Energy	$3.25	$3.35	$3.40	$3.45	$3.50
Southern Co.	$2.20	$2.30	$2.45	$2.60	$2.75
Wisconsin Energy	$2.50	$2.60	$2.73	$2.87	$3.00
WPS Resources	$3.95	$4.05	$4.12	$4.18	$4.25
Xcel Energy Inc.	$1.25	$1.40	$1.52	$1.63	$1.75
AVERAGE	**$2.24**	**$2.34**	**$2.42**	**$2.50**	**$2.59**

Note: Data are from the most current Value Line report(s)

Value Line's Dividends Per Share

COMPANY	2006	2007	2008	2009	2010
Alliant Energy	$1.15	$1.25	$1.33	$1.41	$1.49
Amer. Elec. Power	$1.48	$1.60	$1.70	$1.80	$1.90
Consol. Edison	$2.30	$2.32	$2.34	$2.36	$2.38
Empire Dist. Elec.	$1.28	$1.28	$1.28	$1.28	$1.28
Energy East Corp.	$1.18	$1.24	$1.29	$1.35	$1.40
IDACORP, Inc.	$1.20	$1.20	$1.20	$1.20	$1.20
MGE Energy	$1.38	$1.39	$1.41	$1.42	$1.44
NSTAR	$1.21	$1.26	$1.32	$1.39	$1.45
OGE Energy	$1.33	$1.36	$1.41	$1.45	$1.50
Progress Energy	$2.44	$2.50	$2.54	$2.58	$2.62
Southern Co.	$1.53	$1.59	$1.66	$1.73	$1.80
Wisconsin Energy	$0.92	$0.96	$1.01	$1.05	$1.10
WPS Resources	$2.28	$2.32	$2.36	$2.40	$2.44
Xcel Energy Inc.	$0.88	$0.93	$0.99	$1.04	$1.10
AVERAGE	**$1.47**	**$1.51**	**$1.56**	**$1.60**	**$1.65**

Retention Rate

(Earnings less Dividends divided by Earnings)

	2006	2007	2008	2009	2010
Alliant Energy	46.5%	43.2%	$0.40	$0.38	35.2%
Amer. Elec. Power	43.1%	39.6%	$0.39	$0.38	36.7%
Consol. Edison	24.6%	26.3%	$0.26	$0.27	26.8%
Empire Dist. Elec.	-21.9%	8.6%	$0.11	$0.13	14.7%
Energy East Corp.	32.6%	24.8%	$0.27	$0.28	30.0%
IDACORP, Inc.	35.1%	36.8%	$0.38	$0.39	40.0%
MGE Energy	31.0%	33.8%	$0.37	$0.39	41.2%
NSTAR	36.3%	38.5%	$0.37	$0.36	35.6%
OGE Energy	26.1%	28.4%	$0.30	$0.32	33.3%
Progress Energy	24.9%	25.4%	$0.25	$0.25	25.1%
Southern Co.	30.5%	30.9%	$0.32	$0.33	34.5%
Wisconsin Energy	63.2%	63.1%	$0.63	$0.63	63.3%
WPS Resources	42.3%	42.7%	$0.43	$0.43	42.6%
Xcel Energy Inc.	29.6%	33.6%	$0.35	$0.36	37.1%
AVERAGE	**31.7%**	**34.0%**	**34.5%**	**35.0%**	**35.4%**

RETAINED EARNINGS

	2006	2007	2008	2009	2010
Alliant Energy	$1.00	$0.95	$0.90	$0.86	$0.81
Amer. Elec. Power	$1.12	$1.05	$1.07	$1.08	$1.10
Consol. Edison	$0.75	$0.83	$0.84	$0.86	$0.87
Empire Dist. Elec.	($0.23)	$0.12	$0.15	$0.19	$0.22
Energy East Corp.	$0.57	$0.41	$0.47	$0.54	$0.60
IDACORP, Inc.	$0.65	$0.70	$0.73	$0.77	$0.80
MGE Energy	$0.62	$0.71	$0.81	$0.91	$1.01
NSTAR	$0.69	$0.79	$0.79	$0.80	$0.80
OGE Energy	$0.47	$0.54	$0.61	$0.68	$0.75
Progress Energy	$0.81	$0.85	$0.86	$0.87	$0.88
Southern Co.	$0.67	$0.71	$0.79	$0.87	$0.95
Wisconsin Energy	$1.58	$1.64	$1.73	$1.81	$1.90
WPS Resources	$1.67	$1.73	$1.76	$1.78	$1.81
Xcel Energy Inc.	$0.37	$0.47	$0.53	$0.59	$0.65
AVERAGE	**$0.77**	**$0.82**	**$0.86**	**$0.90**	**$0.94**

VALUE LINE'S BOOK VALUE PER SHARE PROJECTIONS

	2005	2006	2007	2008	2009	2010
Alliant Energy	$22.13	$20.85	$21.90	$23.17	$24.43	$25.70
Amer. Elec. Power	$21.32	$23.08	$24.20	$25.55	$26.90	$28.25
Consol. Edison	$29.09	$30.05	$31.40	$32.67	$33.93	$35.20
Empire Dist. Elec.	$14.76	$15.08	$15.15	$15.52	$15.88	$16.25
Energy East Corp.	$17.89	$18.35	$18.95	$19.63	$20.32	$21.00
IDACORP, Inc.	$23.88	$24.04	$24.95	$26.05	$27.15	$28.25
MGE Energy	$16.59	$16.82	$17.10	$17.75	$18.40	$19.05
NSTAR	$13.52	$14.50	$15.25	$16.42	$17.58	$18.75
OGE Energy	$14.28	$15.19	$15.75	$16.83	$17.92	$19.00
Progress Energy	$30.90	$31.55	$32.30	$33.42	$34.53	$35.65
Southern Co.	$13.86	$14.35	$15.15	$16.40	$17.65	$18.90
Wisconsin Energy	$21.31	$22.90	$24.15	$25.93	$27.72	$29.50
WPS Resources	$29.30	$32.47	$35.55	$38.00	$40.45	$42.90
Xcel Energy Inc.	$12.99	$13.37	$13.95	$14.55	$15.15	$15.75
AVERAGE	**$20.13**	**$20.90**	**$21.84**	**$22.99**	**$24.14**	**$25.30**

SELECTED COMPANIES 40-YEAR MULTISTAGE DCF METHOD — **UE 179** — **Schedule 4 - 40-year 3-stage DCF Model**

Page 1

RESULTING IRR 9.32%

Based on the Recent Price reported in Value Line

Stage	Year	[1] Year End Book	[2] Retention Rate	[3] Dividend	[4] Earnings Per Share	[5] Retained Earnings Per Share	[6] Total Increment to Book	[7] Market Price	[8] Mkt to Book	[9] Expect. Ret. on Equity	[10] Cash Fl. from Stock Trans.	[11] Cash Fl. from Div.	[12] Total Cash Flow	Stage
		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	
First Stage	2005	$20.13						$32.95	1.62		($32.95)		($32.95)	First Stage
	2006	$20.90	34.31%	$1.47	$2.24			$33.88	1.62	10.90%		$1.47	$1.47	
	2007	$21.84	35.17%	$1.51	$2.34			$35.40	1.62	10.93%		$1.51	$1.51	
	2008	$22.99	35.56%	$1.56	$2.42			$37.27	1.62	10.80%		$1.56	$1.56	
	2009	$24.14	35.93%	$1.60	$2.50			$39.14	1.62	10.63%		$1.60	$1.60	
	2010	$25.30	36.28%	$1.65	$2.59			$41.01	1.62	10.47%		$1.65	$1.65	
Second Stage	2011	$26.54	40.00%	$1.87	$3.11	$1.24	$1.24	$43.02	1.62	12.00%		$1.87	$1.87	Second Stage
	2012	$27.85	40.00%	$1.96	$3.26	$1.31	$1.31	$45.14	1.62	12.00%		$1.96	$1.96	
	2013	$29.22	40.00%	$2.05	$3.42	$1.37	$1.37	$47.36	1.62	12.00%		$2.05	$2.05	
	2014	$30.65	40.00%	$2.16	$3.59	$1.44	$1.44	$49.69	1.62	12.00%		$2.16	$2.16	
	2015	$32.16	40.00%	$2.26	$3.77	$1.51	$1.51	$52.13	1.62	12.00%		$2.26	$2.26	
	2016	$33.74	40.00%	$2.37	$3.95	$1.58	$1.58	$54.69	1.62	12.00%		$2.37	$2.37	
	2017	$35.40	40.00%	$2.49	$4.15	$1.66	$1.66	$57.38	1.62	12.00%		$2.49	$2.49	
	2018	$37.14	40.00%	$2.61	$4.35	$1.74	$1.74	$60.21	1.62	12.00%		$2.61	$2.61	
	2019	$38.97	40.00%	$2.74	$4.57	$1.83	$1.83	$63.17	1.62	12.00%		$2.74	$2.74	
	2020	$40.88	40.00%	$2.87	$4.79	$1.92	$1.92	$66.27	1.62	12.00%		$2.87	$2.87	
	2021	$42.90	40.00%	$3.02	$5.03	$2.01	$2.01	$69.53	1.62	12.00%		$3.02	$3.02	
	2022	$45.01	40.00%	$3.16	$5.27	$2.11	$2.11	$72.95	1.62	12.00%		$3.16	$3.16	
	2023	$47.22	40.00%	$3.32	$5.53	$2.21	$2.21	$76.54	1.62	12.00%		$3.32	$3.32	
	2024	$49.54	40.00%	$3.48	$5.81	$2.32	$2.32	$80.30	1.62	12.00%		$3.48	$3.48	
	2025	$51.98	40.00%	$3.65	$6.09	$2.44	$2.44	$84.25	1.62	12.00%		$3.65	$3.65	
	2026	$54.53	40.00%	$3.83	$6.39	$2.56	$2.56	$88.40	1.62	12.00%		$3.83	$3.83	
	2027	$57.22	40.00%	$4.02	$6.70	$2.68	$2.68	$92.75	1.62	12.00%		$4.02	$4.02	
	2028	$60.03	40.00%	$4.22	$7.03	$2.81	$2.81	$97.31	1.62	12.00%		$4.22	$4.22	
	2029	$62.98	40.00%	$4.43	$7.38	$2.95	$2.95	$102.09	1.62	12.00%		$4.43	$4.43	
	2030	$66.08	40.00%	$4.65	$7.74	$3.10	$3.10	$107.11	1.62	12.00%		$4.65	$4.65	
	2031	$69.33	40.00%	$4.87	$8.12	$3.25	$3.25	$112.38	1.62	12.00%		$4.87	$4.87	
	2032	$72.74	40.00%	$5.11	$8.52	$3.41	$3.41	$117.91	1.62	12.00%		$5.11	$5.11	
	2033	$76.32	40.00%	$5.37	$8.94	$3.58	$3.58	$123.71	1.62	12.00%		$5.37	$5.37	
	2034	$80.07	40.00%	$5.63	$9.38	$3.75	$3.75	$129.79	1.62	12.00%		$5.63	$5.63	
	2035	$84.01	40.00%	$5.91	$9.84	$3.94	$3.94	$136.17	1.62	12.00%		$5.91	$5.91	
	2036.	$88.14	40.00%	$6.20	$10.33	$4.13	$4.13	$142.87	1.62	12.00%		$6.20	$6.20	
	2037	$92.47	40.00%	$6.50	$10.84	$4.33	$4.33	$149.90	1.62	12.00%		$6.50	$6.50	
	2038	$97.02	40.00%	$6.82	$11.37	$4.55	$4.55	$157.27	1.62	12.00%		$6.82	$6.82	
	2039	$101.79	40.00%	$7.16	$11.93	$4.77	$4.77	$165.00	1.62	12.00%		$7.16	$7.16	
	2040	$106.80	40.00%	$7.51	$12.52	$5.01	$5.01	$173.12	1.62	12.00%		$7.51	$7.51	
	2041	$112.05	40.00%	$7.88	$13.13	$5.25	$5.25	$181.63	1.62	12.00%		$7.88	$7.88	
	2042	$117.56	40.00%	$8.27	$13.78	$5.51	$5.51	$190.56	1.62	12.00%		$8.27	$8.27	
	2043	$123.34	40.00%	$8.67	$14.45	$5.78	$5.78	$199.94	1.62	12.00%		$8.67	$8.67	
	2044	$129.41	40.00%	$9.10	$15.17	$6.07	$6.07	$209.77	1.62	12.00%		$9.10	$9.10	
3rd Stage	2045	$135.77	40.00%	$9.55	$15.91	$6.36	$6.36	$220.09	1.62	12.00%	$220.09	$9.55	$229.63	3rd Stage

Long-run Retention Rate
40.00%
ROE
12.00%
GROWTH
4.80%

Internal Rate of Return 9.32%

Source:

[A] First Stage is average from Value Line. Second stage is prior years' book value plus value from Col. [6]
[B] First Stage is (Col. [4]-Col.[3]/Col.[4]). First year of second stage computed by 1-dividends/earnings; subsequent years use the same retention rate.
[C] First Stage is from Value Line. First year of second stage determined by Terminal Retention rate and ROE.
Subsequent years of second stage is Col. [4] x (1-Col. [2])
[D] First Stage is from Value line. Second stage is average of current and prior year's value from Col. [1] x Col. [9]
[E] Col. [4] - Col. [3]
[F] [E]
[G] Col. [1] x Col. [10]
[H] Staff/802 Morgan/3 (Schedule 3).
[I] First stage is Col. [4]/Ave. of Current and prior year's Col. [1]. Second stage is input.
[J] Input is "negative" Col. [7] for year of purchase, "positive" Col. [7] for year of sale.
[K] Col. [3]
[L] Col. [10] + Col. [11]

SELECTED COMPANIES 40-YEAR MULTISTAGE DCF METHOD

Schedule 4 - 40-year 3-stage DCF Model Sensitivity Analysis
Page 2

SENSITIVITY ANALYSES, EXPECTED INTERNAL RATE OF RETURN

Terminal Retention Rate	Terminal ROE								
	10.00%	**10.50%**	**11.00%**	**11.50%**	**12.00%**	**12.50%**	**13.00%**	**13.50%**	**14.00%**
30.00%	7.75%	8.05%	8.34%	8.62%	8.91%	9.19%	9.47%	9.75%	10.03%
35.00%	7.91%	8.21%	8.51%	8.81%	9.11%	9.41%	9.70%	9.99%	10.28%
40.00%	8.07%	8.38%	8.70%	9.01%	9.32%	9.62%	9.93%	10.23%	10.53%
45.00%	8.23%	8.56%	8.88%	9.21%	9.53%	9.85%	10.17%	10.48%	10.80%
50.00%	8.40%	8.74%	9.07%	9.41%	9.75%	10.08%	10.41%	10.74%	11.07%

SENSITIVITY ANALYSES, EXPECTED ORGANIC GROWTH RATE

Terminal Retention Rate	Terminal ROE								
	10.00%	**10.50%**	**11.00%**	**11.50%**	**12.00%**	**12.50%**	**13.00%**	**13.50%**	**14.00%**
30.00%	3.00%	3.15%	3.30%	3.45%	3.60%	3.75%	3.90%	4.05%	4.20%
35.00%	3.50%	3.68%	3.85%	4.03%	4.20%	4.38%	4.55%	4.73%	4.90%
40.00%	4.00%	4.20%	4.40%	4.60%	4.80%	5.00%	5.20%	5.40%	5.60%
45.00%	4.50%	4.73%	4.95%	5.18%	5.40%	5.63%	5.85%	6.08%	6.30%
50.00%	5.00%	5.25%	5.50%	5.75%	6.00%	6.25%	6.50%	6.75%	7.00%

Terminal Retention Rate	IRR
25.00%	8.72%
30.00%	8.91%
35.00%	9.11%
40.00%	9.32%
45.00%	9.53%

Terminal ROE	COE
9.50%	7.75%
10.00%	8.07%
10.50%	8.38%
11.00%	8.70%
11.50%	9.01%
12.00%	9.32%

M/B Ratio	IRR
1.250	9.07%
1.375	9.15%
1.500	9.24%
1.625	9.32%
1.750	9.40%

Stock Prices Used in DCF Models Data from: 6/29/2006 **Schedule 5**

UE 179

Stock Quotes Provided by MSN Money

Click here to visit MSN Money

Ticker				Last	Previous Close	High	Low	Volume	Change	% Change	52 Wk High	52 Wk Low	Market Cap	EPS	P/E Ratio	# Shares Out
LNT	Alliant Energy Corporation	Chart	News	33.51	33.28	33.58	33.25	209,400	0.23	0.69%	35.17	25.79	3,938,777,309	-0.1	0	117,540,000
AEP	American Electric Power Company,	Chart	News	33.9	33.72	33.9	33.6	606,900	0.18	0.53%	40.8	32.27	13,353,719,101	2.76	12.2	393,915,000
ED	Consolidated Edison, Inc.	Chart	News	43.55	43.24	43.58	43.35	869,900	0.31	0.72%	49.29	41.17	10,703,544,612	2.94	14.7	245,776,000
EDE	The Empire District Electric Company	Chart	News	20.49	20.51	20.64	20.41	37,100	-0.02	-0.10%	25.01	19.25	536,571,624	0.98	20.9	26,187,000
EAS	Energy East Corporation	Chart	News	23.58	23.45	23.61	23.45	204,100	0.13	0.55%	29.37	22.18	3,482,247,229	1.59	14.7	147,678,000
GMP	Green Mountain Power Corp	Chart	News	33.8	33.78	33.82	33.72	2,200	0.02	0.06%	33.9	26.62	177,585,196	2.23	15.1	5,254,000
IDA	IDACORP, Inc.	Chart	News	33.61	33.54	33.85	33.24	101,600	0.07	0.21%	35.2	27.46	1,438,272,756	1.55	21.6	42,793,000
MGEE	MGE Energy, Inc.	Chart	News	29.59	29.69	29.95	29.3	9,825	-0.1	-0.34%	38.75	29.2	605,233,863	1.77	16.8	20,454,000
NST	NSTAR	Chart	News	28.2	28.21	28.29	28.08	99,800	-0.01	-0.04%	31.46	24.9	3,011,985,681	1.81	15.6	106,808,000
OGE	OGE Energy Corp.	Chart	News	33.98	33.84	34.18	33.87	195,500	0.14	0.41%	34.08	24.41	3,084,466,498	2.52	13.4	90,773,000
PGN	Progress Energy, Inc.	Chart	News	42.14	41.86	42.14	41.82	217,700	0.28	0.67%	46	40.19	10,660,155,646	2.6	16.1	252,970,000
SO	The Southern Company	Chart	News	31.85	31.73	31.9	31.67	1,442,400	0.12	0.38%	36.47	30.48	23,634,229,083	2.41	13.2	742,048,000
WEC	Wisconsin Energy Corporation	Chart	News	39.17	38.99	39.23	38.98	141,300	0.18	0.46%	42.35	36.49	4,582,145,556	2.73	14.3	116,981,000
WPS	WPS Resources Corp	Chart	News	48.67	48.48	48.86	48.48	43,300	0.19	0.39%	60	47.39	1,961,692,946	3.86	12.6	40,306,000
XEL	Xcel Energy Inc.	Chart	News	19	18.71	19	18.74	554,700	0.29	1.55%	20.19	17.8	7,704,196,000	1.3	14.4	405,484,000

COMPARATIVE ELECTRIC COMPANIES **UE 179** **Schedule 6 - Capital Structure Analysis**

Percentage of Common Equity in the Capital Structure

Excluding Short-term Debt

COMPANIES	Ticker	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006 Est.	2007	'09 - '11	Ave. '96-'06	Ave. '96-'10	Ave. '99-'10
Alliant Energy	LNT			49.20%	57.40%	50.20%	42.70%	39.20%	50.00%	50.20%	53.00%	52.50%	52.00%	50.00%	49.38%	49.67%	49.72%
Amer. Elec. Power	AEP					44.40%	44.60%	43.10%	38.70%	43.10%	44.90%	41.50%	39.50%	39.50%	42.90%	42.14%	42.14%
Consol. Edison	ED	55.70%	56.80%	58.40%	53.10%	49.10%	49.60%	48.10%	48.00%	51.00%	49.50%	50.50%	50.50%	51.00%	51.80%	51.64%	50.04%
Empire Dist. Elec.	EDE	45.80%	48.90%	45.20%	40.40%	42.40%	42.80%	44.50%	48.00%	48.70%	49.00%	48.50%	47.50%	47.50%	45.84%	46.09%	45.93%
Energy East Corp.	EAS	51.90%	52.80%	53.50%	53.00%	41.80%	38.40%	39.20%	38.50%	40.60%	41.50%	42.00%	42.00%	43.50%	44.84%	44.52%	42.05%
IDACORP, Inc.	IDA	45.10%	46.80%	44.20%	44.80%	45.90%	47.90%	47.90%	46.40%	50.70%	50.00%	50.50%	50.00%	50.50%	47.29%	47.75%	48.46%
MGE Energy	MGEE	58.10%	58.20%	53.30%	55.50%	52.20%	57.80%	54.20%	56.50%	62.60%	60.70%	60.50%	60.50%	61.00%	57.24%	57.78%	58.15%
NSTAR	NST	44.50%	46.50%	50.10%	47.20%	39.40%	39.50%	37.80%	40.20%	40.20%	41.50%	44.50%	47.50%	54.50%	42.85%	44.11%	43.23%
OGE Energy	OGE	52.30%	52.50%	52.70%	47.20%	39.20%	40.50%	39.60%	45.60%	47.40%	50.50%	48.00%	49.50%	53.50%	46.86%	47.58%	46.10%
Progress Energy	PGN	50.20%	53.20%	52.40%	52.50%	47.60%	38.50%	40.40%	43.40%	44.30%	43.00%	44.00%	44.50%	47.00%	46.32%	46.23%	44.52%
Southern Co.	SO	49.70%	43.50%	42.90%	37.80%	50.60%	42.20%	43.40%	43.60%	44.10%	44.30%	44.50%	44.50%	46.00%	44.24%	44.39%	44.10%
Wisconsin Energy	WEC	57.40%	54.40%	51.70%	45.90%	40.50%	37.20%	39.60%	39.60%	43.30%	46.70%	44.00%	47.00%	48.00%	45.48%	45.79%	43.18%
WPS Resources	WPS	56.70%	57.40%	53.80%	43.90%	41.60%	46.30%	45.80%	52.10%	54.40%	58.70%	57.00%	55.00%	52.50%	51.61%	51.94%	50.73%
Xcel Energy Inc.	XEL						32.80%	39.50%	43.80%	44.10%	47.30%	46.00%	49.50%	52.50%	42.25%	44.44%	44.44%
Average		51.58%	51.91%	50.62%	48.23%	44.99%	42.91%	43.02%	45.31%	47.48%	48.61%	48.14%	48.54%	49.79%	47.06%	47.43%	46.63%
Standard Deviation		5.01%	4.88%	4.55%	6.10%	4.55%	6.19%	4.67%	5.31%	6.06%	5.84%	5.61%	5.31%	5.22%	4.19%	4.13%	4.43%
25th Percentile		47.75%	47.85%	48.20%	44.58%	41.60%	38.75%	39.53%	41.00%	43.50%	44.45%	44.13%	45.13%	47.13%	44.39%	44.46%	43.45%
Median		51.90%	52.80%	52.05%	47.20%	44.40%	42.45%	41.75%	44.70%	45.85%	48.15%	47.00%	48.50%	50.25%	46.08%	46.16%	45.23%
75th Percentile		56.20%	55.60%	53.35%	53.03%	49.10%	45.88%	45.48%	48.00%	50.58%	50.38%	50.50%	50.38%	52.50%	48.86%	49.19%	49.41%
Minimum		44.50%	43.50%	42.90%	37.80%	39.20%	32.80%	37.80%	38.50%	40.20%	41.50%	41.50%	39.50%	39.50%	42.25%	42.14%	42.05%
Maximum		58.10%	58.20%	58.40%	57.40%	52.20%	57.80%	54.20%	56.50%	62.60%	60.70%	60.50%	60.50%	61.00%	57.24%	57.78%	58.15%

Source: Value Line ***Most current through:*** ***Jul-06***

Schedule 7

	Line	Symbol	DivYld	Wt'ed M/B M/B	EOY 2005 M/B
Alliant Energy	1	LNT	3.13%	1.57	1.61
Amer. Elec. Power	2	AEP	4.19%	1.44	1.47
Consol. Edison	3	ED	5.24%	1.42	1.45
Empire Dist. Elec.	4	EDE	6.25%	1.36	1.36
Energy East Corp.	5	EAS	4.75%	1.27	1.29
IDACORP, Inc.	6	IDA	3.57%	1.38	1.40
MGE Energy	7	MGEE	4.63%	1.75	1.76
NSTAR	8	NST	3.09%	1.90	1.94
OGE Energy	9	OGE	3.91%	2.20	2.24
Progress Energy	10	PGN	5.65%	1.32	1.34
Southern Co.	11	SO	4.65%	2.17	2.22
Wisconsin Energy	12	WEC	2.25%	1.67	1.71
WPS Resources	13	WPS	4.60%	1.44	1.50
Xcel Energy Inc.	14	XEL	4.47%	1.40	1.42
			DivYld	**M/B**	**M/B**
Average			4.31%	1.59	1.62
Std. Deviation			1.03%	0.30	0.30
Maximum Value			6.25%	2.20	2.24
Minimum Value			2.25%	1.27	1.29
25th Percentile			3.66%	1.38	1.40
Median			4.54%	1.44	1.48
75th Percentile			4.72%	1.73	1.75

Schedule 7

OUTSTANDING SHARES (millions)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	'09-'11
Alliant Energy									77.63	78.98	79.01	89.68	92.30	110.96	115.74	117.10	118.10	119.10	122.10
Amer. Elec. Power											322.02	322.24	338.84	395.02	395.86	393.72	394.00	396.00	400.00
Consol. Edison	228.23	228.33	233.93	234.37	234.91	234.96	234.99	235.49	232.83	213.81	212.03	212.15	213.93	225.84	242.51	246.00	255.00	257.00	263.00
Empire Dist. Elec.	12.67	12.99	13.29	13.57	13.94	15.22	16.44	16.78	17.11	17.37	17.60	19.76	22.57	24.98	25.70	26.08	27.15	28.20	30.00
Energy East Corp.	124.86	126.80	138.88	141.19	143.01	143.01	139.34	135.02	125.89	109.34	117.66	116.72	144.97	146.26	147.12	147.75	147.75	147.75	147.75
IDACORP, Inc.	33.98	33.98	36.19	37.09	37.61	37.61	37.61	37.61	37.61	37.61	37.61	37.63	38.02	38.34	42.22	42.66	43.90	45.20	46.10
MGE Energy	16.02	16.05	16.05	16.08	16.08	16.08	16.08	16.08	16.08	16.16	16.62	17.07	17.57	18.34	20.39	20.45	20.50	20.50	20.50
NSTAR	78.00	84.09	89.53	90.26	91.07	96.01	97.02	97.03	94.37	116.12	106.07	106.07	106.07	106.07	106.55	106.81	106.81	106.81	106.81
OGE Energy	80.60	80.60	80.66	80.69	80.71	80.75	80.76	80.77	80.80	77.86	77.92	77.99	78.50	87.40	90.00	90.60	91.20	91.80	93.50
Progress Energy												218.73	232.43	246.00	247.00	252.00	254.00	256.00	261.00
Southern Co.					657.00	670.00	677.00	685.00	698.63	666.00	682.00	699.00	716.90	734.80	741.80	745.00	750.00	755.00	780.00
Wisconsin Energy	101.04	101.04	103.09	105.32	108.94	110.82	111.68	112.87	115.61	118.90	118.65	115.42	116.03	118.43	116.99	117.00	117.00	117.00	117.00
WPS Resources	22.89	22.89	23.85	23.90	23.90	23.90	23.90	23.90	26.55	26.85	26.85	31.18	32.01	36.91	37.26	40.16	43.30	43.80	45.30
Xcel Energy Inc.												345.02	398.71	398.96	400.46	403.00	406.00	427.00	435.00
Average																			
Std. Deviation																			
Maximum Value																			
Minimum Value																			
25th Percentile																			
Median																			
75th Percentile																			

