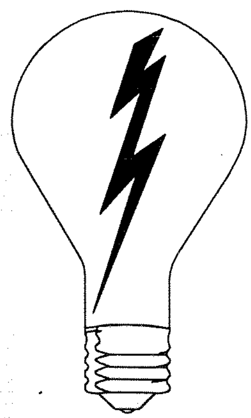
YEAR 1997

ANNUAL REPORT

OF

PACIFICORP dba Pacific Power

ELECTRIC UTILITY



TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 202601
HELENA, MONTANA 59620-2601

Check No. 0399671
Rec'd 4-8-98

Revised November 9, 1994

Electric Annual Report

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Electric Annual Report

Instructions

General

1. A computer disk, formatted with DOS Version 6.0, is being provided for your convenience. The files were created using the DOS version of Lotus 5.0 and were saved with the wk3 extension. Separate files were created for each page. Where multiple schedules are on one page, one file was created. The naming convention of the files is representative of the schedules contained on a page (for example, Schedules 1 and 2 are sch1&2.wk3, Schedule 3 is sch3.wk3). Use of the disk is optional. The disk shall be returned when the report is filed.

2. All forms shall be filled out in permanent ink and be legible. Note: Even if the computer disk is used, a printed version of the report shall be filed.

3. Indicate negative amounts (such as decreases) by enclosing the figures in parentheses (   ).

4. Where space is a consideration, information on financial schedules may be rounded to thousands of dollars. Companies submitting schedules rounded to thousands shall so indicate at the top of the schedule.

5. Where more space is needed or more than one schedule is needed additional schedules may be attached and shall be included directly behind the original schedule to which it pertains and be labeled accordingly (for example, Schedule 1A).

6. The information required with respect to any statement shall be furnished as a minimum requirement to which shall be added such further information as is necessary to make the required schedules not misleading.

7. All companies owned by another company shall attach a corporate structure chart of the holding company.

8. Schedules that have no activity during the year or are not applicable to the respondent shall be marked as not applicable and submitted with the report.

9. The following schedules shall be filled out with information on a total company basis:

Schedules 1 through 5
Schedules 6 and 7
Schedule 14
Schedule 17 and 18
Schedules 23 through 26
Schedules 33 and 34

All other schedules shall be filled out with either Montana specific data, or both total company and Montana specific data, as indicated in the schedule titles and headings.

Financial schedules shall include all amounts originating in Montana or allocated to Montana from other jurisdictions.

10. FERC Form-1 sheets may not be substituted in lieu of completing annual report schedules.

11. Common sense must be used when filling out all schedules.

Specific Instructions

Schedules 6 and 7

1. All transactions with affiliated companies shall be reported. The definition of affiliated companies as set out in 18 C.F.R. Part 101 shall be used.

2. Column (c). Respondents shall indicate in column (c) the method used to determine the price. Respondents shall indicate if a contract is in place between the Affiliate and the Utility. If a contract is in place, respondents shall indicate the year the contract was initiated, the term of the contract and the method used to determine the contract price.

3. Column (c). If the method used to determine the price is different than the previous year, respondents shall provide an explanation, including the reason for the change.

Schedules 8, 18, and 23

1. Include all notes to the financial statements required by the FERC or included in the financial statements issued as audited financial statements. These notes shall be included in the report directly behind the schedules and shall be labeled appropriately (Schedule 8A, etc.).

Schedule 12

1. Respondents shall disclose all payments made during the year for services where the aggregate payment to the recipient was $5,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall report aggregate payments of $25,000 or more. Utilities having jurisdictional revenue equal to or in excess of $10,000,000 shall report aggregate payments of $75,000 or more. Payments must include fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payment for services or as a donation.

Schedule 14

1. Companies with more than one plan (for example, both a retirement plan and a deferred savings plan) shall complete a schedule for each plan.

2. Companies with defined benefit plans must complete the entire form. Lines 17 through 30 shall be filled out using FASB 87 guidelines. Line 32 refers to the minimum required contribution under ERISA. Line 34 refers to the maximum amount deductible for tax purposes.

3. Interest rate percentages (lines 21 and 22) shall be listed to two decimal places.

Schedule 15

1. All changes in the employee benefit plans shall be explained in a narrative on lines 16 through 19. All cost containment measures implemented in the reporting year shall be explained and quantified in a narrative on lines 16 through 19. All assumptions used in quantifying cost containment results shall be disclosed.

