

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

In the Matter of the Application of
PACIFICORP for an Order Authorizing a
Change in Depreciation Rates Applicable to
Electric Property.

Docket No. UE-02_____

PACIFICORP

Direct Testimony of Kathryn C. Hymas

October, 2002

1 **Q. Please state your name, business address and position with PacifiCorp (the**
2 **Company).**

3 A. My name is Kathryn C. Hymas. My business address is 825 N.E. Multnomah Street,
4 Suite 2000, Portland, Oregon, 97232. I am employed by the Company as Managing
5 Director and Corporate Business Services Controller.

6 **Q. Please briefly describe your professional experience and educational background.**

7 A. I have worked for PacifiCorp for the last 19 years in a variety of accounting and finance
8 positions. I have a Bachelor of Science in Accounting and a Masters in Accountancy,
9 both from Brigham Young University. I am a Certified Public Accountant. Prior to my
10 employment at PacifiCorp, I worked for four years in public accounting for Grant
11 Thornton in Chicago, Illinois.

12 **Q. What is the purpose of your testimony?**

13 A. I will summarize the Company's proposal for depreciation rates. I will also summarize
14 the effect on annual depreciation expense from applying the proposed depreciation rates
15 to depreciable plant balances. The rates are contained in the 2002 depreciation study
16 performed on behalf of the Company by Mr. Donald S. Roff of Deloitte & Touche LLP.
17 The depreciation study performed by Mr. Roff is provided as Exhibit___(DSR-3) and will
18 be referred to hereafter as the D&T study.

19 Second, I will introduce the other Company witnesses who will testify in this
20 proceeding.

21 Third, I will provide background information describing the depreciation study
22 process. This information will present the Company's confidence in both the

1 depreciation study process and in the integrity of the Company's accounting data relied
2 on by Mr. Roff in preparing the depreciation study.

3 Fourth, I will discuss a number of significant issues considered during the
4 preparation of this study. The disposition of these issues was reflected in the data
5 provided to Mr. Roff and, in turn, this data formed the basis for the D&T study and the
6 recommended changes in depreciation rates.

7 Finally, I will indicate the Company's proposed effective date for implementing
8 the changes in depreciation rates.

9 **PLANT LIVES, DEPRECIATION RATES AND DEPRECIATION EXPENSE**

10 **Q. What depreciation rates is the Company seeking Commission approval for in this
11 proceeding?**

12 A. The Company seeks Commission approval to adopt the depreciation rates contained in
13 the depreciation study performed by Mr. Donald S. Roff and as recommended in Mr.
14 Roff's testimony. As shown in Table A of Exhibit ____ (DSR-3) and as summarized in
15 Mr. Roff's testimony, the D&T study proposes no change to the composite depreciation
16 rate of 3.11 percent for the Company's electric utility plant. This composite rate is based
17 on the March 31, 2002 depreciable plant balances used in the study. The specific
18 depreciation rate changes recommended for the components of the composite
19 depreciation rate are set forth in account detail in Schedule 1 of the D&T study.

20 **Q. What is the effect on annual depreciation expense from adopting the depreciation rates
21 recommended by Mr. Roff?**

1 A. The effect of applying the recommended depreciation rates to the March 31, 2002
2 depreciable plant balances is a decrease in total Company annual depreciation expense of
3 approximately \$0.7 million, compared with the level of annual depreciation expense
4 developed by application of the currently authorized depreciation rates to the same plant
5 balances. Annual depreciation expense by functional plant classification is summarized
6 in Table A of the D&T study.

7 Adoption of the depreciation rates proposed in the D&T study results in an
8 increase of approximately \$0.3 million in annual Washington jurisdiction depreciation
9 expense, based on March 31, 2002 depreciable plant balances. The calculation of the
10 Washington jurisdiction amount is described in Exhibit ____ (KCH-1).

11 **INTRODUCTION OF WITNESSES**

12 **Q. In addition to yourself, who will be testifying on behalf of PacifiCorp in this**
13 **proceeding?**

14 A. In addition to myself, two witnesses will testify on behalf of the Company. These
15 witnesses are Mr. Donald S. Roff, Director of the Public Utilities Group at Deloitte &
16 Touche LLP and Mr. Barry G. Cunningham, Senior Vice-President of Generation for
17 PacifiCorp.

18 Mr. Roff will present the depreciation rates for which the Company is seeking
19 Commission approval. He describes how the depreciation study was prepared and
20 discusses the primary reasons for the recommended changes in depreciation rates. The
21 first reason Mr. Roff discusses is the effect on depreciation rates of using the estimated
22 generation plant life spans described in Mr. Cunningham's testimony. He also discusses

1 the effect on depreciation rates from the recognition of less negative net salvage for
2 distribution plant assets, the decrease for which is reflective of the Company's current
3 removal and salvage experience. Mr. Roff also discusses the effect on depreciation rates
4 of additional investment in plant, installed since the 1998 depreciation study. That study,
5 which was the basis for the depreciation rates approved by the Commission in Docket No.
6 UE-991832, will be referred to hereafter as the 1998 study.

7 Mr. Cunningham will explain the process used by the Company's generation
8 engineering staffs to develop estimated life spans for the Company's thermal and
9 hydroelectric generating plants. He will also explain why the Company proposes to use
10 the steam plant life spans used to calculate the depreciation rates adopted by the
11 Commission in Docket No. UE-991832 for the purposes of this proceeding. In addition,
12 Mr. Cunningham will explain the reasons for including terminal net salvage in the steam
13 generating plant depreciation rates, and will explain the inclusion of decommissioning
14 and removal costs for the Company's Condit and American Fork Hydroelectric plants.
15 Finally, Mr. Cunningham will discuss the depreciation of water rights acquired for the
16 operation of steam generating plants and explain why such depreciation is appropriate for
17 ratemaking purposes.

18 **DEPRECIATION STUDY BACKGROUND**

19 **Q. Was the D&T study prepared under your direction?**

20 A. Yes. As Controller for Corporate Business Services, I have responsibility for the
21 Company's accounting departments and for implementing Company accounting policies
22 and procedures. This includes periodic review and study of depreciation rates.

1 **Q. Why was it necessary for the Company to conduct the D&T study?**

2 A. It is sound accounting practice to periodically update depreciation rates to recognize
3 additions to investment in plant assets and to reflect changes in asset characteristics,
4 technology, salvage, removal costs, life span estimates and other factors that impact
5 depreciation rate calculations. The depreciation rates approved by the Commission in
6 Docket No. UE-991832 were developed from a study based on depreciable plant balances
7 at December 31, 1997. The Company typically conducts depreciation studies
8 approximately at five-year intervals.

9 **Q. What conclusions has the Company reached in this proceeding?**

10 A. The Company concludes that the D&T study has been prepared in a professional manner,
11 that it is well supported by the underlying engineering and accounting data and that it
12 results in depreciation rates that are fair and reasonable.

13 **Q. Please explain the concept of depreciation.**

14 A. There are many definitions of depreciation. The following definition was put forth by
15 the American Institute of Certified Public Accountants in its Accounting Research and
16 Terminology Bulletin #1:

17 Depreciation accounting is a system of accounting which aims to distribute the
18 cost or other basic value of tangible capital assets, less salvage (if any), over the
19 estimated useful life of the unit (which may be a group of assets) in a systematic
20 and rational manner.

21 The actual payment for electric utility plant assets occurs in the period in which it is
22 acquired through purchase or construction. Depreciation accounting spreads this cost

1 over the useful life of the property. The fundamental reason for recording depreciation is
2 to provide for accurate measurement of a utility's results of operations. Capital
3 investments in the buildings, plant, and equipment necessary to provide electric service
4 are essentially a prepaid expense, and annual depreciation is the part of that expense
5 applicable to each successive accounting period over the service life of the property.
6 Annual depreciation is an important and essential factor in informing investors and others
7 of a company's periodic income. If it is omitted or distorted, a company's periodic
8 income statement is distorted.

9 **Q. Why is depreciation especially important to an electric utility?**

10 A. An electric utility is very capital intensive; that is, it requires a tremendous investment in
11 generation, transmission and distribution equipment with long lives to bring electricity to
12 customers. Thus, the annual depreciation of this equipment is a major item of expense to
13 the utility. Regulated electric prices are expected to allow the utility to fully recover its
14 operating costs and earn a fair return on its investment. If depreciation rates are
15 established at an inadequate level for ratemaking purposes, the utility will not recover its
16 operating costs and will earn less than a fair return on its investment.

17 **Q. Do you believe that the plant lives and depreciation rates developed in the D&T**
18 **study provide the Company with a fair and equitable recovery of its investment in**
19 **electric utility plant and equipment?**

20 A. Yes, I believe the depreciation rates developed in the D&T study produce an annual
21 depreciation expense, which is fair and reasonable for both financial reporting and
22 ratemaking purposes.

1 **Q. What is the basis for your confidence in the D&T study?**

2 A. I believe that a good depreciation study is the product of sound analytical procedures
3 applied to accurate, reliable accounting and engineering data. I have full confidence in
4 Mr. Roff's choice and application of analytical procedures as described in his testimony.
5 With respect to data inputs, the steam generating plant lives used in the study, with the
6 exception of Naughton, are those used to calculate the depreciation rates adopted by the
7 Commission in Docket No. UE-991832. Retirement dates for hydro and other production
8 plant are based on the latest engineering estimates. Life estimates for other types of plant
9 and equipment are based on Mr. Roff's actuarial analysis of the data and reviewed for
10 reasonableness by those familiar with their operation. The accounting data has also been
11 consistently prepared. Company employees trained in depreciation techniques extracted
12 and summarized the retirement, salvage, and removal cost data from the accounting
13 system, and then reviewed it for completeness and accuracy before it was provided to Mr.
14 Roff for use in this study. Because I am comfortable with both the quality of the data
15 inputs and the professionalism of the analysis, I have complete confidence in the
16 recommendations contained in the D&T depreciation study.

17 **SIGNIFICANT ISSUES**

18 **Q. Please summarize the significant issues you've considered in the current study.**

19 A. One factor that the Company believes is important to take into consideration is the
20 relatively short interval between the filing of this depreciation study and the
21 Commission's order in Docket No. UE-991832, approving the depreciation rates
22 developed in the 1998 study. Little more than two years have elapsed since the effective

1 date of the Commission order in that case. This short period is of particular significance
2 with respect to the estimation of an appropriate life span for steam plants, an issue that
3 was fully examined by WUTC Staff in the prior proceeding. PacifiCorp believes that
4 there is no compelling reason to depart from the steam plant lives used to calculate the
5 depreciation rates adopted by the Commission in the UE-991832 case. The current study,
6 therefore, continues to reflect the lives for steam plants from the UE-991832 case,
7 modified only to extend the life span for the Naughton Plant from 44 to 54 years as
8 discussed by Mr. Cunningham.

9 **Q. What is the other significant issue you considered in this study?**

10 A. The other major factor impacting the current study is the reduction in negative net salvage
11 for distribution plant assets.

12 **Q. Please describe negative net salvage for distribution plant and explain why it is**
13 **considered a significant item in this study.**

14 A. Let me begin by first defining the terms net salvage and negative net salvage. Net salvage
15 refers to the salvage value of property retired less the cost of removal. Negative net
16 salvage occurs when the cost of removal exceeds the salvage value for property retired.
17 Annual net salvage is expressed as a percentage in the depreciation study and is
18 calculated by dividing the net salvage amount by the retirement amounts. Mr. Roff in his
19 testimony discusses the propriety of reflecting negative net salvage in depreciation rates
20 and the impact on depreciation rates of recognizing negative net salvage.

21 **Q. What is the reason less negative net salvage is being incurred by the Company for**
22 **distribution plant assets?**

1 A. Various accounting changes have been adopted which have combined to cause a decrease
2 in the recognition of distribution removal costs. In 1999, the Company changed the
3 accounting for various items such as cross-arms, down-guys, anchors, and insulators from
4 recording them as individual retirement units to the concept of the “fully dressed pole”,
5 which treats these items as components of a retirement unit. As a result, removal and
6 replacement of these items, independent of the retirement unit, became an expense
7 transaction instead of removal.

8 Also in 1999, the manual recording of removal costs for both transformers and
9 meters was eliminated as part of process re-engineering to eliminate manual processes.
10 To replace the manual entries for the removal of transformers, the process was automated
11 in the estimating system. The spare line transformers were reclassified from Electric
12 Plant to materials and supplies. This resulted in the accounting for transformers,
13 including removal costs, being estimated and charged along with the other distribution
14 line assets in the work order system. For meters, the manual process of recording
15 removal costs was not replaced at that time; however, a process for recording meter
16 removal costs is being developed, which will result in increased meter removal costs in
17 future analysis.

18 **Q. What procedures does the Company use to ensure salvage and cost of removal for**
19 **distribution plant is properly recorded in the accounting records?**

20 A. The Company uses a work order system to record capital activity including additions,
21 retirements, removal costs and salvage. A work order is established when operating
22 departments identify property retirement units (PRUs) being installed, removed or

1 replaced. Actual project labor and/or contractor costs incurred to remove PRUs are
2 directly charged to the work order and are closed to the general ledger.

3 Distribution projects are estimated by Company engineers using the Regional
4 Construction Management System (RCMS). RCMS uses engineered work standards
5 (“construction standards”) for each PRU to estimate the amount and percentage for
6 allocating labor charges between installation and removal activities. Actual labor costs
7 charged to the work order are allocated to the removal account and to the construction
8 accounts based on these construction standards. Proceeds received from salvage of
9 removed materials are credited back to the work order.

10 The use of work orders, the RCMS system and construction standards combine to
11 provide a reliable and consistent process for recording salvage and cost of removal.

12 **EFFECTIVE DATE**

13 **Q. What does PacifiCorp propose as the effective date for implementing the D&T study**
14 **depreciation rates?**

15 A. The Company proposes that the new depreciation rates be made effective April 1, 2002.

16 **RECOMMENDATIONS**

17 **Q. Summarize your recommendations to the Commission?**

18 A. I recommend that the Commission find the recommendations made by Mr. Roff in the
19 D&T study regarding depreciation rates to be the proper depreciation rates for the
20 Company and that the Commission order the Company to reflect depreciation rates
21 proposed in the D&T study in its accounts and records effective April 1, 2002.

22 **Q. Does this conclude your testimony?**

1 A. Yes.

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In the Matter of the Application of
PACIFICORP for an Order Authorizing a
Change in Depreciation Rates Applicable to
Electric Property.