Schedule 7

BOOK VALUE PER SHARE

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	'09-'11
Alliant Energy									20.69	27.29	25.79	21.39	19.89	21.37	22.13	20.85	21.90	22.95	25.70
Amer. Elec. Power											25.01	25.54	20.85	19.93	21.32	23.08	24.20	25.30	28.25
Consol. Edison	19.73	20.18	20.89	21.63	22.62	23.51	24.37	25.18	25.88	25.31	25.81	26.71	27.68	28.44	29.09	30.05	31.40	32.35	35.20
Empire Dist. Elec.	11.75	12.08	12.29	12.37	12.47	12.69	12.96	13.06	13.43	13.48	13.65	13.58	14.59	15.17	14.76	15.08	15.15	15.60	16.25
Energy East Corp.	10.93	11.08	11.42	11.44	11.64	12.19	12.70	13.36	13.61	12.84	14.59	15.26	16.97	17.59	17.89	18.35	18.95	19.40	21.00
IDACORP, Inc.	17.40	17.06	17.28	17.86	17.91	18.15	18.47	18.93	19.42	20.02	21.82	23.15	23.01	22.54	23.88	24.04	24.95	25.90	28.25
MGE Energy	10.62	10.98	11.24	11.51	11.78	12.01	11.14	11.25	11.34	11.49	12.05	12.67	12.94	14.34	16.59	16.82	17.10	17.55	19.05
NSTAR	8.61	8.96	9.39	9.71	10.06	10.31	10.54	10.98	11.14	13.29	12.65	11.90	12.25	12.84	13.52	14.50	15.25	16.05	18.75
OGE Energy	10.96	11.30	11.18	11.24	11.41	11.61	11.91	12.19	12.91	13.09	13.66	13.34	12.53	13.75	14.28	15.19	15.75	16.40	19.00
Progress Energy												27.45	28.73	30.26	30.90	31.55	32.30	33.05	35.65
Southern Co.					12.46	13.09	13.61	14.08	14.02	13.82	15.67	11.42	12.15	13.13	13.86	14.35	15.15	15.95	18.90
Wisconsin Energy	13.70	14.35	14.97	15.67	16.01	16.89	17.42	16.51	16.46	16.89	17.00	17.81	18.44	19.92	21.31	22.90	24.15	25.45	29.50
WPS Resources	16.26	16.13	17.33	18.18	18.69	19.39	19.56	20.00	19.48	19.97	20.21	22.96	24.45	27.18	29.30	32.47	35.55	37.40	42.90
Xcel Energy Inc.												17.95	11.70	12.95	12.99	13.37	13.95	14.35	15.75
Average	13.33	13.57	14.00	14.40	14.51	14.98	15.27	15.55	16.22	17.04	18.16	18.65	18.30	19.24	20.13	20.90	21.84	22.69	25.30
Std. Deviation	3.49	3.41	3.60	3.85	3.88	4.06	4.26	4.34	4.41	5.15	5.08	5.58	5.74	5.84	6.07	6.44	6.93	7.21	8.04
Maximum Value	19.73	20.18	20.89	21.63	22.62	23.51	24.37	25.18	25.88	27.29	25.81	27.45	28.73	30.26	30.90	32.47	35.55	37.40	42.90
Minimum Value	8.61	8.96	9.39	9.71	10.06	10.31	10.54	10.98	11.14	11.49	12.05	11.42	11.70	12.84	12.99	13.37	13.95	14.35	15.75
25th Percentile	10.93	11.08	11.24	11.44	11.68	12.06	12.11	12.41	13.17	13.19	13.66	13.40	12.63	13.90	14.40	15.11	15.38	16.14	18.93
Median	11.75	12.08	12.29	12.37	12.47	12.89	13.29	13.72	14.02	13.82	16.34	17.88	17.71	18.76	19.60	19.60	20.43	21.18	23.35
75th Percentile	16.26	16.13	17.28	17.86	17.44	17.84	18.21	18.33	19.45	20.00	22.62	23.10	22.47	22.25	23.44	23.80	24.76	25.79	29.19

Schedule 7

DIVIDENDS DECLARED PER SHARE

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	'09-'11
Alliant Energy									2.00	2.00	2.00	2.00	2.00	1.00	1.02	1.05	1.15	1.25	1.49
Amer. Elec. Power											2.40	2.40	2.40	1.65	1.40	1.42	1.48	1.60	1.90
Consol. Edison	1.82	1.86	1.90	1.94	2.00	2.04	2.08	2.10	2.12	2.14	2.18	2.20	2.22	2.24	2.26	2.28	2.30	2.32	2.38
Empire Dist. Elec.	1.18	1.22	1.26	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28
Energy East Corp.	1.03	1.05	1.07	1.09	1.00	0.70	0.70	0.70	0.78	0.84	0.88	0.92	0.96	1.00	1.06	1.12	1.18	1.24	1.40
IDACORP, Inc.	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.70	1.20	1.20	1.20	1.20	1.20
MGE Energy	1.15	1.17	1.19	1.19	1.25	1.26	1.28	1.29	1.30	1.31	1.32	1.33	1.34	1.35	1.36	1.37	1.38	1.39	1.44
NSTAR	0.77	0.80	0.83	0.86	0.89	0.92	0.94	0.94	0.95	0.98	1.01	1.04	1.07	1.09	1.13	0.87	1.21	1.26	1.45
OGE Energy	1.26	1.30	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.36	1.50
Progress Energy												2.14	2.18	2.26	2.32	2.38	2.44	2.50	2.62
Southern Co.							1.26	1.30	1.34	1.34	1.34	1.34	1.36	1.39	1.42	1.48	1.53	1.59	1.80
Wisconsin Energy	1.16	1.23	1.29	1.34	1.40	1.46	1.51	1.54	1.56	1.56	1.37	0.80	0.80	0.80	0.83	0.88	0.92	0.96	1.10
WPS Resources	1.64	1.68	1.72	1.76	1.80	1.84	1.88	1.92	1.96	2.00	2.04	2.08	2.12	2.16	2.20	2.24	2.28	2.32	2.44
Xcel Energy Inc.												1.50	1.13	0.75	0.81	0.85	0.88	0.93	1.10
Average	1.32	1.35	1.38	1.41	1.42	1.41	1.41	1.43	1.50	1.51	1.58	1.59	1.58	1.43	1.40	1.41	1.47	1.51	1.65
Std. Deviation	0.35	0.35	0.35	0.35	0.36	0.42	0.41	0.42	0.42	0.41	0.47	0.50	0.51	0.49	0.49	0.50	0.49	0.49	0.49
Maximum Value	1.86	1.86	1.90	1.94	2.00	2.04	2.08	2.10	2.12	2.14	2.40	2.40	2.40	2.26	2.32	2.38	2.44	2.50	2.62
Minimum Value	0.77	0.80	0.83	0.86	0.89	0.70	0.70	0.70	0.78	0.84	0.88	0.80	0.80	0.75	0.81	0.85	0.88	0.93	1.10
25th Percentile	1.15	1.17	1.19	1.19	1.25	1.26	1.27	1.28	1.29	1.30	1.31	1.29	1.17	1.02	1.08	1.07	1.19	1.24	1.31
Median	1.18	1.23	1.29	1.33	1.33	1.33	1.31	1.32	1.34	1.34	1.36	1.42	1.35	1.34	1.31	1.31	1.31	1.32	1.47
75th Percentile	1.64	1.68	1.72	1.76	1.80	1.84	1.77	1.78	1.91	1.93	2.01	2.06	2.09	1.69	1.42	1.47	1.52	1.60	1.88

Schedule 7

EARNINGS PER SHARE

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	'09-'11
Alliant Energy									1.26	2.19	2.47	2.42	1.18	1.57	1.85	2.03	2.15	2.20	2.30
Amer. Elec. Power											1.04	3.27	2.86	2.53	2.61	2.64	2.60	2.65	3.00
Consol. Edison	2.34	2.32	2.46	2.66	2.98	2.93	2.93	2.95	3.04	3.13	2.74	3.21	3.13	2.83	2.32	2.99	3.05	3.15	3.25
Empire Dist. Elec.	1.28	1.43	1.26	1.16	1.32	1.18	1.23	1.29	1.53	1.13	1.35	0.59	1.19	1.29	0.86	0.92	1.05	1.40	1.50
Energy East Corp.	1.24	1.18	1.20	1.04	1.19	1.25	1.26	1.29	1.51	1.91	2.07	2.00	1.50	1.43	1.62	1.74	1.75	1.65	2.00
IDACORP, Inc.	1.91	1.56	1.55	1.97	1.80	2.10	2.21	2.32	2.37	2.43	3.50	3.35	1.63	0.96	1.90	1.75	1.85	1.90	2.00
MGE Energy	1.36	1.52	1.45	1.51	1.53	1.49	0.82	1.40	1.38	1.48	1.67	1.62	1.69	1.71	1.77	1.57	2.00	2.10	2.45
NSTAR	0.80	0.98	1.05	1.14	1.21	1.04	1.31	1.36	1.38	1.39	1.60	1.64	1.69	1.74	1.76	1.83	1.90	2.05	2.25
OGE Energy	1.69	1.64	1.21	1.39	1.51	1.52	1.62	1.61	2.04	1.94	1.89	1.29	1.43	1.73	1.78	1.83	1.80	1.90	2.25
Progress Energy												3.43	3.84	3.41	3.10	3.33	3.25	3.35	3.50
Southern Co.					1.52	1.66	1.68	1.58	1.73	1.83	2.01	1.61	1.85	1.97	2.06	2.14	2.20	2.30	2.75
Wisconsin Energy	1.85	1.87	1.67	1.81	1.67	2.13	1.97	0.54	1.65	1.88	1.08	1.84	2.32	2.26	1.85	2.56	2.50	2.60	3.00
WPS Resources	2.00	2.23	2.35	2.47	2.21	2.32	2.00	2.13	1.76	2.24	2.43	2.74	2.74	2.76	4.07	4.09	3.95	4.05	4.25
Xcel Energy Inc.												2.27	0.42	1.23	1.27	1.20	1.25	1.40	1.75
Average	1.61	1.64	1.58	1.68	1.69	1.76	1.70	1.65	1.79	1.96	1.99	2.23	1.96	1.96	2.06	2.19	2.24	2.34	2.59
Std. Deviation	0.45	0.42	0.48	0.55	0.51	0.56	0.57	0.63	0.50	0.52	0.69	0.84	0.88	0.68	0.76	0.83	0.75	0.73	0.72
Maximum Value	2.34	2.32	2.46	2.66	2.98	2.93	2.93	2.95	3.04	3.13	3.50	3.43	3.84	3.41	4.07	4.09	3.95	4.05	4.25
Minimum Value	0.80	0.98	1.05	1.04	1.19	1.04	0.82	0.54	1.26	1.13	1.04	0.59	0.42	0.96	0.86	0.92	1.05	1.40	1.50
25th Percentile	1.28	1.43	1.21	1.16	1.37	1.31	1.27	1.31	1.45	1.66	1.54	1.63	1.45	1.47	1.76	1.74	1.81	1.90	2.06
Median	1.69	1.56	1.45	1.51	1.53	1.59	1.65	1.49	1.65	1.91	1.95	2.14	1.69	1.74	1.85	1.93	2.08	2.15	2.38
75th Percentile	1.91	1.87	1.67	1.97	1.77	2.12	1.99	2.00	1.90	2.22	2.44	3.09	2.64	2.46	2.26	2.62	2.58	2.64	3.00

Schedule 7

VALUE LINE'S REPORTED RETURN ON EQUITY (ROE)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	'09-'11
Alliant Energy			6.0%	8.0%	9.6%	9.8%	5.8%	6.7%	8.2%	9.5%	10.0%	9.5%	9.0%
Amer. Elec. Power						12.8%	13.7%	12.4%	12.2%	11.3%	10.5%	10.5%	10.5%
Consol. Edison	11.7%	11.7%	11.8%	12.9%	10.7%	12.0%	11.3%	9.8%	7.8%	10.0%	9.5%	9.5%	9.0%
Empire Dist. Elec.	9.2%	9.8%	11.3%	8.8%	9.8%	3.9%	7.8%	7.8%	5.8%	6.0%	6.5%	8.5%	9.5%
Energy East Corp.	10.1%	9.7%	11.3%	15.8%	13.8%	13.1%	8.0%	8.1%	9.0%	9.5%	9.5%	8.5%	9.5%
IDACORP, Inc.	11.9%	12.2%	12.2%	12.1%	16.0%	14.4%	7.0%	4.2%	7.2%	6.2%	7.5%	7.0%	7.0%
MGE Energy	7.4%	12.4%	12.2%	12.8%	13.7%	12.6%	12.8%	11.6%	10.0%	9.3%	11.0%	12.0%	12.0%
NSTAR	12.3%	12.3%	12.6%	9.1%	13.0%	13.7%	13.8%	13.7%	13.1%	12.5%	12.5%	13.0%	12.5%
OGE Energy	13.6%	13.2%	15.8%	14.8%	13.8%	9.7%	11.4%	11.8%	12.3%	12.1%	11.5%	11.5%	12.5%
Progress Energy						11.5%	12.1%	10.9%	9.9%	10.5%	10.0%	10.0%	10.0%
Southern Co.	12.2%	11.2%	12.2%	13.6%	12.3%	14.0%	15.1%	14.8%	14.9%	15.0%	14.5%	14.5%	14.5%
Wisconsin Energy	11.2%	3.3%	9.9%	10.9%	6.5%	10.6%	12.6%	11.4%	8.8%	11.3%	10.5%	10.5%	10.0%
WPS Resources	10.1%	10.6%	9.0%	11.1%	11.9%	10.8%	11.7%	9.1%	14.0%	11.8%	10.5%	11.0%	10.0%
Xcel Energy Inc.						12.6%	3.7%	9.8%	10.0%	9.2%	10.0%	9.5%	10.5%
Average	10.97%	10.64%	11.30%	11.81%	11.92%	11.54%	10.49%	10.15%	10.23%	10.30%	10.29%	10.39%	10.46%
Std. Deviation	1.70%	2.68%	2.33%	2.38%	2.50%	2.56%	3.29%	2.73%	2.61%	2.29%	1.86%	1.87%	1.81%
Maximum Value	13.60%	13.20%	15.80%	15.80%	16.00%	14.40%	15.10%	14.80%	14.90%	15.00%	14.50%	14.50%	14.50%
Minimum Value	7.40%	3.30%	6.00%	8.00%	6.50%	3.90%	3.70%	4.20%	5.80%	6.00%	6.50%	7.00%	7.00%
25th Percentile	10.10%	10.00%	10.60%	10.00%	10.25%	10.65%	7.85%	8.35%	8.35%	9.35%	9.63%	9.50%	9.50%
Median	11.45%	11.45%	11.80%	12.10%	12.30%	12.30%	11.55%	10.35%	9.95%	10.25%	10.25%	10.25%	10.00%
75th Percentile	12.13%	12.28%	12.20%	13.25%	13.75%	13.03%	12.75%	11.75%	12.28%	11.68%	10.88%	11.38%	11.63%

Analyst Earnings Growth Expectations
UE 179

Schedule 8

Electric Companies		Kiplinger's		Firstcall		Zack's	Reuters	Value Line	Average	Median	Minimum	Maximum
		Last 5 years	Next 5 years	Last 5 years	Next 5 years	Next 5 years	Next 5 years	Next 5 years				
Alliant Energy	LNT	N/A	5.00%	2.80%	2.50%	4.00%	4.00%	6.50%	4.40%	4.00%	2.50%	6.50%
Amer. Elec. Power	AEP	N/A	3.00%	-6.40%	3.00%	6.00%	3.57%	2.00%	3.51%	3.00%	2.00%	6.00%
Consol. Edison	ED	-3.00%	4.00%	-3.00%	4.00%	3.90%	3.67%	1.50%	3.41%	3.90%	1.50%	4.00%
Empire Dist. Elec.	EDE	-1.00%	3.00%	2.60%	3.00%	N/A	2.50%	5.00%	3.38%	3.00%	2.50%	5.00%
Energy East Corp.	EAS	-3.00%	4.00%	-3.10%	4.00%	4.50%	4.33%	4.50%	4.27%	4.33%	4.00%	4.50%
IDACORP, Inc.	IDA	-17.00%	5.00%	-7.40%	5.00%	4.70%	4.75%	4.50%	4.79%	4.75%	4.50%	5.00%
MGE Energy	MGEE	0.00%	N/A	N/A	N/A	N/A	N/A	6.00%	6.00%	6.00%	6.00%	6.00%
NSTAR	NST	N/A	5.00%	2.30%	5.00%	5.00%	5.00%	2.50%	4.50%	5.00%	2.50%	5.00%
OGE Energy	OGE	10.00%	3.00%	7.40%	3.00%	3.00%	3.00%	5.50%	3.50%	3.00%	3.00%	5.50%
Progress Energy	PGN	0.00%	4.00%	-2.90%	3.50%	3.60%	2.87%	N/A	3.49%	3.55%	2.87%	4.00%
Southern Co.	SO	2.00%	5.00%	6.40%	5.00%	4.80%	4.70%	4.00%	4.70%	4.80%	4.00%	5.00%
Wisconsin Energy	WEC	13.00%	8.00%	6.10%	8.00%	7.00%	7.00%	4.00%	6.80%	7.00%	4.00%	8.00%
WPS Resources	WPS	10.00%	5.00%	12.10%	5.00%	4.50%	4.50%	5.00%	4.80%	5.00%	4.50%	5.00%
Xcel Energy Inc.	XEL	N/A	4.00%	-14.30%	4.00%	4.50%	4.29%	7.50%	4.86%	4.29%	4.00%	7.50%
AVERAGE		**1.10%**	**4.46%**	**0.20%**	**4.23%**	**4.63%**	**4.17%**	**4.50%**	**4.46%**	**4.40%**	**3.42%**	**5.50%**
MEDIAN		**0.00%**	**4.00%**	**2.30%**	**4.00%**	**4.50%**	**4.29%**	**4.50%**	**4.45%**	**4.31%**	**3.50%**	**5.00%**
MIN		**-17.00%**	**3.00%**	**-14.30%**	**2.50%**	**3.00%**	**2.50%**	**1.50%**	**3.38%**	**3.00%**	**1.50%**	**4.00%**
MAX		**13.00%**	**8.00%**	**12.10%**	**8.00%**	**7.00%**	**7.00%**	**7.50%**	**6.80%**	**7.00%**	**6.00%**	**8.00%**

CASE: UE 179
WITNESS: Steve W Chriss

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Direct Testimony

July 12, 2006

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

A. My name is Steve W Chriss. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551. I am employed by the Public Utility Commission of Oregon (OPUC or the Commission) as a Senior Utility Analyst in the Electric and Natural Gas Division.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. Exhibit Staff/901 is my Witness Qualification Statement. I have previously testified before the Commission as staff's lead witness in UX 29 and in a supporting role in all three phases of UM 1129.

Q. DID YOU PREPARE EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/902, consisting of eight pages, Exhibit Staff/903, consisting of three pages, Exhibit Staff/904, consisting of two pages, Exhibit Staff/905, consisting of four pages, and Exhibit Staff/906, consisting of one page.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I address rate spread issues, including PacifiCorp's use of the Rate Mitigation Adjustment (RMA) to mitigate the rate impacts for several rate schedules.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

I. Relationship of Marginal Costs to Rates

II. Changes in Rate Schedules

III. Rate Implications of Revenue Requirement Increases

IV. The Rate Mitigation Adjustment (RMA) and Revenue Requirement Increase Implications

V. The RMA Equity Issue

VI. Staff Proposal to Address RMA Concerns

VII. Phasing Out the RMA

Q. PLEASE PROVIDE A SUMMARY OF STAFF'S PROPOSED NET RATE CHANGES FOR EACH RATE SCHEDULE.

A. Table A shows the net rate changes for each rate schedule using staff's revenue requirement and RMA proposals.

Table A. Estimated Net Rates Under Staff's Proposal.

Schedule	No.	Net Rates ($000)	Net Rates (%)
Residential	4	9,953	2.35
General Service < 31 kW	23	2,441	2.89
General Service 31 –-200 kW	28	(6,319)	-5.26
General Service 201— 999 kW	30	(1,626)	-2.34
Lg. General Service ≥ 1,000 kW	48	3,715	2.89
Partial Req. Service ≥ 1,000 kW	47	260	2.89
Agricultural Pumping Service	41	1,192	15.00
Outdoor Area Lighting Service	15	(97)	-6.73
Street Lighting Service	50	(87)	-6.96
Street Lighting Service HPS	51	(184)	-6.71
Street Lighting Service	52	(14)	-6.15
Street Lighting Service	53	(41)	-7.53
Recreational Field Lighting	54	(4)	-5.05
Overall Net Increase		**12,311**	**1.44**

Source: Staff/905, Chriss/3

I. Relationship of Marginal Costs to Rates

Q. PLEASE DEFINE "RECONCILIATION."

A. Reconciliation is the process of comparing marginal cost to target revenues for different customer classes. Historically, reconciliation has been performed in rate spread decisions to allocate changes in overall revenue requirement to move different customer classes closer to recovering the same share of marginal cost. *See* Appendix B of Order 98-374.

Q. WHICH MARGINAL COSTS FILED BY PACIFICORP ARE APPROPRIATE RECONCILIATION COMPARATORS TO THE COMPANY'S TARGET REVENUE REQUIREMENT?

A. The twenty year full marginal costs are the appropriate comparators. This is because the twenty year costs include the costs of additional facilities that would not be built in a short-term case.

Q. ON WHAT BASIS SHOULD RECONCILIATION BE PERFORMED?

A. Reconciliation should be performed on a functionalized basis. For example, comparisons across rate schedules should be made at the level of generation, transmission, distribution, and billing marginal costs and target revenues. This methodology is consistent with Commission Order 98-374.

Q. ARE PACIFICORP'S COSTS RECONCILED IN A MANNER CONSISTENT WITH ORDER 98-374?

A. Yes. For each function, the ratio of target revenue requirement to marginal costs is equal. As a result, the *base* rate for each rate schedule is recovering the same share of marginal cost for each function.

II. Changes in Rate Schedules

Q. HAS PACIFICORP PROPOSED ANY MAJOR CHANGES TO ITS RATE DESIGN?

A. No. PacifiCorp witness Griffith states "The basic structure of the Company's current tariffs…as first approved in UE 116, is proposed to remain in effect." *See* PPL/1100, Griffith/6.

Q. ARE THE RESULTS OF ANALYSIS OF THE COMPANY'S RATE DESIGN MODELS CONSISTENT WITH MR. GRIFFITH'S STATEMENT?

A. Yes. For the most part, changes in prices are tied directly to the percentage increase in a rate schedule's unbundled revenue requirement.

Q. PLEASE EXPLAIN.

A. For example, if the energy revenue requirement for residential customers increased 14 percent, proposed energy charges on the tariff are equal to the previous charge increased by 14 percent.

Q. DO ALL CHARGES CHANGE IN THIS MANNER?

A. No. For example, the demand charge for three-phase residential customer was not changed in PacifiCorp's proposed rates. Additionally, for some rate schedules, the company has catch-all charges that capture revenue requirement monies that are not collected by any other charge.

Q. WHAT CHARGE GENERALLY ACTS AS THE CATCH-ALL CHARGE?

A. The distribution energy charge generally acts as the catch-all charge.

Q. WHY IS A CATCH-ALL CHARGE IMPORTANT?

A. The primary reason a catch-all charge is important is that it may be, as a matter of public policy, not reasonable to charge a customer the full marginal cost for a rate component.

The best example of this is the treatment of the residential basic charge. The basic charge, in theory, recovers commitment and billing costs incurred by the company, such as billing, metering and meter reading, and other fixed costs. The commitment and billing one-year marginal cost for residential customers is $11.18 and the long-term full marginal cost is $24.49. *See* PPL/1007, Table 2.2. PacifiCorp's previous residential customer charge was $7.00 and their proposed customer charge is $8.00. Because the basic charge does not vary with usage, customers must pay this amount every month. An increase in the charge is a guaranteed increase in the bill, because the only way to avoid or reduce the charge is to stop service, which, as a policy matter, is not an option the company or the Commission should endorse. As a result, the remaining revenues need to be collected elsewhere.

For Schedule 4, the remaining revenues are collected in the distribution energy charge. The distribution energy charge is not calculated by multiplying the previous charge by the percentage increase in revenue requirement. However, even with the basic charge for the proposed rate design kept at $7.00, the distribution energy charge increases. This is due to the general increase in revenue requirement, leaving more costs to be caught.

Q. PLEASE DISCUSS THE OTHER CHARGES IN SCHEDULE 4.

A. As I previously stated, PacifiCorp has proposed an increase in the basic charge of one dollar, to $8.00 per customer each month. The corresponding distribution energy charge is 3.32 cents/kWh.

Q. DOES STAFF BELIEVE THAT THIS INCREASE IS REASONABLE?

A. Yes. However, this answer is limited only to the context of PacifiCorp's filed increase. A change in the level of revenue requirement increase will require a recalculation of rates in order to determine the appropriate change in basic charge.

Excluding the possibility of change from the analysis, the increase better reflects the marginal cost of providing service to customers.

Q. DOES YOUR ANALYSIS SHOW PACIFICORP'S BASIC CHARGE TO BE COMPARABLE TO OTHER UTILITIES?

A. No. An analysis of investor-owned electric utilities and large municipally-owned electric utilities operating in the Pacific Northwest shows PacifiCorp to have the second highest basic charge in the region, even before the proposed increase. See Table II-1.

Table II-1. Comparison of Basic Charges.

Company	Jurisdiction	Schedule	Basic Charge
Avista	Washington	1	$5.50
	Idaho	1	$4.00
Clark County PUD	Washington		$6.40
EWEB	Oregon	R6	$6.50
Idaho Power	Oregon	1	$5.25
	Idaho	1	$4.00
PGE	Oregon	7	$10.00
Puget Sound Energy	Washington	7	$5.75
Seattle City Light	Washington	RSS/RSC	$3.00 (est.)[1]
PacifiCorp (current)	Oregon	4	$7.00
PacifiCorp (proposed)	Oregon	4	$8.00

Q. EVEN THOUGH PACIFICORP'S BASIC CHARGE IS AMONG THE HIGHEST OF THE UTILITIES YOU SURVEYED, DO YOU STILL SUPPORT INCREASING THE BASIC CHARGE?

A. Yes. OPUC policy is to have rates reflect costs while tempering such a policy by considering rate impacts on customers within the class. Because the basic charge is still well below costs, including short run costs, an increase in the charge is justified.

Q. HOW ARE THE OTHER SCHEDULE 4 CHARGES CALCULATED?

A. The other Schedule 4 charges are calculated simply by multiplying the previous charges by their appropriate rates of escalation.

[1] Rate is 9.71 cents/day.