2. Lines 36 through 46 on page 1 and lines 18 through 28 on page 2 shall be filled out using FASB 106 guidelines.

Schedule 16

1. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

2. The above compensation items shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

Schedule 17

1. Respondents shall provide all executive compensation information in conformance with that required by the Securities and Exchange Commission (SEC) (Regulation S-K Item 402, Executive Compensation).

2. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

3. All items included in the "other" compensation column shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

4. In addition, respondents shall attach a copy of the executive compensation information provided to the SEC.

Schedule 24

1. Interest expense and debt issuance expense shall be included in the annual net cost column.

Schedule 26

1. Earnings per share and dividends per share shall be reported on a quarterly basis and entries shall be made only to the months that end the respective quarters (for example, March, June, September, and December.)

2. The retention and price/earnings ratios shall be calculated on a year end basis. Enter the actual year end market price in the "TOTAL Year End" row. If the computer disk is used, enter the year end market price in the "High" column.

Schedule 27

1. All entries to lines 9 or 16 must be detailed separately on an attached sheet.

2. Only companies who have specifically been authorized in a Commission Order to include cash working capital in ratebase may include cash working capital in lines 9 or 16. Cash working capital must be calculated using the methodology approved in the Commission Order. The Commission Order specifying cash working capital shall be noted on the attached sheet.

3. Indicate, for each adjustment on lines 28 through 46, if the amount is updated or is from the last rate case. All adjustments shall be calculated using Commission methodology.

Schedule 28

1. Information from this schedule is consolidated with information from other Utilities and reported to the National Association of Regulatory Utility Commissioners (NARUC). Your assistance in completing this schedule, even though information may be located in other areas of the annual report, expedites reporting to the NARUC and is appreciated.

Schedule 31

1. This schedule shall be completed for the year following the reporting year.

2. Respondents shall itemize projects of $50,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall itemize projects of $100,000 or more. Utilities having jurisdictional revenue equal to or in excess of $10,000,000 shall itemize projects of $1,000,000 or more. All projects that are not itemized shall be reported in aggregate and labeled as Other.

Schedule 32

1. Provide a written narrative detailing the sources and amounts of electric supply at the time of the annual peak.

Schedule 34

1. The following categories shall be used in the Type column: Thermal, Hydro, Nuclear, Solar, Wind, GeoThermal, Qualifying Facility (QF), Independent Power Producer (IPP), Off System Purchases, or Other. Spot market purchases shall be separately identified. Entries for the Other category shall be listed as separate line items and include a description.
   Note: For Off System Purchases, the Utility/Company whom the purchases are being made from shall be entered in the Plant Name column, the termination date of the purchased power contract shall be entered in the Location column.

2. Provide a written narrative of all outages exceeding one hour which occurred during the year. Explain the reason for the outage. If routine maintenance schedules are exceeded, explain the reason.

Schedule 35

1. In addition to a description, the year the program was initiated and the projected life of the program shall be included in the program description column.

2. On an attached sheet, define program "participant" and program conservation "unit" for each program. Also, provide the number of program participants and the number of units acquired or processed during this reporting year.

Sch. 1

IDENTIFICATION

Legal Name of Respondent:	PacifiCorp
Name Under Which Respondent Does Business:	Pacific Power / Utah Power
Date Utility Service First Offered in Montana:	May 21, 1954 (Date of Mountain States Power Company merger with Pacific Power)
Person Responsible for Report:	Anne E. Eakin - Assistant Vice President
Telephone Number for Report Inquiries:	(503) 813-6065
Address for Correspondence Concerning Report:	Pacific Power Lloyd Center Tower 825 N. E. Multnomah Street Portland, Oregon 97232

If direct control over respondent is held by another entity, provide below the name, address, means by which control is held and percent ownership of controlling entity:

Sch. 2

BOARD OF DIRECTORS

Director Name & Address (City, State)		Remuneration
Keith R. McKennon (Chairman)	Portland, Oregon	170,351
Frederick W. Buckman (1)	Portland, Oregon	(2)
Kathryn A. Braun	Irvine, Californiz	44,330
C. Todd Conover	Cupertino, California	61,022
W. Charles Armstrong	Vancouver, Washington	47,500
Nolan E. Karras	Roy, Utah	66,080
Robert G. Miller	Portland, Oregon	55,500
Alan K. Simpson	Cody, Wyoming	45,029
Verl R. Topham	Salt Lake City, Utah	(2)
Don M. Wheeler	Salt Lake City, Utah	57,400
Nancy Wilgenbusch	Marylhurst, Oregon	58,750
Peter I. Wold	Casper, Wyoming	34,865

(1) President and Chief Executive Officer of the Company

(2) No remuneration as a director, officer of the Company during 1997.