Docket No. UE-02 ____

PACIFICORP

Exhibit of Kathryn C. Hymas

WASHINGTON Depreciation Rate Comparison - FYMar02

October, 2002

PACIFICORP

WASHINGTON Depreciation Rate Comparison - FYMar02

PLANT	ACCT	PLANT-IN-SERVICE			DEP RATE		TOTAL COMPANY DEPRECIATION			WASHINGTON ALLOCATION	
		TOTAL	NONDEP	NET	EXISTING	PROPOSED	EXISTING	PROPOSED	DIFFERENCE	FACTOR	AMOUNT
Steam Production Plant	DGP	1,282,396,016.80	(2,635,923.53)	1,279,760,093.27	2.85%	3.31%	36,475,639.18	42,372,454.52	5,896,815.33	16.64%	981,106.97
Steam Production Plant	DGU	1,441,149,590.75	(7,456,889.87)	1,433,692,700.88	3.02%	3.33%	43,287,827.94	47,736,746.76	4,448,918.81	0.00%	-
Steam Production Plant	SG	1,456,678,760.32	(32,708,156.27)	1,423,970,604.05	2.91%	3.38%	41,368,994.12	48,088,826.05	6,719,831.93	8.61%	578,430.20
TOTAL STEAM		4,180,224,367.87	(42,800,969.67)	4,137,423,398.20	2.93%	3.34%	121,132,461.24	138,198,027.32	17,065,566.08		1,559,537.17
Hydraulic Production Plant	DGP	248,981,329.88	(3,391,763.38)	245,589,566.50	2.44%	2.75%	5,992,377.93	6,746,289.85	753,879.92	16.64%	125,429.88
Hydraulic Production Plant	DGU	49,396,985.22	(4,456,877.47)	44,940,107.75	2.39%	2.76%	1,074,750.13	1,241,289.49	166,539.49	0.00%	-
Hydraulic Production Plant	SG	180,530,798.49	(4,399,381.02)	176,131,417.47	3.74%	4.16%	6,590,770.02	7,320,991.33	730,221.31	8.61%	62,856.04
TOTAL HYDRO		478,909,112.79	(12,248,021.87)	466,661,090.92	2.93%	3.28%	13,657,898.09	15,308,538.81	1,650,640.72		188,285.93
Other Production Plant	DGP	3,059,951.14	(635.22)	3,059,315.92	0.00%	0.00%	-	-	-	16.64%	-
Other Production Plant	DGU	199,454,480.95	(842,244.88)	198,612,236.07	4.12%	3.51%	125,926.91	107,256.69	(18,670.23)	0.00%	-
Other Production Plant	SG	202,514,432.09	(842,880.10)	201,671,551.99	2.86%	3.24%	5,686,888.01	6,438,799.11	751,911.10	8.61%	64,723.06
TOTAL OTHER		613,400,753.47	(2,470,691.11)	610,930,062.36	2.88%	3.25%	5,812,814.92	6,546,055.80	733,240.87		64,723.06
Transmission Plant	DGP	680,459,971.05	(27,350,581.95)	653,109,389.10	1.98%	2.17%	12,120,733.86	13,273,630.68	1,152,896.82	16.64%	191,817.96
Transmission Plant	DGU	955,639,636.14	(2,552,950.33)	953,086,685.81	2.01%	2.17%	13,153,296.08	14,165,650.52	1,012,354.44	0.00%	-
Transmission Plant	SG	2,249,500,360.66	(32,374,223.39)	2,217,126,137.27	2.08%	2.19%	19,838,475.15	20,863,641.41	1,025,166.27	0.00%	-
TOTAL TRANSMISSION		164,832,602.56	(116,221.85)	164,716,380.71	2.03%	2.18%	45,112,505.08	48,302,922.61	3,190,417.53	8.61%	88,244.34
Distribution Plant	CA	185,717,671.53	(189,958.87)	185,527,712.66	4.11%	2.63%	6,774,254.44	4,334,053.34	(2,440,201.11)	0.00%	-
Distribution Plant	IDU	1,279,163,133.88	(3,452,055.29)	1,275,711,078.59	3.55%	2.99%	6,589,963.78	5,547,991.46	(1,041,972.31)	0.00%	-
Distribution Plant	OR	1,460,568,149.39	(6,262,718.17)	1,454,305,431.22	4.16%	3.17%	53,058,175.77	40,382,074.25	(12,676,101.51)	0.00%	-
Distribution Plant	UT	294,081,503.33	(659,888.80)	293,421,614.53	3.81%	3.06%	11,193,829.28	8,972,161.48	(2,221,667.80)	0.00%	-
Distribution Plant	WA	328,304,186.51	(477,336.93)	327,826,849.58	3.46%	3.05%	11,342,673.44	10,005,580.09	(1,337,093.36)	100.00%	(2,221,667.80)
Distribution Plant	WYP	60,438,166.01	(48,779.75)	60,389,386.26	3.54%	3.25%	2,135,765.63	1,964,937.36	(170,828.27)	0.00%	-
TOTAL DISTRIBUTION		3,773,105,413.21	(11,206,959.66)	3,761,898,453.55	3.70%	2.99%	139,259,869.93	112,501,900.49	(26,757,969.45)		(2,221,667.80)
General Plant - Depreciable	CA	217,568.45	(217,568.45)	-	2.51%	2.36%	-	-	-	0.00%	-
General Plant - Depreciable	CN	1,109,264.15	(1,109,264.15)	-	2.51%	2.36%	-	-	-	7.88%	-
General Plant - Depreciable	DGU	16,174.13	(12,946.30)	3,227.83	2.51%	2.36%	81.02	76.18	(4.84)	0.00%	-
General Plant - Depreciable	SG	1,227.55	-	1,227.55	2.51%	2.36%	30.81	28.97	(1.84)	8.61%	(0.16)
General Plant - Depreciable	IDU	382,543.07	(380,220.81)	2,322.26	2.51%	2.36%	58.29	54.81	(3.48)	0.00%	-
General Plant - Depreciable	OR	1,298,320.96	(1,298,320.96)	-	2.51%	2.36%	-	-	-	0.00%	-
General Plant - Depreciable	SO	5,830,111.92	(5,830,111.92)	-	2.51%	2.36%	-	-	-	0.00%	-
General Plant - Depreciable	UT	3,007,112.85	(2,973,724.80)	33,388.05	2.51%	2.36%	838.04	787.96	(50.08)	8.22%	-
General Plant - Depreciable	WA	1,254,137.46	(1,254,137.46)	-	2.51%	2.36%	-	-	-	0.00%	-
General Plant - Depreciable	WYP	139,755.65	(139,728.57)	27.08	0.00%	0.00%	-	-	-	100.00%	-
General Plant - Depreciable	WYU	825,613.55	(825,613.55)	-	2.51%	2.36%	-	-	-	0.00%	-
General Plant - Depreciable	CA	2,016,090.81	(605,832.87)	1,410,257.94	1.93%	2.22%	27,217.98	31,307.73	4,089.75	0.00%	-
General Plant - Depreciable	CN	9,878,185.32	(2,335,156.37)	7,543,028.95	2.38%	2.43%	179,524.09	183,295.60	3,771.51	0.00%	-
General Plant - Depreciable	DGU	9,180.36	-	9,180.36	2.55%	2.74%	234.10	251.54	17.44	7.88%	297.13
General Plant - Depreciable	SG	26,472.29	-	26,472.29	2.55%	2.74%	675.04	725.34	50.30	16.64%	8.37
General Plant - Depreciable	IDU	46,441.61	-	46,441.61	3.12%	3.80%	1,448.98	1,764.78	315.80	16.64%	52.54
General Plant - Depreciable	DGP	129,705.98	-	129,705.98	3.19%	2.58%	4,137.62	3,346.41	(791.21)	16.64%	(131.64)
General Plant - Depreciable	DGU	182,702.78	-	182,702.78	3.32%	2.33%	6,065.73	4,256.97	(1,808.76)	16.64%	(300.94)
General Plant - Depreciable	DGU	1,525,772.82	-	1,525,772.82	2.38%	2.43%	36,313.39	37,076.28	762.89	0.00%	-
General Plant - Depreciable	DGU	151,835.77	-	151,835.77	3.19%	2.58%	4,843.56	3,917.36	(926.20)	0.00%	-
General Plant - Depreciable	IDU	9,083,487.09	-	9,083,487.09	2.38%	2.43%	216,186.99	220,728.74	4,541.74	0.00%	-
General Plant - Depreciable	OR	24,083,033.84	(9,667,672.11)	14,415,361.73	2.55%	2.74%	367,591.72	394,980.91	27,389.19	0.00%	-
General Plant - Depreciable	SG	2,748.74	-	2,748.74	1.93%	2.22%	53.05	61.02	7.97	8.61%	0.69
General Plant - Depreciable	SG	1,255,510.36	-	1,255,510.36	2.38%	2.43%	29,881.15	30,508.90	627.76	8.61%	54.04
General Plant - Depreciable	SG	1,354,493.83	-	1,354,493.83	2.55%	2.74%	34,539.59	37,113.13	2,573.54	8.61%	221.53

PACIFICORP

WASHINGTON Depreciation Rate Comparison - FYMar02

PLANT	ACCT	PLANT-IN-SERVICE			NET	DEP RATE		TOTAL COMPANY DEPRECIATION			DIFFERENCE	WASHINGTON ALLOCATION FACTOR	WASHINGTON ALLOCATION AMOUNT
		TOTAL	NONDEP			EXISTING	PROPOSED	EXISTING	PROPOSED				
General Plant - Depreciable	390	SG	18,204.39	-	18,204.39	3.12%	3.80%	567.98	691.77	123.79	8.61%	10.66	
General Plant - Depreciable	390	SG	68,814.93	-	68,814.93	3.19%	2.58%	2,195.20	1,775.43	(419.77)	8.61%	(36.13)	
General Plant - Depreciable	390	SG	157,010.79	-	157,010.79	3.32%	2.33%	5,212.76	3,658.35	(1,554.41)	8.61%	(133.80)	
General Plant - Depreciable	390	SO	45,047,281.79	(10,621,334.41)	34,425,947.38	2.38%	2.43%	819,337.55	836,550.52	17,212.97	8.22%	1,415.06	
General Plant - Depreciable	390	SO	38,861,504.58	-	38,861,504.58	2.55%	2.74%	990,968.37	1,064,805.23	73,836.86	8.22%	6,070.06	
General Plant - Depreciable	390	UT	30,691,472.62	-	30,691,472.62	2.38%	2.43%	730,457.05	745,802.78	15,345.74	0.00%	-	
General Plant - Depreciable	390	WA	11,301,600.32	(1,999,061.69)	9,302,538.63	3.12%	3.80%	290,239.21	353,496.47	63,257.26	100.00%	63,257.26	
General Plant - Depreciable	390	WYP	8,125,937.54	(6,495,698.59)	1,630,238.95	3.19%	2.58%	52,004.62	42,060.16	(9,944.46)	0.00%	-	
General Plant - Depreciable	390	WYU	3,067,565.19	-	3,067,565.19	3.19%	2.58%	97,855.33	79,143.18	(18,712.15)	0.00%	-	
General Plant - Depreciable	391	SO	5,191,952.96	-	5,191,952.96	2.42%	2.65%	125,645.26	107,634.37	1,268,394.11	8.22%	104,273.55	
General Plant - Depreciable	397	CA	2,593,599.27	-	2,593,599.27	3.89%	4.15%	100,891.01	107,634.37	6,743.36	0.00%	-	
General Plant - Depreciable	397	CN	2,016,271.87	-	2,016,271.87	5.03%	4.75%	101,418.48	95,772.91	(5,645.56)	7.88%	(444.78)	
General Plant - Depreciable	397	CN	3,118,952.65	-	3,118,952.65	5.58%	6.28%	174,037.56	195,870.23	21,832.67	7.88%	1,720.05	
General Plant - Depreciable	397	DGP	1,133,951.77	-	1,133,951.77	3.75%	5.30%	42,523.19	60,099.44	17,576.25	16.64%	2,924.32	
General Plant - Depreciable	397	DGP	244,253.82	-	244,253.82	3.89%	4.15%	9,501.47	10,136.53	635.06	16.64%	105.66	
General Plant - Depreciable	397	DGP	1,078,073.22	-	1,078,073.22	4.97%	3.93%	53,580.24	42,368.28	(11,211.96)	16.64%	(1,865.44)	
General Plant - Depreciable	397	DGP	40,545.44	-	40,545.44	5.03%	4.75%	2,039.44	1,925.91	(113.53)	16.64%	(18.89)	
General Plant - Depreciable	397	DGP	1,349,339.96	-	1,349,339.96	5.34%	4.86%	72,054.75	65,577.92	(6,476.83)	16.64%	(1,077.61)	
General Plant - Depreciable	397	DGP	2,984,178.30	-	2,984,178.30	5.58%	6.28%	166,517.15	187,406.40	20,889.25	16.64%	3,475.53	
General Plant - Depreciable	397	DGU	9,572,676.08	-	9,572,676.08	5.03%	4.75%	481,505.61	454,702.11	(26,803.49)	0.00%	-	
General Plant - Depreciable	397	DGU	1,047,122.95	-	1,047,122.95	5.34%	4.86%	55,916.37	50,890.18	(5,026.19)	0.00%	-	
General Plant - Depreciable	397	IDU	5,473,416.54	-	5,473,416.54	5.03%	4.75%	275,312.85	259,987.29	(15,325.57)	0.00%	-	
General Plant - Depreciable	397	OR	35,801,956.17	-	35,801,956.17	5.58%	6.28%	1,997,749.15	2,248,362.85	250,613.69	0.00%	-	
General Plant - Depreciable	397	SE	6,215.27	-	6,215.27	5.03%	4.75%	312.63	295.23	(17.40)	8.51%	(1.48)	
General Plant - Depreciable	397	SG	1,693,829.79	-	1,693,829.79	3.75%	5.30%	63,518.62	89,772.98	26,254.36	8.61%	2,259.92	
General Plant - Depreciable	397	SG	1,213,848.29	-	1,213,848.29	3.89%	4.15%	47,218.70	50,374.70	3,156.01	8.61%	271.66	
General Plant - Depreciable	397	SG	1,247,183.96	-	1,247,183.96	4.97%	3.93%	61,985.04	49,014.33	(12,970.71)	8.61%	(1,116.49)	
General Plant - Depreciable	397	SG	10,641,261.74	-	10,641,261.74	5.03%	4.75%	535,255.47	505,459.93	(29,795.53)	8.61%	(2,564.74)	
General Plant - Depreciable	397	SG	5,309,520.00	-	5,309,520.00	5.34%	4.86%	283,528.37	258,042.67	(25,485.70)	8.61%	(2,193.76)	
General Plant - Depreciable	397	SG	13,264,204.57	-	13,264,204.57	5.58%	6.28%	740,142.62	832,992.05	92,849.43	8.61%	7,992.30	
General Plant - Depreciable	397	SO	13,997,926.41	-	13,997,926.41	5.03%	4.75%	704,095.70	664,901.50	(39,194.19)	8.22%	(3,222.12)	
General Plant - Depreciable	397	SO	129,596.64	-	129,596.64	5.34%	4.86%	6,920.46	6,298.40	(622.06)	8.22%	(51.14)	
General Plant - Depreciable	397	SO	33,917,274.87	-	33,917,274.87	5.58%	6.28%	1,892,583.94	2,130,004.86	237,420.92	8.22%	19,518.16	
General Plant - Depreciable	397	UT	20,972,581.22	-	20,972,581.22	5.03%	4.75%	1,054,920.84	996,197.61	(58,723.23)	0.00%	-	
General Plant - Depreciable	397	WA	8,448,923.00	-	8,448,923.00	3.75%	5.30%	316,834.61	447,792.92	130,958.31	100.00%	130,958.31	
General Plant - Depreciable	397	WYP	13,060,549.16	-	13,060,549.16	5.34%	4.86%	697,433.33	634,742.69	(62,690.64)	0.00%	-	
General Plant - Depreciable	397	WYU	1,857,973.76	-	1,857,973.76	5.34%	4.86%	99,215.80	90,297.52	(8,918.27)	0.00%	-	
TOTAL GNL PLANT DEPRECIABLE			398,574,063.17	(45,766,393.01)	352,807,670.16	3.99%	4.54%	14,061,217.84	16,009,227.71	1,948,009.86	0.00%	331,729.07	
General Plant - Vehicles	392	CA	276,974.91	-	276,974.91	3.24%	2.30%	8,973.99	6,370.42	(2,603.56)	0.00%	-	
General Plant - Vehicles	392	CA	313,402.26	-	313,402.26	6.09%	5.04%	19,086.20	15,795.47	(3,290.72)	0.00%	-	
General Plant - Vehicles	392	CA	469,477.76	-	469,477.76	10.90%	6.31%	51,173.08	29,624.05	(21,549.03)	0.00%	-	
General Plant - Vehicles	392	CN	12,977.97	-	12,977.97	10.78%	8.92%	1,399.03	1,157.63	(241.39)	7.88%	(19.02)	
General Plant - Vehicles	392	DGP	2,022.76	-	2,022.76	2.25%	2.52%	45.51	50.97	5.46	16.64%	0.91	
General Plant - Vehicles	392	DGP	14,658.20	-	14,658.20	6.31%	6.65%	924.93	974.77	49.84	16.64%	8.29	
General Plant - Vehicles	392	DGP	27,049.58	-	27,049.58	6.46%	7.34%	1,747.40	1,985.44	238.04	16.64%	39.60	
General Plant - Vehicles	392	DGP	145,201.68	-	145,201.68	8.76%	4.67%	12,719.67	6,780.92	(5,938.75)	16.64%	(988.08)	
General Plant - Vehicles	392	DGP	39,560.88	-	39,560.88	12.75%	5.89%	5,044.01	2,330.14	(2,713.88)	16.64%	(451.53)	
General Plant - Vehicles	392	DGU	29,778.33	-	29,778.33	1.75%	2.51%	521.12	747.44	226.32	0.00%	-	
General Plant - Vehicles	392	DGU	32,613.04	-	32,613.04	3.55%	3.27%	1,157.76	1,066.45	(91.32)	0.00%	-	