III. Rate Implications of Revenue Requirement Increases

Q. PLEASE DESCRIBE YOUR ANALYSIS OF THE ESTIMATED RATE IMPLICATIONS OF INCREASES TO THE REVENUE REQUIREMENT.

A. I analyzed the estimated rate implications of increases to the revenue requirement at four levels of increase. The first level of increase is $25 million. The second level of increase is $50 million. The third level of increase is $75. Finally, the fourth level of increase, $110 million, is the increase requested by PacifiCorp.

Q. WHAT IS THE INTENT OF THIS ANALYSIS?

A. The intent of this analysis is to provide the Commission with points of reference along the scale of potential revenue requirement increases. However, analysis of these price levels does not constitute an endorsement of any revenue requirement level other than staff's recommended revenue requirement.

Revenue Requirement Increase of $25 Million

Q. WHAT ARE THE ESTIMATED RATE IMPACTS OF A REVENUE REQUIREMENT INCREASE OF $25 MILLION?

A. The overall estimated net impact of a $25 million increase is an increase of 2.95 percent. The changes in individual rate schedules vary widely, from a reduction of 5.49 percent to an increase of 37.29 percent. *See* Table III-1. The details of the calculations can be found at Staff/902, Chriss/1.

Q. DO THESE ESTIMATES TAKE THE RMA INTO ACCOUNT?

A. No. These estimates are the net rate increases in the absence of the RMA. I will discuss the RMA and dollars transferred between classes later in my testimony. That discussion will also include the calculation of net rates, including the RMA, for the four levels of revenue requirement increase.

Q. LOOKING AT TABLE III-1, WHY ARE THE NET RATE INCREASES FOR SCHEDULE 23 AND 41 SO MUCH HIGHER THAN THOSE FOR OTHER SCHEDULES?

A. The increases for these rate schedules are higher because the baselines to which the new net rates were compared are PacifiCorp's current rates. The increases reflect a move from current rates with the current RMA in place, which recover a relatively low level of respective marginal costs, to a strict application of traditional rate spread policies. The increase in base rates, which is before the adders (including the RMA) are factored in, for Schedule 23 is 2.95 percent. The increase in base rates for Schedule 41 is 3.46 percent.

Table III-1. Estimated Rate Impacts of a Revenue Requirement Increase of $25 Million (RMA Excluded.)

Schedule	No.	Net Rates ($000)	Net Rates (%)
Residential	4	10,213	2.41
General Service < 31 kW	23	9,118	10.79
General Service 31 –-200 kW	28	(4,672)	-3.89
General Service 201— 999 kW	30	(396)	-0.57
Lg. General Service ≥ 1,000 kW	48	7,686	5.98
Partial Req. Service ≥ 1,000 kW	47	548	6.08
Agricultural Pumping Service	41	2,962	37.29
Outdoor Area Lighting Service	15	(68)	-4.66
Street Lighting Service	50	(62)	-4.90
Street Lighting Service HPS	51	(127)	-4.64
Street Lighting Service	52	(9)	-4.09
Street Lighting Service	53	(30)	-5.49
Recreational Field Lighting	54	(2)	-2.95
Overall Net Increase		**25,116**	**2.95**
Source: Staff/902, Chriss/1			

Table III-2. Estimated Rate Impacts of a Revenue Requirement Increase of $50 Million (RMA Excluded.)

Schedule	No.	Net Rates ($000)	Net Rates (%)
Residential	4	20,425	4.81
General Service < 31 kW	23	11,773	13.94
General Service 31 –-200 kW	28	(1,453)	-1.21
General Service 201— 999 kW	30	2,006	2.89
Lg. General Service ≥ 1,000 kW	48	13,190	10.26
Partial Req. Service ≥ 1,000 kW	47	950	10.54
Agricultural Pumping Service	41	3,324	41.85
Outdoor Area Lighting Service	15	(9)	-0.62
Street Lighting Service	50	(11)	-0.88
Street Lighting Service HPS	51	(17)	-0.62
Street Lighting Service	52	(0)	-0.06
Street Lighting Service	53	(8)	-1.50
Recreational Field Lighting	54	1	1.13
Overall Net Increase		**50,126**	**5.88**
Source: Staff/902, Chriss/3			

Revenue Requirement Increase of $50 Million

Q. WHAT ARE THE ESTIMATED RATE IMPACTS OF A REVENUE REQUIREMENT INCREASE OF $50 MILLION?

A. The overall estimated net impact of a $50 million increase is an increase of 5.88 percent. The changes in individual rate schedules vary widely, from a reduction of 1.50 percent to an increase of 41.85 percent. *See* Table III-2. The details of the calculations can be found at Staff/902, Chriss/3.

The increases for Schedules 23 and 41 are similar to the increases for those Schedules under a revenue requirement increase of $25 million.

Revenue Requirement Increase of $75 Million

Q. WHAT ARE THE ESTIMATED RATE IMPACTS OF A REVENUE REQUIREMENT INCREASE OF $75 MILLION?

A. The overall estimated net impact of a $75 million increase is an increase of 8.82 percent. The changes in individual rate schedules vary, and for the first time all schedules see an increase in net rates. Changes range from a 1.47 percent to 46.40 percent. *See* Table III-3. The details of the calculations can be found at Staff/902, Chriss/5.

The increases for Schedules 23 and 41 are similar to the increases for those Schedules under previous revenue requirement increases.

Table III-3. Estimated Rate Impacts of a Revenue Requirement Increase of $75 Million (RMA Excluded.)

Schedule	No.	Net Rates ($000)	Net Rates (%)
Residential	4	30,638	7.22
General Service < 31 kW	23	14,429	17.08
General Service 31 –-200 kW	28	1,765	1.47
General Service 201— 999 kW	30	4,408	6.36
Lg. General Service ≥ 1,000 kW	48	18,695	14.54
Partial Req. Service ≥ 1,000 kW	47	1,352	15.00
Agricultural Pumping Service	41	3,686	46.40
Outdoor Area Lighting Service	15	49	3.41
Street Lighting Service	50	39	3.13
Street Lighting Service HPS	51	94	3.41
Street Lighting Service	52	9	3.96
Street Lighting Service	53	14	2.48
Recreational Field Lighting	54	4	5.22
Overall Net Increase		**75,136**	**8.82**

Source: Staff/902, Chriss/5

Revenue Requirement Increase of $110 Million

Q. WHAT ARE THE ESTIMATED RATE IMPACTS OF A REVENUE REQUIREMENT INCREASE OF $110 MILLION?

A. The overall estimated net impact of a $110 million increase is an increase of 12.92 percent. The changes in individual rate schedules vary from 5.22 percent to 52.79 percent. *See* Table III-4. The details of the calculations can be found at Staff/902, Chriss/7.

The increases for Schedules 23 and 41 are similar to the increases for those Schedules under previous revenue requirement increases.

Table III-4. Estimated Rate Impacts of a Revenue Requirement Increase of $110 Million (RMA Excluded.)

Schedule	No.	Net Rates ($000)	Net Rates (%)
Residential	4	44,936	10.59
General Service < 31 kW	23	18,146	21.48
General Service 31 –-200 kW	28	6,270	5.22
General Service 201— 999 kW	30	7,711	11.21
Lg. General Service ≥ 1,000 kW	48	26,401	20.53
Partial Req. Service ≥ 1,000 kW	47	1,914	21.25
Agricultural Pumping Service	41	4,193	52.79
Outdoor Area Lighting Service	15	131	9.07
Street Lighting Service	50	110	8.76
Street Lighting Service HPS	51	248	9.04
Street Lighting Service	52	21	9.59
Street Lighting Service	53	44	8.06
Recreational Field Lighting	54	8	10.94
Overall Net Increase		**110,150**	**12.92**

Source: Staff/902, Chriss/7

IV. The Rate Mitigation Adjustment (RMA) and Revenue Requirement Increase Implications

Q. WHAT IS THE RMA DESIGNED TO DO?

A. The RMA, PacifiCorp Schedule 299, is designed to "mitigate the impacts of changes in the functionalized revenue requirement on net prices across rate schedules." *See* PPL/1100, Griffith/4. More simply, when the net rate increase for a rate schedule exceeds a capped value, the excess revenue requirement is paid via allocations to other rate schedules. Essentially, rate schedules that do not exceed the capped value subsidize those that do.

Q. WHAT CAP VALUE DOES PACIFICORP PROPOSE?

A. PacifiCorp proposes a cap for each rate schedule of 1.5 times the overall net price increase. This proposal is consistent with the cap approved by the Commission in UE 170.

Q. WHAT IS THE BASIS FOR THE LEVEL OF THE CAP?

A. The cap is set arbitrarily. *See* Staff/903, Chriss/1. The company believes that 1.5 times the overall net price increase balances appropriate price signals with past Commission decisions to mitigate rate impacts. *See* PPL/1100, Griffith/4.

Q. HOW DOES PACIFICORP PROPOSE TO IMPLEMENT THE RMA?

A. PacifiCorp's filing implements RMA payments on a per kilowatt-hour basis to General Service Schedule 23/723, Large General Service Schedule 48/748, and Agricultural Pumping Service Schedule 41/741. Additionally, partial requirements customers on Schedule 47/747 are slated to receive RMA payments. *See* PPL/1101, Schedule 299.

Q. WHICH SCHEDULES PAY IN TO THE RMA?

A. Two General Service Schedules, 28 and 30, pay in to the RMA. On a per kilowatt-hour basis, Schedule 28's payment, as filed by PacifiCorp, is about three times higher than that of Schedule 30. *See* PPL/1101, Schedule 299.

Q. HOW DID PACIFICORP DETERMINE WHICH SCHEDULES WOULD PAY IN TO THE RMA?

A. This determination is also arbitrary, though the company has proposed to limit the flows of RMA dollars to the Commercial & Industrial class. Exclusion of residential customers was determined as part of a stipulation in UE 170. *See* Staff/903, Chriss/2.

Q. ARE ANY RATE SCHEDULES IN THE REVENUE REQUIREMENT INCREASE EXAMPLES PROVIDED IN TABLES III-1 THROUGH III-4 SUBJECT TO THE RMA?

A. Yes. There are RMA implications at all of the levels of revenue requirement increase in Tables III-1 through III-4. Tables IV-1 through IV-4 illustrate the RMA implications for schedules with increases that exceed the cap at PacifiCorp's proposed cap of 1.5 times the overall net price increase.

Q. DO TABLES IV-1 THROUGH IV-4 SHOW THE IMPLICATIONS OF THE ESTIMATED RMA IMPACTS?

A. No. I will address the implications of the RMA impacts in Section V, which discusses staff's proposal to address RMA equity concerns.

Table IV-1. Estimated RMA Impacts of a Revenue Requirement Increase of $25 Million, with RMA at 1.5X.

Schedule	No.	RMA ($000)	Net Rates ($000)	Net Rates (%)
General Service < 31 kW	23	(5,384)	3,734	4.42
Lg. General Service ≥ 1,000 kW	48	(2,002)	5,684	4.42
Partial Req. Service ≥ 1,000 kW	47	(150)	398	4.42
Agricultural Pumping Service	41	(2,611)	351	4.42
Overall Net Increase		**(10,146)**	**25,116**	**2.95**

Source: Staff/902, Chriss/2

Table IV-2. Estimated RMA Impacts of a Revenue Requirement Increase of $50 Million, with RMA at 1.5X.

Schedule	No.	RMA ($000)	Net Rates ($000)	Net Rates (%)
General Service < 31 kW	23	(4,320)	7,453	8.82
Lg. General Service ≥ 1,000 kW	48	(1,847)	11,343	8.82
Partial Req. Service ≥ 1,000 kW	47	(155)	795	8.82
Agricultural Pumping Service	41	(2,623)	701	8.82
Overall Net Increase		**(8,946)**	**50,126**	**5.88**

Source: Staff/902, Chriss/4

Table IV-3. Estimated RMA Impacts of a Revenue Requirement Increase of $75 Million, with RMA at 1.5X.

Schedule	No.	RMA ($000)	Net Rates ($000)	Net Rates (%)
General Service < 31 kW	23	(3,257)	11,172	13.22
Lg. General Service ≥ 1,000 kW	48	(2,002)	17,003	13.22
Partial Req. Service ≥ 1,000 kW	47	(150)	1,352	13.22
Agricultural Pumping Service	41	(2,611)	1,051	13.22
Overall Net Increase		**(7,745)**	**75,136**	**8.82**

Source: Staff/902, Chriss/6

Table IV-4. Estimated RMA Impacts of a Revenue Requirement Increase of $110 Million, with RMA at 1.5X.

Schedule	No.	RMA ($000)	Net Rates ($000)	Net Rates (%)
General Service < 31 kW	23	(2,194)	14,890	17.63
Lg. General Service ≥ 1,000 kW	48	(1,537)	22,663	17.63
Partial Req. Service ≥ 1,000 kW	47	(165)	1,588	17.63
Agricultural Pumping Service	41	(2,648)	1,400	17.63
Overall Net Increase		**(6,544)**	**100,146**	**11.75**
Source: Staff/902, Chriss/8				

Q. AS THE REVENUE REQUIREMENT INCREASES DECREASE, THE RMA AMOUNT INCREASES. IS THAT OBSERVATION CORRECT?

A. Yes.

Q. PLEASE EXPLAIN.

A. As the change in revenue requirement decreases, the overall percentage change in rates is lower. This decreases the level of the cap value because the cap value is 1.5 multiplied by the overall percentage rate increase. For example, a ten percent overall net price increase would result in a cap of 15 percent for each rate schedule. On the other hand, a two percent overall net price increase would result in a cap of three percent.

Before application of the cap, as the level of increase in revenue requirement rises, less of the schedule's increase falls outside of the cap's maximum percentage increase.

Q. IS IT POSSIBLE TO MITIGATE AN INCREASE IN THE RMA AS THE INCREASE IN REVENUE REQUIREMENT DECREASES?

A. Yes. Depending on the level of increase in revenue requirement, it may be appropriate to correspondingly increase the cap multiplier to mitigate the level of dollar transfers between customer classes.

Q. SHOULD RAISING THE CAP MULTIPLIER AT HIGHER LEVELS OF REVENUE REQUIREMENT INCREASE BE CONSIDERED?

A. Yes. At higher levels of revenue requirement increase, raising the cap multiplier can decrease the number of rate schedules that exceed the cap level and thus qualify for some rate increase mitigation. For example, at a $50 million increase, raising the cap multiplier to 2 times the overall net price increase removes Schedules 47 and 48 from the group of schedules that receives the RMA payments. This also serves to reduce the amount of money in the RMA pool by over half when compared to a $25 million increase. *See* Staff/902, Chriss/4.

Q. ARE THERE ANY OTHER OPTIONS TO CONSIDER WHEN SETTING THE RMA CAP?

A. Yes. The Commission could consider a hard cap in lieu of the cap multiplier. For instance, if the overall net price increase is two percent, a 1.5X cap multiplier would result in a RMA cap of three percent and a 2X cap multiplier would result in a RMA cap of four percent. It could happen that, for purposes of RMA reduction or other public policy goals, a larger cap for the individual rate schedules would be a more optimal result.

The commission has a long history of setting rates based on cost of service while recognizing some mitigation might be necessary. The PacifiCorp proposal is consistent with that approach; however, there needs to be a vision that through time, rates will be transitioned to reflect cost-base rates.

V. The RMA Equity Issue

Q. DOES STAFF AGREE WITH PACIFICORP'S IMPLEMENTATION OF THE RMA?

A. Not as proposed. There are two issues that the Commission should address in its consideration of the implementation of the RMA. The first issue is previously discussed cap multiplier. The second issue is an equity issue tied to customer surcharges under the RMA.

Q. WHAT IS THE EQUITY ISSUE THAT THE COMMISSION SHOULD CONSIDER?

A. Customers on Schedule 28 are charged 0.227 cents/kWh for payments into the RMA, and customers on Schedule 30 are charged 0.072 cents/kWh. Residential and lighting customers do not pay into the RMA at all. *See* PPL/1101, Schedule 299. While it is commendable that the company is trying to minimize the number of schedules affected by the RMA, the nature of the payment suggests that inclusion of all rate schedules not receiving the RMA payments is a better solution.

Q. PLEASE EXPLAIN "THE NATURE OF THE PAYMENT."

A. The RMA could be thought of as quasi-taxation, under which rates are not designed to offset the cost incurred by the producer in supplying the service, but to make an adjustment for unequal contributions to costs among the different classes of consumers.[2]

[2] See Bonbright, James C. *Principles of Public Utility Rates, 2nd Ed.* Arlington: Public Utilities Reports, Inc. 101-103.

Payments into the RMA, such as those for Schedules 28 and 30, are not payments for costs incurred by PacifiCorp for Schedules 28 and 30. Instead, the payments are a form of quasi-taxation, with inclusion of judgment to minimize the immediate level of rate increase or decrease.

While the burden of a quasi-tax with the purpose of providing support is never an economically optimal result, it is oftentimes a result of practical necessity. In this docket, the practical necessity is preventing rate shocks to customers served by some rate schedules facing significant one-time increases. Staff recommends that the best way to make the carrying of this burden fair is to spread out RMA contributions to all of the rate schedules for which the increase is less than the cap approved by the Commission.

Q. WHAT IS THE EFFECT OF MORE RATE SCHEDULES PAYING INTO THE RMA?

A. The effect is the reduction in the amount individual customers pay into the RMA. For example, under PacifiCorp's filed rate spread, applying an equal charge to all eligible kilowatt-hours results in a 0.064 cent/kWh payment into the RMA for each affected customer. *See* Staff/904, Chriss/2. This amount is lower than PacifiCorp's filed surcharges for Schedules 28 and 30.

While this charge presents an additional burden to residential and lighting customers, the charge is low enough that the effect on customer bills should be minimal. In addition, a per kWh charge, instead of a percentage increase in rates, is a reasonable resolution for including residential customers in funding the RMA. For example, a customer who consumes 1,000 kWh/month will see a RMA charge of 63 cents on their monthly bill. Many residential customers would pay less than one dollar a month and the largest residential customers, those consuming 4,500 to 5,000 kWh/month, would only pay about $3.00 per month, which is less than one percent of their proposed total monthly bill. *See* PPL/1102 Griffith/4 and Staff/903, Chriss/3.

Additionally, depending on the level of revenue requirement and cap multiplier, a rate schedule may be removed from receiving the RMA payments. The removed schedule would then pay into the mechanism, which would reduce the surcharge amount for all customers.

VI. Staff Proposal to Address RMA Concerns

Q. HAS STAFF PREPARED A PROPOSAL TO ADDRESS ITS CONCERNS REGARDING PACIFICORP'S IMPLEMENTATION OF THE RMA?

A. Yes. Staff's "surcharge equity" proposal addresses the equity issues raised earlier in this testimony through applying the RMA surcharge to all rate classes that are not receiving RMA surcredits. Schedule 33, Agricultural Pumping – Other, is exempt from this proposal due to separate rate treatment and mitigation as ordered by the Commission in Order 06-172.

Q. HOW WILL THE RMA BE APPLIED TO THE AFFECTED RATE SCHEDULES?

A. Rate schedules paying in to the RMA will pay on a per kilowatt-hour basis. The kilowatt-hour basis will also apply to schedules receiving the surcredit.

Q. HOW IS THE PER KILOWATT-HOUR SURCHARGE CALCULATED?

A. After the revenue requirement is determined, the value is entered into a rate spread model to determine which schedules will be receiving RMA monies and how much money per schedule will be paid. *See* Staff/905, Chriss/1-2. After the total RMA monies and beneficiary schedules are calculated, the kilowatt-hours for the remaining schedules are summed, and the RMA monies are divided by the applicable kilowatt-hours. The resulting number is the cents/kWh surcharge. *See* Staff/905, Chriss/3.

Q. HOW IS THE PER KILOWATT-HOUR SURCREDIT CALCULATED?

A. The per kilowatt-hour surcredit is calculated by dividing the RMA amount for each beneficiary rate schedule by its number of kilowatt-hours in the rate spread model. *See* Staff/906, Chriss/1.

Q. GIVEN STAFF'S REVENUE REQUIREMENT, PLEASE PRESENT YOUR SPECIFIC PROPOSAL.

A. Using staff's revenue requirement increase of $12.2 million, I propose the implementation of the surcharge equity proposal and a maximum increase for any class of customers, except Schedule 41, of two times the overall net increase.

Q. WHAT DO YOU PROPOSE FOR SCHEDULE 41?

A. For Schedule 41, the change in rates should be the greater of 15 percent and twice the company overall increase.

Q. WHY DO YOU PROPOSE AT LEAST A 15 PERCENT INCREASE FOR SCHEDULE 41 RATHER THAN LIMITING THE INCREASE TO NO MORE THAN TWICE THE OVERALL COMPANY INCREASE?

A. As can be seen from Table VI-1, Schedule 41 currently recovers far less of its respective share of its costs than do other classes of customers. Therefore it is reasonable to differentiate that class of customers and take action to bring that customer class closer to parity in recovery of costs.

Table VI-1. Ratio of Current Net Rates to Marginal Costs.

	Schedule	Marginal Cost	Current Net Rates	CNR/MC
Residential	4	$ 551,674	$ 424,382	77%
General Service	23	$ 121,546	$ 84,480	70%
General Service	28	$ 160,866	$ 120,200	75%
General Service	30	$ 99,181	$ 69,338	70%
Irrigation	41	$ 14,131	$ 7,944	56%
Large Power Service	48	$ 203,579	$ 128,577	63%
Street Lighting	51/53/54	$ 4,158	$ 3,365	81%

Source: PPL/1005, PPL/1102.

Q. WHAT ARE THE NET RATES FOR EACH SCHEDULE UNDER STAFF'S PROPOSAL?

A. Table VI-2 shows the estimated net rates for each rate schedule under staff's proposal. *See* Staff/905, Chriss/3 for more detailed calculations.

Table VI-2. Estimated Net Rates Under Staff's Proposal.

Schedule	No.	Net Rates ($000)	Net Rates (%)
Residential	4	9,953	2.35
General Service < 31 kW	23	2,441	2.89
General Service 31 –-200 kW	28	(6,319)	-5.26
General Service 201— 999 kW	30	(1,626)	-2.34
Lg. General Service ≥ 1,000 kW	48	3,715	2.89
Partial Req. Service ≥ 1,000 kW	47	260	2.89
Agricultural Pumping Service	41	1,192	15.00
Outdoor Area Lighting Service	15	(97)	-6.73
Street Lighting Service	50	(87)	-6.96
Street Lighting Service HPS	51	(184)	-6.71
Street Lighting Service	52	(14)	-6.15
Street Lighting Service	53	(41)	-7.53
Recreational Field Lighting	54	(4)	-5.05
Overall Net Increase		**12,311**	**1.44**

Source: Staff/905, Chriss/3

Q. WHY DID YOU CHOOSE A RMA MULTIPLIER OF TWO TIMES THE OVERALL NET INCREASE?

A. The two times multiplier was chosen because using a multiplier of 1.5 times the overall net increase resulted in an increase higher than the RMA cap for the residential schedule. This cap breach occurred because of the amount of the schedule's RMA payments. *See* Staff/905, Chriss/4.

Q. UNDER THIS PROPOSAL, WHAT IS THE AMOUNT OF MONEY IN THE RMA MECHANISM?

A. Approximately $8.1 million. This is significantly higher than the amount in the RMA under PacifiCorp's filing. A further reduction in RMA monies would require a RMA cap of more than two times the overall net increase.

Q. UNDER THIS PROPOSAL, WHAT IS THE RMA SURCHARGE?

A. The RMA surcharge under the proposal is 0.092 cents/kWh. When compared to PacifiCorp's filing, this is a reduction for Schedule 28 and a slight increase for Schedule 30.

VII. Phasing Out the RMA

Q. WHAT IS THE PRIMARY REASON TO PHASE OUT THE RMA?

A. The primary reason to phase out the RMA is the importance of each customer class paying its share of revenue requirements as determined by Commission policy.

Q. WHY IS IT IMPORTANT FOR EACH CUSTOMER CLASS TO PAY AN EQUAL PERCENTAGE OF MARGINAL COSTS ON A NET RATE BASIS?

A. Rates based on these costs will send correct price signals to all customers. For example, PacifiCorp is proposing a 2.446 cents/kWh RMA surcredit for customers on Schedule 41. This surcredit essentially cuts the schedule's energy rate in half. As a result, customer consumption may differ from what would be consumed if prices reflected the actual cost of service. Returning all customers to paying an equal percentage of marginal cost on a *net* rate basis would eliminate potential over-consumption due to incorrect price signals.

Q. HOW SHOULD THE RMA BE PHASED OUT?

A. As future rate cases arise, reductions in the RMA should occur by moving rate schedules closer to paying an equivalent share of marginal costs. This is staff's primary recommendation at this time.

Q. ARE THERE ANY POTENTIAL MECHANISMS THAT COULD BE USED TO PHASE OUT THE RMA?

A. One potential mechanism is a multiyear year phase out. The first year of the mechanism would reflect the full amount of the RMA as calculated in the rate spread model. For each year following, the percent reduction in the RMA amount would be calculated by diving 100 percent by the number of years in the phase out. For example, a five year phase out would reduce the RMA amount by 20 percent of the initial RMA amount each year after the first year of the plan. Surcharges and surcredits would be calculated for each year of the mechanism.

Q. WHAT CONSIDERATIONS NEED TO BE MADE IN IMPLEMENTING A PHASE OUT MECHANISM?

A. The first consideration is finding an annual level of reduction in RMA monies that achieves the goal of moving RMA monies towards zero but also minimizes rate shocks to rate schedules receiving the surcredits. The second consideration is that, as cost and RMA calculations change in each rate case, so too will the mechanism calculations if PacifiCorp were to file a rate case before the phase out is complete.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 179
WITNESS: Steve W Chriss

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 901

Witness Qualification Statement

July 12, 2006

WITNESS QUALIFICATIONS STATEMENT

NAME: STEVE W CHRISS

EMPLOYER: PUBLIC UTILITY COMMISSION OF OREGON

TITLE: SENIOR UTILITY ANALYST

ADDRESS: 550 CAPITOL ST. NE, SUITE 215, SALEM, OR 97310-1380

EDUCATION: Masters of Science degree, Agricultural Economics, from Louisiana State University (2001).

Bachelor of Science degree, Agricultural Development, from Texas A&M University (1997).

Bachelor of Science degree, Horticulture, from Texas A&M University (1997).

EXPERIENCE: Employed with the Public Utility Commission of Oregon (OPUC) as a Senior Utility Analyst in the Electric and Natural Gas Division. Previously employed with the OPUC as an Economist in the Economic Research and Financial Analysis Division from June, 2003 through February, 2006. Previously submitted testimony as the lead witness in Oregon docket UX 29 and as a supporting witness in Oregon docket UM 1129.

Employed as an Analyst and Senior Analyst at the Houston office of Econ One Research, Inc., a Los Angeles-based economic and regulatory consulting firm, between 2001 and 2003. Worked on regulatory and market issues in electricity, natural gas, and oil in both domestic and international markets.

Employed by North Harris College in Houston as an adjunct microeconomics instructor from January through May 2003.