OFFICERS

Title	Department Supervised	Name
President and Chief Executive Officer		Frederick W. Buckman
Senior Vice President		Paul G. Lorenzini
Senior Vice President and General Counsel		Verl R. Topham
Senior Vice President		Daniel L. Spalding
Senior Vice President		John A. Bohling
Senior Vice President		John E. Mooney (1)
Senior Vice President		Dennis P. Steinberg
Senior Vice President		Shelley R. Faigle
Senior Vice President and Chief Financial Officer		Richard T. O'Brien
Senior Vice President		William C. Brauer
Vice President		J. Brett Harvey (2)
Vice President		David P. Hoffman
Vice President		Thomas J. Imeson
Vice President and Corporate Secretary		Sally A. Nofziger
Vice President		Edward J. O'Mara (3)
Vice President		Michael J. Pittman
Vice President		Paul W. Pechersky (4)
Vice President		Ernest E. Wessman
Vice President		Thomas W. Forsgren
Vice President		Thomas A. Lockhart
Vice President		Richard D. Westerberg
Vice President		Michael C. Henderson (5)
Vice President and Treasurer		William E. Peressini
Vice President		Donald A. Bloodworth (6)
Vice President		Anne E. Eakin (7)

OFFICERS

Title	Department Supervised	Name
Vice President		Donald N. Furman (8)
Vice President and Controller		James H. Huesgen (9)
Vice President		Timothy E. Meier (10)
Vice President		Brian D. Sickels (11)

(1) Retired March 31, 1997
(2) Resigned December 31, 1997
(3) Resigned March 25, 1997
(4) Resigned July 18, 1997
(5) Resigned Febuary 1, 1998
(6) Resigned April 11, 1997 and hired November 11, 1997
(7) Elected Febuary 12, 1997
(8) Elected Febuary 12, 1997
(9) Elected November 11, 1997
(10) Elected September 1, 1997
(11) Elected Febuary 12, 1997

Sch. 4

CORPORATE STRUCTURE

Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
PacifiCorp Holdings, Inc.	Holding company	472,541,568	99.70%
Demand Side Receivable	Demand Side loan holder	858,510	0.18%
PacifiCorp Investment Management Inc.		4,895	0.00%
PFS Acquisition Corp.		551,700	0.12%
TOTAL		473,956,673	100%

Sch. 5

CORPORATE ALLOCATIONS

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Corporate Management Fee		Three Factor Method			
2	$18,267,600	January - December	77.6% to Electric Utility Operations			
3						
4						
5	Electric Utility Portion					
6	$14,175,658			287,341	2.0270%	13,888,317
7						
8						
9						
10						
11						
12						
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16						
17						
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20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34	TOTAL			287,341	2.0270%	13,888,317

Sch. 6 **AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY**

	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	Pacific Telecom	Shareholder Service Records	Cost	8,626	(a)	175
2		Customer Billing	Cost	899,043	(a)	18,224
3		Telephone Svc & Pole Attach	Cost	207,630	(a)	28,337
4						
5	PacifiCorp Trans	Air Transportation	Cost	6,029,956	79.09%	108,648
6						
7	Centralia Mining	Coal & Mine Mgt	Cost	53,980,496	(b)	1,122,039
8						
9	Energy West	Coal & Mine Mgt	Cost	121,668,825	(b)	2,529,008
10						
11	Glenrock Coal	Coal & Mine Mgt	Cost	34,950,273	(b)	726,476
12						
13	Williams Fork	Coal & Mine Mgt	Cost	7,301,283	(b)	151,764
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26	(a) This company was sold in 1997. No balance sheet or income statement is available.					
27	(b) This company is not evaluated on a stand-alone basis. No balance sheet or income statement is available.					
28						
29						
30						
31						
32	TOTAL			225,046,132		4,684,671