PACIFICORP

WASHINGTON Depreciation Rate Comparison - FYMar02

PLANT	ACCT	AF	PLANT-IN-SERVICE		NET	DEP RATE		TOTAL COMPANY DEPRECIATION			WASHINGTON ALLOCATION	
			TOTAL	NONDEP		EXISTING	PROPOSED	EXISTING	PROPOSED	DIFFERENCE	FACTOR	AMOUNT
General Plant - Vehicles	392	DGU	757,450.59	-	757,450.59	4.62%	5.64%	34,994.22	42,720.21	7,726.00	0.00%	-
General Plant - Vehicles	392	DGU	191,620.22	-	191,620.22	5.47%	6.69%	10,481.63	12,819.39	2,337.77	0.00%	-
General Plant - Vehicles	392	DGU	44,694.29	-	44,694.29	8.76%	4.67%	3,915.22	2,087.22	(1,828.00)	0.00%	-
General Plant - Vehicles	392	DGU	12,834.33	-	12,834.33	12.75%	5.89%	1,636.38	755.94	(880.44)	0.00%	-
General Plant - Vehicles	392	IDU	530,628.60	-	530,628.60	1.75%	2.51%	9,286.00	13,318.78	4,032.78	0.00%	-
General Plant - Vehicles	392	IDU	1,474,699.87	-	1,474,699.87	4.62%	5.64%	68,131.13	83,173.07	15,041.94	0.00%	-
General Plant - Vehicles	392	IDU	1,662,312.04	-	1,662,312.04	5.47%	6.69%	90,928.47	111,208.68	20,280.21	0.00%	-
General Plant - Vehicles	392	OR	2,103,293.24	-	2,103,293.24	2.25%	2.52%	47,324.10	53,002.99	5,678.89	0.00%	-
General Plant - Vehicles	392	OR	5,204,299.84	-	5,204,299.84	6.31%	6.65%	328,391.32	346,085.94	17,694.62	0.00%	-
General Plant - Vehicles	392	OR	5,206,833.03	-	5,206,833.03	10.78%	8.92%	561,296.60	464,449.51	(96,847.09)	0.00%	-
General Plant - Vehicles	392	SE	5,383.91	-	5,383.91	1.75%	1.75%	94.22	135.14	40.92	8.51%	3.48
General Plant - Vehicles	392	SE	57,420.98	-	57,420.98	4.62%	5.64%	2,652.85	3,238.54	585.69	8.51%	49.87
General Plant - Vehicles	392	SE	330,408.14	-	330,408.14	5.47%	6.69%	18,073.33	22,104.30	4,030.98	8.51%	343.21
General Plant - Vehicles	392	SG	219,077.11	-	219,077.11	1.75%	2.51%	3,833.85	5,498.84	1,664.99	8.61%	143.32
General Plant - Vehicles	392	SG	141,005.85	-	141,005.85	2.25%	2.52%	3,172.63	3,553.35	380.72	8.61%	32.77
General Plant - Vehicles	392	SG	26,302.47	-	26,302.47	2.30%	2.67%	604.96	702.28	97.32	8.61%	8.38
General Plant - Vehicles	392	SG	44,566.96	-	44,566.96	3.55%	3.27%	1,582.13	1,457.34	(124.79)	8.61%	(10.74)
General Plant - Vehicles	392	SG	1,304,562.74	-	1,304,562.74	4.62%	5.64%	60,270.80	73,577.34	13,306.54	8.61%	1,145.40
General Plant - Vehicles	392	SG	2,143,684.35	-	2,143,684.35	5.47%	6.69%	117,259.53	143,412.48	26,152.95	8.61%	2,251.20
General Plant - Vehicles	392	SG	57,885.35	-	57,885.35	6.09%	5.04%	3,525.22	2,917.42	(607.80)	8.61%	(52.32)
General Plant - Vehicles	392	SG	514,170.43	-	514,170.43	6.31%	6.65%	32,444.15	34,192.33	1,748.18	8.61%	150.48
General Plant - Vehicles	392	SG	404,107.32	-	404,107.32	6.46%	7.34%	26,105.33	29,661.48	3,556.14	8.61%	306.11
General Plant - Vehicles	392	SG	1,685.24	-	1,685.24	7.09%	6.89%	119.48	116.11	(3.37)	8.61%	(0.29)
General Plant - Vehicles	392	SG	416,697.54	-	416,697.54	8.76%	4.67%	36,502.70	19,459.78	(17,042.93)	8.61%	(1,464.02)
General Plant - Vehicles	392	SG	364,866.01	-	364,866.01	10.78%	8.92%	39,332.56	32,546.05	(6,786.51)	8.61%	(584.17)
General Plant - Vehicles	392	SG	15,406.72	-	15,406.72	10.90%	6.31%	1,679.33	972.16	(707.17)	8.61%	(60.87)
General Plant - Vehicles	392	SG	335,973.14	-	335,973.14	12.49%	7.11%	41,963.05	23,887.69	(18,075.35)	8.61%	(1,555.89)
General Plant - Vehicles	392	SG	844,758.26	-	844,758.26	12.75%	5.89%	107,706.68	49,756.26	(57,950.42)	8.61%	(4,988.26)
General Plant - Vehicles	392	SO	1,398,506.53	-	1,398,506.53	1.75%	2.51%	24,473.86	35,102.51	10,628.65	8.22%	873.77
General Plant - Vehicles	392	SO	5,271.50	-	5,271.50	2.25%	2.52%	118.61	132.84	14.23	8.22%	1.17
General Plant - Vehicles	392	SO	1,572,202.95	-	1,572,202.95	4.62%	5.64%	72,635.78	88,672.25	16,036.47	8.22%	1,318.34
General Plant - Vehicles	392	SO	1,664,343.24	-	1,664,343.24	5.47%	6.69%	91,039.58	111,344.56	20,304.99	8.22%	1,669.25
General Plant - Vehicles	392	SO	163,790.01	-	163,790.01	6.31%	6.65%	10,335.15	10,892.04	556.89	8.22%	45.78
General Plant - Vehicles	392	SO	35,464.13	-	35,464.13	8.76%	4.67%	3,106.66	1,656.17	(1,450.48)	8.22%	(119.24)
General Plant - Vehicles	392	SO	955,666.97	-	955,666.97	10.78%	8.92%	103,020.90	85,245.49	(17,775.41)	8.22%	(1,461.30)
General Plant - Vehicles	392	SO	111,558.24	-	111,558.24	12.75%	5.89%	14,223.68	6,570.78	(7,652.90)	8.22%	(629.14)
General Plant - Vehicles	392	UT	4,605,459.65	-	4,605,459.65	1.75%	2.51%	80,595.54	115,597.04	35,001.49	0.00%	-
General Plant - Vehicles	392	UT	12,609,748.98	-	12,609,748.98	4.62%	5.64%	582,570.40	711,189.84	128,619.44	0.00%	-
General Plant - Vehicles	392	UT	11,224,936.08	-	11,224,936.08	5.47%	6.69%	614,004.00	750,948.22	136,944.22	0.00%	-
General Plant - Vehicles	392	WA	372,709.54	-	372,709.54	2.30%	2.67%	8,572.32	9,951.34	1,379.03	100.00%	1,379.03
General Plant - Vehicles	392	WA	1,118,673.13	-	1,118,673.13	6.46%	7.34%	72,266.28	82,110.61	9,844.32	100.00%	9,844.32
General Plant - Vehicles	392	WA	1,088,294.60	-	1,088,294.60	12.49%	7.11%	135,928.00	77,377.75	(58,550.25)	100.00%	(58,550.25)
General Plant - Vehicles	392	WYP	1,369,130.98	-	1,369,130.98	3.55%	3.27%	48,604.15	44,770.58	(3,833.57)	0.00%	-
General Plant - Vehicles	392	WYP	2,074,973.45	-	2,074,973.45	8.76%	4.67%	181,767.67	96,901.26	(84,866.41)	0.00%	-
General Plant - Vehicles	392	WYP	1,922,940.79	-	1,922,940.79	12.75%	5.89%	245,174.95	113,261.21	(131,913.74)	0.00%	-
General Plant - Vehicles	392	WYU	514,238.80	-	514,238.80	3.55%	3.27%	18,255.48	16,815.61	(1,439.87)	0.00%	-
General Plant - Vehicles	392	WYU	818,172.76	-	818,172.76	8.76%	4.67%	71,671.93	38,208.67	(33,463.27)	0.00%	-
General Plant - Vehicles	392	WYU	663,767.72	-	663,767.72	12.75%	5.89%	84,630.38	39,095.92	(45,534.47)	0.00%	-
General Plant - Vehicles	396	CA	2,190,660.26	-	2,190,660.26	5.45%	4.13%	119,390.98	90,475.95	(28,915.03)	0.00%	-

PACIFICORP
 WASHINGTON Depreciation Rate Comparison - FYMar02

PLANT	ACCT	AF	PLANT-IN-SERVICE		NET	DEP RATE		TOTAL COMPANY DEPRECIATION			WASHINGTON ALLOCATION	
			TOTAL	NONDEP		EXISTING	PROPOSED	EXISTING	PROPOSED	DIFFERENCE	FACTOR	AMOUNT
General Plant - Vehicles	396	DGP	6,555.64	-	6,555.64	4.25%	5.11%	278.61	334.99	56.38	16.64%	9.38
General Plant - Vehicles	396	DGP	1,286,172.67	-	1,286,172.67	6.40%	3.93%	82,315.05	50,546.59	(31,768.46)	16.64%	(5,285.61)
General Plant - Vehicles	396	DGU	695,788.75	-	695,788.75	4.06%	5.81%	28,249.02	40,425.33	12,176.30	0.00%	-
General Plant - Vehicles	396	IDU	5,630,838.87	-	5,630,838.87	4.06%	6.34%	228,612.06	357,141.89	128,529.83	0.00%	-
General Plant - Vehicles	396	OR	19,920,029.39	-	19,920,029.39	4.25%	5.67%	846,601.25	1,129,571.52	282,970.27	0.00%	-
General Plant - Vehicles	396	SE	160,302.88	-	160,302.88	4.06%	5.81%	6,508.30	9,313.60	2,805.30	8.51%	238.85
General Plant - Vehicles	396	SG	3,423,321.07	-	3,423,321.07	4.06%	5.81%	138,986.84	198,894.95	59,908.12	8.61%	5,156.78
General Plant - Vehicles	396	SG	1,223,707.73	-	1,223,707.73	4.25%	5.11%	52,007.58	62,531.47	10,523.89	8.61%	905.88
General Plant - Vehicles	396	SG	362,566.41	-	362,566.41	6.21%	7.16%	22,515.37	25,959.75	3,444.38	8.61%	296.49
General Plant - Vehicles	396	SG	6,777,591.96	-	6,777,591.96	6.40%	3.93%	433,765.89	266,359.36	(167,406.52)	8.61%	(14,410.03)
General Plant - Vehicles	396	SG	15,167.19	-	15,167.19	6.69%	6.05%	1,014.69	917.61	(97.07)	8.61%	(8.36)
General Plant - Vehicles	396	SO	2,239,407.83	-	2,239,407.83	4.06%	5.81%	90,919.96	130,109.59	39,189.64	8.22%	3,221.75
General Plant - Vehicles	396	SO	918,116.00	-	918,116.00	4.25%	5.11%	39,019.93	46,915.73	7,895.80	8.22%	649.11
General Plant - Vehicles	396	SO	221,266.57	-	221,266.57	6.40%	3.93%	14,161.06	8,695.78	(5,465.28)	8.22%	(449.30)
General Plant - Vehicles	396	UT	29,562,004.04	-	29,562,004.04	4.06%	6.14%	1,200,217.36	1,814,479.65	614,262.29	0.00%	-
General Plant - Vehicles	396	WA	5,484,951.05	-	5,484,951.05	6.21%	7.59%	340,615.46	416,461.29	75,845.83	100.00%	75,845.83
General Plant - Vehicles	396	WYP	6,932,062.80	-	6,932,062.80	6.40%	4.54%	443,652.02	314,686.63	(128,965.39)	0.00%	-
General Plant - Vehicles	396	WYU	2,372,587.74	-	2,372,587.74	6.40%	4.20%	151,845.62	99,668.21	(52,177.41)	0.00%	-
TOTAL GNL PLANT VEHICLES			159,493,294.84	-	159,493,294.84	5.30%	5.73%	8,459,772.92	9,143,028.93	683,256.00		14,847.31
TOTAL GENERAL PLANT			558,067,358.01	(45,766,393.01)	512,300,965.00	4.40%	4.91%	22,520,990.77	25,152,256.63	2,631,265.87		346,576.38
Mining Plant		SE	260,565,862.27	(85,034,983.27)	175,530,879.00	5.55%	5.98%	9,736,013.00	10,490,705.00	754,692.00	8.51%	64,256.41
TOTAL COMPANY			11,702,886,906.90	(230,274,430.97)	11,472,612,475.93	3.11%	3.11%	357,232,553.03	356,500,406.65	(732,146.38)		281,773.45

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

In the Matter of the Application of
PACIFICORP for an Order Authorizing a
Change in Depreciation Rates Applicable to
Electric Property.

Docket No. UE-02_____

PACIFICORP

Direct Testimony of Donald S. Roff

October, 2002

1 **Introduction and Background**

2 **Q. Please state your name, occupation, business address, employer and job title.**

3 A. My name is Donald S. Roff. I am a Director with the public accounting
4 firm of Deloitte & Touche LLP. My business address is 2200 Ross Avenue,
5 Dallas, Texas 75201.

6 **Q. On whose behalf are you testifying?**

7 A. I am testifying on behalf of PacifiCorp (“the Company”).

8 **Q. Please state your qualifications.**

9 A. My qualifications are described on Exhibit____(DSR-1).

10 **Q. Have you previously testified before this or any other regulatory body?**

11 A. Yes. A list of my regulatory appearances and related jurisdictions is attached as
12 Exhibit____ (DSR-2).

13 **Q. What is the purpose of your testimony?**

14 A. I have been asked by PacifiCorp to testify as to the recommended depreciation
15 rates to be used by the Company for the accrual of depreciation expense.

16 **Q. Please summarize your testimony.**

17 A. Based upon my depreciation study, a copy of which is attached to my Direct
18 Testimony as Exhibit____ (DSR-3), conducted as of March 31, 2002, I
19 recommend changes to the depreciation rates currently in use, as illustrated by the
20 following comparison:

1	<u>Function</u>	<u>Existing</u>	<u>Recommended</u>
2		%	%
3	Steam Production Plant	2.93	3.34
4	Hydraulic Production Plant	2.93	3.28
5	Other Production Plant	2.88	3.25
6	Transmission Plant	2.03	2.18
7	Distribution Plant	3.70	2.99
8	General Plant	4.40	4.91
9	Mining Operations	5.55	5.98
10	Total Electric Plant	3.11	3.11

11 This summary is taken from Table A, page 3 of Exhibit ____ (DSR-3).

12 Application of my recommended rates to the March 31, 2002 depreciable
13 balances results in a decrease in annual depreciation expense of \$732,000. The
14 following sections of my testimony discuss the depreciation study procedure, life
15 analysis, interim activity, salvage and cost of removal analysis, and the results for
16 Steam, Hydraulic and Other Production Plant, Transmission, Distribution and
17 General Plant, and Mining Operations and my recommendations.

18 **Q. What are the primary reasons for the minimal change in depreciation that**
19 **you recommend?**

20 A. There are two factors that influence the level of depreciation expense change that I
21 recommend. The first factor is recognition of less negative net salvage for
22 Transmission and Distribution Plant asset categories, reflective of current

1 experience. The second element is additional investment installed since the prior
2 study.