CASE: UE 179
WITNESS: Steve W Chriss

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 902

Exhibits in Support
of Direct Testimony

July 12, 2006

Staff's Estimated Rate Spread Using Revenue Requirement Increase of $25 Million

		From PPL/1102 Griffith/1					Apply Staff							
		Present Revenues ($000)			PacifiCorp		Multiplier		PacifiCorp					
	Sch.	Base		Net	Proposed Base	PacifiCorp	To Determine	Staff Estimated	Adders	Staff Estimated	Base Rates		Net Rates	
	No.	Rates	Adders	Rates	Rates	Difference	Increase	Base Rates	(RMA Excluded)	Net Rates	($000)	(%)	($000)	(%)
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
						(4) - (1)	(5) * (SM)	(1) + (6)		(7) + (8)	(7) - (1)	(7) / (1)	(9) - (3)	(9) / (3)
Residential														
Residential	4	$ 422,917	$ 1,465	$ 424,382	$ 468,661	$ 45,744	$ 10,213	$ 433,130	$ 1,465	$ 434,595	$ 10,213	2.41%	$ 10,213	2.41%
Total Residential		**$ 422,917**	**$ 1,465**	**$ 424,382**	**$ 468,661**	**$ 45,744**	**$ 10,213**	**$ 433,130**	**$ 1,465**	**$ 434,595**	**$ 10,213**	**2.41%**	**$ 10,213**	**2.41%**
Commercial & Industrial														
Gen. Svc. < 31 kW	23	$ 90,122	$ (5,642)	$ 84,480	$ 102,015	$ 11,893	$ 2,655	$ 92,777	$ 821	$ 93,598	$ 2,655	2.95%	$ 9,118	10.79%
Gen. Svc. 31 - 200 kW	28	$ 110,982	$ 9,218	$ 120,200	$ 125,397	$ 14,415	$ 3,218	$ 114,200	$ 1,328	$ 115,528	$ 3,218	2.90%	$ (4,672)	-3.89%
Gen. Svc. 201 - 999 kW	30	$ 65,688	$ 3,650	$ 69,338	$ 76,447	$ 10,759	$ 2,402	$ 68,090	$ 852	$ 68,942	$ 2,402	3.66%	$ (396)	-0.57%
Large General Service >= 1,000 kW	48	$ 128,855	$ (278)	$ 128,577	$ 153,511	$ 24,656	$ 5,505	$ 134,360	$ 1,903	$ 136,263	$ 5,505	4.27%	$ 7,686	5.98%
Partial Req. Svc. >= 1,000 kW	47	$ 9,039	$ (29)	$ 9,010	$ 10,839	$ 1,800	$ 402	$ 9,441	$ 117	$ 9,558	$ 402	4.45%	$ 548	6.08%
Agricultural Pumping Service	41	$ 10,468	$ (2,524)	$ 7,944	$ 12,090	$ 1,622	$ 362	$ 10,830	$ 76	$ 10,906	$ 362	3.46%	$ 2,962	37.29%
Agricultural Pumping - Other	33	$ 915	$ -	$ 915	$ 915	$ -	$ -	$ 915	$ -	$ 915	$ -	0.00%	$ -	0.00%
Total Commercial & Industrial		**$ 416,069**	**$ 4,395**	**$ 420,464**	**$ 481,214**	**$ 65,145**	**$ 14,544**	**$ 430,613**	**$ 5,097**	**$ 435,710**	**$ 14,544**	**3.50%**	**$ 15,246**	**3.63%**
Lighting														
Outdoor Area Lighting Service	15	$ 1,316	$ 133	$ 1,449	$ 1,578	$ 262	$ 58	$ 1,374	$ 7	$ 1,381	$ 58	4.44%	$ (68)	-4.66%
Street Lighting Service	50	$ 1,137	$ 119	$ 1,256	$ 1,363	$ 226	$ 50	$ 1,187	$ 7	$ 1,194	$ 50	4.44%	$ (62)	-4.90%
Street Lighting Service HPS	51	$ 2,496	$ 249	$ 2,745	$ 2,991	$ 495	$ 111	$ 2,607	$ 11	$ 2,618	$ 111	4.43%	$ (127)	-4.64%
Street Lighting Service	52	$ 203	$ 19	$ 222	$ 243	$ 40	$ 9	$ 212	$ 1	$ 213	$ 9	4.40%	$ (9)	-4.09%
Street Lighting Service	53	$ 492	$ 57	$ 549	$ 590	$ 98	$ 22	$ 514	$ 5	$ 519	$ 22	4.45%	$ (30)	-5.49%
Recreational Field Lighting	54	$ 65	$ 6	$ 71	$ 78	$ 13	$ 3	$ 68	$ 1	$ 69	$ 3	4.47%	$ (2)	-2.95%
Total Public Street Lighting		**$ 5,709**	**$ 583**	**$ 6,292**	**$ 6,843**	**$ 1,134**	**$ 253**	**$ 5,962**	**$ 32**	**$ 5,994**	**$ 253**	**4.43%**	**$ (298)**	**-4.73%**
Total Sales to Ultimate Consumers		$ 844,695	$ 6,443	$ 851,138	$ 956,718	$ 112,023	$ 25,010	$ 869,705	$ 6,594	$ 876,299	$ 25,010	2.96%	$ 25,161	2.96%
Employee Discount		$ (418)	$ (1)	$ (419)	$ (463)			$ (463)	$ (1)	$ (464)	$ (45)		$ (45)	
Total Sales with Employee Discount		$ 844,277	$ 6,442	$ 850,719	$ 956,255			$ 869,242	$ 6,593	$ 875,835	$ 24,965	2.96%	$ 25,116	2.95%
AGA Revenue		$ 1,554		$ 1,554	$ 1,554			$ 1,554		$ 1,554				
Total Sales with Employee Discount and AGA		$ 845,831	$ 6,442	$ 852,273	$ 957,809	$ 111,978		$ 870,796	$ 6,593	$ 877,389	$ 24,965	2.95%	$ 25,116	2.95%

From PPL/1102 Griffith/2

PacifiCorp Increase:	$ 111,978.00
Staff Increase:	$ 25,000.00
Staff Multiplier (SM):	0.22325814

INPUT

Staff Rate Mitigation Adjustment Estimates at 1.5X, 2X, and at a 5 Percent Cap, Revenue Requirement Increase of $25 Million

	Sch. No.	Base Rates ($000)	(%)	Net Rates ($000)	(%)	Max Increase at RMA @ 1.5X ($000)	RMA Amount ($000)	Max Increase at RMA @ 2X ($000)	RMA Amount ($000)	Max Increase at 5% Cap ($000)	RMA Amount ($000)
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Residential											
Residential	4	$ 10,213	2.41%	$ 10,213	2.41%	$ 18,759	$ -	$ 25,013	$ -	$ 21,219	$ -
Total Residential		**$ 10,213**	**2.41%**	**$ 10,213**	**2.41%**						
Commercial & Industrial											
Gen. Svc. < 31 kW	23	$ 2,655	2.95%	$ 9,118	10.79%	$ 3,734	$ (5,384)	$ 4,979	$ (4,139)	$ 4,224	$ (4,894)
Gen. Svc. 31 - 200 kW	28	$ 3,218	2.90%	$ (4,672)	-3.89%	$ 5,313	$ -	$ 7,084	$ -	$ 6,010	$ -
Gen. Svc. 201 - 999 kW	30	$ 2,402	3.66%	$ (396)	-0.57%	$ 3,065	$ -	$ 4,087	$ -	$ 3,467	$ -
Large General Service >= 1,000 kW	48	$ 5,505	4.27%	$ 7,686	5.98%	$ 5,684	$ (2,002)	$ 7,578	$ (107)	$ 6,429	$ (1,257)
Partial Req. Svc. >= 1,000 kW	47	$ 402	4.45%	$ 548	6.08%	$ 398	$ (150)	$ 531	$ (17)	$ 451	$ (97)
Agricultural Pumping Service	41	$ 362	3.46%	$ 2,962	37.29%	$ 351	$ (2,611)	$ 468	$ (2,494)	$ 397	$ (2,565)
Agricultural Pumping - Other	33	$ -	0.00%	$ -	0.00%	$ 40	$ -	$ 54	$ -	$ 46	$ -
Total Commercial & Industrial		**$ 14,544**	**3.50%**	**$ 15,246**	**3.63%**						
Lighting											
Outdoor Area Lighting Service	15	$ 58	4.44%	$ (68)	-4.66%	$ 64	$ -	$ 85	$ -	$ 72	$ -
Street Lighting Service	50	$ 50	4.44%	$ (62)	-4.90%	$ 56	$ -	$ 74	$ -	$ 63	$ -
Street Lighting Service HPS	51	$ 111	4.43%	$ (127)	-4.64%	$ 121	$ -	$ 162	$ -	$ 137	$ -
Street Lighting Service	52	$ 9	4.40%	$ (9)	-4.09%	$ 10	$ -	$ 13	$ -	$ 11	$ -
Street Lighting Service	53	$ 22	4.45%	$ (30)	-5.49%	$ 24	$ -	$ 32	$ -	$ 27	$ -
Recreational Field Lighting	54	$ 3	4.47%	$ (2)	-2.95%	$ 3	$ -	$ 4	$ -	$ 4	$ -
Total Public Street Lighting		**$ 253**	**4.43%**	**$ (298)**	**-4.73%**		**$ (10,146)**		**$ (6,757)**		**$ (8,813)**
Total Sales with Employee Discount and AGA		**$ 24,965**	**2.95%**	**$ 25,116**	**2.95%**						

RMA @ 1.5X =	4.42%
RMA @ 2X =	5.89%

Staff's Estimated Rate Spread Using Revenue Requirement Increase of $50 Million

	Sch. No.	From PPL/1102 Griffith/1 – Present Revenues ($000) – Base Rates	Adders	Net Rates	PacifiCorp Proposed Base Rates	PacifiCorp Difference	Apply Staff Multiplier To Determine Increase	Staff Estimated Base Rates	PacifiCorp Adders (RMA Excluded)	Staff Estimated Net Rates	Base Rates ($000)	Base Rates (%)	Net Rates ($000)	Net Rates (%)
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
						(4) - (1)	(5) * (SM)	(1) + (6)		(7) + (8)	(7) - (1)	(7) / (1)	(9) - (3)	(9) / (3)
Residential														
Residential	4	$ 422,917	$ 1,465	$ 424,382	$ 468,661	$ 45,744	$ 20,425	$ 443,342	$ 1,465	$ 444,807	$ 20,425	4.83%	$ 20,425	4.81%
Total Residential		$ 422,917	$ 1,465	$ 424,382	$ 468,661	$ 45,744	$ 20,425	$ 443,342	$ 1,465	$ 444,807	$ 20,425	4.83%	$ 20,425	4.81%
Commercial & Industrial														
Gen. Svc. < 31 kW	23	$ 90,122	$ (5,642)	$ 84,480	$ 102,015	$ 11,893	$ 5,310	$ 95,432	$ 821	$ 96,253	$ 5,310	5.89%	$ 11,773	13.94%
Gen. Svc. 31 - 200 kW	28	$ 110,982	$ 9,218	$ 120,200	$ 125,397	$ 14,415	$ 6,437	$ 117,419	$ 1,328	$ 118,747	$ 6,437	5.80%	$ (1,453)	-1.21%
Gen. Svc. 201 - 999 kW	30	$ 65,688	$ 3,650	$ 69,338	$ 76,447	$ 10,759	$ 4,804	$ 70,492	$ 852	$ 71,344	$ 4,804	7.31%	$ 2,006	2.89%
Large General Service >= 1,000 kW	48	$ 128,855	$ (278)	$ 128,577	$ 153,511	$ 24,656	$ 11,009	$ 139,864	$ 1,903	$ 141,767	$ 11,009	8.54%	$ 13,190	10.26%
Partial Req. Svc. >= 1,000 kW	47	$ 9,039	$ (29)	$ 9,010	$ 10,839	$ 1,800	$ 804	$ 9,843	$ 117	$ 9,960	$ 804	8.89%	$ 950	10.54%
Agricultural Pumping Service	41	$ 10,468	$ (2,524)	$ 7,944	$ 12,090	$ 1,622	$ 724	$ 11,192	$ 76	$ 11,268	$ 724	6.92%	$ 3,324	41.85%
Agricultural Pumping - Other	33	$ 915	$ -	$ 915	$ 915	$ -	$ -	$ 915	$ -	$ 915	$ -	0.00%	$ -	0.00%
Total Commercial & Industrial		$ 416,069	$ 4,395	$ 420,464	$ 481,214	$ 65,145	$ 29,088	$ 445,157	$ 5,097	$ 450,254	$ 29,088	6.99%	$ 29,790	7.09%
Lighting														
Outdoor Area Lighting Service	15	$ 1,316	$ 133	$ 1,449	$ 1,578	$ 262	$ 117	$ 1,433	$ 7	$ 1,440	$ 117	8.89%	$ (9)	-0.62%
Street Lighting Service	50	$ 1,137	$ 119	$ 1,256	$ 1,363	$ 226	$ 101	$ 1,238	$ 7	$ 1,245	$ 101	8.88%	$ (11)	-0.88%
Street Lighting Service HPS	51	$ 2,496	$ 249	$ 2,745	$ 2,991	$ 495	$ 221	$ 2,717	$ 11	$ 2,728	$ 221	8.86%	$ (17)	-0.62%
Street Lighting Service	52	$ 203	$ 19	$ 222	$ 243	$ 40	$ 18	$ 221	$ 1	$ 222	$ 18	8.80%	$ (0)	-0.06%
Street Lighting Service	53	$ 492	$ 57	$ 549	$ 590	$ 98	$ 44	$ 536	$ 5	$ 541	$ 44	8.89%	$ (8)	-1.50%
Recreational Field Lighting	54	$ 65	$ 6	$ 71	$ 78	$ 13	$ 6	$ 71	$ 1	$ 72	$ 6	8.93%	$ 1	1.13%
Total Public Street Lighting		$ 5,709	$ 583	$ 6,292	$ 6,843	$ 1,134	$ 506	$ 6,215	$ 32	$ 6,247	$ 506	8.87%	$ (45)	-0.71%
Total Sales to Ultimate Consumers		$ 844,695	$ 6,443	$ 851,138	$ 956,718	$ 112,023	$ 50,020	$ 894,715	$ 6,594	$ 901,309	$ 50,020	5.92%	$ 50,171	5.89%
Employee Discount		$ (418)	$ (1)	$ (419)	$ (463)			$ (463)	$ (1)	$ (464)	$ (45)		$ (45)	
Total Sales with Employee Discount		$ 844,277	$ 6,442	$ 850,719	$ 956,255			$ 894,252	$ 6,593	$ 900,845	$ 49,975	5.92%	$ 50,126	5.89%
AGA Revenue		$ 1,554		$ 1,554	$ 1,554			$ 1,554		$ 1,554				
Total Sales with Employee Discount and AGA		$ 845,831	$ 6,442	$ 852,273	$ 957,809	$ 111,978		$ 895,806	$ 6,593	$ 902,399	$ 49,975	5.91%	$ 50,126	5.88%

From PPL/1102 Griffith/2

PacifiCorp Increase:	$ 111,978.00
Staff Increase:	$ 50,000.00
Staff Multiplier (SM):	0.44651628

← INPUT

Staff Rate Mitigation Adjustment Estimates at 1.5X, 2X, and at a 5 Percent Cap, Revenue Requirement Increase of $50 Million

	Sch. No.	Base Rates ($000) (1)	Base Rates (%) (2)	Net Rates ($000) (3)	Net Rates (%) (4)	Max Increase at RMA @ 1.5X ($000) (5)	RMA Amount ($000) (6)	Max Increase at RMA @ 2X ($000) (7)	RMA Amount ($000) (8)
Residential									
Residential	4	$ 20,425 0	4.83%	$ 20,425	4.81%	$ 37,440	$ -	$ 49,920	$ -
Total Residential		**$ 20,425 0**	**4.83%**	**$ 20,425**	**4.81%**				
Commercial & Industrial									
Gen. Svc. < 31 kW	23	$ 5,310 0	5.89%	$ 11,773	13.94%	$ 7,453	$ (4,320)	$ 9,937	$ (1,836)
Gen. Svc. 31 - 200 kW	28	$ 6,437 0	5.80%	$ (1,453)	-1.21%	$ 10,604	$ -	$ 14,139	$ -
Gen. Svc. 201 - 999 kW	30	$ 4,804 0	7.31%	$ 2,006	2.89%	$ 6,117	$ -	$ 8,156	$ -
Large General Service >= 1,000 kW	48	$ 11,009 0	8.54%	$ 13,190	10.26%	$ 11,343	$ (1,847)	$ 15,124	$ -
Partial Req. Svc. >= 1,000 kW	47	$ 804 0	8.89%	$ 950	10.54%	$ 795	$ (155)	$ 1,060	$ -
Agricultural Pumping Service	41	$ 724 0	6.92%	$ 3,324	41.85%	$ 701	$ (2,623)	$ 934	$ (2,390)
Agricultural Pumping - Other	33	$ - 0	0.00%	$ -	0.00%	$ 81	$ -	$ 108	$ -
Total Commercial & Industrial		**$ 29,088 0**	**6.99%**	**$ 58,879**	**7.09%**				
Lighting									
Outdoor Area Lighting Service	15	$ 117 0	8.89%	$ (9)	-0.62%	$ 128	$ -	$ 170	$ -
Street Lighting Service	50	$ 101 0	8.88%	$ (11)	-0.88%	$ 111	$ -	$ 148	$ -
Street Lighting Service HPS	51	$ 221 0	8.86%	$ (17)	-0.62%	$ 242	$ -	$ 323	$ -
Street Lighting Service	52	$ 18 0	8.80%	$ (0)	-0.06%	$ 20	$ -	$ 26	$ -
Street Lighting Service	53	$ 44 0	8.89%	$ (8)	-1.50%	$ 48	$ -	$ 65	$ -
Recreational Field Lighting	54	$ 6 0	8.93%	$ 1	1.13%	$ 6	$ -	$ 8	$ -
Total Public Street Lighting		**$ 506 0**	**8.87%**	**$ (45)**	**-0.71%**		**$ (8,946)**		**$ (4,226)**
Total Sales with Employee Discount and AGA		**$ 49,975 0**	**5.91%**	**$ 50,126**	**5.88%**				

RMA @ 1.5X =	8.82%
RMA @ 2X =	11.76%

Staff's Estimated Rate Spread Using Revenue Requirement Increase of $75 Million

	Sch. No.	From PPL/1102 Griffith/1 — Present Revenues ($000) — Base Rates (1)	Adders (2)	Net Rates (3)	PacifiCorp Proposed Base Rates (4)	PacifiCorp Difference (5) (4) - (1)	Apply Staff Multiplier To Determine Increase (6) (5) * (SM)	Staff Estimated Base Rates (7) (1) + (6)	PacifiCorp Adders (RMA Excluded) (8)	Staff Estimated Net Rates (9) (7) + (8)	Base Rates ($000) (10) (7) - (1)	Base Rates (%) (11) (7) / (1)	Net Rates ($000) (12) (9) - (3)	Net Rates (%) (13) (9) / (3)
Residential														
Residential	4	$ 422,917	$ 1,465	$ 424,382	$ 468,661	$ 45,744	$ 30,638	$ 453,555	$ 1,465	$ 455,020	$ 30,638	7.24%	$ 30,638	7.22%
Total Residential		$ 422,917	$ 1,465	$ 424,382	$ 468,661	$ 45,744	$ 30,638	$ 453,555	$ 1,465	$ 455,020	$ 30,638	7.24%	$ 30,638	7.22%
Commercial & Industrial														
Gen. Svc. < 31 kW	23	$ 90,122	$ (5,642)	$ 84,480	$ 102,015	$ 11,893	$ 7,966	$ 98,088	$ 821	$ 98,909	$ 7,966	8.84%	$ 14,429	17.08%
Gen. Svc. 31 - 200 kW	28	$ 110,982	$ 9,218	$ 120,200	$ 125,397	$ 14,415	$ 9,655	$ 120,637	$ 1,328	$ 121,965	$ 9,655	8.70%	$ 1,765	1.47%
Gen. Svc. 201 - 999 kW	30	$ 65,688	$ 3,650	$ 69,338	$ 76,447	$ 10,759	$ 7,206	$ 72,894	$ 852	$ 73,746	$ 7,206	10.97%	$ 4,408	6.36%
Large General Service >= 1,000 kW	48	$ 128,855	$ (278)	$ 128,577	$ 153,511	$ 24,656	$ 16,514	$ 145,369	$ 1,903	$ 147,272	$ 16,514	12.82%	$ 18,695	14.54%
Partial Req. Svc. >= 1,000 kW	47	$ 9,039	$ (29)	$ 9,010	$ 10,839	$ 1,800	$ 1,206	$ 10,245	$ 117	$ 10,362	$ 1,206	13.34%	$ 1,352	15.00%
Agricultural Pumping Service	41	$ 10,468	$ (2,524)	$ 7,944	$ 12,090	$ 1,622	$ 1,086	$ 11,554	$ 76	$ 11,630	$ 1,086	10.38%	$ 3,686	46.40%
Agricultural Pumping - Other	33	$ 915	$ -	$ 915	$ 915	$ -	$ -	$ 915	$ -	$ 915	$ -	0.00%	$ -	0.00%
Total Commercial & Industrial		$ 416,069	$ 4,395	$ 420,464	$ 481,214	$ 65,145	$ 43,632	$ 459,701	$ 5,097	$ 464,798	$ 43,632	10.49%	$ 44,334	10.54%
Lighting														
Outdoor Area Lighting Service	15	$ 1,316	$ 133	$ 1,449	$ 1,578	$ 262	$ 175	$ 1,491	$ 7	$ 1,498	$ 175	13.33%	$ 49	3.41%
Street Lighting Service	50	$ 1,137	$ 119	$ 1,256	$ 1,363	$ 226	$ 151	$ 1,288	$ 7	$ 1,295	$ 151	13.31%	$ 39	3.13%
Street Lighting Service HPS	51	$ 2,496	$ 249	$ 2,745	$ 2,991	$ 495	$ 332	$ 2,828	$ 11	$ 2,839	$ 332	13.28%	$ 94	3.41%
Street Lighting Service	52	$ 203	$ 19	$ 222	$ 243	$ 40	$ 27	$ 230	$ 1	$ 231	$ 27	13.20%	$ 9	3.96%
Street Lighting Service	53	$ 492	$ 57	$ 549	$ 590	$ 98	$ 66	$ 558	$ 5	$ 563	$ 66	13.34%	$ 14	2.48%
Recreational Field Lighting	54	$ 65	$ 6	$ 71	$ 78	$ 13	$ 9	$ 74	$ 1	$ 75	$ 9	13.40%	$ 4	5.22%
Total Public Street Lighting		$ 5,709	$ 583	$ 6,292	$ 6,843	$ 1,134	$ 760	$ 6,469	$ 32	$ 6,501	$ 760	13.30%	$ 209	3.31%
Total Sales to Ultimate Consumers		$ 844,695	$ 6,443	$ 851,138	$ 956,718	$ 112,023	$ 75,030	$ 919,725	$ 6,594	$ 926,319	$ 75,030	8.88%	$ 75,181	8.83%
Employee Discount		$ (418)	$ (1)	$ (419)	$ (463)			$ (463)	$ (1)	$ (464)	$ (45)		$ (45)	
Total Sales with Employee Discount		$ 844,277	$ 6,442	$ 850,719	$ 956,255			$ 919,262	$ 6,593	$ 925,855	$ 74,985	8.88%	$ 75,136	8.83%
AGA Revenue		$ 1,554		$ 1,554	$ 1,554			$ 1,554		$ 1,554				
Total Sales with Employee Discount and AGA		$ 845,831	$ 6,442	$ 852,273	$ 957,809	$ 111,978		$ 920,816	$ 6,593	$ 927,409	$ 74,985	8.87%	$ 75,136	8.82%

From PPL/1102 Griffith/2

PacifiCorp Increase:	$ 111,978.00
Staff Increase:	$ 75,000.00
Staff Multiplier (SM):	0.66977442

← INPUT

Staff Rate Mitigation Adjustment Estimates at 1.5X, 2X, and at a 5 Percent Cap, Revenue Requirement Increase of $75 Million

	Sch. No.	Base Rates ($000)	Base Rates (%)	Net Rates ($000)	Net Rates (%)	Max Increase at RMA @ 1.5X ($000)	RMA Amount ($000)	Max Increase at RMA @ 2X ($000)	RMA Amount ($000)
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Residential									
Residential	4	$ 30,638	7.24%	$ 30,638	7.22%	$ 56,120	$ -	$ 74,827	$ -
Total Residential		**$ 30,638**	**7.24%**	**$ 30,638**	**7.22%**				
Commercial & Industrial									
Gen. Svc. < 31 kW	23	$ 7,966	8.84%	$ 14,429	17.08%	$ 11,172	$ (3,257)	$ 14,895	$ -
Gen. Svc. 31 - 200 kW	28	$ 9,655	8.70%	$ 1,765	1.47%	$ 15,895	$ -	$ 21,194	$ -
Gen. Svc. 201 - 999 kW	30	$ 7,206	10.97%	$ 4,408	6.36%	$ 9,169	$ -	$ 12,226	$ -
Large General Service >= 1,000 kW	48	$ 16,514	12.82%	$ 18,695	14.54%	$ 17,003	$ (1,692)	$ 22,671	$ -
Partial Req. Svc. >= 1,000 kW	47	$ 1,206	13.34%	$ 1,352	15.00%	$ 1,191	$ (160)	$ 1,589	$ -
Agricultural Pumping Service	41	$ 1,086	10.38%	$ 3,686	46.40%	$ 1,051	$ (2,636)	$ 1,401	$ (2,286)
Agricultural Pumping - Other	33	$ -	0.00%	$ -	0.00%	$ 121	$ -	$ 161	$ -
Total Commercial & Industrial		**$ 43,632**	**10.49%**	**$ 44,334**	**10.54%**				
Lighting									
Outdoor Area Lighting Service	15	$ 175	13.33%	$ 49	3.41%	$ 192	$ -	$ 255	$ -
Street Lighting Service	50	$ 151	13.31%	$ 39	3.13%	$ 166	$ -	$ 221	$ -
Street Lighting Service HPS	51	$ 332	13.28%	$ 94	3.41%	$ 363	$ -	$ 484	$ -
Street Lighting Service	52	$ 27	13.20%	$ 9	3.96%	$ 29	$ -	$ 39	$ -
Street Lighting Service	53	$ 66	13.34%	$ 14	2.48%	$ 73	$ -	$ 97	$ -
Recreational Field Lighting	54	$ 9	13.40%	$ 4	5.22%	$ 9	$ -	$ 13	$ -
Total Public Street Lighting		**$ 760**	**13.30%**	**$ 209**	**3.31%**		**$ (7,745)**		**$ (2,286)**
Total Sales with Employee Discount and AGA		**$ 74,985**	**8.87%**	**$ 75,136**	**8.82%**				