Sch. 7 **AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY**

	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	Pacific Telecom	Printing Service	Cost	35	(a)	0
2		Pole Contact Rental	Cost	234,291	(a)	0
3		Consulting Service	Cost	238,852	(a)	0
4						
5	Pacific Generation	Printing Service	Cost	1,008	(a)	0
6		Consulting Service	Cost	353,270	(a)	0
7						
8	PacifiCorp Trans	Accounting Service	Cost	7,253	0.1080%	0
9		Office Rent	Cost	2,372	0.0353%	0
10		Printing Service	Cost	3,828	0.0570%	0
11						
12	PacifiCorp Holdings, Inc.	Consulting Service	Cost	483,233	0.0191%	0
13						
14	PacifiCorp Energy, Inc	Payroll Processing	Cost	1,226	0.0188%	0
15		Consulting Service	Cost	1,462,213	22.4404%	0
16						
17	PacifiCorp Power Marketing, Inc.	Printing Services	Cost	251	0.0033%	0
18		Consulting Service	Cost	1,018,866	13.5908%	0
19						
20	PacifiCorp Kentucky Energy	Consulting Service	Cost	51,069	62.1179%	0
21						
22	Powercor	Consulting Service	Cost	433,861	N/A	0
23						
24	Hazelwood	Consulting Service	Cost	427,287	N/A	0
25						
26						
27	(a) The company was sold in 1997. No income statement is available.					
28						
29	Note: Transactions involving goods and services to affiliated companies are recorded in account 186, Miscellaneous					
30	Deferred Debits. Billings to affiliates do not result in charges to accounts affecting ratepayers.					
31						
32	TOTAL			4,718,915		0

Sch. 8

MONTANA UTILITY INCOME STATEMENT

Line	Acct.	Account Number & Title	Last Year	This Year	% Change
1	400	Operating Revenues	47,111,260	74,245,258	57.60%
2					
3		Operating Expenses			
4	401	Operation Expenses	29,536,256	50,314,895	70.35%
5	402	Maintenance Expenses	3,419,027	3,796,219	11.03%
6	403	Depreciation Expenses	5,411,909	6,596,046	21.88%
7	404-405	Amortization of Electric Plant	474,007	804,196	69.66%
8	406	Amort. of Plant Acquisition Adjustments	111,510	119,084	6.79%
9	407	Amort. of Property Losses, Unrecovered Plant	33,663	42,208	25.38%
10		& Regulatory Study Costs			
11	408.1	Taxes Other Than Income Taxes	1,623,244	1,699,090	4.67%
12	409.1	Income Taxes - Federal	2,571,949	5,546,903	115.67%
13		- Other	364,199	767,569	110.76%
14	410.1	Provision for Deferred Income Taxes	2,832,047	1,938,096	-31.57%
15	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	(1,730,322)	(4,226,858)	-144.28%
16	411.4	Investment Tax Credit Adjustment	0	0	
17	411.6	(Less) Gains from Disposition of Utility Plant	0	0	
18	411.7	Losses from Disposition of Utility Plant	0	0	
19	411.8	(Less) Gains from Sales of Emmission Allow.	(133,438)	(433,446)	
20		TOTAL Utility Operating Expenses	44,514,051	66,964,002	50.43%
21		NET UTILITY OPERATING INCOME	11,304,964	7,281,255	-35.59%

Sch. 9

MONTANA REVENUES

Line	Acct.	Account Number & Title	This Year		% Change
22		Sales of Electricity			
23	440	Residential	18,161,798	18,160,261	-0.01%
24	442	Commercial & Industrial - Small	12,549,315	12,521,172	-0.22%
25		Commercial & Industrial - Large	10,858,213	12,723,215	17.18%
26	444	Public Street & Highway Lighting	157,610	149,049	-5.43%
27	445	Other Sales to Public Authorities	0	0	
28	446	Sales to Railroads & Railways			
29	448	Interdepartmental Sales	0	0	
30					
31		TOTAL Sales to Ultimate Consumers	41,726,936	43,553,697	4.38%
32	447	Sales for Resale	13,302,591	29,260,533	119.96%
33					
34		TOTAL Sales of Electricity	55,029,527	72,814,230	32.32%
35	449.1	(Less) Provision for Rate Refunds	0	0	
36					
37		TOTAL Revenue Net of Provision for Refunds	55,029,527	72,814,230	32.32%
38		Other Operating Revenues			
39	450	Forfeited Discounts & Late Payment Revenues	50,600	62,271	23.07%
40	451	Miscellaneous Service Revenues	6,742	35,208	422.26%
41	453	Sales of Water & Water Power	0	0	
42	454	Rent From Electric Property	248,231	313,225	26.18%
43	455	Interdepartmental Rents	0	0	
44	456	Other Electric Revenues	483,916	1,020,323	110.85%
45					
46		TOTAL Other Operating Revenues	789,488	1,431,028	81.26%
47		Total Electric Operating Revenues	55,819,015	74,245,258	33.01%