3 **Depreciation Study Procedure**

4 **Q. What is depreciation?**

5 A. The most widely recognized accounting definition of depreciation is that of the
6 American Institute of Certified Public Accountants, which states:

7 “Depreciation accounting is a system of accounting which aims to
8 distribute the cost or other basic value of tangible capital assets, less
9 salvage (if any), over the estimated useful life of the unit (which may
10 be a group of assets) in a systematic and rational manner. It is a process of
11 allocation, not of valuation.”¹

12 **Q. What is the significance of this definition?**

13 A. This definition of depreciation accounting forms the accounting framework under
14 which my depreciation study was conducted. Several aspects of this definition are
15 particularly significant. Salvage (net salvage) is to be recognized. The allocation
16 of costs is over the useful life of the assets. Grouping of assets is permissible.
17 Depreciation accounting is not a valuation process. And the cost allocation must
18 be both systematic and rational.

19 **Q. Please explain the importance of the terms “systematic and rational”.**

20 A. Systematic implies the use of a formula, and the formula used for calculating the
21 recommended depreciation rates is shown on Page 15 of Exhibit ____ (DSR-3).

1 Accounting Research Bulletin No. 43, Chapter 9, Paragraph 5 (June 1953).

1 Rational means that the pattern of depreciation, in this case, the depreciation rate
2 itself, must match either the pattern of revenues produced by the asset, or match
3 the consumption of the asset. Since revenues are determined through regulation
4 and are expected to continue to be so determined, asset consumption must be
5 directly measured and reflected in depreciation rates. This measurement of asset
6 consumption is accomplished by conducting a depreciation study.

7 **Q. Are there other definitions of depreciation?**

8 A. Yes. The Federal Energy Regulatory Commission Uniform System of Accounts,
9 followed by the Company, provides a series of definitions related to depreciation
10 as shown on Page 7 of Exhibit ____ (DSR-3). These definitions of depreciation
11 make reference to asset consumption, and therefore relate very well to the
12 accounting framework for depreciation. These definitions form the regulatory
13 framework under which my depreciation study was conducted. Remaining life
14 rates are recommended, which depreciation rates provide for full recovery of net
15 investment adjusted for net salvage over the future useful life of each asset
16 category, and are consistent with past practice.

17 **Q. How does your depreciation study recognize asset consumption?**

18 A. Asset consumption in my depreciation study is recognized in two different ways,
19 depending upon the type of asset. For mass property, asset consumption
20 (retirement dispersion) is defined by the use of Iowa type curves and related
21 average service lives. For life span property (power plants), asset consumption is
22 recognized through the use of interim activity factors, which provide a form of
23 retirement dispersion.

1 **Q. What is retirement dispersion?**

2 A. Retirement dispersion merely recognizes that groups of assets have individual
3 assets of different lives, i.e., each asset retires at differing ages. Retirement
4 dispersion is the scattering of retirements by age around the average service life
5 for each group of assets.

6 **Q. Please describe how these elements were determined and utilized in your
7 depreciation study.**

8 A. A depreciation study consists of four distinct yet related phases - data collection,
9 analysis, evaluation and rate calculation. Data collection refers to the gathering of
10 historical accounting information for use in the other phases. PacifiCorp
11 personnel assisted with this effort, and provided a large amount of historical
12 accounting data. Analysis refers to the statistical processing of the data collected
13 in the first phase. There are two separate analysis procedures, one for life, and
14 one for salvage and cost of removal. The evaluation phase incorporates the
15 information developed in the data collection and analysis phases, to determine the
16 applicability of the historical relationships developed in these phases to the future.
17 The rate calculation phase merely utilizes the parameters developed in the other
18 phases in the computation of the recommended depreciation rates.

19 **Q. What are the parameters used in the calculation of your recommended
20 depreciation rates?**

21 A. The parameters are the estimated retirement date for Production Plants or average
22 service life for Transmission, Distribution and General Plant; retirement
23 dispersion defined by interim retirement factors for Production Plant and by Iowa

1 curves for the mass accounts; and interim and terminal net salvage factors for
2 Production Plant and terminal net salvage factors for the mass accounts. Also
3 used are the depreciable plant balance, the accumulated provision for
4 depreciation, and the average remaining life. How these factors are used in the
5 calculation is discussed on Pages 15 and 16 of Exhibit ____ (DSR-3). Individual
6 parameters are shown on Schedule 3 of Exhibit ____ (DSR-3).

7 **Life Analysis**

8 **Q. Please explain the life analysis phase of your study of production plant.**

9 A. There are two parts to the life analysis phase of my study of Production Plant.
10 The first is the determination of the estimated retirement date for each plant
11 suitable for the calculation of depreciation rates. The second part is the
12 determination of interim retirement ratios and interim addition factors from an
13 analysis of historical experience.

14 **Q. What was the basis for the retirement dates used in your depreciation study
15 of production plant?**

16 A. These retirement dates were provided to me by PacifiCorp planning personnel,
17 and are contained on Exhibit ____ (DSR-3), Schedule 3. It is my understanding that
18 these estimated retirement dates give consideration to the age of the plant, it's
19 operating characteristics, and economic and environmental constraints.

20 **Q. Are these dates reasonable and consistent with your knowledge and
21 experience?**

22 A. Yes. These retirement dates produce life spans, which are reasonable and
23 consistent with my experience. It is my understanding that these dates reflect the

1 current best estimate of when the generating units will retire, giving due
2 consideration to each unit's age, location, operating characteristics and expected
3 future usage, and therefore represent the appropriate period over which the
4 allocation of cost should occur.

5 **Q. Please describe the life analysis procedure utilized for non-production plant**
6 **asset categories.**

7 A. For most asset categories, PacifiCorp maintains vintaged accounting records, that
8 is, the age of property retired and property surviving is known. The exception is
9 Account 370, Meters and the Distribution line accounts in Utah and Idaho
10 (Account 364 – Account 373). For the aged asset categories the actuarial method
11 of life analysis was utilized. For the unaged asset categories, the Simulated Plant
12 Record (“SPR”) method was utilized.

13 **Q. Please Describe Actuarial Analysis.**

14 A. Actuarial analysis uses the age information contained in the historical property
15 records to determine life tables (survivor curves) for various bands of experience.
16 These plots of percent surviving as a function of age are then compared to
17 standard distributions (Iowa curves) to arrive at an historical average service life
18 and curve shape.

19 **Q. Please describe SPR analysis.**

20 A. SPR analysis determines retirement dispersion and average service life
21 combinations for various bands of years that best match the actual retirements
22 and/or balances for each asset category. The simulated balances procedure
23 consists of applying survivor ratios (portion surviving at each age) from Iowa-type

1 dispersion patters in order to calculate annual balances, and then comparing the
2 calculated balances with the actual balances for several periods, followed by
3 statistical comparisons of differences in balances. The simulated retirements
4 procedure is similar, except that the retirement frequency rates of the Iowa
5 patterns are utilized to calculate annual retirements, and the comparisons are to
6 actual retirements rather than to balances. Tabulations of the best ranking curves
7 were made and this became the starting point for the evaluation phase of my
8 depreciation study.

9 **Interim Activity**

10 **Q. What are interim retirements?**

11 A. Interim retirements are the retirements of plant components between the date of
12 original installation and the date of final retirement of a plant or unit.

13 **Q. What are interim additions?**

14 A. Interim additions are the replacement of retired plant components, or the addition
15 of new plant components not originally necessary, between the date of original
16 installation and the date of final retirement of a plant or unit.

17 **Q. Is the analysis of interim activity, that is, both interim additions and interim
18 retirements, an accepted analytical procedure?**

19 A. Yes. These accounting histories are readily available, sufficient, and provide
20 useful information upon which to base meaningful conclusions. A description of
21 this analysis process is provided in Exhibit ____ (DSR-3) at Pages 10 and 11.

22 **Q. Why should interim additions and retirements be included in the calculation
23 of depreciation rates for production plant?**

1 A. Interim retirements occur over the life of a production unit as items are replaced
2 or retired. This is clearly evident from a review of historical investment
3 experience. Recognition of the effect of these interim retirements in the
4 depreciation rate calculation is necessary to ensure that these interim retirements
5 are fully depreciated by the time they occur. Similarly, interim additions occur
6 over the life of a production unit as items are replaced or new items are installed.
7 This activity is also clearly evident from a review of historical investment
8 experience. Recognition of the effect of these interim additions in the
9 depreciation rate calculation is necessary because the estimated retirement dates
10 cannot occur without the replacement activity, and the estimated retirement dates
11 assume this activity will occur.

12 **Q. What interim activity factors were developed in your depreciation study?**

13 A. The interim retirement ratios and interim addition factors utilized in my
14 depreciation study are shown in Exhibit____ (DSR-3), Schedule 3, pages 65 and
15 66, columns 4 and 5.

16 **Q. Were these factors used in the calculation of your recommended depreciation
17 rates for production plant?**

18 A. My recommended depreciation rates for Production Plant include no interim
19 addition factor, but do include interim retirements.

20 **Q. Why were interim additions excluded?**

21 A. While it would be appropriate to include interim additions, they were excluded
22 from the depreciation rate calculations for two reasons. The primary reason was

1 to mitigate the effect of the change in depreciation rates. The second reason was
2 to limit, to the extent possible, the issues before the Commission in this case.

3 **Q. What would be the effect of including all interim additions in the**
4 **depreciation rate calculation?**

5 A. The recommended depreciation rates for Production Plant would have been
6 substantially higher.

7 **Q. What is the effect on the annual depreciation rate of ignoring these interim**
8 **additions?**

9 A. Initially, the depreciation rate would be slightly lower, but would increase at each
10 recalculation. Exhibit ____ (DSR-4) has been prepared to illustrate this effect. Of
11 particular interest is the pattern of depreciation rates shown in Column 13. This
12 ever-increasing pattern of depreciation rates would be appropriate only if asset
13 consumption is ever increasing.

14 **Salvage and Cost of Removal Analysis**

15 **Q. Please discuss the cost of removal and salvage analysis portion of your study**
16 **of production plant.**

17 A. There are two separate components of cost of removal and salvage for Production
18 Plant: interim and terminal. Interim net salvage refers to the cost of removal net
19 of salvage related to interim retirements. Terminal net salvage refers to the net
20 demolition cost of a plant or unit at final retirement. Interim net salvage factors
21 were determined based upon an analysis of historical experience. Terminal net
22 salvage factors were projected based upon a review of the site-specific demolition
23 cost estimates of others.

1 **Q. How were the interim net salvage factors for production plant determined?**

2 A. Primary account summaries of retirements, salvage and cost of removal were
3 provided by PacifiCorp personnel. I examined the ratio of salvage, cost of
4 removal and net salvage to retirements and looked at the trends over time. I then
5 selected an interim net salvage factor for each primary account.

6 **Q. How were the terminal net salvage factors for production plant determined?**

7 A. I have collected the site-specific demolition cost estimates of over 500 units,
8 which are in the public record. For each unit I have computed the net demolition
9 cost per kW of generating capacity by fuel type. This average figure is about
10 \$50/kW in 2001 price levels for coal-fired units. Exhibit ____ (DSR-5) provides a
11 summary of the site-specific demolition cost studies. I conservatively used this
12 \$50/kW for coal units to recognize the ongoing environmental control facilities
13 additions. This number is conservative because additional pollution control
14 requirements are expected which will increase this unit cost. The net demolition
15 amounts were then allocated to accounts on the basis of plant investment, and
16 used in the depreciation rate calculations. A similar process was used for the units
17 that are not coal-fired.

18 **Steam Production Plant Results**

19 **Q. Please summarize your results for steam production plant.**

20 A. Use of the parameters described above results in a composite depreciation rate of
21 3.34 percent, which produces an annual depreciation expense increase of
22 \$17,100,000, or about 14 percent above the existing rate.

23 **Q. What is the reason for this increase in depreciation expense?**

1 A. The primary reason for the increase is additional investment installed since the
2 prior study, which must be recovered over a period shorter than the original life
3 span.

4 **Hydraulic Production Plant Results**

5 **Q. Please discuss the results of your depreciation study for hydraulic production**
6 **plant.**

7 A. Retirement dates were tied to license expiration dates or expected license renewal
8 dates. Interim activity has been limited, and no interim additions were included,
9 although a figure greater than one is justified by historical experience. Zero
10 terminal net salvage has been used, with the exception of the Condit and
11 American Fork Plant. The composite depreciation rate for Hydraulic Production
12 Plant increased from 2.93 percent to 3.28 percent, primarily due to the effect of
13 some relatively new investments. Note that this depreciation rate comparison
14 incorporates the removal cost provision for Condit and American Fork. The net
15 change in annual depreciation for Hydraulic Production Plant is approximately
16 \$1,650,000.

17 **Other Production Plant Results**

18 **Q. Please discuss the results of your study of other production plant.**

19 A. The composite depreciation rate for Other Production Plant increased from 2.88
20 percent to 3.25 percent, reflecting little change to existing parameters. The
21 change produced an increase in annual depreciation expense of \$733,000, or about
22 13 percent, primarily due to the addition of the Wyoming Wind Farm.

1 **Transmission, Distribution and General Plant**

2 **Q. Please discuss the life analysis procedure for transmission, distribution and**
3 **general plant.**

4 A. For most asset categories the age of both surviving and retired property is known,
5 and actuarial analysis was utilized for these property groups. Actuarial analysis is
6 described on Pages 11 and 12 of Exhibit ____ (DSR-3). For some asset groups,
7 the age of property retired is not known, and a Simulated Plant Record Analysis
8 was performed. The SPR method determines retirement dispersion and average
9 service life combinations for various bands of years that best match the actual
10 retirements and balances for each asset category.

11 **Q. What are Iowa-type curves?**

12 A. The Iowa-type curves were devised empirically over 60 years ago by the
13 Engineering Research Institute at what is now Iowa State University to provide a
14 set of standard definitions of retirement dispersion. Retirement dispersion merely
15 recognizes that groups of assets have individual assets of different lives, i.e., each
16 asset retires at differing ages. Retirement dispersion is the scattering of
17 retirements by age around the average service life for each group of assets.
18 Standard dispersion patterns are useful because they make calculations of the
19 remaining life of existing property possible and allow life characteristics to be
20 compared.

21 The Engineering Research Institute collected dated retirement information
22 on many types of industrial and utility property and devised empirical curves that
23 matched the range of patterns found. A total of 18 curves were defined. There

1 were six left-skewed, seven symmetrical and five right-skewed curves, varying
2 from wide to narrow dispersion patterns. The Iowa-curve naming convention
3 allows the analyst to relate easily to the patterns. The left-skewed curves are
4 known as the "L series", the symmetrical as the "S series" and the right-skewed as
5 the "R series." A number identifies the range of dispersion. A low number
6 represents a wide pattern and a high number a narrow pattern. The combination
7 of one letter and one number defines a unique dispersion pattern.

8 **Q. How were the Iowa curve shapes and average service life selections made?**

9 A. Summaries of the individual asset category life analysis indications were prepared
10 and discussed with PacifiCorp personnel. Anomalies and trends were identified
11 and engineering and operations input was requested where necessary. A single
12 average service life and Iowa curve was selected for each asset category reflecting
13 the combination of the historical results and the additional information obtained
14 from the engineering, accounting and operations personnel. This process is a part
15 of the evaluation phase of the depreciation study.

16 **Q. Please explain the salvage and cost of removal analysis.**

17 A. Annual salvage amounts, cost of removal and retirements were provided by
18 functional group for the period 1990 through 2002. Annual salvage, cost of
19 removal and net salvage percentages were calculated by dividing by the retirement
20 amounts. Rolling and shrinking bands were also developed to illustrate trends.

21 **Q. Please summarize your results for transmission, distribution and general**
22 **plant.**

1 A. In general, average service lives have increased, and net salvage factors have
2 become less negative. The composite depreciation rate for Transmission Plant
3 increased from 2.03 percent to 2.18 percent, an annual expense increase of about
4 \$3,190,000, or about 7 percent. The primary reasons are slightly decreased
5 average service lives and slightly more negative net salvage.
6 The composite depreciation rate for Distribution Plant decreased from 3.70
7 percent to 2.99 percent, an annual expense decrease of over \$26,700,000, or about
8 19 percent. Increased average service lives were compounded by less negative net
9 salvage.
10 The composite depreciation rate for General Plant increased from 4.40 percent to
11 4.91 percent, an annual expense increase of roughly \$2,600,000, or nearly 12
12 percent. The primary reason for the increase is the effect of less positive net
13 salvage.