RMA @ 1.5X =	13.22%
RMA @ 2X =	17.63%

Staff's Estimated Rate Spread Using Revenue Requirement Increase of $110 Million

	Sch. No.	From PPL/1102 Griffith/1 — Present Revenues ($000) Base Rates (1)	Adders (2)	Net Rates (3)	PacifiCorp Proposed Base Rates (4)	PacifiCorp Difference (5) (4) - (1)	Apply Staff Multiplier To Determine Increase (6) (5) * (SM)	Staff Estimated Base Rates (7) (1) + (6)	PacifiCorp Adders (RMA Excluded) (8)	Staff Estimated Net Rates (9) (7) + (8)	Base Rates ($000) (10) (7) - (1)	Base Rates (%) (11) (7) / (1)	Net Rates ($000) (12) (9) - (3)	Net Rates (%) (13) (9) / (3)
Residential														
Residential	4	$ 422,917	$ 1,465	$ 424,382	$ 468,661	$ 45,744	$ 44,936	$ 467,853	$ 1,465	$ 469,318	$ 44,936	10.63%	$ 44,936	10.59%
Total Residential		**$ 422,917**	**$ 1,465**	**$ 424,382**	**$ 468,661**	**$ 45,744**	**$ 44,936**	**$ 467,853**	**$ 1,465**	**$ 469,318**	**$ 44,936**	**10.63%**	**$ 44,936**	**10.59%**
Commercial & Industrial														
Gen. Svc. < 31 kW	23	$ 90,122	$ (5,642)	$ 84,480	$ 102,015	$ 11,893	$ 11,683	$ 101,805	$ 821	$ 102,626	$ 11,683	12.96%	$ 18,146	21.48%
Gen. Svc. 31 - 200 kW	28	$ 110,982	$ 9,218	$ 120,200	$ 125,397	$ 14,415	$ 14,160	$ 125,142	$ 1,328	$ 126,470	$ 14,160	12.76%	$ 6,270	5.22%
Gen. Svc. 201 - 999 kW	30	$ 65,688	$ 3,650	$ 69,338	$ 76,447	$ 10,759	$ 10,569	$ 76,257	$ 852	$ 77,109	$ 10,569	16.09%	$ 7,771	11.21%
Large General Service >= 1,000 kW	48	$ 128,855	$ (278)	$ 128,577	$ 153,511	$ 24,656	$ 24,220	$ 153,075	$ 1,903	$ 154,978	$ 24,220	18.80%	$ 26,401	20.53%
Partial Req. Svc. >= 1,000 kW	47	$ 9,039	$ (29)	$ 9,010	$ 10,839	$ 1,800	$ 1,768	$ 10,807	$ 117	$ 10,924	$ 1,768	19.56%	$ 1,914	21.25%
Agricultural Pumping Service	41	$ 10,468	$ (2,524)	$ 7,944	$ 12,090	$ 1,622	$ 1,593	$ 12,061	$ 76	$ 12,137	$ 1,593	15.22%	$ 4,193	52.79%
Agricultural Pumping - Other	33	$ 915	$ -	$ 915	$ 915	$ -	$ -	$ 915	$ -	$ 915	$ -	0.00%	$ -	0.00%
Total Commercial & Industrial		**$ 416,069**	**$ 4,395**	**$ 420,464**	**$ 481,214**	**$ 65,145**	**$ 63,994**	**$ 480,063**	**$ 5,097**	**$ 485,160**	**$ 63,994**	**15.38%**	**$ 64,696**	**15.39%**
Lighting														
Outdoor Area Lighting Service	15	$ 1,316	$ 133	$ 1,449	$ 1,578	$ 262	$ 257	$ 1,573	$ 7	$ 1,580	$ 257	19.56%	$ 131	9.07%
Street Lighting Service	50	$ 1,137	$ 119	$ 1,256	$ 1,363	$ 226	$ 222	$ 1,359	$ 7	$ 1,366	$ 222	19.53%	$ 110	8.76%
Street Lighting Service HPS	51	$ 2,496	$ 249	$ 2,745	$ 2,991	$ 495	$ 486	$ 2,982	$ 11	$ 2,993	$ 486	19.48%	$ 248	9.04%
Street Lighting Service	52	$ 203	$ 19	$ 222	$ 243	$ 40	$ 39	$ 242	$ 1	$ 243	$ 39	19.36%	$ 21	9.59%
Street Lighting Service	53	$ 492	$ 57	$ 549	$ 590	$ 98	$ 96	$ 588	$ 5	$ 593	$ 96	19.57%	$ 44	8.06%
Recreational Field Lighting	54	$ 65	$ 6	$ 71	$ 78	$ 13	$ 13	$ 78	$ 1	$ 79	$ 13	19.65%	$ 8	10.94%
Total Public Street Lighting		**$ 5,709**	**$ 583**	**$ 6,292**	**$ 6,843**	**$ 1,134**	**$ 1,114**	**$ 6,823**	**$ 32**	**$ 6,855**	**$ 1,114**	**19.51%**	**$ 563**	**8.95%**
Total Sales to Ultimate Consumers		$ 844,695	$ 6,443	$ 851,138	$ 956,718	$ 112,023	$ 110,044	$ 954,739	$ 6,594	$ 961,333	$ 110,044	13.03%	$ 110,195	12.95%
Employee Discount		$ (418)	$ (1)	$ (419)	$ (463)			$ (463)	$ (1)	$ (464)	$ (45)		$ (45)	
Total Sales with Employee Discount		$ 844,277	$ 6,442	$ 850,719	$ 956,255			$ 954,276	$ 6,593	$ 960,869	$ 109,999	13.03%	$ 110,150	12.95%
AGA Revenue		$ 1,554		$ 1,554	$ 1,554			$ 1,554		$ 1,554				
Total Sales with Employee Discount and AGA		$ 845,831	$ 6,442	$ 852,273	$ 957,809	$ 111,978		$ 955,830	$ 6,593	$ 962,423	$ 109,999	13.00%	$ 110,150	12.92%

From PPL/1102 Griffith/2

PacifiCorp Increase:	$ 111,978.00
Staff Increase:	$ 110,000.00
Staff Multiplier (SM):	0.982335816

INPUT

Staff Rate Mitigation Adjustment Estimates at 1.5X, 2X, and at a 5 Percent Cap, Revenue Requirement Increase of $110 Million

	Sch. No.	Base Rates ($000)	Base Rates (%)	Net Rates ($000)	Net Rates (%)	Max Increase at RMA @ 1.5X ($000)	RMA Amount ($000)	Max Increase at RMA @ 2X ($000)	RMA Amount ($000)
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Residential									
Residential	4	$ 44,936	10.63%	$ 44,936	10.59%	$ 82,273	$ -	$ 109,697	$ -
Total Residential		**$ 44,936**	**10.63%**	**$ 44,936**	**10.59%**				
Commercial & Industrial									
Gen. Svc. < 31 kW	23	$ 11,683	12.96%	$ 18,146	21.48%	$ 16,378	$ (1,768)	$ 21,837	$ -
Gen. Svc. 31 - 200 kW	28	$ 14,160	12.76%	$ 6,270	5.22%	$ 23,302	$ -	$ 31,070	$ -
Gen. Svc. 201 - 999 kW	30	$ 10,569	16.09%	$ 7,771	11.21%	$ 13,442	$ -	$ 17,923	$ -
Large General Service >= 1,000 kW	48	$ 24,220	18.80%	$ 26,401	20.53%	$ 24,926	$ (1,475)	$ 33,235	$ -
Partial Req. Svc. >= 1,000 kW	47	$ 1,768	19.56%	$ 1,914	21.25%	$ 1,747	$ (167)	$ 2,329	$ -
Agricultural Pumping Service	41	$ 1,593	15.22%	$ 4,193	52.79%	$ 1,540	$ (2,653)	$ 2,053	$ (2,140)
Agricultural Pumping - Other	33	$ -	0.00%	$ -	0.00%	$ 177	$ -	$ 237	$ -
Total Commercial & Industrial		**$ 63,994**	**15.38%**	**$ 64,696**	**15.39%**				
Lighting									
Outdoor Area Lighting Service	15	$ 257	19.56%	$ 131	9.07%	$ 281	$ -	$ 375	$ -
Street Lighting Service	50	$ 222	19.53%	$ 110	8.76%	$ 243	$ -	$ 325	$ -
Street Lighting Service HPS	51	$ 486	19.48%	$ 248	9.04%	$ 532	$ -	$ 710	$ -
Street Lighting Service	52	$ 39	19.36%	$ 21	9.59%	$ 43	$ -	$ 57	$ -
Street Lighting Service	53	$ 96	19.57%	$ 44	8.06%	$ 106	$ -	$ 142	$ -
Recreational Field Lighting	54	$ 13	19.65%	$ 8	10.94%	$ 14	$ -	$ 18	$ -
Total Public Street Lighting		**$ 1,114**	**19.51%**	**$ 563**	**8.95%**		**$ (6,064)**		**$ (2,140)**
Total Sales with Employee Discount and AGA		**$ 109,999**	**13.00%**	**$ 110,150**	**12.92%**				

RMA @ 1.5X =	19.39%
RMA @ 2X =	25.85%

CASE: UE 179
WITNESS: Steve W Chriss

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 903

Exhibits in Support
of Direct Testimony

July 12, 2006

UE-179/PacifiCorp
April 27, 2006
OPUC Data Request 290

OPUC Data Request 290

Please see PPL/1100, Griffith/4. Please provide the methodology used to determine the use of 1.5 times the overall net average as a cap on price increases. Please provide all workpapers, from this docket and earlier dockets, used in determining the cap.

Response to OPUC Data Request 290

The cap of 1.5 times the overall net average was chosen based on reasonableness, its ability to mitigate large rate increases while still minimizing subsidies, and on Commission acceptance of previous rate caps in this range. There are no workpapers showing the development of the cap value proposed in this case or caps proposed in previous cases.

UE-179/PacifiCorp
April 27, 2006
OPUC Data Request 291

OPUC Data Request 291

Please see PPL/1100, Griffith/4 and PPL/1102, Griffith/2. Please explain how PacifiCorp determines which customer classes pay in to the RMA mechanism and which customer classes receive payment.

Response to OPUC Data Request 291

The RMA is used to implement the chosen rate cap of 1.5 times the overall net increase. Schedules which would see a net increase greater than 1.5 times the overall net increase receive an RMA credit sufficient to bring their increase down to the cap. In the UE-170 rate spread and rate design stipulation (Fourth Partial Stipulation), parties agreed that residential customers would no longer receive nor pay an RMA. In this proceeding, in order to further minimize application of an RMA, the Company has proposed to keep the RMA dollars within the Commercial & Industrial class. To achieve this, commercial and industrial schedules not receiving surcredits receive surcharges sufficient to offset the credit dollars.

Pacific Power
Bills and Customers by KWh Range
Forecast 12 Months Ended December 31, 2007

kWh Category	KWh per Bill	Forecast Bills	Customers (Bills/12)
100	0-100	222,790	18,566
200	101-200	294,721	24,560
300	201-300	217,699	18,142
400	301-400	256,106	21,342
500	401-500	219,580	18,298
600	501-600	188,441	15,703
700	601-700	160,950	13,412
800	701-800	137,602	11,467
900	801-900	116,881	9,740
1000	901-1000	99,894	8,324
1100	1001-1100	85,386	7,116
1200	1101-1200	73,636	6,136
1300	1201-1300	62,761	5,230
1400	1301-1400	290,598	24,217
1500	1401-1500	54,358	4,530
1600	1501-1600	47,149	3,929
1700	1601-1700	40,524	3,377
1800	1701-1800	34,720	2,893
1900	1801-1900	30,044	2,504
2000	1901-2000	26,145	2,179
2100	2001-2100	22,369	1,864
2200	2101-2200	19,352	1,613
2300	2201-2300	17,031	1,419
2400	2301-2400	14,625	1,219
2500	2401-2500	368,951	30,746
2600	2501-2600	12,832	1,069
2700	2601-2700	10,938	911
2800	2701-2800	9,580	798
2900	2801-2900	8,233	686
3000	2901-3000	7,395	616
3100	3001-3100	6,325	527
3200	3101-3200	5,433	453
3300	3201-3300	4,926	411
3400	3301-3400	4,255	355
3500	3401-3500	3,674	306
3600	3501-3600	420,662	35,055
3700	3601-3700	3,328	277
3800	3701-3800	2,821	235
3900	3801-3900	2,540	212
4000	3901-4000	2,224	185
4100	4001-4100	1,947	162
4200	4101-4200	1,762	147
4300	4201-4300	1,557	130
4400	4301-4400	1,427	119
4500	4401-4500	1,187	99
4600	4501-4600	439,143	36,595
4700	4601-4700	431,711	35,976
4800	4701-4800	407,818	33,985
4900	4801-4900	373,383	31,115
5000	4901-5000	335,981	27,998
> 5000	> 5000	11,950	996
Total		5,615,347	467,946

CASE: UE 179
WITNESS: Steve W Chriss

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 904

Exhibits in Support
of Direct Testimony

July 12, 2006

Determining the Total Amount of the RMA ($000)

From PPL/1102 Griffith/2

Description		RMA 299 ($000) PRO
Residential		
Residential	$	-
Total Residential		
Commercial & Industrial		
Gen. Svc. < 31 kW	$	(1,596)
Gen. Svc. 31 - 200 kW	$	4,714
Gen. Svc. 201 - 999 kW	$	959
Large General Service >= 1,000 kW	$	(1,340)
Partial Req. Svc. >= 1,000 kW	$	(90)
Agricultural Pumping Service	$	(2,646)
Agricultural Pumping - Other	$	-
Total Commercial & Industrial	$	1
Lighting		
Outdoor Area Lighting Service	$	-
Street Lighting Service	$	-
Street Lighting Service HPS	$	-
Street Lighting Service	$	-
Street Lighting Service	$	-
Recreational Field Lighting	$	-
Total Public Street Lighting	$	-

$	(1,596)	
$	(1,340)	
$	(90)	
$	(2,646)	
$	**(5,672)**	**Total RMA ($000)**

Application of Staff Proposal to RMA As-Filed by PacifiCorp

From PPL/1102 Griffith/1

Description	Sch No.	MWh	Pay-in kWh (RMA as-filed)	Contribution By Schedule ($)
Residential				
Residential	4	5,423,448	5,423,448,000	$ 3,463,547
Total Residential		**5,423,448**	**5,423,448,000**	
Commercial & Industrial				
Gen. Svc. < 31 kW	23	1,156,146	-	
Gen. Svc. 31 - 200 kW	28	2,076,347	2,076,347,000	$ 1,326,006
Gen. Svc. 201 - 999 kW	30	1,332,133	1,332,133,000	$ 850,733
Large General Service >= 1,000 kW	48	3,116,066	-	
Partial Req. Svc. >= 1,000 kW	47	208,767	-	
Agricultural Pumping Service	41	108,189	-	
Agricultural Pumping - Other	33	106,792	-	
Total Commercial & Industrial		**8,104,440**	**3,408,480,000**	
Lighting				
Outdoor Area Lighting Service	15	11,556	11,556,000	$ 7,380
Street Lighting Service	50	11,406	11,406,000	$ 7,284
Street Lighting Service HPS	51	15,575	15,575,000	$ 9,947
Street Lighting Service	52	1,828	1,828,000	$ 1,167
Street Lighting Service	53	8,459	8,459,000	$ 5,402
Recreational Field Lighting	54	836	836,000	$ 534
Total Public Street Lighting		**49,660**	**49,660,000**	
		Total Pay-In kWh:	**8,881,588,000**	**$ 5,672,000**

Total RMA:	$ (5,672,000)
Total Pay-In kWh:	8,881,588,000
Customer Payment ($/kWh):	0.00064
	x100
Customer Payment (c/kWh):	**0.064**
Per Month Contribution:	**$/month**
100 kWh/month:	$ 0.06
1,000 kWh/month:	$ 0.64
10,000 kWh/month:	$ 6.39
50,000 kWh/month:	$ 31.93
100,000 kWh/month:	$ 63.86

CASE: UE 179
WITNESS: Steve W Chriss

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 905

Exhibits in Support
of Direct Testimony

July 12, 2006

Staff's Estimated Rate Spread Using Staff's Revenue Requirement

	Sch. No.	From PPL/1102 Griffith/1 Present Revenues ($000) Base Rates (1)	Adders (2)	Net Rates (3)	PacifiCorp Proposed Base Rates (4)	PacifiCorp Difference (5) (4) - (1)	Apply Staff Multiplier To Determine Increase (6) (5) * (SM)	Staff Estimated Base Rates (7) (1) + (6)	PacifiCorp Adders (RMA Excluded) (8)	Staff Estimated Net Rates (9) (7) + (8)	Base Rates ($000) (10) (7) - (1)	Base Rates (%) (11) (7) / (1)	Net Rates ($000) (12) (9) - (3)	Net Rates (%) (13) (9) / (3)
Residential														
Residential	4	$ 422,917	$ 1,465	$ 424,382	$ 468,661	$ 45,744	$ 4,984	$ 427,901	$ 1,465	$ 429,366	$ 4,984	1.18%	$ 4,984	1.17%
Total Residential		$ 422,917	$ 1,465	$ 424,382	$ 468,661	$ 45,744	$ 4,984	$ 427,901	$ 1,465	$ 429,366	$ 4,984	1.18%	$ 4,984	1.17%
Commercial & Industrial														
Gen. Svc. < 31 kW	23	$ 90,122	$ (5,642)	$ 84,480	$ 102,015	$ 11,893	$ 1,296	$ 91,418	$ 821	$ 92,239	$ 1,296	1.44%	$ 7,759	9.18%
Gen. Svc. 31 - 200 kW	28	$ 110,982	$ 9,218	$ 120,200	$ 125,397	$ 14,415	$ 1,571	$ 112,553	$ 1,328	$ 113,881	$ 1,571	1.42%	$ (6,319)	-5.26%
Gen. Svc. 201 - 999 kW	30	$ 65,688	$ 3,650	$ 69,338	$ 76,447	$ 10,759	$ 1,172	$ 66,860	$ 852	$ 67,712	$ 1,172	1.78%	$ (1,626)	-2.34%
Large General Service >= 1,000 kW	48	$ 128,855	$ (278)	$ 128,577	$ 153,511	$ 24,656	$ 2,686	$ 131,541	$ 1,903	$ 133,444	$ 2,686	2.08%	$ 4,867	3.79%
Partial Req. Svc. >= 1,000 kW	47	$ 9,039	$ (29)	$ 9,010	$ 10,839	$ 1,800	$ 196	$ 9,235	$ 117	$ 9,352	$ 196	2.17%	$ 342	3.80%
Agricultural Pumping Service	41	$ 10,468	$ (2,524)	$ 7,944	$ 12,090	$ 1,622	$ 177	$ 10,645	$ 76	$ 10,721	$ 177	1.69%	$ 2,777	34.95%
Agricultural Pumping - Other	33	$ 915	$ -	$ 915	$ 915	$ -	$ -	$ 915	$ -	$ 915	$ -	0.00%	$ -	0.00%
Total Commercial & Industrial		$ 416,069	$ 4,395	$ 420,464	$ 481,214	$ 65,145	$ 7,098	$ 423,167	$ 5,097	$ 428,264	$ 7,098	1.71%	$ 7,800	1.85%
Lighting														
Outdoor Area Lighting Service	15	$ 1,316	$ 133	$ 1,449	$ 1,578	$ 262	$ 29	$ 1,345	$ 7	$ 1,352	$ 29	2.17%	$ (97)	-6.73%
Street Lighting Service	50	$ 1,137	$ 119	$ 1,256	$ 1,363	$ 226	$ 25	$ 1,162	$ 7	$ 1,169	$ 25	2.17%	$ (87)	-6.96%
Street Lighting Service HPS	51	$ 2,496	$ 249	$ 2,745	$ 2,991	$ 495	$ 54	$ 2,550	$ 11	$ 2,561	$ 54	2.16%	$ (184)	-6.71%
Street Lighting Service	52	$ 203	$ 19	$ 222	$ 243	$ 40	$ 4	$ 207	$ 1	$ 208	$ 4	2.15%	$ (14)	-6.15%
Street Lighting Service	53	$ 492	$ 57	$ 549	$ 590	$ 98	$ 11	$ 503	$ 5	$ 508	$ 11	2.17%	$ (41)	-7.53%
Recreational Field Lighting	54	$ 65	$ 6	$ 71	$ 78	$ 13	$ 1	$ 66	$ 1	$ 67	$ 1	2.18%	$ (4)	-5.05%
Total Public Street Lighting		$ 5,709	$ 583	$ 6,292	$ 6,843	$ 1,134	$ 124	$ 5,833	$ 32	$ 5,865	$ 124	2.16%	$ (427)	-6.79%
Total Sales to Ultimate Consumers		$ 844,695	$ 6,443	$ 851,138	$ 956,718	$ 112,023	$ 12,205	$ 856,900	$ 6,594	$ 863,494	$ 12,205	1.44%	$ 12,356	1.45%
Employee Discount		$ (418)	$ (1)	$ (419)	$ (463)			$ (463)	$ (1)	$ (464)	$ (45)		$ (45)	
Total Sales with Employee Discount		$ 844,277	$ 6,442	$ 850,719	$ 956,255			$ 856,437	$ 6,593	$ 863,030	$ 12,160	1.44%	$ 12,311	1.45%
AGA Revenue		$ 1,554		$ 1,554	$ 1,554			$ 1,554		$ 1,554				
Total Sales with Employee Discount and AGA		$ 845,831	$ 6,442	$ 852,273	$ 957,809	$ 111,978		$ 857,991	$ 6,593	$ 864,584	$ 12,160	1.44%	$ 12,311	1.44%

From PPL/1102 Griffith/2

PacifiCorp Increase:	$ 111,978.00
Staff Increase:	$ 12,200.00
Staff Multiplier (SM):	0.108949972

← INPUT

Staff Rate Mitigation Adjustment Estimates at 1.5X, 2X, and at a 5 Percent Cap (Staff Revenue Requirement)

	Sch. No.	Base Rates ($000)	Base Rates (%)	Net Rates ($000)	Net Rates (%)	Max Increase at RMA @ 1.5X ($000)	RMA Amount ($000)	Max Increase at RMA @ 2X ($000)	RMA Amount ($000)	Max Increase at 5% Cap ($000)	RMA Amount ($000)	Max Inc. Staff's Proposal ($000)	RMA Amount ($000)
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Residential													
Residential	4	$ 4,984	1.18%	$ 4,984	1.17%	$ 9,195	$ -	$ 12,260	$ -	$ 21,219	$ -	$ 12,260	$ -
Total Residential		$ 4,984	1.18%	$ 4,984	1.17%								
Commercial & Industrial													
Gen. Svc. < 31 kW	23	$ 1,296	1.44%	$ 7,759	9.18%	$ 1,830	$ (5,928)	$ 2,441	$ (5,318)	$ 4,224	$ (3,535)	$ 2,441	$ (5,318)
Gen. Svc. 31 - 200 kW	28	$ 1,571	1.42%	$ (6,319)	-5.26%	$ 2,604	$ -	$ 3,473	$ -	$ 6,010	$ -	$ 3,473	$ -
Gen. Svc. 201 - 999 kW	30	$ 1,172	1.78%	$ (1,626)	-2.34%	$ 1,502	$ -	$ 2,003	$ -	$ 3,467	$ -	$ 2,003	$ -
Large General Service >= 1,000 kW	48	$ 2,686	2.08%	$ 4,867	3.79%	$ 2,786	$ (2,081)	$ 3,715	$ (1,153)	$ 6,429	$ -	$ 3,715	$ (1,153)
Partial Req. Svc. >= 1,000 kW	47	$ 196	2.17%	$ 342	3.80%	$ 195	$ (147)	$ 260	$ (82)	$ 451	$ -	$ 260	$ (82)
Agricultural Pumping Service	41	$ 177	1.69%	$ 2,777	34.95%	$ 172	$ (2,605)	$ 229	$ (2,547)	$ 397	$ (2,380)	$ 1,192	$ (1,585)
Agricultural Pumping - Other	33	$ -	0.00%	$ -	0.00%	$ 20	$ -	$ 26	$ -	$ 46	$ -	$ 26	$ -
Total Commercial & Industrial		$ 7,098	1.71%	$ 7,800	1.85%								
Lighting													
Outdoor Area Lighting Service	15	$ 29	2.17%	$ (97)	-6.73%	$ 31	$ -	$ 42	$ -	$ 72	$ -	$ 42	$ -
Street Lighting Service	50	$ 25	2.17%	$ (87)	-6.96%	$ 27	$ -	$ 36	$ -	$ 63	$ -	$ 36	$ -
Street Lighting Service HPS	51	$ 54	2.16%	$ (184)	-6.71%	$ 59	$ -	$ 79	$ -	$ 137	$ -	$ 79	$ -
Street Lighting Service	52	$ 4	2.15%	$ (14)	-6.15%	$ 5	$ -	$ 6	$ -	$ 11	$ -	$ 6	$ -
Street Lighting Service	53	$ 11	2.17%	$ (41)	-7.53%	$ 12	$ -	$ 16	$ -	$ 27	$ -	$ 16	$ -
Recreational Field Lighting	54	$ 1	2.18%	$ (4)	-5.05%	$ 2	$ -	$ 2	$ -	$ 4	$ -	$ 2	$ -
Total Public Street Lighting		$ 124	2.16%	$ (427)	-6.79%		$ (10,761)		$ (9,100)		$ (5,914)		$ (8,138)
Total Sales with Employee Discount and AGA		$ 12,160	1.44%	$ 12,311	1.44%								

Hard Cap Level	5%
Irrigator Cap	15%

RMA @ 1.5X =	2.17%
RMA @ 2X =	2.89%

Application of Staff Surcharge Equity Proposal, Staff Revenue Requirement

	Sch. No.	Max Increase ($000) (1)	RMA Amount ($000) (2)	MWh (3)	Pay-in kWh (4)	Contribution by Schedule ($) (5)	Net Rates Including RMA ($000) (6)	Net Rates Including RMA (%) (7)
Residential								
Residential	4	$ 12,260	$ -	5,423,448	5,423,448,000	$ 4,969,273	$ 9,953	2.35%
Total Residential				**5,423,448**				
Commercial & Industrial								
Gen. Svc. < 31 kW	23	$ 2,441	$ (5,318)	1,156,146	-	$ -	$ 2,441	2.89%
Gen. Svc. 31 - 200 kW	28	$ 3,473	$ -	2,076,347	2,076,347,000	$ 1,902,468	$ (6,319)	-5.26%
Gen. Svc. 201 - 999 kW	30	$ 2,003	$ -	1,332,133	1,332,133,000	$ 1,220,576	$ (1,626)	-2.34%
Large General Service >= 1,000 kW	48	$ 3,715	$ (1,153)	3,116,066	-	$ -	$ 3,715	2.89%
Partial Req. Svc. >= 1,000 kW	47	$ 260	$ (82)	208,767	-	$ -	$ 260	2.89%
Agricultural Pumping Service	41	$ 1,192	$ (1,585)	108,189	-	$ -	$ 1,192	15.00%
Agricultural Pumping - Other	33	$ 26	$ -	106,792	-	$ -	$ -	
Total Commercial & Industrial				**8,104,440**				
Lighting								
Outdoor Area Lighting Service	15	$ 42	$ -	11,556	11,556,000	$ 10,588	$ (97)	-6.73%
Street Lighting Service	50	$ 36	$ -	11,406	11,406,000	$ 10,451	$ (87)	-6.96%
Street Lighting Service HPS	51	$ 79	$ -	15,575	15,575,000	$ 14,271	$ (184)	-6.71%
Street Lighting Service	52	$ 6	$ -	1,828	1,828,000	$ 1,675	$ (14)	-6.15%
Street Lighting Service	53	$ 16	$ -	8,459	8,459,000	$ 7,751	$ (41)	-7.53%
Recreational Field Lighting	54	$ 2	$ -	836	836,000	$ 766	$ (4)	-5.05%
Total Public Street Lighting				**49,660**				

Total RMA ($000):	$ **(8,138)**	**8,881,588,000**	100 kWh/month:	0.09
RMA Cap: 2.89%	**Customer Payment ($/kWh):**	(0.00092)	1,000 kWh/month:	0.92
		x100	10,000 kWh/month:	9.16
	Customer Payment (c/kWh):	(0.092)	50,000 kWh/month:	45.81
			100,000 kWh/month:	91.63

Application of Staff Surcharge Equity Proposal to RMA @ 1.5X, Staff Revenue Requirement

	Sch. No.	Max Increase at RMA @ 1.5X ($000) (1)	RMA Amount ($000) (2)	MWh (3)	Pay-in kWh (4)	Contribution by Schedule ($) (5)	Net Rates Including RMA ($000) (6)	Net Rates Including RMA (%) (7)
Residential								
Residential	4	$ 9,195	$ -	5,423,448	5,423,448,000	$ 6,571,182	$ 11,555	2.72%
Total Residential				**5,423,448**				
Commercial & Industrial								
Gen. Svc. < 31 kW	23	$ 1,830	$ (5,928)	1,156,146	-	$ -	$ 1,830	2.17%
Gen. Svc. 31 - 200 kW	28	$ 2,604	$ -	2,076,347	2,076,347,000	$ 2,515,753	$ (3,804)	-3.16%
Gen. Svc. 201 - 999 kW	30	$ 1,502	$ -	1,332,133	1,332,133,000	$ 1,614,045	$ (12)	-0.02%
Large General Service >= 1,000 kW	48	$ 2,786	$ (2,081)	3,116,066	-	$ -	$ 2,786	2.17%
Partial Req. Svc. >= 1,000 kW	47	$ 195	$ (147)	208,767	-	$ -	$ 195	2.17%
Agricultural Pumping Service	41	$ 172	$ (2,605)	108,189	-	$ -	$ 172	2.17%
Agricultural Pumping - Other	33	$ 20	$ -	106,792	-	$ -	$ -	
Total Commercial & Industrial				**8,104,440**				
Lighting								
Outdoor Area Lighting Service	15	$ 31	$ -	11,556	11,556,000	$ 14,002	$ (83)	-5.76%
Street Lighting Service	50	$ 27	$ -	11,406	11,406,000	$ 13,820	$ (74)	-5.86%
Street Lighting Service HPS	51	$ 59	$ -	15,575	15,575,000	$ 18,871	$ (165)	-6.02%
Street Lighting Service	52	$ 5	$ -	1,828	1,828,000	$ 2,215	$ (11)	-5.15%
Street Lighting Service	53	$ 12	$ -	8,459	8,459,000	$ 10,249	$ (31)	-5.66%
Recreational Field Lighting	54	$ 2	$ -	836	836,000	$ 1,013	$ (3)	-3.62%
Total Public Street Lighting				**49,660**				

Total RMA ($000):	**$ (10,761)**	**8,881,588,000**	100 kWh/month:	0.12
RMA Cap %: 2.17%	**Customer Payment ($/kWh):**	(0.00121)	1,000 kWh/month:	1.21
		x100	10,000 kWh/month:	12.12
	Customer Payment (c/kWh):	(0.121)	50,000 kWh/month:	60.58
			100,000 kWh/month:	121.16

CASE: UE 179
WITNESS: Steve W Chriss

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 906

Exhibits in Support
of Direct Testimony

July 12, 2006

Application of Staff RMA Proposal, RMA @ 2X, Staff Revenue Requirement

Total RMA:	$	(8,137,818)

RMA $/year:		
Gen. Svc. < 31 kW	$	(5,318,151)
Large General Service >= 1,000 kW	$	(1,152,736)
Partial Req. Svc. >= 1,000 kW	$	(81,815)
Agricultural Pumping Service	$	(1,585,117)

kWh/year:	
Gen. Svc. < 31 kW	1,156,146,000
Large General Service >= 1,000 kW	3,116,066,000
Partial Req. Svc. >= 1,000 kW	208,767,000
Agricultural Pumping Service	108,189,000

Schedule 299 Rate:	**c/kWh**
Gen. Svc. < 31 kW	(0.460)
Large General Service >= 1,000 kW	(0.037)
Partial Req. Svc. >= 1,000 kW	(0.039)
Agricultural Pumping Service	(1.465)

CASE: UE 179
WITNESS: J.R. Gonzalez and
Ed Durrenberger

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1000

Direct Testimony

July 12, 2006

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

A. My name is J.R. Gonzalez and my name is Ed Durrenberger. We are sponsoring joint direct testimony on Power Delivery New Projects in UE 179. We are both employed by the Oregon Public Utility Commission and our business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. The Witness Qualification Statement for J.R. Gonzalez is found in Exhibit Staff/1001. The Witness Qualification Statement for Ed Durrenberger is found in Exhibit Staff/201.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. We prepared Exhibit Staff/1002, consisting of 28 pages.