14 **Mining Operations**

15 **Q. Please summarize your results for mining operations.**

16 A. Certainly. The composite depreciation rate increased from 5.55 percent to 5.98
17 percent. Average service lives have both increased and decreased, as have net
18 salvage allowances.

19 **Q. What is the total change in annual depreciation indicated by your study?**

20 A. At the total Company depreciable investment level, the decrease in annual
21 depreciation expense indicated by my study is about \$732,000.

22 **Recommendations**

23 **Q. Please summarize your recommendations.**

1 A. I recommend that PacifiCorp adopt the depreciation rates shown in Column 12 of
2 Schedule 1 of Exhibit ____ (DSR-3), and that this Commission approve their use.

3 I base this recommendation on the fact that I have conducted a comprehensive
4 depreciation study, giving appropriate recognition to historical experience, recent
5 trends and Company expectations. My study results in a fair and reasonable level
6 of depreciation expense which, when incorporated into a revenue stream, will
7 provide the Company with adequate capital recovery until such time as a new
8 depreciation study indicates a need for change.

9 **Q. Does this complete your direct testimony?**

10 A. Yes, it does.

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

In the Matter of the Application of
PACIFICORP for an Order Authorizing a
Change in Depreciation Rates Applicable to
Electric Property.

Docket No. UE-02_____

PACIFICORP

Exhibit of Donald S. Roff

Qualifications

October, 2002

Academic Background

Donald S. Roff graduated from Rensselaer Polytechnic Institute with a Bachelor of Science degree in Management Engineering in 1972.

Mr. Roff has also received specialized training in the area of depreciation from Western Michigan University's Institute of Technological Studies. This training involved three forty-hour seminars on depreciation entitled "Fundamentals of Depreciation", "Fundamentals of Service Life Forecasting" and "Making a Depreciation Study" and included such topics as accounting for depreciation, estimating service life, and estimating salvage and cost of removal.

Employment and Professional Experience

Following graduation, Mr. Roff was employed for eleven and one-half years by Gilbert Associates, Inc., as an engineer in the Management Consulting Division. In this capacity, he held positions of increasing responsibility related to the conduct and preparation of various capital recovery and valuation assignments.

In 1984, Mr. Roff was employed by Ernst & Whinney and was involved in several depreciation rate studies and utility consulting assignments.

In 1985, Mr. Roff joined Deloitte Haskins & Sells (DH&S), which, in 1989, merged with Touche Ross & Co. to form Deloitte & Touche. In 1995, Mr. Roff was appointed as a Director with Deloitte & Touche.

During his tenure with Gilbert Associates, Inc., Ernst & Whinney, DH&S and Deloitte & Touche, Mr. Roff has participated in or directed depreciation studies for electric, gas, water and steam heat utilities, pipelines, railroad and telecommunication companies in over 30 states, several Canadian provinces and Puerto Rico. This work requires an in-depth knowledge of depreciation accounting and regulatory principles, mortality analysis techniques and financial practices. At these firms, Mr. Roff has had varying degrees of responsibility for valuation studies, development of depreciation accrual rates, consultation on the unitization of property records, and other studies concerned with the inspection and appraisals of utility property, preparation of rate case testimony and support exhibits, data responses and rebuttal testimony, in addition to appearing as an expert witness.

Industry and Technical Affiliations

Mr. Roff is a registered Professional Engineer in Pennsylvania (by examination).

Mr. Roff is a member of the Society of Depreciation Professionals and a Certified Depreciation Professional, and a Technical Associate of the American Gas Association (A.G.A.) Depreciation Committee. He currently serves as the lead instructor for the A.G.A.'s Principles of Depreciation Course.

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

In the Matter of the Application of
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Electric Property.

Docket No. UE-02 ____

PACIFICORP

Exhibit of Donald S. Roff

Testimony Experience

October, 2002

TESTIMONY EXPERIENCE

DONALD S. ROFF

<u>CASE NO.</u>	<u>DATE</u>	<u>COMPANY</u>	<u>JURISDICTION</u>	<u>SUBJECT</u>
Docket No. 93-3005	July 1993	Southwest Gas Corporation	Nevada	Gas Depreciation Rates
Docket No. 93-3025	July 1993	Southwest Gas Corporation	Nevada	Gas Depreciation Rates
Docket No. 12820	June 1994	Central Power and Light Company	Texas	Electric Depreciation Rates
Case No. U-10380	Dec 1994	Consumers Power Company	Michigan	Gas Depreciation Rates and Accounting
Cause No. 39938	April 1995	Indianapolis Power & Light Company	Indiana	Electric Depreciation Rates
Case No. U-10754	July 1995	Consumers Power Company	Michigan	Electric Depreciation Rates and Accounting
Docket No. 13369	Aug 1995	West Texas Utilities Company	Texas	Electric Depreciation Rates
Docket No. 95-02116	Sept 1995	Chattanooga Gas Company	Tennessee	Electric Depreciation Rates and Accounting
Docket No. 95-715-G	Oct 1995	Piedmont Natural Gas Company	Texas	Gas Depreciation Rates
Docket No. 14965	Dec 1995	Central Power and Light Company	Texas	Gas Depreciation Rates
Cause No. 40395 (I)	Feb 1996	Wabash Valley Power Association, Inc.	Indiana	Electric Depreciation Rates
GUD NO. 8664	Oct 1996	Lone Star Pipeline Company	Texas	Electric Depreciation Rates
Docket No. 96-360-U	Nov 1996	Entergy Arkansas Inc.	Arkansas	Electric Depreciation Rates
Docket No. 16705	Nov 1996	Entergy Gulf States Inc.	Texas	Electric Depreciation Rates
Docket No. ER-97-394	Mar 1997	Missouri Public Service	Missouri	Electric Depreciation Rates
Docket No. U-22092	Mar 1997	Entergy Gulf States Inc.	Louisiana	Electric Depreciation Rates
Docket No. 97-00982	May 1997	Chattanooga Gas Company	Tennessee	Gas Depreciation Rates
Cause No. 40395 (II)	June 1997	Wabash Valley Power Association, Inc.	Indiana	Electric Depreciation Rates/Competitive Issues
Case No. U-11509	Sept 1997	Consumers Energy Company	Michigan	Electric Depreciation Rates/Competitive Issues
Docket No. ER98-11	Sept 1997	Long Island Lighting Company	FERC	Gas Depreciation Rates and Accounting
Docket No. 8390-U	Dec 1997	Atlanta Gas Light Company	Georgia	Electric Depreciation Rates
Cause No. 41118	Mar 1998	Wabash Valley Power Association, Inc.	Indiana	Gas Depreciation Rates and Accounting
Case No. U-11722	Oct 1998	Detroit Edison Company	Michigan	Electric Depreciation Rates
Docket No. 98-2035-03	Nov 1998	PacifiCorp	Utah	Electric Depreciation Rates
Docket No. 99-4006	April 1999	Nevada Power Company	Nevada	Electric Depreciation Rates
GUD Docket No. 9030	March 2000	Atmos Energy Corporation	Texas	Gas Depreciation Rates and Accounting
GUD Docket No. 9145	April 2000	TXU Gas Distribution	Texas	Gas Depreciation Rates
City of Tyler	Dec 2000	Reliant Energy Entex	Texas	Gas Depreciation Rates and Accounting
Docket No. U-24993	March 2001	Entergy Gulf States Inc.	Louisiana	Electric Depreciation Rates and Accounting
Docket Nos. GR01050328/GR01050297	May 2001	Public Service Electric & Gas	New Jersey	Electric Depreciation Rates and Accounting
Case No. U-12999	July 2001	Consumers Energy Company	Michigan	Gas Depreciation Rates and Accounting
Docket No. 01-10002	Oct 2001	Nevada Power Company	Nevada	Gas Depreciation Rates and Accounting
Docket No. 14618-U	Nov 2001	Savannah Electric and Power Company	Georgia	Electric Depreciation Rates
Docket No. 01-11031	Dec 2001	Sierra Pacific Power Company	Nevada	Electric Depreciation Rates
Docket No. 010949-EL	Jan 2002	Gulf Power Company	Florida	Electric Depreciation Rates
Docket No. 14311-U	Jan 2002	Atlanta Gas Light Company	Georgia	Gas Depreciation Rates and Accounting
Docket No. UD-00-2	March 2002	Entergy New Orleans, Inc.	New Orleans	Electric Depreciation Accounting

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

In the Matter of the Application of
PACIFICORP for an Order Authorizing a
Change in Depreciation Rates Applicable to
Electric Property.

Docket No. UE-02 ____

PACIFICORP

Exhibit of Donald S. Roff

Book Depreciation Study of Electric Property as of March 31, 2002

**THIS EXHIBIT IS VOLUMINOUS AND
HAS BEEN PROVIDED AS A
SEPARATE VOLUME**

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

In the Matter of the Application of
PACIFICORP for an Order Authorizing a
Change in Depreciation Rates Applicable to
Electric Property.

Docket No. UE-02 ____

PACIFICORP

Exhibit of Donald S. Roff

Annual Accrual Rate Determination

October, 2002

PACIFICORP
 ANNUAL ACCRUAL RATE DETERMINATION
 ACCOUNT 312, BOILER PLANT EQUIPMENT
 HUNTER (300305)
 IRP DATES
 WITH INTERIM ADDITIONS

-10.00%
 -4.88%
 -5.18%
 19.00
 19.80
 38.80
 32.6%
 9,651,719
 0.0035
 4.0
 3.67%

Interim Net Salvage =
 Terminal Net Salvage
 Average Future Net Salvage =
 Average Age Survivors =
 Average Remaining Life (yrs) =
 Average Service Life =
 Book Reserve Ratio =
 Terminal COR Reserve =
 Interim Retirement Ratio =
 Interim Addition Factor =
 Depreciation Rate =

[1] Year	[2] Interim Retirements \$	[3] Interim Net Salvage \$	[4] Terminal Retirements \$	[5] Terminal Net Salvage \$	[6] Interim Additions \$	[7] Ending Balance \$	[8] Average Balance \$	[9] Annual Amount \$	[10] Ending Reserve \$	[11] Remaining Life yrs	[12] Annual Amount \$	[13] Rate %	[14] Ending Reserve \$
2002						486,169,151			207,432,846				207,432,846
2003	1,701,592	(170,159)			6,806,368	491,273,927	486,721,539	17,916,429	223,477,524	22.50	13,686,775	2.80	219,247,869
2004	1,719,459	(171,946)			6,877,835	496,432,303	493,853,115	18,104,552	239,690,671	21.50	14,011,264	2.84	231,367,729
2005	1,737,513	(173,751)			6,950,052	501,644,843	499,038,573	18,294,649	256,074,056	20.50	14,355,156	2.88	243,811,621
2006	1,755,757	(175,576)			7,023,028	506,912,113	504,278,478	18,486,743	272,629,466	19.50	14,720,479	2.92	256,600,767
2007	1,774,192	(177,419)			7,096,770	512,234,691	509,573,402	18,680,854	289,358,709	18.50	15,109,593	2.97	269,758,748
2008	1,792,821	(179,282)			7,171,286	517,613,155	514,923,923	18,877,003	306,263,608	17.50	15,525,261	3.02	283,311,906
2009	1,811,646	(181,165)			7,246,584	523,048,093	520,330,624	19,075,212	323,346,009	16.50	15,970,750	3.07	297,289,845
2010	1,830,668	(183,067)			7,322,673	528,540,098	525,794,095	19,275,501	340,607,775	15.50	16,449,959	3.13	311,726,069
2011	1,849,890	(184,989)			7,399,561	534,089,769	531,314,933	19,477,894	358,050,790	14.50	16,967,597	3.19	326,668,786
2012	1,869,314	(186,931)			7,477,257	539,697,711	536,893,740	19,682,412	375,676,956	13.50	17,529,415	3.26	342,131,956
2013	1,888,942	(188,894)			7,555,768	545,364,537	542,531,124	19,889,077	393,488,197	12.50	18,142,550	3.34	358,196,670
2014	1,908,776	(190,878)			7,635,104	551,090,865	548,227,701	20,097,913	411,486,456	11.50	18,815,999	3.43	374,913,016
2015	1,928,818	(192,882)			7,715,272	556,877,319	553,984,092	20,308,941	429,673,697	10.50	19,561,331	3.53	392,352,647
2016	1,949,071	(194,907)			7,796,282	562,724,531	559,800,925	20,522,184	448,051,904	9.50	20,393,768	3.64	410,602,437
2017	1,969,536	(196,954)			7,878,143	568,633,139	565,678,835	20,737,667	466,623,082	8.50	21,333,908	3.77	429,769,855
2018	1,990,216	(199,022)			7,960,864	574,603,787	571,618,463	20,955,413	485,389,257	7.50	22,410,587	3.92	449,991,205
2019	2,011,113	(201,111)			8,044,453	580,637,126	577,620,456	21,175,445	504,352,477	6.50	23,665,954	4.10	471,444,935
2020	2,032,230	(203,223)			8,128,920	586,733,816	583,685,471	21,397,787	523,514,811	5.50	25,165,148	4.31	494,374,630
2021	2,053,568	(205,357)			8,214,273	592,894,521	589,814,169	21,622,464	542,878,350	4.50	27,016,735	4.58	519,132,440
2022	2,075,131	(207,513)			8,300,523	599,119,914	596,007,217	21,849,500	562,445,206	3.50	29,422,344	4.94	546,272,140
2023		-			-	599,119,914	599,119,914	21,963,610	584,408,816	2.50	32,825,558	5.48	579,097,699
2024		-			-	599,119,914	599,119,914	21,963,610	606,372,426	1.50	32,825,558	5.48	611,923,257
2025		-	599,119,914	(29,216,123)	-	-	599,119,914	21,963,610	(0)	0.50	32,825,558	5.48	-
Totals	37,650,254	(3,765,025)	599,119,914	(29,216,123)	150,601,017		12,611,050,618						

EXHIBIT - ____ (DSR-5)

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

In the Matter of the Application of
PACIFICORP for an Order Authorizing a
Change in Depreciation Rates Applicable to
Electric Property.

Docket No. UE-02 ____

PACIFICORP

Exhibit of Donald S. Roff

Steam Production Plant
Terminal Net Salvage

October, 2002

STEAM PRODUCTION PLANT
Net Salvage Indicated by Engineering Studies of the Removal of Coal and
Lignite Units

(1) Utility and Plant	(2) Number of Units	(3) Total Owned Capacity MW	(4) Average Capacity MW	(5) Study Date	(6) All Units		(8) Net Removal Cost at Study Date \$
					Current	2001	
					Removal Cost \$	(a) \$/kW	
Alabama Power Company							
Barry 1 - 5	5	1,658	332	2001	98,468,000	59	98,468,000
Chickasaw 1 - 3	3	120	40	1993	4,422,294	37	3,491,000
Gasden 1 & 2	2	130	65	2001	6,331,000	49	6,331,000
Green County 1 & 2 (60% owned)	2	337	280	2001	21,225,600	63	21,225,600
Gorgas 6 - 9	4	565	141	2001	20,137,000	36	20,137,000
Gorgas 10	1	673	673	2001	40,446,000	60	40,446,000
Miller 1 - 4	4	1,471	383	2001	100,969,000	69	100,969,000
Appalachian Power Company							
Amos 1 - 3	3	2,033	678	1990	92,989,833	46	67,177,834
Clinch River 1 - 3	3	705	235	1990	24,686,855	35	17,834,309
Glen Lyn 5 & 6	2	335	168	1990	15,797,732	47	11,412,618
Kanawha River 1 & 2	2	400	200	1990	15,465,115	39	11,172,328
Mountaineer 1	1	1,300	1,300	1990	50,696,285	39	36,624,075
Sporn 1 & 3	2	300	150	1990	16,192,611	54	11,697,887
Consumers Power Company							
Campbell 1 - 3	3	1,294	431	1993	35,844,146	28	28,295,700
Cobb 1 - 5	5	436	87	1993	10,309,355	24	8,138,300
Karn 1 & 2	2	515	258	1993	35,100,172	68	27,708,400
Weadock 1 - 8	8	612	77	1993	1,790,453	3	1,413,400
Whiting 1 - 3	3	310	103	1993	8,377,277	27	6,613,100
Edmonton Power Authority							
Genessee 1 & 2	2	758	379	1995	27,846,494	37	23,321,000
Florida Power Corporation							
Crystal River North 4 & 5	2	1,479	740	1992	53,737,027	36	41,184,957
Crystal River South 1 & 2	2	964	482	1992	55,520,993	58	42,552,218
Florida Power & Light Company							
Scherer 4	1	818	818	1998	20,919,582	26	19,144,381
St. Johns 1 & 2 (20% owned)	2	272	679	1998	17,632,913	65	16,136,613
Georgia Power Company							
Arkwright 1 - 4	4	160	40	1997	11,745,810	73	10,436,000
Bowen 1 - 4	4	3,160	790	1997	67,860,303	21	60,293,000
Branch 1 - 4	4	1,468	367	1997	55,770,087	38	49,551,000
Hammond 1 - 4	4	800	200	1997	32,912,129	41	29,242,000
McDonough 1 & 2	2	490	245	1997	17,924,853	37	15,926,000
Mitchell 1 - 3	3	171	57	1997	16,090,274	94	14,296,000
Scherer 1 - 3 (31% owned)	3	751	807	1997	18,511,677	25	16,447,385
Wansley 1 & 2 (53.5% owned)	2	926	865	1997	23,309,721	25	20,710,385
Yates 1 - 7	7	1,250	179	1997	62,056,054	50	55,136,000
Gulf Power Company							

STEAM PRODUCTION PLANT
Net Salvage Indicated by Engineering Studies of the Removal of Coal and
Lignite Units

(1) Utility and Plant	(2) Number of Units	(3) Total Owned Capacity MW	(4) Average Capacity MW	(5) Study Date	(6) All Units		(8) Net Removal Cost at Study Date \$
					Current	2001	
					Removal Cost \$	(a) \$/kW	
Crist 1 - 7	7	1,055	151	2001	56,368,000	53	56,368,000
Daniel 1 & 2 (50% owned)	2	500	500	2001	17,052,500	34	17,052,500
Scherer 3 (25% owned)	1	205	818	2001	5,109,000	25	5,109,000
Scholz 1 & 2	2	80	40	2001	10,126,000	127	10,126,000
Smith 1 & 2	2	305	153	2001	23,676,000	78	23,676,000
Indiana Michigan Power Company							
Breed 1	1	400	400	1993	18,180,084	45	14,351,526
Rockport 1	1	1,300	1,300	1993	27,480,811	21	21,693,606
Tanners Creek 1 - 4	4	995	249	1993	29,900,156	30	23,603,459
Indianapolis Power & Light Company							
Petersburg 1 - 4	4	1,713	428	1993	80,576,212	47	63,607,606
Pritchard 3 - 6	4	276	69	1993	25,018,510	91	19,749,843
Stout 5 - 7	3	630	210	1993	34,061,953	54	26,888,820
Minnesota Power & Light Company							
Boswell 1 & 2	2	138	69	1992	2,590,298	19	1,985,248
Boswell 3	1	350	350	1992	13,859,960	40	10,622,505
Boswell 4 (80% owned)	1	428	535	1992	16,174,617	38	12,396,497
Hibbard 1 & 2	2	50	25	1992	1,295,642	26	993,002
Laskin 1 & 2	2	110	55	1992	6,786,107	62	5,200,986
Mississippi Power Company							
Daniel 1 & 2 (50% owned)	2	500	500	1996	18,532,735	37	15,986,500
Green County 1 & 2 (40% owned)	2	200	250	1996	15,057,115	75	12,988,400
Watson 1 - 5	5	1,012	202	1996	47,076,961	47	40,609,000
Montana Power Company							
Colstrip 1 & 2 (50% owned)	2	333	333	1994	23,259,989	70	18,912,500
Colstrip 3 & 4 (30% owned)	2	431	719	1994	32,615,148	76	26,519,100
Corette 1	1	163	163	1994	19,698,890	121	16,017,000
Ohio Power Company							
Amos 3 (2/3 owned)	1	867	1,300	1993	36,478,328	42	28,796,329
Cardinal 1	1	600	600	1993	8,894,684	15	7,021,546
Gavin 1 - 2	2	2,600	1,300	1993	27,283,223	10	21,537,628
Kammer 1 - 3	3	630	210	1993	36,189,171	57	28,568,066
Mitchell 1 - 2	2	1,600	800	1993	25,686,910	16	20,277,484
Muskingum River 1 - 4	4	840	210	1993	18,012,242	21	14,219,030
Muskingum River 5	1	585	585	1993	12,516,981	21	9,881,020
Sporn 2, 4 & 5	3	750	250	1993	37,338,030	50	29,474,986
Otter Tail Power Company							
Big Stone	1	456	456	1996	5,086,431	11	4,387,600
PECO Energy Company							

STEAM PRODUCTION PLANT
Net Salvage Indicated by Engineering Studies of the Removal of Coal and
Lignite Units

(1) Utility and Plant	(2) Number of Units	(3) Total Owned Capacity MW	(4) Average Capacity MW	(5) Study Date	(6) All Units		(8) Net Removal Cost at Study Date \$
					Current	2001	
					Removal Cost \$	(a) \$/kW	
Conemaugh 1 & 2 (20.72% owned)	2	352	850	1997	23,653,560	67	21,015,882
Cromby 1 & 2	2	345	173	1997	27,072,989	78	24,054,000
Edystone 1 & 2	2	581	291	1997	34,851,380	60	30,965,000
Keystone 1 & 2 (20.99% owned)	2	357	850	1997	24,467,822	69	21,739,343
Pennsylvania Power & Light Company							
Brunner Island 1 - 3	3	1,442	481	1994	206,719,659	143	168,082,000
Holtwood 15 - 17	3	102	34	1994	53,639,719	526	43,614,000
Martins Creek 1 & 2	2	300	150	1994	88,387,345	295	71,867,000
Montour 1 & 2	2	1,500	750	1994	164,666,582	110	133,889,000
Sunbury 1 - 4	4	425	106	1994	167,769,554	395	136,412,000
Public Service Co. of Indiana							
Cayuga 1 & 2	2	995	498	1991	35,995,792	36	26,784,250
Edwardsport 6 - 8	3	160	53	1991	11,841,247	74	8,811,000
Gallagher 1 - 4	4	560	140	1991	22,790,974	41	16,958,625
Gibson 1 - 5	5	2,853	571	1991	89,228,011	31	66,394,020
Noblesville 1 & 2	2	90	45	1991	7,342,823	82	5,463,750
Wabash 1 - 5	5	435	87	1991	21,419,339	49	15,938,000
Wabash 6	1	318	318	1991	10,342,780	33	7,696,000
Public Service Electric & Gas Company							
Mercer 1	1	326	326	1998	7,038,255	22	6,441,000
Mercer 2	1	326	326	1998	17,411,512	53	15,934,000
Hudson 1	1	455	455	1998	21,451,324	47	19,631,000
Hudson 2	1	660	660	1998	46,986,168	71	42,999,000
Savannah Electric Company							
Kraft 1 - 4	4	323	81	2000	28,188,010	87	27,367,000
McIntosh 1	1	168	168	2000	12,387,810	74	12,027,000
Southern California Edison Co.							
Four Corners 4 & 5 (48% owned)	2	754	785	1993	18,312,631	24	14,456,160
Mohave 1 & 2 (56% owned)	2	885	790	1995	25,099,170	28	21,020,160
Southern Electric Generating Company							
Gaston 1 - 4	4	1,000	250	1993	51,348,525	51	40,535,000
Tampa Electric Company							
Big Bend 1 - 4	4	1,635	409	1998	56,508,196	35	51,713,004
Gannon 1 - 6	6	1,180	197	1998	41,931,080	36	38,372,878
TransAlta Utilities Corp.							
Keephills 1 & 2	2	754	377	1995	20,911,438	28	17,513,000
Sheerness 1 (50% owned)	1	183	366	1995	10,056,308	55	8,422,000
Sundance 1 - 6	6	1,987	331	1995	36,885,469	19	30,891,000
Wabamun 1 - 4	4	569	142	1995	21,268,460	37	17,812,000

STEAM PRODUCTION PLANT
Net Salvage Indicated by Engineering Studies of the Removal of Coal and Lignite Units

(1) Utility and Plant	(2) Number of Units	(3) Total Owned Capacity MW	(4) Average Capacity MW	(5) Study Date	(6) All Units Current Removal Cost \$	(7) 2001 (a) \$/KW	(8) Net Removal Cost at Study Date \$
Wisconsin Electric Power Company Port Washington 1 - 5	5	400	80	1990	53,846,285	135	38,899,702
Total or Average	<u>257</u>	<u>69,181</u>	269		<u>3,272,889,551</u>	47	<u>2,745,871,051</u>

NOTES:

(a) Inflation from study date at: 3.00% Average Standard Dev. 60.4
69.8

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

In the Matter of the Application of
PACIFICORP for an Order Authorizing a
Change in Depreciation Rates Applicable to
Electric Property.

Docket No. UE-02____

PACIFICORP

Direct Testimony of Barry G. Cunningham

October, 2002

1 **Q. Please state your name, business address, and position with PacifiCorp (the**
2 **Company).**

3 A. My name is Barry G. Cunningham. My business address is 201 South Main, Suite
4 2300, One Utah Center, Salt Lake City, Utah. My position is Senior Vice President
5 of Generation for PacifiCorp.

6 **Q. Please describe your education and business experience.**

7 A. I have a Bachelor of Arts degree in Physical Science. During my career with
8 PacifiCorp, I have served as a Trainer, Trainer Manager, Assistant Operations
9 Superintendent, a Maintenance Superintendent, a Plant Manager and the Director of
10 Technical Support with responsibility for all of PacifiCorp's small plants. I became
11 Assistant Vice President of Generation in 1998, Vice President of Generation in 1999
12 and Senior Vice President in 2002, with responsibility for all thermal and hydro
13 generation assets.

14 **Q. What is the purpose of your testimony in this proceeding?**

15 A. The purpose of my testimony is threefold. First, I will describe the process used by
16 PacifiCorp engineers to develop estimated life spans for the Company's steam
17 generating stations. I will explain how steam plant life spans were chosen for this
18 purpose of this proceeding, and I will show how these life span estimates provide a
19 framework for estimating the retirement date for each steam plant. In a similar
20 manner I will describe the procedure used to estimate the retirement date for the
21 Company's hydroelectric generating stations. Retirement dates for each steam and
22 hydro plant were provided by PacifiCorp to Mr. Donald Roff of Deloitte & Touche
23 for use in preparing the depreciation study that is the subject of this proceeding. The

1 depreciation study performed by Mr. Roff (Exhibit ____ (DSR-3)), which is based
2 on plant balances at March 31, 2002, will be referred to hereafter as “the D&T
3 study”. The retirement dates provided by the Company to Mr. Roff are the same
4 retirement dates contained in Schedule 3 of the D&T study. I will demonstrate that
5 the estimated retirement dates proposed by the Company for both steam and hydro
6 generation plants are reasonable and prudent and are appropriate inputs for Mr.
7 Roff’s depreciation analysis.

8 Second, I will explain why it is reasonable and necessary to include terminal
9 net salvage, or “decommissioning costs”, in the calculation of depreciation rates for
10 generating plants.

11 Third, I will discuss the depreciation of water rights acquired for the
12 operation of steam generating plants and explain why such depreciation is
13 appropriate for ratemaking purposes.

14 **GENERATION PLANT LIFE ESTIMATION**

15 Steam Plant Life Spans

16 **Q. Please explain what you mean by the “life span” of a steam generating plant.**

17 A. For the purpose of determining depreciation, the life span of a steam plant is the
18 period of time that begins when the plant is initially placed in service and begins to
19 generate electricity and ends when the plant is finally removed from service and
20 ceases to generate electricity. In other words it is the period of time during which
21 electric customers benefit from the generation output of the plant.

22 **Q. When a steam plant is removed from service, will it be retired and its**
23 **investment removed from the Company’s accounting records?**

1 A. It may not be immediately retired from an accounting perspective. More likely the
2 plant will be retained in a reserve status for a period of time until plans for its final
3 disposition are made.

4 **Q. If an accounting retirement is not made, will the plant remain in rate base and**
5 **continue to impose costs on customers?**

6 A. No. Under the life span concept a plant will be fully depreciated by the time it is
7 finally removed from service.

8 **Q. Why is it necessary to estimate the life span of a steam plant?**

9 A. One major component of PacifiCorp's cost of service is the recovery of capital
10 investment in steam generating plants. This recovery is accomplished through
11 depreciation expense over the productive life of each plant. From the standpoint of
12 setting depreciation rates it is necessary to have a reasonable estimate of the life span
13 of a plant as soon as it is placed in service. For depreciation purposes all steam plant
14 life spans are estimates that may be adjusted over time as circumstances warrant.

15 **Q. What is PacifiCorp's current estimated life span for steam generating plants?**

16 A. The Company estimates that, absent extenuating circumstances, the life span of its
17 steam generating units is 40 years. After careful analysis the Company estimates that
18 all of its steam plants have 40 year life spans, except for Gadsby, Dave Johnston,
19 Hayden, Carbon, and Naughton, which are estimated to have life spans of at least 50
20 years.

21 **Q. Who prepared the life span analysis?**

22 A. The life span analysis was prepared by PacifiCorp's Generation Engineering staff
23 under my direction. This group includes individuals with over twenty years of

1 service with the Company who are experienced in all areas of steam plant operation,
2 including the design, construction, operation and maintenance of the Company's
3 existing units.

4 **Q. What criteria were considered in the life span analysis?**

5 A. The life span analysis focused on four main areas: (1) an examination of the original
6 engineering design life of the plants; (2) an evaluation of the operating and
7 maintenance history of the plants as determined by owner operational requirements;
8 (3) an assessment of the current condition of major equipment components; and (4)
9 an assessment of current and potential future issues that may affect the continued
10 operation of coal-fired generation plants, such as new generation technology and
11 environmental issues.

12 **Q. Please describe the Company's examination of engineering design lives.**

13 A. One of the fundamental assumptions underlying the analysis is that the life span of
14 PacifiCorp generating units should be consistent with their original engineering
15 design lives, absent some event or set of circumstances that would indicate a need to
16 change. To determine the original design life the Company contacted several of the
17 engineer/architects of its existing plants; specifically, Bechtel for Naughton Units 1
18 and 2, Jim Bridger and Centralia, Raytheon Engineers and Constructors (formerly
19 Stearns-Roger) for Naughton Unit 3, Huntington Units 1 and 2 and Hunter Units 1
20 and 2, and Brown and Root for Hunter Unit 3. Discussions with these
21 engineers/architects led to the conclusion that the design life of PacifiCorp steam
22 plants constructed from the late 1960's through the early 1980's was 30-35 years. To
23 confirm the reasonableness of the design life estimates, the Company also contacted

1 the suppliers of the majority of our major steam plant equipment—General Electric
2 for steam turbine-generators and ABB for boiler equipment. Discussions with these
3 two equipment vendors suggested that during the period in which our major plants
4 were designed, boiler equipment had an expected life of 30 years while steam
5 turbines were expected to last 40 years. Thus, based on information provided by
6 design engineers and equipment suppliers, the Company concluded that 35-40 years
7 was a reasonable estimate for the original design life of its major steam generating
8 plants.

9 **Q. You indicated that there might be events or circumstances occurring during the**
10 **life of a steam generating plant that could affect its original design life. What**
11 **kind of events or circumstances were you referring to?**

12 A. In preparing its life span analysis the Company considered three types of
13 extraordinary events, the occurrence of any one of which might require a departure
14 from original plant design life. One such event would be plant operating experience
15 or maintenance practices that departed significantly from the original manufacturer's
16 operating procedures or design parameters. The second type of event would be the
17 installation of equipment or the imposition of operating restrictions necessitated by
18 environmental regulations not anticipated at the time of original plant design. The
19 third type of event would be the infusion of life-extending capital that might lengthen
20 the lives of major equipment items, compensate for aggressive operating and
21 maintenance practices or respond to the requirements of environmental regulation.