Q. DO YOU PROPOSE AN ADJUSTMENT TO THE COMPANY'S POWER DELIVERY NEW PROGRAMS INCREASE?

A. Yes we do. The Power Delivery (PD) New Programs are described in the testimony of Paul Wrigley in PPL/900 pages 21-22 and PPL/901, Tab 4.10. Our adjustment is S-11 in Exhibit Staff/202. The Company has requested an increase to Operating and Maintenance (O&M) expenses for some new transmission and distribution programs. The new programs deal with safety, reliability, load growth and certain administrative and general (A&G) expenses. The Company's proposal would increase the system-wide budget permanently by over $19 million, and includes an increase to the O&M head count by approximately 160. The Oregon-allocated revenue requirement would be $3,903,400.

Q. HAVE YOU EVALUATED THIS REQUESTED INCREASE?

A. Yes, we have. Because of the size of the requested annual increase we have spent a considerable amount of time evaluating the Company's request and have discussed the new programs with Mr. Darrell Gerrard, VP T&D Engineering & Asset Management at Pacific Power-on more than one occasion.

Q. WHAT ADJUSTMENTS DO YOU PROPOSE?

A. The PD New Programs adjustment is broken down by the Company into a number of elements (*See* Exhibit Staff/1002 pages 2-16). The first element is a Maintenance of Miscellaneous Transmission Plant component. The Company originally requested an increase of $9.1 million which it updated recently to $10.8 million (the A&G adjustment was reduced correspondingly leaving the overall PD New Programs total unchanged). The adjustment has two components; one is additional transmission line vegetation management programs which are expected to cost $1.2 million each year. The other is a pole test and treat cycle upgrade in jurisdictions outside Oregon and includes system-wide substation major equipment maintenance and security upgrades that are projected to cost $9.6 million per year. The enhanced pole and substation maintenance is also projected to increase head-count by 55 on an on-going basis

Q. WHAT IS YOUR ASSESSMENT OF THESE TRANSMISSION NEW PROJECTS?

A. The Company's requested increase is very large. It represents a 30% increase in the entire transmission budget after disallowing for wheeling costs which have nothing to do with maintenance. Nonetheless we would propose to accept the transmission line vegetation control new programs adjustment costing $1.2 million annually. Although vegetation control in the state is in the best shape ever, the Company has made a convincing case for additional transmission line vegetation control which we believe saves money in the long run.

Q. WHAT ABOUT THE SECOND COMPONENT OF THE TRANSMISSION NEW PROJECTS?

A. For the second transmission component, the pole test and treat and substation maintenance and security upgrades, we would propose adjusting the Company's request as follows:

1. The amount of the requested increase for pole test and treat and substation maintenance is too large. We would reason that improving the pole test and treat in other states from a 16 year cycle to a 10 year cycle is a 60% increase in program activities. We propose an adjustment that would increase the non-Oregon overhead transmission line budget by 60% to cover the additional costs.
2. Transmission substation maintenance tasks discussed in the Company's Supplemental Data Response OPUC 331 (*See* Exhibit Staff/203, pages 10-

15) do not appear to represent new incremental tasks that have not been required in the past. Additionally the Company has been meeting its Service Quality metrics for system reliability. We cannot see that an increase to the escalated budget is justified. Although the Company stated that the adjustment in this category included improvements to security monitoring in transmission substations, they provided no specifics about programs or costs. In this case we reject the request as unwarranted.

Q. ARE THERE OTHER ELEMENTS TO THE PD NEW PROGRAM ADJUSTMENT?

A. Yes. Another element to the PD New Projects is Distribution Plant new projects which includes IT projects, Support staff for capital and O&M, an EMS/SCADA O&M component, Grid Ops Security, Mapping, Field Operations and Transport /logistics support and Health and Safety and environmental programs.

Q. DO YOU PROPOSE TO ADJUST THE NEW DISTRIBUTION PROGRAMS?

A. Yes, the Distribution Plants Programs include a total of $10.9 million in increases and $4.9 million in efficiency savings for a net increase of $6 million (system-wide). We propose allowing $7.5 million in new program increases and $4.9 million in efficiencies for a net increase of $2.6 million to new Distribution programs.

Q. HOW DID YOU ARRIVE AT THIS TOTAL?

A. We evaluated the Company's Testimony and supporting exhibits, requested further data in Data Requests and met with PacifiCorp representatives both by phone and in person to discuss the new PD programs. There are a large and varied number of programs included in this element. We propose that the PD New Programs distribution adjustment increase include an allowance for $4.3 million in 21st Century, EMS/SCADA new annual O&M expense (including adding an additional 35 new employees). We would also allow $400,000 to increase Grid Ops Security and $300,000 for one-half of the Health and Safety new programs, which benefit shareholders as well as customers by keeping costs down. We agree that an incremental $500,000 for the Raptor Protection program new initiatives should be added to the budget. In addition we are allowing $2.0 million in support of the distribution O&M programs. The basis for this allowance is primarily due to the fact that the overall budget for distribution O&M expense is reasonable for a company the size of PacifiCorp in Oregon.

Q. PLEASE CONTINUE.

A. Included in the PD New Programs Adjustment proposed by the Company were increases in O&M that were caused by customer growth. These increases appear warranted. They include $1.8 million in new metering, $900,000 in growth related customer service, and a $1.3 million change in bad debt that was examined by Staff Witness Paul Rossow and addressed elsewhere. Finally the company included an A&G new program increase of $2.5 million that was subsequently reduced to $1.1 million due to reclassification of some new program costs into Transmission as noted above. The description of these new cost increases were Communications Maintenance resulting from upgrades and growth. Staff proposes to adjust the A&G increase to $600,000; this represents a 2.5% escalation to the maintenance of the general plant account to accommodate customer growth.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENT TO THE COMPANY'S PD NEW PROGRAMS REQUEST.

A. As requested by the Company's filing, the Power Delivery New Programs adjustment would increase annual costs $19.6 million (system-wide) and increase head count by approximately 160. We propose, for the reasons given above, that the system wide Power Delivery New Programs costs should increase at a more modest yet significant rate and propose an increase of $7.3 million (system-wide). Applying the appropriate allocation factors and including efficiencies that the Company suggests can be realized, the net effect on an Oregon-allocated basis is to reduce Company's requested increase for PD New Programs by $4.9 million.

Item	Company Adjustment	Staff Position	System Difference	Oregon Allocated Staff Adjustment
Transmission Plant Maint.	$10,800	$4,526	$(6,274)	($1,671)
Distribution Plant Maint.	$6,000	$2,600	($3,400)	($1,008)

Distribution Plant (OR)	($2344)	$(4,400)	($2.056)	($2,056)
Metering	$1,809	$1,809	$0	$0
Customer Receipts	$891	$891	$0	$0
Uncollectibles	$1,300	$1,300	$0	$0
Gen Maint A&G	$1,100	$600	($500)	($142)
Total	$19,556	$7,326	($12,230	($4,876)

Q. DOES THIS CONCLUDE YOUR JOINT TESTIMONY?

A. Yes it does.

CASE: UE 179
WITNESS: J. R. Gonzalez

PUBLIC UTILITY COMMISSION
OF
OREGON

EXHIBIT STAFF 1001

Witness Qualification Statement

July 12, 2006

WITNESS QUALIFICATION STATEMENT

NAME: J.R. Gonzalez

EMPLOYER: Oregon Public Utility Commission

TITLE: Program Manager, Utility Safety and Reliability

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

EDUCATION: Master in Business Administration (1984) – City University
Bachelor of Science, Mechanical Engineering (1981) - Portland State University
Associate Degree in Machines and Motors (1976) - Campinas State University

PROFESSIONAL LICENSES: Registered Professional Engineer in the States of Oregon and Washington

EXPERIENCE: I have been employed by the Oregon Public Utility Commission since May 2004 as program manager of Utility Safety and Reliability.

Before coming to the PUC, I spent two years in my own consulting firm where I supported Rogers International Consulting, L.L.C. with the Tropical Hardwood Project for environmentally safe wood poles and crossarms in partnership with EPRI. Prior to my consulting activities I worked eight years on wireless telecommunications and telemetry programs in Europe, Latin America and Canada.

From 1981 through 1997, I worked at Puget Sound Power & Light Co, now Puget Sound Energy, where I started as an engineer in power generation. Next, I worked in transmission and distribution engineering, then customer programs including conservation, voltage stability and power quality. After that, I worked in transmission and distribution operations, where I as the lead consulting engineer managing PSE's maintenance programs. I performed several failure investigations of large equipments, supported the standardization process of all commodities at Puget Power, audited field practices and commodity suppliers, and wrote work practices. Another area I was actively involved with was training programs for operations and engineering personnel. My last position at PSE was manager of the metering, distribution transformers, and test, repair and calibration department.

CASE: UE 179
WITNESS: J. R. Gonzalez and
Ed Durrenberger

PUBLIC UTILITY COMMISSION OF OREGON

EXHIBIT STAFF 1002

Exhibit in Support of Direct Testimony

July 12, 2006

OPUC 142: Referring to O&M adjustment 4.10, Power Delivery Programs, please detail each of the programs included in this adjustment by providing the work scope, budget, implementation schedule and cost justification for each.

Base Period - FY March 31, 2005; Test Period - CY December 31, 2007

$ in Millions		Adjustment Amount	Work Scope		CY07 Budget	Implementation Schedule	Cost Justification
Transmission Vegetation		1.2	The Vegetation Management department has identified main grid and local transmission lines that require prunning to maintain clearance requirements. The plan is line segment specific.		5.5	Full implementation of these identified lines will be complete by the end of FY 07.	Ensuring that we meet NESC requirements and deliver safe and reliable power to our customers.
Transmission Maintenance		7.9	Changed Pole Test and Treat cycle in CA, ID, UT and WY to 10 years. Separation of Local Transmission Substation assets from distribution assets in FY06 accounts for the majority of the increase. Increased funding for Substation Major equipment preventative and corrective maintenance activities. Increased costs of maintenance on security monitoring equipment in critical path substations.		17.6	These programs are scheduled to start 4/1/06 and run indefinitely.	Pole test and treat cycles now 10 years due to expected life of fumigant (8-10 years) in order to increase life expectancy of pole population. Increase in substation equipment and relay maintenance activities of 30% to bring all equipment on recommended cycles. Security monitoring of critical path substations is a federal requirement.
Total Transmission		**9.1**			**23.1**		
IT Project Expense		1.0	Technology framework studies and continuing to enhance and upgrade our customer call center systems and dispatch and outage management systems.		2.5	These programs are currently scheduled to start during the summer of 2006 and run through calendar year 2007.	Increase due to new programs implemented to achieve efficiencies that will have long-term benefits to our customers.
Increased Eng. & AM to support Capital and O&M		1.6	Increase engineers, mappers and construction design employees		9.0	Starting during December 2005 continuing into summer 2006.	Additional positions are necessary to keep up with the growing capital and maintenance programs
Programs (21st Century, EMS/SCADA, etc.)		4.3			17.0		
Increased Support Costs		4.0			54.0		
BPI, Street Ltg, Grid Ops, etc	1.2		Grid Ops Security increase $0.4 million to comply with NESC Requirements, Joint Use inventory for Oregon $1.0 million. Partially offset by ($0.2) of changes in capitalizations.	6.0		Plan to be implemented in FY 07	NESC Requirement, Commitment to Regulators to complete the Oregon Joint Use Inventory
Mapping Contractors, etc.	0.7		Entry of maps in to OMS and FastGate to ensure consistent data quality between the two systems.	2.5		The majority of these people have been hired.	Allows Dispatch and Field Operations to closely coordinate outage restoration. These costs were partially offset by efficiencies.
Field Ops support	0.5		To ensure that our contractors are fixing conditions and we are in compliance to meet NESC Code Requirements.	5.0		This was fully implemented in FY 06.	The compliance employees are here to ensure that our contractors are following NESC requirements and fixing conditions to ensure that our customers have safe and reliable power.
Transport/Logistics	0.5		The fleet has grown and we have incurred additional costs to maintain vehicles.	28.0		Already Implemented	Offset by efficiencies

OPUC 142: Referring to O&M adjustment 4.10, Power Delivery Programs, please detail each of the programs included in this adjustment by providing the work scope, budget, implementation schedule and cost justification for each.

Base Period - FY March 31, 2005; Test Period - CY December 31, 2007							
$ in Millions		Adjustment Amount	Work Scope		CY07 Budget	Implementation Schedule	Cost Justification
Health, Safety and Environmental Programs	1.1		Mandated and the addition of new health, safety and environmental programs has resulted in an increase in safety and training positions	12.5		The safety program started during FY06 with six new safety positions have been filled during FY06 and will continue into 2007. New raptor protection programs and environmental spill programs were also implemented during FY06.	Safety managers are required to complete and implement safety plans and programs to improve health and safety performance of our employees, as well as educute our customers on public safety. The environmental and other safety-related programs are necessary to meet regulatory requirements and policy commitments.
Efficiencies		(4.9)	Added efficiencies to offset some additional programs		(4.9)	This will be implemented as we try to offset new programs	This is actually a reduction to our O&M.
Total Distribution		**6.0**			**77.6**		
Metering Programs		**1.8**	Growth related to additional customers in 2007 when compared to FY05		**52.5**	The costs will be implemented as customers increase. The adjustment amount reflects the CY2007 sustained amount above FY2005.	Power Delivery has used a 2.1% growth rate for these additional costs. It is assumed as the customer numbers continue to grow, we will need additional staff to read and maintain the additional meters.
New Customer Service Programs and Growth		**0.9**	Growth related to additional customers in 2007 when compared to FY05		**54.0**	The costs will be implemented as customers increase. The adjustment amount reflects the CY2007 sustained amount above FY2005.	Power Delivery has used a 2.1% growth rate for these additional costs. It is assumed as the customer numbers continue to grow, we will need additional staff to handle increase call volume at the call centers.
Change in Bad Debt		**1.3**	FY05 was benefited by a change in reserve factors during the year.		**11.0**	It is expected that the bad debt will not benefit from a change in reserve during 2007	The uncollectible accounts is budgeted at 0.37% of retail revenue for CY2007. This experience is better than the 0.40% we had in FY05.
Communications Maintenance		**2.5**	Combination of growth of communications systems, installation of fiber, and separation of transmission and distribution assets. Preventative maintenance funding for RTU's increased.		**4.5**	Communication systems growth has accelerated especially along the Wasatch Front including the installation of fiber optics between critical substations and dispatch. Increased RTU funding began in FY06.	Due to access issues to communications sites, the timing of when communications maintenance work is performed is a portion of the cost difference.
Total System-Wide Programs		**21.6**			**222.7**		
Situs Programs							

OPUC 142: Referring to O&M adjustment 4.10, Power Delivery Programs, please detail each of the programs included in this adjustment by providing the work scope, budget, implementation schedule and cost justification for each.

Base Period - FY March 31, 2005; Test Period - CY December 31, 2007

$ in Millions		Adjustment Amount	Work Scope		CY07 Budget	Implementation Schedule	Cost Justification
Oregon Vegetation		(5.3)	Over the last few years desired cycle times have been accelerated and additional money spent to bring Oregon vegetation management on an optimal cycle. Oregon has a 4 year optimal cycle which is based on historical costs per mile, tree density and species of trees. Oregon is now nearly all on cycle and costs per year for tree trimming are decreasing as it cost less to maintain the optimal cycles. The tree trimming costs are a function of the prudent industry cycle times, number of miles, and cost per mile based on tree species and density. We started moving toward optimum cycles to improve service reliability over our service territory.		14.5	The efficiencies is fully recognized by the end of FY 07.	Ensuring that we meet NESC requirements and deliver safe and reliable power to our customers.
Oregon Distribution Maintenance		2.9	Increased funding for bird related work in Southern OR. Increased Substation Major Equipment preventative maintenance including CB and relay overhauls.		17.6	The bird work program began in FY06 and will continue through FY10. The substation and relay maintenance activities will begin 4/1/06.	PacifiCorp commitments to USDFW on bird work due to high raptor mortality in specific Southern OR locations. Increase in substation equipment and relay maintenance activities of 30% to bring all equipment on recommended cycles.
		(2.3)			**32.1**		
Total Adjustment		**19.3**			**254.8**		

OPUC Data Request 331

The following are questions related to OPUC 142 and PacifiCorp adjustment 4.10:

a. IT project O&M expense increases; Does PacifiCorp plan to consolidate its IT Systems with the MEHC or any of its energy affiliates? If so does this increase include expenses for that purpose? Would these be one time costs?

b. What IT programs will be implemented above and beyond what is currently in place? Please list not only the programs but the capital cost, program schedule and each program's ongoing O&M expenses.

c. What is inadequate about the current IT systems?

d. Will the current CADOPS system continue to be used? How will it be improved?

e. What are the "efficiencies that will have long term benefits to …customers"? How and when will the customers realize the benefits?

f. Concerning Transmission Maintenance O&M expense increases; Are some of these costs the result of post MEHC acquisition organizational changes for instance splitting distribution from generation into different subsidiaries? Are the separation of local transmission substation assets from distribution assets a 'one time cost' or ongoing costs? Please explain your answer.

g. The Oregon service territory is already using the Test and Treat cycle you describe; have other states contributed to the Oregon local transmission and distribution maintenance costs over the last five years and if so how much?

h. O&M adjustment for Health, Safety and Environmental Programs; Which programs are in Oregon? How many new safety employees are assigned to Oregon and what are the regulatory requirements for implementing these new programs, what are the policy requirements?

i. O&M increases related to Oregon Distribution Maintenance; Please detail which Oregon substations will be receiving 30% more maintenance on an ongoing basis, what specifically will be done and why. How did the company came up with the costs? Are the costs associated with the Southern Oregon bird program also counted in the costs for Health, Safety And Environmental programs? What are the bird program costs?

j. The Maintenance O&M increases for Communication Systems; What are the specific projects that cannot be funded through routine O&M budgets and how do Oregon customers benefit from communication maintenance growth along Utah's Wasatch Front? Are any of the increases due to structural changes driven by the reorganization of the company into distribution and generation subsidiaries? Are any of the increases driven by integration of PacifiCorp's Communication system with that of the new parent organization or its energy subsidiaries?

k. How many Full Time Employees have been or will be added to the workforce as a result of the PD new programs adjustment 4.10? Are any of the adjustments to workforce included in the test period head count and labor costs in section 4.3? If not, are wages, salaries and benefit costs included in this O&M adjustment? If so why is this appropriate?

Response to OPUC Data Request 331

a. Yes, PacifiCorp plans to examine opportunities to consolidate IT systems with MEHC or other affiliates but specific consolidations have not yet been identified. This increase does not include expenses for this purpose. The O&M expense increase is expected to remain in future years; it is not intended to be a one-time cost.

b. There will be a number of IT programs implemented as part of improving/maintaining stability of existing systems or enhancements designed to make our electricity delivery system more reliable and our customer service more responsive. The programs that will be implemented include three large efforts targeted at replacing or upgrading core applications that provide critical services to customers including management of the electrical network, managing outages, and taking customer calls. These projects are to be implemented in a manner that ensures these core technologies are stable and supported by their vendor in order to prevent failures. These programs include:

- <u>EMS/SCADA Replacement Project Phase 2</u>: The CY 2007 capital spending is estimated to be $3.2m with the total capital cost projected to be approximately $9.65m. This may continue to change somewhat as costs are moved from other parts of the RANGER program into this workstream. Current plans are to implement the majority of this project by November 2006 with some remaining workstreams going into July 2007. The ongoing O&M for the complete RANGER program (of which this is one part) is estimated to be $5.3m per year after implementation.

- <u>CADOPS Windows Upgrade:</u> The CY 2007 capital amount is expected to be approximately $1.5m and the total project capital cost is expected to be $2.3m. The schedule for this project is under development. The final implementation date could vary from August 2007 to August 2008, depending on decisions currently under consideration. This project is not expected to incur ongoing O&M incremental costs since it is an upgrade of the existing CADOPS application and is not expected to introduce new systems or require additional support staff.

- Customer Services Agent Access Router and Interactive Voice Response Replacement Project: The Company is still reviewing technology/vendor options for this project. The actual capital costs of the project are not yet known as the specific technology solution has not been chosen. Current rough estimates are $3m in CY 2007 and total project capital of $6.5m, with the project being implemented in phases through CY 2007 and CY 2008.. Ongoing O&M expense has been estimated at approximately $200k per year after implementation.

c. Many of these initiatives are targeted for IT systems that are obsolete, that is, no longer supported by the vendor. If the systems remain in the current obsolete state, there is a large likelihood of failure and if the system fails, the vendor may not be able to provide assistance in restoring the system.

d. Yes, the current CADOPS system will continue to be used, the CADOPS Windows Upgrade project is an effort to bring the application up to the current version supported by the vendor in order to remain in compliance with the software maintenance agreement.

e. Please see Response to part b., above for the projects that have been identified and their purposes. Customers will benefit by having updated fully supported key systems. These projects will be phased in over 2 years - 2007 thru 2008 and customers will begin to see the benefits of the projects in that time frame.

f. The Transmission Maintenance O&M expense increases are not the result of post MEHC acquisition organizational changes.

The separation of substation assets between distribution and local transmission will be an ongoing cost, because this sets the new baseline for these types of expenditures. Now that the assets are established in their asset class all expenses associated with the classification will be budgeted and reported accordingly

g. Other states have contributed to the local transmission, because Local Transmission is treated as an allocated cost. The following is the total amount of Local Transmission Test and Treat that was allocated based on factors (i.e. SG for the current case):

FY03 $400.0k FY04 $293.5k FY05 $328.6k
FY06 $874.5k

h. PacifiCorp has generated an assurance plan and a long term safety plan that will both show efficiencies and add value to the organization. The mandated training and apprenticeships will continue as "status quo" but will be looked at a future date for efficiencies.

The company is committed to keeping 100% compliance with the environmental and bird management programs. These will be part of PacifiCorp's long term plans that will look at any efficiency gains that could result in these programs without compromising the Company's obligations.

No new safety employees have been added for Oregon and the Company has added no additional safety resources.

The policy requirements are built into the plans to maintain a consistent message across the organization and to insure compliance with all required aspects of the Health, Safety and Environmental departments.

i. PacifiCorp's method of tracking substation maintenance work does permit identification of substations requiring 30% more maintenance. During the monthly inspection process for substations, corrective maintenance items are identified. Please see Attachment OPUC 331 i for a listing of substations identified as needing corrective maintenance. The substation name and a brief description of the work are listed in column D. Column E, "Plan Work," is the estimated number of labor hours.

Based on the orders created from the information presented in Attachment OPUC 331.i, man hours, material and contract costs were estimated to help establish the budget.

Regarding costs associated with the Southern Oregon bird program, the cost of the survey work is included in the Health, Safety and Environmental programs. All of the corrective maintenance activities resulting from the survey work are not included in the Health, Safety and Environmental programs. They are captured in the corrective maintenance budget at the levels shown below.

FY05 $350k FY06 $550k FY07 $850k

j. We have increased maintenance costs for the mobile radio replacement project. The new radio system will require more hill top sites that need to be maintained on an ongoing basis.

Communication assets in the Wasatch Front help provide reliable communication systems for line protection and remedial action schemes that increase the overall reliability of the main grid transmission system, which provides a service reliability benefit to Oregon customers.

No, the increases are not due to structural changes driven by the reorganization of the company.

No, the increases are not driven by the integration of PacifiCorp's Communication system with that of the new parent organization or its energy subsidiaries.

k. See Attachment OPUC 331.k.

Attachment OPUC 331.i

Rpt Dist	State	Created on	SUBSTATION NAME: identified work	PlanWork
Albany	OR	4/14/2006	35TH ST: BO INSULATORS	4
Albany	OR	4/13/2005	ALBANY PLT:JOINT METER TESTS	0
Albany	OR	1/19/2006	ALBANY PWR:BUILD CART FOR BOOSTER PMP	40
Portland	OR	11/3/2005	Albina 3P534 switch repair	16
Portland	OR	2/15/2005	Albina 5P111 add animal guards	8
Portland	OR	11/30/2005	Albina 5P111 disconnects hard to operate	24
Portland	OR	6/22/2005	Albina 5P127 b/o lower cabinet heater	16
Portland	OR	3/3/2005	Albina 5P13 bypass SW needs maint	16
Portland	OR	2/15/2005	Albina 5P150 add animal guards	8
Portland	OR	2/15/2005	Albina 5P196 add animal guards	8
Portland	OR	2/15/2005	Albina 5P200 add animal guards	8
Portland	OR	2/15/2005	Albina 5P40 add animal guards	8
Portland	OR	2/15/2005	Albina 5P60 add animal guards	8
Portland	OR	2/15/2005	Albina 5P66 add animal guards	8
Portland	OR	2/15/2005	Albina 5P70 add animal guards	8
Portland	OR	3/3/2005	Albina 5P70 piston leaking water	16
Portland	OR	2/15/2005	Albina 5P91 add animal guards	8
Portland	OR	2/15/2005	Albina 5P92 add animal guards	8
Portland	OR	1/31/2006	Albina 69kv bus b/o light socket	8
Portland	OR	3/14/2006	Alderwood 5P22 DPU relay repair	4
Portland	OR	9/28/2005	Alderwood lightning arrestor-damage?	8
Portland	OR	10/27/2005	Alderwood T3970 relay setting change	24
Medford	OR	9/26/2005	APPLEGATE SUB-LOW N2 ON T3975	2
Medford	OR	2/10/2005	Ashland repair station heat	4
Walla Walla OR	OR	11/1/2005	ATHENA - R0229 REPAIR OIL LEAK	16
Medford	OR	4/25/2006	BEACON SUB-REPLACE JUNCTION BOXES	0
Bend	OR	4/12/2006	BEND MOBILE T3830 BAD O/C RELAY ON HI SI	40
Bend	OR	4/5/2006	BEND PLNT SUB-REPAIR FENCE	0
Bend	OR	4/24/2006	BEND PLNT-TRF0981 LEAKING FROM RADIATOR	120
Bend	OR	3/24/2006	BEND-MOBILE T3830 CORRECT WIRING OF CT'S	0
Walla Walla OR	OR	2/7/2005	BLALOCK - B/O TEMP GUAGE	0
Walla Walla OR	OR	1/17/2006	BLALOCK- R1676 MOISTUR AMETER GLASS CS	8
Portland	OR	10/21/2005	Bloss 5P172 C phase amp meter b/o	8
Portland	OR	12/28/2005	Bloss STA battery needs cleaned	8
Portland	OR	2/15/2005	Bloss T3896 add animal guards	16
Portland	OR	10/31/2005	Bloss T3896 relay setting change	32
Portland	OR	2/15/2005	Bloss T3907 add animal guards	16
Portland	OR	10/21/2005	Bloss T3907 B phase AC volt mtr b/o	8
Portland	OR	4/6/2006	Bloss T3907 oil leak-cooling fin manifld	8
K. Falls	OR	4/4/2006	BONANZA-BYPASS DISCONNECT IS BENT	32
Medford	OR	6/8/2005	BROOKHURST-LOW LTC OIL INDICATION	0
Medford	OR	3/28/2006	BROOKHURST-RPLC B/O CONTACT ON 5R131	0
Albany	OR	1/20/2006	BROWNSVILLE: 4M17 R/R LATCH CTRL BOX	8
Albany	OR	2/17/2006	BUCHANAN: 4M130 RPL COUNTER	8
Albany	OR	5/12/2005	BUCHANAN: 4M131 CLEAN & INSPECT	16
Albany	OR	5/10/2005	BUCHANAN: 4M143 CLEAN & INSP. A PHASE	8
Albany	OR	1/17/2006	BUCHANAN:4M130 TARGETS DROPPING	8
Albany	OR	5/11/2005	BUCHANAN:CLEAN/ INSP LINE SIDE DISC	8
Albany	OR	5/10/2005	BUCHANON:CLEAN & INSP CAP BNK FUSE	8
Walla Walla OR	OR	8/9/2005	BUCKAROO - 5W202 OIL LEAK @ INDICATOR	16
Portland	OR	2/15/2005	Cannon Beach T3656 add animal guards	16
Medford	OR	12/5/2005	CAVE JCT-REPAIR CIRCUIT SW./OUTAGE	0
Medford	OR	2/27/2006	CAVEMAN - INSTALL BIRD GUARD ON T3289	0
Medford	OR	5/19/2005	Caveman, T-3289 needs painting	80
Medford	OR	2/22/2006	CAVEMAN-RPLC VELCON FILTER PIPING	0
Bend	OR	3/8/2006	CHERRY LANE-5D295 DPU POWER SUPPLY FAIL	40
K. Falls	OR	3/6/2006	CHILOQUIN MARKET-GRND GRID EXPOSED	0

Attachment OPUC 331.i

Rpt Dist	State	Created on	SUBSTATION NAME: identified work	PlanWork
K. Falls	OR	3/1/2005	CHILOQUIN-TRF3869 GASSING	0
Portland	OR	11/16/2005	Columbia 5P472 disconnect adjustment	24
Portland	OR	12/21/2005	Columbia 2 batteries w/cracked term base	4
Portland	OR	5/16/2005	Columbia 2P72 IR hot spots C phase	16
Portland	OR	5/16/2005	Columbia 3P765 IR hot spots C phase	16
Portland	OR	5/16/2005	Columbia 5P268 IR hot spots line disc.	16
Portland	OR	6/22/2005	Columbia batteries need cleaning	4
Portland	OR	10/21/2005	Columbia CAP0455 blown fuse	8
Portland	OR	6/3/2005	Columbia PLC/HMI stalled	10
Portland	OR	11/30/2005	Columbia repair fence	4
Portland	OR	10/21/2005	Columbia T3501 oil leak from main tank	8
Roseburg	OR	4/25/2006	COQUILLE SUB:4C41:REPLACE ARRESTER	0
Albany	OR	3/4/2005	CROWFOOT: T-3257 LTC OIL FILTER LEAKING	40
Portland	OR	10/21/2005	Cully 5P290 b/o counter	8
Portland	OR	4/6/2006	Cully CAP0485-2 small leaking caps	8
Portland	OR	4/4/2005	Cully MC roof bushings-add animal guards	16
Portland	OR	6/21/2005	Cully T3704 replace LTC contactors	80
Bend	OR	4/4/2006	CULVER-BATERY CHARGER ALARM	0
Albany	OR	12/19/2005	DALLAS: 2M150 NOT CLOSING BY SCADA	24
Albany	OR	4/3/2006	DALLAS: T3658 LTC OUT OF STEP	20
Albany	OR	3/27/2006	DALLAS: T3671 RPL LTC CTRL RELAYS	40
Albany	OR	1/30/2006	DALLAS: T3671 RPL TEMP GAUGE	8
Albany	OR	6/29/2005	DALLAS:4M201 INSULATOR CHIPPED	10
Albany	OR	12/5/2005	DALLAS:CHG0169:BATTERY VOLTAGE LOW	18
Albany	OR	5/10/2005	DEVILS LAKE:4A312 CLEAN/INSPECT BUS DISC	8
Roseburg	OR	4/13/2006	EMPIRE:T1185:N2 GAGE W/ALRM NOT WORKING	4
Walla Walla OR	OR	1/30/2006	ENTERPRISE - T2068 B/O GAUGES	8
Portland	OR	2/15/2005	Fern Hill T3973 add animal guards	16
Portland	OR	6/22/2005	Fernhill 5A51 heater strip & fan b/o	8
Portland	OR	1/24/2006	Fernhill needs photo cell added	4
Medford	OR	8/3/2005	Fielder Cr., 2R761, C phase vac. bottle	0
K. Falls	OR	4/5/2006	FORT KLAMATH-NEEDS GRAVEL	16
Roseburg	OR	4/7/2006	GARDEN VLY:T3544:B/O FANS IN LTC OIL CAB	4
Roseburg	OR	5/2/2006	GAZLEY:CB5U63:REPLACE BROKEN ROD	4
Portland	OR	9/29/2005	Gearhart cross arms rotten-need replaced	32
Portland	OR	2/15/2005	Gearhart T920, 921, 922 add animal guard	16
Portland	OR	2/15/2005	Gordon Hollow 4K1 add animal guards	8
Portland	OR	2/15/2005	Gordon Hollow R433 add animal guards	16
Albany	OR	8/12/2005	GOSHEN: BATT CHRGR FAILURE ALARM	4
Albany	OR	1/24/2006	GOSHEN: T-3542 RPL WINDING TEMP GAUGE	10
Albany	OR	2/8/2006	GRANT ST: LTC VAC BTL FAILURE ALARM	40
Albany	OR	12/22/2005	GRANT ST:T-3789 PARALLEL SCHEME	8
Albany	OR	4/6/2006	GRANT: T-3268 HIGH VOLT. ALARM	10
Medford	OR	1/25/2005	Grants Pass 2R5 compressor leak	6
Portland	OR	2/15/2005	Grass Valley 8K4 add animal guards	8
Portland	OR	1/24/2006	Grass Valley need flood light base	4
Portland	OR	2/15/2005	Grass Valley R611 add animal guards	16
Portland	OR	2/15/2005	Grass Valley R612 add animal guards	16
Portland	OR	2/15/2005	Grass Valley T571, 2, 3 add animal guard	16
Portland	OR	2/15/2005	Grass Valley T9368 add animal guards	16
Albany	OR	4/12/2006	HARRISBURG: 4M400 R & R COUNTER	8
K. Falls	OR	3/21/2006	HENLEY- 5L59 BAD ORDER GROUND RELAY	16
K. Falls	OR	4/11/2006	HENLEY-5L59 DISABLE I.T'S DUE TO BIRDS	8
Walla Walla OR	OR	2/7/2006	HERMISTON - 5W601 FITTING LEAKS OIL	8
Walla Walla OR	OR	12/7/2005	HERMISTON - T3614 HIGH OIL LEVEL IN LTC	40
Albany	OR	1/30/2006	HILLVIEW: 4M180 COUNTER NOT WRKING	4
Albany	OR	2/28/2006	HILLVIEW: 4M180 RPL COUNTER	8

Attachment OPUC 331.i

Rpt Dist	State	Created on	SUBSTATION NAME: identified work	PlanWork
Albany	OR	2/28/2006	HILLVIEW: R&R YARD LIGHTS AT SUB	6
Albany	OR	1/24/2006	HILLVIEW:CTRL HSE LEAKING WATER	40
Albany	OR	7/22/2005	HILLVIEW:T-3231 B/O FAN MOTOR	4
Albany	OR	6/15/2005	HILLVIEW:T3231 CLEAN BUS DISC	16
Portland	OR	11/14/2005	Holladay 5P145 check manual trip adjust	16
Portland	OR	3/24/2006	Holladay 5P145 emerg. trip misoperation	8
Portland	OR	3/24/2006	Holladay 5P146 emerg. trip misoperation	8
Portland	OR	12/29/2005	Holladay BAT0138 corrosion on #1 & #2	8
Portland	OR	10/17/2005	Holladay BAT105 replace one battery	8
Portland	OR	1/31/2005	Holladay damage to brick wall	16
Portland	OR	2/16/2006	Holladay gate not opening properly	4
Portland	OR	2/15/2005	Holladay T3538 add animal guards	16
Portland	OR	9/29/2005	Holladay T3538 b/o arrestor X 2	8
Portland	OR	1/24/2006	Holladay T3538 needs new oil temp gauge	8
Portland	OR	2/15/2005	Holladay T3539 add animal guards	16
Portland	OR	6/23/2005	Holladay T3539 leaks oil near radiators	8
Portland	OR	2/15/2005	Holladay T3799 add animal guards	16
Portland	OR	3/21/2005	Hollywood 5P201 add animal guards	8
Portland	OR	7/28/2005	Hollywood 5P205 counter b/o	8
Portland	OR	10/19/2005	Hollywood BAT106 clean, grease, add H20	6
Portland	OR	4/11/2005	Hollywood cap LO rly not dropping target	24
Portland	OR	11/14/2005	Hood River 5K37 disconnects hot on IR	24
Portland	OR	3/21/2005	Hood River T3228 add animal guards	16
K. Falls	OR	12/20/2005	HORNET SUB-T3545 B/O OIL TEMP GAUGE	0
K. Falls	OR	4/11/2006	HORNET-5L45 DISABLE I.T'S DUE TO BIRDS	8
K. Falls	OR	2/24/2005	HORNET-CLEAN UP OIL SPILL	20
Albany	OR	4/26/2006	INDEPENDENCE: T3477 LTC HOUR METER	8
Albany	OR	2/20/2006	JEFFERSON: 3M130 SWITCH IN TRANSIT	4
Albany	OR	11/1/2005	JEFFERSON: 3M130 VACUUM BTL BROKEN	20
Albany	OR	2/20/2006	JEFFERSON:3M130 R&R HYDRAULIC LINES	40
Medford	OR	10/25/2005	JEROME PRAIRIE-ADD N2 TO T3768	0
Medford	OR	5/6/2005	JEROME PRAIRIE-Ground wire on AC panel	0
Roseburg	OR	4/6/2005	JORDAN PT:CAP585-5C21:WILL NOT TRIP	16
Walla Walla OR	OR	12/15/2005	JOSEPH - REG370359 B/O DRAG HANDS	8
Albany	OR	3/6/2006	JUNCTION CITY: REPAIR GATE	4
Portland	OR	3/21/2005	Kenwood 5K50 & getaway add animal guards	8
Portland	OR	3/25/2005	Kenwood 5K50 change CT's	24
Portland	OR	3/21/2005	Kenwood R1145 add animal guards	16
Portland	OR	10/21/2005	Kenwood R1145 minor oil leak	8
Portland	OR	1/24/2006	Kenwood relay cabinet fans b/o	8
Portland	OR	3/21/2005	Kenwood T2903, 2904, 2905 add animal grd	16
Portland	OR	11/3/2005	Killingsworth 5P123 b/o ammeter switch	16
Portland	OR	3/21/2005	Killingsworth 5P210 add animal guards	8
Portland	OR	3/9/2005	Killingsworth 5P218 open/close indic b/o	16
Portland	OR	4/4/2005	Killingsworth 5P41 counter b/o	16
Portland	OR	11/3/2005	Killingsworth battery charger light	4
Portland	OR	10/31/2005	Killingsworth CHG0108 A/C light b/o	4
Portland	OR	4/18/2005	Killingsworth SC321-blown fuse	8
Portland	OR	3/21/2005	Killingsworth T3467 add animal guards	16
Portland	OR	6/6/2005	Killingsworth T3467 leaking WTG well	32
Portland	OR	6/2/2005	Killingsworth T3467 tap board issues	80
Portland	OR	6/6/2005	Killingsworth T3468 leaking WTG well	32
Portland	OR	7/12/2005	Killingsworth T3468 LTC moisture in oil	4
Portland	OR	5/27/2005	Killingsworth T3468 LTC R/L contactors	16
Portland	OR	12/1/2005	Killingsworth T3468 N2 leak	16
K. Falls	OR	3/29/2006	KLAMATH SUB OPS-DOBLE 6150 COMM PROBLEM	0
Portland	OR	1/7/2005	Knappa 5A93 b/o Basler relay	16

Attachment OPUC 331.i

Rpt Dist	State	Created on	SUBSTATION NAME: identified work	PlanWork
Portland	OR	7/21/2005	Knappa T2069 b/o winding temp gauges	24
Portland	OR	11/1/2005	Knappa window louver rusty	8
Portland	OR	8/5/2005	Knott 5P231 counter b/o	8
Portland	OR	3/21/2005	Knott 5P241 add animal guards	8
Portland	OR	3/22/2006	Knott 5P241 will not open electronically	8
Portland	OR	5/6/2005	Knott building window repairs	16
Portland	OR	10/21/2005	Knott CAP0320 3 capacitors leaking	8
Portland	OR	7/28/2005	Knott I879 still leaking	8
Portland	OR	3/21/2005	Knott R273 add animal guards	16
Portland	OR	1/20/2006	Knott repair gutters & downspouts	8
Portland	OR	12/27/2005	Knott Sub roof leak	8
Portland	OR	3/21/2005	Knott T3436 add animal guards	16
Portland	OR	4/12/2005	Knott T3436 b/o oil temperature gauge	8
Portland	OR	3/21/2005	Knott T3444 add animal guards	16
Portland	OR	3/21/2005	Knott T3452 & bus add animal guards	16
Albany	OR	12/22/2005	LEBANON: XFMRS WILL NOT PARALLEL	16
Portland	OR	2/24/2006	Lincoln 5P462 b/o demand on kwh meter	2
Portland	OR	4/4/2005	Lincoln SC527-add animal guards	8
Portland	OR	4/4/2005	Lincoln SC531-add animal guards	8
Portland	OR	4/4/2005	Lincoln SC532-add animal guards	8
Portland	OR	4/4/2005	Lincoln T3464 & bus-add animal guards	16
Portland	OR	4/4/2005	Lincoln T3770 & bus-add animal guards	16
Portland	OR	4/4/2005	Lincoln T3771 & bus-add animal guards	16
Roseburg	OR	3/21/2006	LOCKHART:T2300:LOWER N2 BOTTLE CABINET	16
Roseburg	OR	3/21/2006	LOCKHART:T2301:LOWER N2 BOTTLE CABINET	16
Medford	OR	3/17/2005	Lone Pine Bank 4 T3077 b/o fans	12
Medford	OR	3/17/2005	Lone Pine Bank 4 T3078 b/o fan	8
Medford	OR	3/17/2005	Lone Pine Bank 4 update wiring	24
Medford	OR	3/17/2005	Lone Pine Bank T3076 4 b/o fan	21
Medford	OR	3/17/2005	Lone Pine PT #3 rewire test	25
Albany	OR	9/13/2005	LYONS: 4M69 B/O COUNTER	4
Albany	OR	3/20/2006	LYONS: R&R LIGHTS CTRL HSE	4
Albany	OR	7/15/2005	LYONS: RPL LIGHT BULBS IN CTRL HSE	2
Portland	OR	4/4/2005	Mallory SG roof bushings-add animal grds	16
Portland	OR	3/21/2005	Mallory T3814 & bus add animal guards	16
Portland	OR	1/13/2005	Mallory T3814 has oil leak	8
Albany	OR	5/12/2005	MARYS RIVER:4M153 CLEAN MAIN BUS DISCON	8
Medford	OR	5/2/2006	MEDFORD SUB-RPLC PANEL METERS T3923	0
Medford	OR	5/2/2006	MEDFORD-RPLC PANEL METERS T3971	0
Medford	OR	10/27/2005	MERLIN - B/O COUNTER ON 5R249	0
Medford	OR	1/25/2005	Merlin T3608 Velcon meter b\o	6
Medford	OR	5/19/2005	Merlin, Station Batt. corroded terminals	0
Medford	OR	10/6/2005	MERLIN-REPLACE COUNTER & THERMOSTAT	8
Portland	OR	4/19/2006	Mobile T3510 add non-skid strips	8
K. Falls	OR	2/28/2006	MODOC-5L36 BAD ORDER COUNTER	8
Portland	OR	3/21/2005	Moro 8K6 add animal guards	8
Portland	OR	3/21/2005	Moro R615, R616 add animal guards	16
Portland	OR	3/21/2005	Moro T3727, 3728, 3729 add animal guards	16
Albany	OR	1/4/2005	MURDER CREEK: BROKEN INSULATOR	2
Albany	OR	3/29/2005	MURDER CREEK: 4M240 B/O CTRL COUNTER	4
Albany	OR	3/28/2005	MURDER CREEK: 4M241 B/O CTRL COUNTER	4
Albany	OR	1/17/2006	MURDER CREEK:T3658 LTC OIL FILTER HR MTR	8
Albany	OR	1/20/2006	MURDER CRK: T-3657 MOISTURE IN GAUGES	8
Albany	OR	1/21/2005	MURDER CRK: T3657 RPL 84A TIMER	32
Albany	OR	1/20/2006	MURDER CRK: T-3658 MOISTURE IN GAUGES	8
Albany	OR	1/20/2006	MURDER CRK: T-3659 MOISTURE IN GAUGES	8
Albany	OR	1/20/2006	MURDER CRK: T-3660 MOISTURE IN GAUGES	8

Attachment OPUC 331.i

Rpt Dist	State	Created on	SUBSTATION NAME: identified work	PlanWork
Roseburg	OR	2/21/2006	MYRTLE CK:CB5U77:DPU 2000R CPU FAILURE	32
Roseburg	OR	3/21/2006	MYRTLE CK:REPLACE B/O YARD LIGHT	6
Roseburg	OR	4/25/2006	MYRTLE CREEK SUB:REPLACE ARRESTER	0
Albany	OR	12/21/2005	NELSCOTT:RPL VAR MTR RESET	8
Medford	OR	4/27/2005	New O'brien, T-2208, Liquid Temp. guage	0
Albany	OR	1/9/2006	OREMET:T3244: B.O. LTC OIL FILTER HR MTR	12
Albany	OR	1/9/2006	OREMET:T3746:OIL LEAK -LTC HOSE CONNECTR	10
Portland	OR	2/2/2005	Parkrose 5P244 DPU2000R osc/488 LAN b/o	16
Portland	OR	2/2/2005	Parkrose 5P246 DPU2000R osc/488 LAN b/o	16
Portland	OR	2/2/2005	Parkrose 5P252 DPU2000R osc/488 LAN b/o	16
Portland	OR	5/1/2006	Parkrose add dog signs	8
Portland	OR	12/14/2005	Parkrose CB cabinets add heaters	16
Portland	OR	12/1/2005	Parkrose outdoor lighting problems	8
Portland	OR	12/29/2005	Parkrose T3445 - 2 fans b/o	16
Portland	OR	12/1/2005	Parkrose T3445 LTC oil level gauge leak	24
Portland	OR	3/21/2005	Parkrose T3446 add animal guards	16
Portland	OR	3/14/2005	PDXTO-spare REG 2287 has oil leak	8
Albany	OR	3/18/2005	PELLET MILL:CONNECT FAN SOURCE LOW SIDE	10
Walla Walla OR	OR	2/1/2005	PENDLETON - 3W130 B/O ACCUMLTR BLADDER	40
Walla Walla OR	OR	2/14/2005	PENDLETON - T0821 B/O OIL LEVEL GAUGE	0
Walla Walla OR	OR	1/17/2006	PENDLETON - T3241 B/O COUNTER	8
Walla Walla OR	OR	11/15/2005	PENDLETON- T0820 OIL LEAK LOW SIDE	20
Bend	OR	10/20/2005	POWELL BUTTE-SW 2D13 & 2D45 ARCING HORNS	0
Bend	OR	8/11/2005	POWELL BUTTE-TIGHTEN BOLTS ON XARM	20
Medford	OR	4/28/2006	PROVOLT SUB-VOLTAGE SPIKES R0506	0
Albany	OR	2/6/2006	QUEEN: 4M258 NO COUNTER ON BREAKER	12
Albany	OR	11/4/2005	QUEEN: T3547 RPL SILICA JEL	2
Bend	OR	4/24/2006	REDMOND-5D226 BREAKER FAILED TO RECLOSE	0
Portland	OR	3/15/2005	Rich T3588 nitrogen leak	16
Portland	OR	2/8/2005	Rich T3588 replace temperature device	16
Roseburg	OR	2/7/2006	RIDDLE VNR:CAP204:REPAIR LEAKY CAPACITOR	6
Roseburg	OR	4/26/2006	RIDDLE:CB5U1:MODIFICATION OF RELAY.	16
Roseburg	OR	4/20/2006	RIDDLE:CB5U2:FAILED RECLOSING RELAY	16
Roseburg	OR	4/26/2006	RIDDLE:CB5U3:MODIFICATION OF RELAY.	16
Medford	OR	1/28/2005	ROGUE RIVER-Change Control Hs AC panel	0
Roseburg	OR	12/15/2005	ROSEBURG:CB4U10:REPLACE COUNTER	4
Roseburg	OR	12/6/2005	ROSEBURG:T3837:HIGH WINDING TEMP	2
K. Falls	OR	4/13/2006	ROSS-5L47 BAD COUNTER	8
K. Falls	OR	2/23/2006	ROSS-CAP BRKR 5L306 BAD CONTROL CABLE	120
K. Falls	OR	12/20/2005	ROSS-T3010, 11 & 12 BO PRESSURE GAUGE	0
K. Falls	OR	12/20/2005	ROSS-TRF3010 B/O TEMP GAUGE WILL BE REPL	0
Walla Walla OR	OR	3/7/2005	ROUNDUP - L1123 REPLACE CONTACTS	16
Medford	OR	11/14/2005	ROXY ANN - T3247 LOW NITROGEN	0
Medford	OR	5/19/2005	Ruch, R-1455, Bad drag hands	0
K. Falls	OR	3/20/2006	RUNING Y-YARD LIGHTS BURNED OUT SGN GONE	16
Portland	OR	2/1/2006	Russellville BAT 9 cracked O-rings	8
Portland	OR	3/20/2006	Russellville PLC stall alarm	16
Portland	OR	4/4/2005	Russellville SG bushings-add animal grds	16
Portland	OR	4/7/2005	Russellville T3687 LTC counter b/o	8
Portland	OR	12/14/2005	Russelville CB cabinets add heaters	16
Albany	OR	4/14/2005	SCIO:CONTACTOR NOT SEALING	8
Portland	OR	3/21/2005	Seaside 5A78 add animal guards	8
Portland	OR	12/23/2005	Seaside 5A80 b/o relay-failure	6
Portland	OR	3/21/2005	Seaside 5A80, 5A81 print corrections	24
Portland	OR	3/21/2005	Seaside 5A82 add animal guards	8
Portland	OR	3/21/2005	Seaside 5A90 add animal guards	8
Portland	OR	3/21/2005	Seaside T2312 add animal guards	16