22 **Q. Did the Company evaluate the operating and maintenance history of its steam**
23 **plants to determine compliance with original design parameters?**

1 A. Yes. A review of historical records indicates that PacifiCorp's steam plants have
2 been operated and maintained in a manner consistent with the 35-40 year life
3 expectation reflected in original design parameters. Manufacturer's guidelines
4 and/or operating recommendations from design engineers have been translated into
5 training materials and operating procedures used throughout the Company's thermal
6 fleet. A review of preventative maintenance logs, work order and equipment
7 histories, and overhaul histories indicates that required maintenance procedures have
8 been consistently applied for all plants. This is further demonstrated by the high
9 capacity factors and low forced outage rates exhibited by PacifiCorp's thermal fleet.

10 **Q. Has the Company identified significant environmental issues, not anticipated at**
11 **the time of plant design, that could affect the 35-40 year original design life**
12 **expectation?**

13 A. The following environmental issues are creating risk that the Company's newer coal-
14 fired generating plants may not reach their original design life estimate:

15 1. The Environmental Protection Agency (EPA) continues to emphasize the need
16 for continued reductions in sulfur dioxide (SO₂) and oxides of nitrogen (NO_x)
17 emissions. Vehicles for achieving these reductions include the work of the
18 Grand Canyon Transport Commission, new visibility initiatives, enforcement of
19 New Source Review (NSR) regulations, and proposed new legislation aimed at
20 substantial reductions in SO₂ and NO_x. Major legislative proposals include
21 Senate Bill S556, sponsored by Senator Jeffords and President Bush's Clean
22 Skies Initiative (CSI).

- 1 2. Success of OTAG (Ozone Transport Assessment Group) implementation in the
2 eastern United States will hasten the implementation of new requirements for
3 NOx reductions to the 0.2 to 0.10 lb/mmBtu level. Reductions to this level on
4 our coal-fired boilers will require the addition of Selective Catalytic Reduction
5 (SCR) equipment.
- 6 3. There are continued efforts by many groups to commit the U.S. to reduce carbon
7 dioxide (CO2) emissions. Current schedules under the Kyoto Agreement call
8 for reductions in CO2 emissions beginning in 2008.
- 9 4. The Maximum Achievable Control Technology (MACT) rule under the Clean
10 Air Act (CAA) has identified a need to reduce mercury emissions by 2008.
11 Rulemaking on emission reduction requirements will be proposed by the end of
12 2003 and finalized by the end of 2004.
- 13 5. There is continued vocal opposition to coal-fired generation from environmental
14 groups, with an increasing likelihood of citizen suits to restrict the status-quo
15 level of coal-based generation, similar to the Company's experience at its
16 Hayden and Craig plants.

17 While it is impossible to quantify the potential effect of each of these initiatives on
18 individual Company plants at this time, the range and magnitude of future
19 environmental issues raises serious questions about the long term viability of coal-
20 fired generation. From the standpoint of life span analysis PacifiCorp believes it is
21 likely that future environmental costs will substantially affect the economics for
22 plants whose design life would expire in the 2010-2025 time frame.

1 Q. **Has the expenditure of life-extending capital had an effect on the life span**
2 **estimates for any of the Company's generating plants?**

3 A. Yes. The infusion of life-extending capital has extended the estimated life span to at
4 least 50 years for Gadsby, Hayden and Dave Johnston. Gadsby was refurbished in
5 connection with its conversion to gas firing capabilities in the early 1990's. The
6 Company anticipates that the addition of a scrubber at Hayden will allow the plant to
7 comply with environmental regulations and achieve a 50-year life span, although
8 there remains some risk that additional environmental regulations could limit this
9 life. At Dave Johnston, the installation of new coal unloading facilities will allow
10 the plant to burn purchased coal and continue to operate beyond the closure of the
11 adjacent Glenrock Coal Mine.

12 Q. **Based on its evaluation of the criteria you have just described, how did the**
13 **Company arrive at a life span of 40 years for plants that have not had life-**
14 **extending capital additions?**

15 A. As I explained previously, PacifiCorp believes that, absent extenuating
16 circumstances, steam plant life span should be consistent with original design life.
17 Design life was determined to be 35-40 years. An examination of plant operating
18 and maintenance histories and an evaluation of environmental issues indicates that
19 there is no compelling reason to depart from the design life at this time. Therefore, a
20 40-year life span is a conservative reflection of the original design life estimate.

21 Q. **Why is a 40-year life span more "conservative" than a 35-year life span?**

22 A. The life span analysis was prepared to provide inputs to the depreciation study. All
23 else being equal, longer plant lives mean lower depreciation rates. Therefore, a 40-

1 year life span is more conservative than 35 years because it results in more
2 conservative (lower) depreciation rates.

3 Recommended Steam Plant Life Spans for Depreciation Study

4 **Q. You have just explained that 40 years would be an appropriate life span for the**
5 **Company's steam generating plants, with the exception of certain plants that**
6 **have had life-extending capital additions. Has the Company reflected these life**
7 **span estimates in the current depreciation study?**

8 A. No. For purposes of the current depreciation study PacifiCorp has elected to
9 continue using the steam plant life spans reflected in the depreciation rates approved
10 by the Commission in its order dated August 9, 2000 in Docket No. UE-991832.
11 The depreciation rates approved in that order for the Gadsby, Dave Johnston, Hayden
12 and Carbon Plants are based on life spans of 54 years, Blundell of 37 years and
13 James River of 20 years, and all other PacifiCorp steam plants on life spans of 44
14 years. The only change the Company has made to these Commission-approved life
15 spans is to further extend the life span for the Naughton Plant from 44 years to 54
16 years, to reflect the most recent engineering analysis.

17 **Q. Why did PacifiCorp choose to use steam plant life spans that are longer than**
18 **those supported by its own engineers?**

19 A. While the Company believes than a strong case can be made for the use of a 40-year
20 life span, experience in the last depreciation case suggests that other parties will
21 support longer life spans. The proceeding in Docket No. UE-991832 included a
22 thorough WUTC Staff review of key depreciation parameters. Much of this review
23 centered on the appropriate life span for steam plants. Now, little more than two

1 years from the April 1, 2000 effective date of the Commission order in that docket,
2 PacifiCorp does not believe it is an efficient use of Company or Staff resources to
3 repeat this process. When PacifiCorp files its next depreciation study, typically in
4 five years, it may be appropriate to revisit this issue.

5 Steam Plant Retirement Dates

6 **Q. How was the estimated life span for each plant converted into an estimated**
7 **retirement date?**

8 A. The estimated life span was added to the original in-service date for each generating
9 unit to arrive at its estimated retirement date. For example, if a unit had an in-service
10 date of 1980 and a 44-year estimated life span, its estimated retirement date would be
11 2024. For multiple-unit plants, the age was calculated for each unit. Then a
12 weighted-average age for the entire plant was determined by weighting the capacity
13 of each unit. An average retirement date was then calculated based on the remaining
14 life.

15 **Q. Were the estimated retirement dates calculated by the Company for each steam**
16 **plant based on current Commission-approved life spans provided to Mr. Roff**
17 **for use in preparing the depreciation study?**

18 A. Yes. The estimated plant retirement dates were provided to Mr. Roff in the form of
19 the document contained in Exhibit ____ (BGC-1).

20 Hydroelectric Plant Retirement Dates

21 **Q. Is the process used to estimate retirement dates for PacifiCorp's hydro**
22 **generation plants similar to the process used for steam plants?**

1 A. Conceptually the process is very similar. The primary difference is that it is not
2 possible to use generic life span estimates for hydro plants. While steam plants of
3 similar size, vintage, and design requirements would be expected to have the same
4 life span, each hydro plant is unique. Therefore, it is necessary to estimate the life
5 span of each hydro plant separately; or in effect, to determine the retirement date for
6 each hydro plant on an individual basis.

7 **Q. What criteria are important in estimating the retirement date of a hydro plant?**

8 A. The remaining useful lives of hydro facilities are governed either by the terms of
9 operating licenses or by the remaining life of critical civil/structural or electro-
10 mechanical components.

11 **Q. Who prepared the estimated retirement dates for hydro plants?**

12 A. The hydro plant retirement dates were estimated by PacifiCorp's Hydro Engineering
13 and Planning staff. These individuals have experience in both plant operation and
14 maintenance and in project relicensing.

15 **Q. What license are you referring to?**

16 A. The majority of PacifiCorp's hydro projects are federally licensed under the
17 jurisdiction of the Federal Energy Regulatory Commission (FERC) which acts under
18 the authority of the Federal Power Act (FPA). Hydro projects receive their initial
19 license when they are first placed in service and may be relicensed upon expiration of
20 the initial term. This initial term is usually for 50 years. FERC may grant new
21 licenses of up to 50 years, depending upon the unique circumstances at each project.
22 Currently, the most common relicensing period is 30 years. Over 90 percent of the

1 Company's hydro capacity is or will be in the relicensing process in the next few
2 years.

3 **Q. How were the decision criteria applied to determine the retirement date for**
4 **each hydro plant?**

5 A. As previously mentioned, most of the Company's hydro capacity has been recently
6 relicensed, is currently undergoing relicensing or soon will be. For plants currently
7 in the relicensing process and plants that will begin relicensing in the near future, the
8 estimated retirement date is the date of expiration of the current license plus 30 years
9 (the most common period for new FERC licenses). For example, if a plant's current
10 license expires in 2000, the estimated retirement date for that facility is 2030. For
11 plants that have been recently relicensed, the estimated retirement date is the
12 expiration date of the new license. The remaining life span of the plant is the same
13 as the life of the license.

14 **Q. Is there any exception to the practice of basing estimated retirement dates on**
15 **FERC license expirations?**

16 A. Yes. As I indicated before, the other primary driver of expected hydro plant life is
17 the remaining life of critical components. PacifiCorp has a number of smaller hydro
18 projects where significant new investment could make the plants uneconomical to
19 operate given current alternative options to supply this energy. If an aging critical
20 component were to fail at such a plant, it is likely that an economic analysis would
21 indicate that the Company should retire the facility rather than spend the capital
22 necessary to operate the plant for the remainder of its license term. For plants where
23 Company engineers have determined that the expected remaining life of a critical

1 component is shorter than the FERC license period, the retirement date of that plant
2 has been estimated to reflect only the remaining useful life of the component. For
3 example, consider a hydro plant with a FERC license expiration of 2025 that will
4 require a complete flowline replacement in 2015. Company engineers believe that
5 replacement of the flowline cannot be economically justified. The estimated
6 retirement date for that plant will be based on the expected critical component failure
7 date of 2015 rather than the 2025 license expiration date.

8 **Q. If the continued operation of a hydro plant is not constrained by critical**
9 **component failures, why should its life span be limited to the expiration of a**
10 **FERC license? Wouldn't it be reasonable to expect FERC licenses to continue**
11 **to be renewed indefinitely?**

12 A. It would be imprudent to anticipate approval of license renewals beyond the near
13 term. The FERC is responsible for hydroelectric project licensing under the Federal
14 Power Act . Historically, FERC has balanced the need for power produced by
15 projects with the need to protect the surrounding environment and natural resources.
16 However, FERC no longer has the discretion to balance hydro interests with other
17 resource issues given the U.S. Supreme Court's rulings on Section 401 of the Clean
18 Water Act (CWA), endangered species listings under the Endangered Species Act
19 (ESA) and other rulings under the FPA. For example, the U.S. Fish and Wildlife
20 Service and the National Marine Fisheries Service have prescriptive authority under
21 the FPA to provide fish passage in any manner they deem reasonable. As a result,
22 typical license conditions now routinely include revised operating requirements and
23 construction of new environmental mitigation facilities that may make the project(s)

1 uneconomical to continue to operate in the future. This economic viability will need
2 to be determined for each project, but such determination cannot be conclusively
3 made until a new license is re-issued by FERC. For this reason PacifiCorp cannot
4 reliably forecast operating lives beyond current license expiration dates. The
5 estimated hydro plant retirement dates developed by Company engineers using the
6 criteria that I have just described are reasonable and prudent in this dynamic,
7 changing arena and are the appropriate inputs for Mr. Roff's depreciation analysis.

8 **Q. How were the estimated hydro plant retirement dates developed by the**
9 **Company provided to Mr. Roff?**

10 A. The estimated hydro plant retirement dates were provided to Mr. Roff in the form of
11 Exhibit ____ (BGC-2).

12 **OTHER PRODUCTION PLANT**

13 **Q. What process was used by PacifiCorp to estimate retirement dates for its Other**
14 **Production Plants?**

15 A. The process was similar to that used for the hydro generation facilities. The life
16 spans for Other Production were assumed to be the length of either the Power
17 Purchase Agreement for the specific facility or the expected life of a critical
18 component. Little Mountain and Foote Creek (aka Wyoming Wind) use the contract
19 length as the estimated life span for their respective facilities. The estimated life
20 spans for the Gadsby Units 4, 5 and 6 were based on the 25-year design life span of
21 the combustion turbine.

22 **Q. Why is the contract life a good estimate of plant life?**

1 A. Given the uncertainty in the power market, it is difficult to project the economic
2 value of the plant past the end of the contract life. The future economic viability for
3 each project will need to be evaluated as it nears the end of its estimated life span.

4 **Q. Why is there a different life span for the Hermiston gas-fired plant than the**
5 **Gadsby gas-fired plant?**

6 A. The Hermiston gas-fired plant is a combined cycle base-loaded facility, which is
7 designed to run at a steady state condition. Gadsby Units 4, 5 and 6 are peakers, and
8 are therefore expected to cycle on and off at a higher rate. The cycling of the plant
9 takes life out of the combustion turbines and reduces their life span.

10 **Q. How were the estimated other production plant retirement dates developed by**
11 **the Company provided to Mr. Roff?**

12 A. The estimated other production plant retirement dates are included in Exhibit ____
13 (BGC-1).

14 **TERMINAL NET SALVAGE (DECOMMISSIONING COST)**

15 **Q. Please explain the term “terminal net salvage” or “decommissioning cost”?**

16 A. As I use the term, terminal net salvage refers to the cost of removing facilities that
17 have been retired and restoring the site to its original grade. It does not contemplate
18 site re-vegetation or other landscaping activities.

19 **Q. Do the depreciation rates being proposed by the Company in this proceeding**
20 **include recovery of terminal net salvage for generation plants?**

21 A. The depreciation rates for steam generating plants include recovery of terminal net
22 salvage. With the exception of the Condit and American Fork Plants, which the

1 Company expects to remove, the depreciation rates for hydro plants do not provide
2 for recovery of terminal net salvage.

3 **Q. Why should there be a difference in the recovery of terminal net salvage**
4 **between steam and hydro plants?**

5 A. Conceptually there should be no difference—terminal net salvage should be reflected
6 in depreciation rates. The cost of removing coal-fired plants is generally consistent
7 for plants of similar size and vintage. This consistency facilitates preparation of
8 reasonable terminal net salvage estimates for steam plants. However, every hydro
9 plant is uniquely situated and the estimated removal costs would have to be
10 individually determined. PacifiCorp will continue to evaluate the most appropriate
11 way to reflect hydro terminal net salvage in future depreciation studies, but it was
12 decided not to include these costs in the current study.

13 **Q. How were the terminal net salvage factors for steam production plant**
14 **determined?**

15 A. The terminal net salvage for PacifiCorp's steam generating plants was estimated by
16 Mr. Roff. A description of the procedures used is presented in his direct testimony
17 filed in this proceeding on page 11.

18 **Q. Based on the Company's actual experience, does Mr. Roff's estimate of terminal**
19 **net salvage for steam plants appear to be reasonable for PacifiCorp?**

20 A. Yes, in fact it appears to be rather conservative. Mr. Roff estimates approximately 8
21 percent negative net salvage (8 %) for steam plant decommissioning. (Net salvage is
22 negative when cost of removal exceeds salvage value. The net salvage percentage is
23 calculated by dividing the net salvage amount by the retirement amount.) PacifiCorp

1 has retired two steam generating plants in the last fifteen years—the Hale Plant and
2 the Jordan Plant—both of which have been removed. The Company’s actual
3 terminal negative net salvage for the Hale Plant was (14%) and for the Jordan Plant it
4 was (190%).

5 **Q. Does PacifiCorp expect to remove steam generating plants that are retired in**
6 **the future?**

7 A. Yes. It has been the Company’s practice to remove thermal plants upon retirement
8 for a variety of reasons, and it is its current intention to continue to do so. PacifiCorp
9 assumes that even if laws and regulations do not currently exist which require
10 removal of generation plants upon retirement, laws and regulations may be enacted
11 that would require removal if the owner or operator fails to do so. There are public
12 safety and environmental issues associated with generation plants, and the public
13 may demand their removal if the owner or operator does not do so. The Company
14 does not believe it is reasonable to assume that retired generation plants will be
15 allowed to remain in place indefinitely in the future. In addition, it is unlikely that
16 PacifiCorp could dispose of the sites of retired generation plants without removal. In
17 fact, even if the Company were to retain the site for its own use, it would probably be
18 necessary to remove the old plant before a new plant could utilize transmission or
19 other site advantages. The Company believes that consideration of the potential
20 obligations associated with indefinitely holding a retired generation plant might
21 indicate that removal is the most prudent course and may be in the long-term public
22 interest.

1 **Q. Does recovery of terminal net salvage costs through steam plant depreciation**
2 **expense represent sound ratemaking policy?**

3 A. Yes, it does. Two of the most basic precepts of ratemaking policy are that customers
4 should pay for their cost of service and that costs should be matched with benefits.
5 Consistent with these principles, customers who benefit from the output of a steam
6 generating plant should bear all the costs of producing that output, including the cost
7 of constructing the plant and subsequent capital additions, the costs of operating and
8 maintaining the plant over its productive life, and ultimately the cost of retiring and
9 removing the plant. Recovery of terminal net salvage through depreciation expense
10 over the useful life of the plant is the only way to achieve a full and fair matching of
11 costs and benefits. If recovery of terminal net salvage were to be deferred until the
12 plant is actually retired, some customers would inevitably pay less than their cost of
13 service while other customers would pay more than their fair share.

14 **Q. Is the estimated removal cost for the Condit and American Fork hydro plants**
15 **included in the current depreciation study prepared by Mr. Roff?**

16 A. Yes. The depreciation rates developed by Mr. Roff for the Condit Plant reflect the
17 recovery of \$19.7 million for removal of the Condit dam and \$1 million for removal
18 of the American Fork facilities. This recovery is explained in Mr. Roff's direct
19 testimony on page 12 and is documented in the depreciation study, Exhibit ____
20 (DSR-3), Schedule 3.

21 **Q. Are Condit dam removal costs reflected in currently authorized depreciation**
22 **rates?**

1 A. Yes. The depreciation rates approved by the Commission in Docket No. UE-991832
2 that became effective April 1, 2000 include recovery of Condit removal costs.

3 **Q. Please describe the situation involving the American Fork Plant.**

4 A. The cost of removing the American Fork Plant has not been addressed in previous
5 depreciation studies. However, the current FERC license for operating the plant
6 expires in 2008, and PacifiCorp is faced with two alternatives—relicense the project
7 and continue to operate it or decommission the facility. Since economic analysis has
8 demonstrated that a relicensed American Fork project would not be cost effective,
9 the Company does not plan to continue to operate the plant after the current license
10 expires in 2008. The Company's current estimate of the cost that will be required to
11 decommission the American Fork Plant is \$1 million. This amount is included in the
12 current depreciation study as removal cost in order to recover it over the remaining
13 useful life of the plant from the customers who will be served by the plant.

14 **DEPRECIATION OF WATER RIGHTS**

15 **Q. Please describe the water rights that are at issue in this proceeding?**

16 A. Coal-fired generating plants require significant amounts of water for operating and
17 cooling purposes. The water rights at issue, most of which are associated with the
18 Hunter, Huntington, and Dave Johnston Plants, were acquired to satisfy this
19 operational need for water. For the most part the cost of obtaining these rights was
20 included in the original plant construction cost, although some additional rights have
21 been acquired over the years to meet changing needs.

22 **Q. Why is it appropriate to depreciate the cost of water rights?**

1 A. All generating plant construction costs, including water rights, should be recovered
2 from those customers who benefit from the output of the unit over its productive life.
3 It is necessary, then, to allocate the cost of water rights to generation expense in a
4 systematic and rational fashion over the life of the plant. This allocation is
5 accomplished through depreciation.

6 **Q. For the most part, PacifiCorp's coal-fired generating plants are located in arid**
7 **areas where water is a scarce commodity. Why wouldn't the value of water**
8 **rights be expected to actually appreciate over the life of the plant—thereby**
9 **eliminating any need for cost allocation through depreciation?**

10 A. Although the value of water rights might be expected to increase over time, this
11 expectation is based on the water being used for the same purpose at the time of
12 acquisition and sale. The fact is that the Company was required to pay a significant
13 premium above the market value of water for agricultural purposes to acquire the
14 large blocks of water necessary to operate a generating plant. To operate the Hunter
15 and Huntington plants, PacifiCorp had to acquire one-third of the water rights in
16 Emery County, Utah. The water will be sold for agricultural purposes. Upon plant
17 retirement, PacifiCorp will be unable to recover the premium it paid at acquisition by
18 selling large blocks of water whose only use is growing hay and raising cattle.

19 **Q. What makes you think that the water rights currently owned by PacifiCorp will**
20 **not be needed in the future for non-agricultural purposes in Emery County?**

21 A. These water rights will not be available until the Hunter and Huntington Plants are
22 retired and closed. In 1998, between the generating plants and their associated coal
23 mines, PacifiCorp directly employed more than 20 percent of the employed labor

1 force in Emery County and made possible many additional jobs in supporting
2 industries. The Company also paid more than 70 percent of total Emery County
3 property taxes in 1998. Closure of the Company facilities will be a major economic
4 blow to the area and may provide the impetus for an outward migration of job-
5 seekers. Under these circumstances the municipalities in Emery County will likely
6 need less water rather than more, and there are few prospects for other major
7 industrial development in this area. Thus, the major use for the water rights owned
8 by the Company will undoubtedly be agricultural.

9 **Q. Is there a similar situation with the water rights acquired for the Dave Johnston**
10 **Plant in Wyoming?**

11 A. Yes. PacifiCorp needed to acquire very high quality water rights to ensure the
12 continued, uninterrupted operation of the Dave Johnston Plant because there is no
13 water storage capability in the area. The rights acquired were converted from
14 agricultural use at a substantial premium. Because the value of water for generation
15 is so much greater than the value of water for ranching, it is unrealistic to expect the
16 conversion premium to be regained when the water is again made available for
17 agricultural use.

18 **Q. How do the facts you have just described support the depreciation of water**
19 **rights?**

20 A. Since the future value of water rights is expected to be small compared to their
21 acquisition cost, it is sound ratemaking policy to recover the cost of these rights
22 through depreciation expense from the customers who benefit from their use. It

1 makes no sense to require a future generation of customers to bear the risk of paying
2 for water rights for a plant that never served them.

3 **Q. You have explained that when the steam plants are retired, the residual value of**
4 **water rights will be small compared to their acquisition costs. How has this**
5 **residual value been reflected in the depreciation study?**

6 A. In arid states such as Utah and Wyoming, water rights will always have value. For
7 purposes of the depreciation study, the Company has included a ten percent salvage
8 value for the water rights when they are converted from industrial to agricultural use
9 upon the retirement of the generating plants. Such inclusion reduces depreciation
10 expense for these plants.

11 **CONCLUSION**

12 **Q. Based on the foregoing testimony, what conclusions have you reached?**

13 A. It is my opinion that the life spans approved by the Commission in Docket No. UE-
14 991832 for PacifiCorp's steam generating plants (adjusted only to extend the life of
15 the Naughton Plant) provide a reasonable basis in this case for the estimated
16 retirement dates used as inputs for Mr. Roff's depreciation analysis. Similarly, it is
17 my opinion that the hydro plant retirement dates provided to Mr. Roff are reasonable
18 and are based on the latest engineering estimates. I conclude that the terminal net
19 salvage calculated by Mr. Roff for PacifiCorp steam generating plants is reasonable
20 and conservative, based on the Company's actual experience. It is necessary to
21 include steam plant terminal net salvage in depreciation rates to properly match
22 customer benefits with customer costs and to ensure that all customers pay their full
23 and fair cost of service. These same principles of ratepayer equity require that the

1 Condit and American Fork hydro plant decommissioning costs be recovered through
2 depreciation expense from the customers being served by the these hydro plants.
3 Finally, I conclude that the cost of water rights acquired to operate steam generating
4 plants should be recovered through depreciation from the generation of customers
5 who were served by those plants.

6 **Q. Does this conclude your testimony?**

7 A. Yes.

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

In the Matter of the Application of
PACIFICORP for an Order Authorizing a
Change in Depreciation Rates Applicable to
Electric Property.

Docket No. UE-02 ____

PACIFICORP

Exhibit of Barry G. Cunningham

Steam Plant Retirement Dates

October, 2002

Power Supply Estimated Plant Lives

Plant	PacifiCorp Share Net Rating (MW)	Commercial Date	Current Age of Unit	Weighted Average Age of Plant	Power Supply Recommended Life	Power Supply Recommendation Year Ending Life	Years Remaining from 2002
Blundell	23	1984	18	18.0	37.0	2021	19
Carbon-1	70	1954	48				
Carbon-2	105	1957	45	46.2	54.0	2010	8
Cholla-4	380	1981	21	21.0	44.0	2025	23
Colstrip-3	72	1984	18				
Colstrip-4	72	1986	16	17.0	44.0	2029	27
Craig-1	83	1980	22				
Craig-2	83	1979	23	22.5	44.0	2024	22
Dave Johnston-1	106	1959	43				
Dave Johnston-2	106	1960	42				
Dave Johnston-3	230	1964	38				
Dave Johnston-4	330	1972	30	35.8	54.0	2020	18
Foote Creek	33	1999	3	3.0	25.0	2024	22
Gadsby-1	60	1951	51				
Gadsby-2	75	1952	50				
Gadsby-3	100	1955	47	49.0	54.0	2007	5
Gadsby-4	40	2002	0				
Gadsby-5	40	2002	0				
Gadsby-6	40	2002	0	0.0	25.0	2027	25
Hayden-1	45	1965	37				
Hayden-2	33	1976	26	32.3	54.0	2024	22
Hermiston 1	119	1996	6	6.0			
Hermiston 2	119	1996	6	6.0	35.0	2031	29
Hunter-1	389	1978	24				
Hunter-2	259	1980	22				
Hunter-3	460	1983	19	21.5	44.0	2025	23
Huntington-1	440	1977	25				
Huntington-2	455	1974	28	26.5	44.0	2019	17
James River	52	1996	6	6.0	20.0	2016	14
Jim Bridger-1	353	1974	28				
Jim Bridger-2	353	1975	27				
Jim Bridger-3	353	1976	26				
Jim Bridger-4	347	1979	23	26.0	44.0	2020	18
Little Mountain	14	1971	31	31.0	35.0	2006	4
Naughton-1	160	1963	39				
Naughton-2	210	1968	34				
Naughton-3	330	1971	31	33.7	54.0	2022	20
Wyodak-1	268	1978	24	24.0	44.0	2022	20

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

In the Matter of the Application of
PACIFICORP for an Order Authorizing a
Change in Depreciation Rates Applicable to
Electric Property.

Docket No. UE-02 ____

PACIFICORP

Exhibit of Barry G. Cunningham

Hydro Plant Retirement Dates

October 2002

Power Supply Estimated Plant Lives

Plant	PacifiCorp Share Net Rating (MW)	Location	Commercial Date	Current Age of Unit	Weighted Average Age of Plant	Power Supply Recommended Life	License Expiration Date	Power Supply Recommended Year Ending Life	Years Remaining from 2002
Ashton	6.85	Idaho	1923	79	79	105	2028	2028	26
Bend	1.11	Oregon	1913	89	89	92	Unlicensed	2005	3
Big Fork	4.15	Montana	1924	78	78	107	2001	2031	29
Clearwater-1	15.00	Oregon	1953	49	49	87	1997	2040	38
Clearwater-2	26.00	Oregon	1953	49	49	87	1997	2040	38
Cline Falls	1.00	Oregon	1943	59	59	62	Unlicensed	2005	3
Condit	9.60	Washington	1913	89	89	91	1993	2006	4
Copco-1	20.00	Oregon	1918	84	84	118	2006	2036	34
Copco-2	27.00	Oregon	1925	77	77	100	2006	2025	23
Cove	7.50	Idaho	1917	85	85	114	2001	2031	29
Cutler	30.00	Utah	1927	75	75	97	2024	2024	22
Eagle Point	2.80	Oregon	1957	45	45	53	Unlicensed	2010	8
East Side	3.20	Oregon	1924	78	78	82	2006	2010	8
Fall Creek	2.20	Oregon	1908	94	94	98	2006	2036	34
Fish Creek	11.00	Oregon	1952	50	50	88	1997	2040	38
Fountain Green	0.16	Utah	1922	80	80	88	Exempt	2010	8
Grace	33.00	Idaho	1923	79	79	108	2001	2031	29
Granite	2.00	Utah	1896	106	106	134	Unlicensed	2030	28
Gunlock	0.75	Utah	1917	85	85	103	Exempt	2020	18
Iron Gate	18.00	Oregon	1962	40	40	74	2006	2036	34
JC Boyle	80.00	Oregon	1958	44	44	78	2006	2036	34
Last Chance	1.70	Idaho	1984	18	18	41	Exempt	2025	23
Lemolo-1	29.00	Oregon	1955	47	47	85	1997	2040	38
Lemolo-2	33.00	Oregon	1956	46	46	84	1997	2040	38
Merwin	136.00	Washington	1932	70	70	104	2009	2036	34
Naches	6.37	Washington	1909	93	93	97	Unlicensed	2006	4
Naches Drop	1.40	Washington	1915	87	87	91	Unlicensed	2006	4
Onieda	30.00	Idaho	1915	87	87	116	2001	2031	29
Paris	0.70	Idaho	1910	92	92	105	Exempt	2015	13
Pioneer	5.00	Utah	1914	88	88	116	2000	2030	28
Powerdale	6.00	Oregon	1923	79	79	95	2000	2018	16
Prospect-1, 2 & 4	36.76	Oregon	1912	90	90	123	2005	2035	33
Prospect-3	7.20	Oregon	1932	70	70	87	2019	2019	17
Sand Cove	0.80	Utah	1920	82	82	100	Exempt	2020	18
Skookumchuck	1.00	Washington	1990	12	12	58	Exempt	2048	46
Slide Creek	18.00	Oregon	1951	51	51	89	1997	2040	38
Snake Creek	1.18	Utah	1910	92	92	110	Unlicensed	2020	18
Soda	14.00	Idaho	1924	78	78	107	2001	2031	29
Soda Springs	11.00	Oregon	1952	50	50	88	1997	2040	38

Power Supply Estimated Plant Lives

Plant	PacifiCorp Share Net Rating (MW)	Location	Commercial Date	Current Age of Unit	Weighted Average Age of Plant	Power Supply Recommended Life	License Expiration Date	Power Supply Recommendation Year Ending Life	Years Remaining from 2002
St. Anthony	0.50	Idaho	1915	87	87	113	2028	2028	26
Stairs	1.00	Utah	1914	88	88	111	2000	2025	23
Swift-1	240.00	Washington	1958	44	44	78	2006	2036	34
Tokatee	42.50	Oregon	1939	63	63	101	1997	2040	38
Upper American Fork	0.95	Utah	1964	38	38	66	2000	2008	6
Upper Beaver	2.52	Utah	1907	95	95	123	Exempt	2030	28
Veyo	0.50	Utah	1920	82	82	100	Exempt	2020	18
Viva Naughton	0.74	Wyoming	1986	16	16	54	Exempt	2040	38
Wallowa Falls	1.10	Oregon	1921	81	81	95	2016	2016	14
Weber	3.85	Utah	1949	53	53	71	2020	2020	18
West Side	0.60	Oregon	1908	94	94	98	2006	2010	8
Yale	134.00	Washington	1963	39	39	73	2001	2036	34
	1,068.69								

The following are associated with and support PacifiCorp's Hydro facilities, but do not have generation

Keno Regulating Dam								2036	34
Klamath Lake Reservoir								2036	34
Lifton								2048	46
North Umpqua General								2040	38

The following is operated by PacifiCorp, but is owned by others

Olmsted	10.30							2016	14
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