Attachment OPUC 331.i

Rpt Dist	State	Created on	SUBSTATION NAME: identified work	PlanWork
Portland	OR	4/6/2006	Seaside T2312 LTC step gauge b/o	8
Portland	OR	9/29/2005	Seaside T3246 one fan b/o	8
Walla Walla OR	OR	1/17/2006	SIMTAG BP - T3581 MOISTURE IN TEMP GAUGE	8
Walla Walla OR	OR	3/30/2005	SIMTAG SUB - REPAIR YARD LIGHTS	16
Walla Walla OR	OR	1/17/2006	SIMTAG- T3581 OIL GAUGE WILL NOT RESET	8
Walla Walla OR	OR	10/13/2005	SIMTAG- T3582 OIL GAUGE WILL NOT RESET	8
Walla Walla OR	OR	1/17/2006	SIMTAG- T3582 OIL GAUGE WILL NOT RESET	8
Albany	OR	5/9/2005	SPARE T2161:RPL DIAPHRAGM	0
K. Falls	OR	4/7/2006	SPRAGUE RIVER-T2888 LTC OIL LEAK	24
K. Falls	OR	4/7/2006	SPRAGUE RIVER-T2889 LTC OIL LEAK	24
Roseburg	OR	5/9/2005	STATE ST:SW2C503:OUT OF ADJUSTMENT	32
Roseburg	OR	4/5/2006	SUTHERLIN:REPAIR HEAT PUMP-NOT OPERATING	8
Albany	OR	6/29/2005	SWEET HOME: T3543 LTC OIL FILTER LEAKING	4
Albany	OR	12/20/2005	SWEET HOME:VERIFY BANK NUMBERS	8
Medford	OR	1/25/2006	TALENT-CLEAN & ALIGN SWITCHES	0
Medford	OR	4/7/2005	TALENT-REPAIR BASLER RELAY	0
Medford	OR	2/7/2006	TALENT-RPLC CURRENT XFMRS ON 5R237	40
Walla Walla OR	OR	3/8/2005	UMAPINE - BAT0309 DIRTY TERMINALS	1
Albany	OR	6/3/2005	US PLYWOOD:T3266 RPL HIGH SIDE FUSE INSL	0
Portland	OR	3/17/2006	Vernon 5P396 bus tie brkr b/o counter	8
Portland	OR	1/4/2006	Vernon leaking roof	8
Portland	OR	4/4/2005	Vernon SG bypass bus-add animal guards	16
Portland	OR	4/4/2005	Vernon T3743 bus-add animal guards	16
Portland	OR	4/4/2005	Vernon T3747 bus-add animal guards	16
Albany	OR	11/10/2005	VILLAGE GREEN: 4M86 COUNTER NOT WORKING	8
Albany	OR	11/10/2005	VILLAGE GREEN: FENCE REPAIR	4
Albany	OR	2/9/2006	VILLAGE GRN: 2M18 AIRBRK SWTCH NOT OPER	24
Albany	OR	7/11/2005	VINE ST: T 3611 B/O FAN	8
Albany	OR	8/8/2005	VINE ST:3M19 B/O SWITCH	4
Albany	OR	1/19/2006	VINE: T3611 MOISTURE IN TEMP GAUGE	8
Albany	OR	1/27/2006	VINE:RPL 4 CELLS IN BATT BANK	8
Walla Walla OR	OR	9/7/2005	WALLA WALLA POWER-R1259 CHECK OUT	10
Portland	OR	3/30/2005	Warrenton 5A15 missing 1 animal guard	8
Portland	OR	3/30/2005	Warrenton 5A16 add animal guards	8
Portland	OR	3/30/2005	Warrenton 5A19 missing 2 animal guards	8
Portland	OR	3/30/2005	Warrenton 5A20 missing 1 animal guard	8
Portland	OR	3/30/2005	Warrenton T3156 add animal guards	16
Portland	OR	3/30/2005	Warrenton T3782 add animal guards	16
Portland	OR	3/30/2005	Wasco 7K1 add animal guards	8
Portland	OR	3/30/2005	Wasco R873 add animal guards	16
Portland	OR	10/31/2005	Wasco R873 b/o counter	8
Portland	OR	3/30/2005	Wasco R874 add animal guards	16
Portland	OR	3/30/2005	Wasco R875 add animal guards	16
Portland	OR	3/30/2005	Wasco T1605/ T1606/T1607 add animal grds	16
Albany	OR	3/8/2006	WECOMA: RELAMP STATION LIGHTS	3
Albany	OR	2/6/2006	WESTERN KRAFT: T-3566 LTC BEARING NOISE	12
K. Falls	OR	3/6/2006	WESTSIDE-FLOODING HAS ERODED ROAD	16
K. Falls	OR	2/1/2006	WESTSIDE-TRF2555 OIL TEMP GAUGE MISSING	0
Medford	OR	2/24/2006	WHITE CITY-INSTALL BIRD GUARD 5R270	0
Walla Walla OR	OR	1/17/2006	WILLOW COVE - T3519 MOISTURE TEMP GAUGE	8
Walla Walla OR	OR	1/17/2006	WILLOW COVE- CAP0341 1B/O FUSE 3LEAK CAP	16
Walla Walla OR	OR	1/20/2005	WILLOW CREEK - T2474 B/0 FAN SWITCH	40
Portland	OR	1/24/2006	Youngs Bay outer fence needs repair	8
Portland	OR	12/30/2005	Youngs Bay T2239 - 2 fans missing	16

OREGON

2006 GENERAL RATE CASE

UE-179

PACIFICORP

OPUC STAFF DATA REQUEST

ATTACHMENT OPUC 331 k

ATTACHMENT OPUC 331-k

	(1) FTE's included in Adj 4.10*	(2) FTE's included in Column 1 also included in Adj. 4.3	(3) Are Wages & Benefits included in this adj?	(4) Are any employees included in both Adjustment 4.10 and Adjustment 4.3?
Trans Vegetation	0	0	No FTE's in adjustment	Not applicable
Trans Maint	55	0	Wages & Benefits included for employees in column 1	Not applicable
IT Project Expense	0	0	No FTE's in adjustment	Not applicable
Increased Eng & AM	36	0	Wages & Benefits included for employees in column 1	Not applicable
21st Century, EMS/SCADA	35	6	Wages & Benefits included for employees in column 1	6 employees were included in Adjustment 4.10 that were also included in Adjustment 4.3.
Metering Programs	10	0	Wages & Benefits included for employees in column 1	Not applicable
New Customer Service Programs	6	0	Wages & Benefits included for employees in column 1	Not applicable
Change in Bad Debt	0	0	No FTE's in adjustment	Not applicable
Communications Maint	7	0	Wages & Benefits included for employees in column 1	Not applicable
Oregon Vegetation	0	0	No FTE's in adjustment	Not applicable
Oregon Distr Maint	21	0	Wages & Benefits included for employees in column 1	Not applicable

*These may or may not be new hires. They could be transfers in from other areas or contractors

Impact on Adj. 4.3 O&M of 6 employees included in Adj 4.10 that were also included in Adj 4.3

Wages	501,671
Less: Capital Portion	132,888
Total Company	368,783
Oregon Portion	105,357

Overview of Power Delivery Programs

In Adjustment S-11, Staff proposes disallowances in 4 of 7 categories of power delivery programs: transmission, distribution, communication maintenance and Oregon distribution maintenance. PacifiCorp's costs in transmission, distribution and communication maintenance have increased due to a combination of factors, including the need for greater security, heightened concerns about reliability and the integrity of the electric grid, interest in increasing system efficiency and pressures to lessen the environmental impact of the system. PacifiCorp's power delivery programs are designed to ensure compliance with all government safety, reliability and environmental regulations and permit PacifiCorp to meet high standards for reliability and customer service. At the same time, PacifiCorp looks to optimize its spending on power delivery programs, seeking efficiencies and cost savings to balance the need for increased investment in this area.

PacifiCorp's projected power delivery cost increases for CY 2007 are based upon budgets that include specific programs and associated costs. PacifiCorp has prepared a Supplemental Response to OPUC Staff DR 331 (transmission, communication maintenance and distribution maintenance) and OPUC Staff DR 142 (distribution) to provide more detail about the power delivery programs included in the categories where Staff has proposed adjustments. The impact of Staff's proposed adjustments would be to eliminate or reduce the power delivery programs described in this Supplemental Response.

Supplemental Response to OPUC 331 & OPUC 142

1) Supplement to DR 331 (g) Transmission Maintenance (Increase of $9.1 million revised to $10.8 million)

In its filing, the Company misclassified certain increases in Transmission and Communication Maintenance. Correcting the error lowers the Communication Maintenance increase on a system basis by $1.4 million from $2.5 million to $1.1 million and increases Transmission Maintenance on a system basis by $1.7 million from $7.9 million to $9.6 million. As illustrated in the table below, there is no revenue requirement impact associated with the classification correction:

in millions	Submitted Rate Case Increase	Revised Increase due to Re-Class	Difference		Allocation Factor	Oregon Impact based on Allocation Factor
Communication Maintenance - System Wide Program	2.5	1.1	(1.4)	SO	0.28441941	(0.4)
Transmission Maintenance - System Wide Program	7.9	9.6	1.7	SG	0.266278773	0.4
Total Communication and Transmission Maintenance Impact to Revenue Requirement						0.0

Transmission programs are the area of the company's largest power delivery cost increases. The table below illustrates the level of increase from FY 2005, divided into Transmission Vegetation and Transmission Maintenance, and demonstrates that a significant percentage of the increase is already reflected in actual FY 2006 costs.

	FY 2005 (Base Period)	FY 2006	Increase from Base Period	% Increases	CY 2007 (Rate Case Test Year)	Increase from Base Period	% Increases from Base
Transmission Vegetation	4.4	6.7	2.3	52.9%	5.5	1.2	27.3%
Transmission Maintenance	8.3	13.5	5.2	63.4%	17.9	9.6	116.5%
Total Transmission	12.6	20.2	7.5	59.8%	23.4	10.8	85.7%

Transmission Vegetation

The $1.2 million increase is for reclaiming existing rights-of-way, with emphasis on lower voltage transmission lines, and for application of herbicides to control future vegetation costs across the transmission system. This is critical for the safety of Oregon customers and to protect the integrity of the electric grid. This investment ultimately reduces long-term costs.

Transmission Maintenance

The $9.6 million increase for maintenance is for the following items:

- Implementation of a company policy change moving from a 16-year pole test and treat cycle in ID, UT and WY to a 10-year cycle. Oregon has already mandated a 10-year cycle, so this change is consistent with Oregon Commission standards. By moving from a 16-year cycle to a 10-year cycle, there will also be additional corrective maintenance activity that occurs. More poles are inspected which results in an increase in the corrective maintenance budget to fix conditions on the system that are found during inspection. The reduction of the test and treat cycle improves system safety and reliability, an important benefit for Oregon customers who rely on system transmission to access power from out-of-state generation plants.

- PacifiCorp reviews all time-based and condition-based maintenance policies annually and strives to maintain substation equipment at optimum performance levels. Maintenance policies changes were made in 2005 to some maintenance equipment maintenance cycles. Increased funding for local transmission and main grid transmission substation major equipment preventative and corrective maintenance is required to meet this policy. This includes maintenance and overhauls on intervals on circuit breakers, operational relay testing and transformer/regulator load tap changer overhauls. The benefits result in better reliability, long-term equipment health and minimized reactive costs for breakdowns. The funding for the maintenance activities reflects putting into action the complete maintenance plans according to company policies for 2006 and 2007. Funding not only supports preventative maintenance, but also corrective maintenance for items discovered during the monthly substation inspection process. The company's intent is to not let preventative maintenance fall behind scheduled intervals.
- In recent years, particular focus has been dedicated to bringing the sub-transmission substations to the same performance levels as main-grid substations. This has resulted in establishing preventative maintenance programs that will have long-term benefits for customers via quality of supply and reduced operations cost due to outage response while minimizing overall lifecycle cost of ownership.
- Increased funding for maintaining new critical path substation security equipment. This equipment is a recent addition to company assets and the company is capturing operating and maintenance costs. This is a federal requirement for Critical Infrastructure Protection.

2) Supplement to DR 142 Distribution (Increase of $6.0 million)

a. I/T Project Expense ($1.0 million increase)

1) Customer Services Agent Access Router and Interactive Voice Response Replacement Project: The Company is still reviewing technology/vendor options for this project. Ongoing O&M expense has been estimated at approximately $0.2 million per year after implementation.
2) PRISM: The ongoing O&M costs for Prism are $0.2 million.
3) Feederall Integration: The ongoing O&M costs are $0.2 million.
4) License & Maintenance Costs: The ongoing O&M costs are $0.4 million.

b. 21st Century & EMS SCADA ($4.3 million increase)

21st Century

21st Century operations project was initiated to improve the system wide operational performance of Grid Operations and network dispatching organizations and to insure the continued security and high availability of the PacifiCorp T&D networks. The proposals and cost estimates to implement these improvements were developed by the 21st Century Operations project team.

The dispatch organizations involved in the improvement efforts are:

- Grid Operations organization located at the PCC dispatch center in Portland. This group is responsible for operation of the bulk transmission system including day ahead scheduling activities and coordinating operations with all other interconnected utilities.

- PCC dispatch located at the PCC dispatch center in Portland. This group is responsible for operational switching and trouble call dispatching for Oregon, California, Washington and eastern Wyoming.

- SCC dispatch located at the NTO office in Salt Lake City. This group is responsible for operational switching and trouble call dispatching for Utah, Idaho and western Wyoming.

The project was initiated to reduce the number of switching or operational errors which may impact electric system security of supply, customer sensitivity and potentially could lead to safety issues. Switching and reconfiguration of PacifiCorp's extensive electric system is required to accommodate new infrastructure additions, connections to third parties, scheduled maintenance and emergency restoration. In addition, improvements were sought in the overall outage management process to reduce customer outage minutes to benefit customers.

Changes developed and being implemented by the project include:

- Additions to management staff including shift supervision positions.
- Additions to the dispatching staff to provide for a regular relief shift rotation to enable training.
- Creation of a new distribution dispatcher position to improve the outage restoration process and better manage the overall workload within the dispatch offices.
- Creation of a technical support and training group to provide much needed technical support and guidance in day to day operations and develop and implement dispatch training programs.

Implementation of the project recommendations is approximately 75% complete. Costs associated with the 21st Century Operations project are primarily labor and employee related costs associated with the recommended employee additions with some contractor costs.

EMS/SCADA Support Costs

The Ranger system is replacing nine existing outdated SCADA and Energy Management Systems (EMS) with one system to be used company-wide for T&D dispatching and generation control. The majority of these nine systems are obsolete and no longer supported by vendors. The system has experienced a number of failures and unacceptable down time during the past two years.

During the development, design and installation period required for such a complex system, FERC began to specify a number of new system requirements as a result of the new Critical Infrastructure Protection Standards.

The new Ranger EMS/SCADA system is scheduled for final cutover in November 2006. The new system will provide much needed additional functionality to improve the operational performance and efficiency of the transmission and distribution system. This functionality does not exist in the current system and includes:

- Dispatcher Load Flow: an interactive application that allows the operator to calculate power flows and detect overloading and voltage issues in a simulation model.
- Security Analysis: Enables operators to study effects of real time disturbances on line and substation equipment.
- State Estimator: Provides a "snapshot" of real time system conditions to be used for analysis of operating scenarios.
- Outage Scheduler: Tool to analyze the impact of scheduled outages on system operations.
- Optimal Power Flow: Allows operator to determine proper operation actions to minimize system losses and improve efficiency of electric delivery.

- Dispatch Training Simulator: A copy of the production system to be used to train dispatchers and operators on the SCADA system and to respond to blackout and other operating situations.
- Intranet Interface: Allow viewing of critical SCADA information for field and office staff via intranet.
- PI Historian: Stores all SCADA data in time sequenced database for use in system studies.

In addition to the above requirements the Ranger system will also required to have a separate quality assurance system (QAS). This system provides a software and hardware system environment (nearly a redundant and reversionary EMS/SCADA system) that is used to test software and data updates prior to putting them into production. This testing is required to meet FERC security requirements. The added functionality of the system and the demands required to implement and operate the QAS system will require an increase in resources beyond those needed to operate the legacy systems.

c. Increased Engineering & Asset Management to support Capital/O&M

This increase is due to additional positions added over a 2-year period needed to deliver the growing capital and maintenance programs company-wide.

Changes in the energy supply picture in the west have resulted in an increasing number of requests to PacifiCorp for Generator Interconnections on the company's Transmission and Distribution Systems. There are also an increasing number of requests for new transmission services on and across the PacifiCorp Grid. Additional resources are required to comply with FERC mandated rules, PacifiCorp Open Access Transmission Tariff (OATT) and requirements to provide applicants project feasibility, design impact and facility study activities.

- Capital and maintenance activities are increasing due to customer load growth, and the aging infrastructure.
- Maintenance is increasing by $10-15 million and capital is increasing by $100-120 million.
- Increased requirements to provide detailed, longer-range electric system plans for permitting, route and site selection and coordination with state, city, county growth and infrastructure plans.

The level of Capital and Maintenance is expected to be sustained requiring an increase of 17 engineers, 7 project managers and 6 asset management planners to be added to the workforce. Without these additions, the successful completion of the increased capital and maintenance plans could be jeopardized.

A number of these employees are entry/associate level positions that provide and additional benefit to customers by addressing the Company's workforce age demographics in the engineering and technical profession. This will help to insure that the Company has the talent and skills to meet customer needs and expectations over the long-term.

d. BPI, Street Ltg, Grid Ops, etc ($1.2 million)

The costs in this category ($1.0M) are primarily due to a proposed inventory program across the company for Joint Use contacts on utility poles, a program that initiated from Oregon Commission review of pole attachment and safety issues. This inventory is proposed to start in Oregon in 2006 to help improve quality of pole contact information, gain clarification on pole attachment ownership and to help resolve issues related correcting code infractions that exist on the network. This program is incremental to current transmission and distribution inspection programs in the state.

e. Grid Operations ($0.4) million

New physical plant security requirements mandated by Critical Infrastructure Security programs require addition various levels of security monitoring at major substations and power stations. This includes a mix of new entrance card key access, video real time and on demand, and perimeter intrusion protection systems. These stations require "round the clock" security and monitoring and system administration. PacifiCorp has established a new security and alarm monitoring center at Portland Control Center in Portland to provide this function. Staffing is required to support this new requirement.

f. Mapping ($0.7 million)

The Company has begun staffing up the Mapping department to ensure that there is consistent data between FastGate and OMS. The company has consistently carried a back log of mapping revisions which need posting to insure operating maps are available to field operations. The increased map postings are a direct result of increased load growth, capital and maintenance activities and the need to update company mapping records. Not increasing mapping impacts our ability to coordinate outages between Dispatch and Operations and to provide customer service levels expected. (Note: a portion of these costs were offset by the efficiencies indicated in the OPUC Data Request 142)

g. Field Operations Support ($0.5 million)

The increase has been fully implemented in FY 2006.

h. Transport/Logistics ($0.5 million)

The increase has been fully implemented in FY 2006.

i. Health, Safety and Environmental Programs ($1.1 million)

Increases over 2005 levels are required for more aggressive programs to prevent Raptor Bird fatalities across the company. There are continually increasing levels of enforcement (fines and sanctions) and scrutiny by Federal and State agencies regarding protection of birds of prey. These regulatory agencies are demanding that PacifiCorp develop a new and more aggressive preventative electrocution program for these protected species. The company has identified five "high risk areas" across the company which require mitigation programs over a number of years, with the Klamath Basin area in Oregon being the largest high-risk area of exposure. It will require $500,000 annually to improve PacifiCorp's T&D system in these areas. This revised program is incremental to past efforts and programs currently in place.

In addition, the new safety program started during FY06 with six new safety positions and will continue into 2007. Safety managers are required to complete and implement safety plans and programs to improve health and safety performance of our employees, as well as educate our customers on public safety. The environmental and other safety-related programs are necessary to meet regulatory requirements and policy commitments.

3) Supplemental DR 331 (j) Communication Maintenance (Increase of $1.1 million revised from $2.5 million)

	FY 2005 (Base Period)	FY 2006	Increase from Base Period	% Increases	CY 2007 (Rate Case Test Year)	Increase from Base Period	% Increases from Base
Total Communications	3.4	3.5	.2	4.6%	4.5	1.1	34.1%

The increase for maintenance on communication assets benefits Oregon customers for the following reasons:

- Over the last three years, PacifiCorp has added over 200 miles of new fiber optic cable and related fiber optic nodes. PacifiCorp has also added more than 20 new substations, all of which require extensive communication equipment. These additions are due to load growth and new generation interconnections and result in costs above what would be included in inflation indices. Security concerns have increased the importance of maintaining and improving communication systems. Corrective maintenance has also increased for communication equipment due to aging microwave radios, remote terminal units located in substations and communication sites.
- The communication assets are used system-wide for the benefit of all customers. The Grid Operations dispatchers at Portland Control Center use the communication systems including fiber optic and microwave systems to remotely control and operate substation equipment including re-configuring the transmission network. This is critical because, for example, a transmission line outage in Wyoming can impact the flow of electricity into Oregon. Using the SCADA system and associated communication systems, Grid Operations can remotely make changes to the electrical network to minimize customer impacts.
- The systems include the voice mobile radio system which is used by dispatchers and field crews to install, maintain and repair substation equipment, transmission lines, and distribution lines across the service territory. This mobile radio system is used day-to-day during normal operating periods and during system emergencies for system restoration.
- The communication systems are also used to automatically support the reliable operation of the electrical network. The communication system provides paths for the transmission line protection relays to ensure line protection schemes are reliable.
- Many of these critical communication systems require planned maintenance to ensure FCC license compliance and to ensure the systems are reliable in good working condition. Failure of the communication systems to properly operate could lead to system-wide power delivery problems, extended power outages or damage of high value power system equipment at specific locations.

4) Supplemental DR 331 (i) Oregon Distribution Maintenance (Net decrease of $2.3 million)

	FY 2005 (Base Period)	FY 2006	Increase from Base Period	% Increases	CY 2007 (Rate Case Test Year)	Increase from Base Period	% Increases from Base
Distribution Vegetation	19.8	15.6	(4.1)	-21.0%	14.5	(5.3)	-26.6%
Distribution Maintenance	14.7	14.7	(.0)	-0.3%	17.6	2.9	19.9%
Total Distribution	**34.5**	**30.3**	**(4.2)**	**-12.1%**	**32.2**	**(2.3)**	**-6.8%**

Distribution Vegetation

The ($5.3) million decrease in Distribution Vegetation is the benefit from being on cycle in Oregon.

Distribution Maintenance

The $2.9 million increase for Distribution Maintenance is made up of bird control project cost of $0.9 million and increased corrective maintenance of distribution line assets of $2.0 million.

The majority of the cost increase for distribution line assets is due to PacifiCorp's disciplined approach in utilizing NESC inspection standards when performing scheduled detailed inspections. Oregon Safety Staff performs quality control inspections as a follow-up to the company inspection process and expects high standards in recognition and recording of code violations. As a consequence, the company has accumulated a significant number of outstanding code conditions that must be repaired according to the Oregon Service Standards.

Additional cost increases are due to a requirement to repair non-critical conditions such as joint use infractions on utility poles within 18 months. This replaces the requirement to make such repairs during the next regular inspection or maintenance performed, or not longer than 10 years.

The original response on DR 331 and DR 142 incorrectly stated that the $2.9 million increase in Distribution Maintenance included increased Oregon substation maintenance. As just noted, the increase in the Distribution Maintenance is due to additional corrective maintenance on the lines. Increases in substation maintenance are limited to transmission substation maintenance.

S-12

O & M Normalization adjustment					
FY2005	Escalated FY2006	Actual FY2006	Requested Adjustment	Known & Measurable Description for CY 2007	Known & Measurable increases for CY 2007
114,098	118,416	118,057	14,832	New Huntington Unit 2 Scrubber Reagent	1,967
				Hydro Relicensing Commitments	3,485
				Joint Owned Plant Commitments	3,275
				Increases in Excess of Global Insights	2,361
				Total Known & Measurable Amount	**11,088**

UE 179 - For Settlement Purposes Only

CERTIFICATE OF SERVICE

UE 179

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 12th day of July, 2006.

Jason Jones
Assistant Attorney General
Of Attorneys for Public Utility Commission's Staff
1162 Court Street NE
Salem, Oregon 97301-4096
Telephone: (503) 378-6322

UE 179
Service List (Parties)

JIM DEASON **(Q)** ATTORNEY AT LAW	521 SW CLAY ST STE 107 PORTLAND OR 97201-5407 jimdeason@comcast.net
BOEHM KURTZ & LOWRY KURT J BOEHM **(Q)** ATTORNEY	36 E SEVENTH ST - STE 1510 CINCINNATI OH 45202 kboehm@bkllawfirm.com
MICHAEL L KURTZ **(Q)**	36 E 7TH ST STE 1510 CINCINNATI OH 45202-4454 mkurtz@bkllawfirm.com
BRUBAKER & ASSOCIATES INC JAMES T SELECKY	1215 FERN RIDGE PKWY - STE 208 ST. LOUIS MO 63141 jtselecky@consultbai.com
CABLE HUSTON BENEDICT HAAGENSEN & LLOYD LLP EDWARD A FINKLEA	1001 SW 5TH - STE 2000 PORTLAND OR 97204 efinklea@chbh.com
RICHARD LORENZ	1001 SW FIFTH AVE - STE 2000 PORTLAND OR 97204-1136 rlorenz@chbh.com
CITIZENS' UTILITY BOARD OF OREGON OPUC DOCKETS	610 SW BROADWAY STE 308 PORTLAND OR 97205 dockets@oregoncub.org
COMMUNITY ACTION DIRECTORS OF OREGON JIM ABRAHAMSON **(Q)** COORDINATOR	PO BOX 7964 SALEM OR 97303-0208 jim@cado-oregon.org

DAVISON VAN CLEVE IRION A SANGER **(Q)** ASSOCIATE ATTORNEY	 333 SW TAYLOR - STE 400 PORTLAND OR 97204 ias@dvclaw.com
DAVISON VAN CLEVE PC MELINDA J DAVISON **(Q)**	 333 SW TAYLOR - STE 400 PORTLAND OR 97204 mail@dvclaw.com
DEPARTMENT OF JUSTICE JASON W JONES **(Q)** ASSISTANT ATTORNEY GENERAL	 REGULATED UTILITY & BUSINESS SECTION 1162 COURT ST NE SALEM OR 97301-4096 jason.w.jones@state.or.us
MICHAEL T WEIRICH **(Q)** ASSISTANT ATTORNEY GENERAL	REGULATED UTILITY & BUSINESS SECTION 1162 COURT ST NE SALEM OR 97301-4096 michael.weirich@doj.state.or.us
LEAGUE OF OREGON CITIES ANDREA FOGUE **(Q)** SENIOR STAFF ASSOCIATE	 PO BOX 928 1201 COURT ST NE STE 200 SALEM OR 97308 afogue@orcities.org
MCDOWELL & ASSOCIATES PC KATHERINE A MCDOWELL **(Q)** ATTORNEY	 520 SW SIXTH AVE - SUITE 830 PORTLAND OR 97204 katherine@mcd-law.com
NORTHWEST ECONOMIC RESEARCH INC LON L PETERS **(Q)**	 607 SE MANCHESTER PLACE PORTLAND OR 97202 lpeters@pacifier.com
OREGON ENERGY COORDINATORS ASSOCIATION KARL HANS TANNER **(Q)** PRESIDENT	 2448 W HARVARD BLVD ROSEBURG OR 97470 karl.tanner@ucancap.org

PACIFICORP LAURA BEANE MANAGER - REGULATORY	 825 MULTNOMAH STE 300 PORTLAND OR 97232 laura.beane@pacificorp.com
PORTLAND CITY OF - OFFICE OF CITY ATTORNEY BENJAMIN WALTERS **(Q)** DEPUTY CITY ATTORNEY	 1221 SW 4TH AVE - RM 430 PORTLAND OR 97204 bwalters@ci.portland.or.us
PORTLAND CITY OF - OFFICE OF TRANSPORTATION RICHARD GRAY STRATEGIC PROJECTS MGR/SMIF ADMINISTRATOR	 1120 SW 5TH AVE RM 800 PORTLAND OR 97204 richard.gray@pdxtrans.org
PORTLAND CITY OF ENERGY OFFICE DAVID TOOZE SENIOR ENERGY SPECIALIST	 721 NW 9TH AVE -- SUITE 350 PORTLAND OR 97209-3447 dtooze@ci.portland.or.us
PORTLAND GENERAL ELECTRIC RATES & REGULATORY AFFAIRS	 RATES & REGULATORY AFFAIRS 121 SW SALMON ST 1WTC0702 PORTLAND OR 97204 pge.opuc.filings@pgn.com
DOUGLAS C TINGEY	121 SW SALMON 1WTC13 PORTLAND OR 97204 doug.tingey@pgn.com