MONTANA OPERATION & MAINTENANCE EXPENSES

Line	Account Number & Title		Last Year	This Year	% Change
1		Power Production Expenses			
2					
3	Steam Power Generation				
4	Operation				
5	500	Operation Supervision & Engineering	235,052	260,651	10.89%
6	501	Fuel	9,015,410	9,153,642	1.53%
7	502	Steam Expenses	456,696	471,400	3.22%
8	503	Steam from Other Sources	98,130	160,070	63.12%
9	504	(Less) Steam Transferred - Cr.	0	0	
10	505	Electric Expenses	249,856	263,996	5.66%
11	506	Miscellaneous Steam Power Expenses	470,228	470,861	0.13%
12	507	Rents	(48)	247	611.29%
13					
14		TOTAL Operation - Steam	10,525,323	10,780,867	2.43%
15					
16	Maintenance				
17	510	Maintenance Supervision & Engineering	264,535	294,003	11.14%
18	511	Maintenance of Structures	119,652	113,948	-4.77%
19	512	Maintenance of Boiler Plant	842,599	960,946	14.05%
20	513	Maintenance of Electric Plant	217,224	219,744	1.16%
21	514	Maintenance of Miscellaneous Steam Plant	262,474	261,613	-0.33%
22					
23		TOTAL Maintenance - Steam	1,706,484	1,850,254	8.42%
24					
25		TOTAL Steam Power Production Expenses	12,231,807	12,631,121	3.26%
26					
27	Nuclear Power Generation				
28	Operation				
29	517	Operation Supervision & Engineering	0	0	
30	518	Nuclear Fuel Expense	0	0	
31	519	Coolants & Water	0	0	
32	520	Steam Expenses	0	0	
33	521	Steam from Other Sources	0	0	
34	522	(Less) Steam Transferred - Cr.	0	0	
35	523	Electric Expenses	0	0	
36	524	Miscellaneous Nuclear Power Expenses	0	0	
37	525	Rents	0	0	
38					
39		TOTAL Operation - Nuclear	0	0	
40					
41	Maintenance				
42	528	Maintenance Supervision & Engineering	0	0	
43	529	Maintenance of Structures	0	0	
44	530	Maintenance of Reactor Plant Equipment	0	0	
45	531	Maintenance of Electric Plant	0	0	
46	532	Maintenance of Miscellaneous Nuclear Plant	0	0	
47					
48		TOTAL Maintenance - Nuclear	0	0	
49					
50		TOTAL Nuclear Power Production Expenses	0	0	

Account Number	& Title	Last Year	This Year	% Change
	Power Production Expenses -continued			
Hydraulic Power Generation				
Operation				
535	Operation Supervision & Engineering	22,264	16,312	-26.73%
536	Water for Power	1,242	1,558	25.39%
537	Hydraulic Expenses	90,202	87,174	-3.36%
538	Electric Expenses	84,278	84,158	-0.14%
539	Miscellaneous Hydraulic Power Gen. Expenses	135,866	151,161	11.26%
540	Rents	301	103	-65.80%
	TOTAL Operation - Hydraulic	334,153	340,466	1.89%
Maintenance				
541	Maintenance Supervision & Engineering	16,902	16,576	-1.93%
542	Maintenance of Structures	8,460	11,915	40.84%
543	Maint. of Reservoirs, Dams & Waterways	34,925	32,844	-5.96%
544	Maintenance of Electric Plant	74,563	75,128	0.76%
545	Maintenance of Miscellaneous Hydro Plant	36,386	69,983	92.34%
	TOTAL Maintenance - Hydraulic	171,236	206,445	20.56%
	TOTAL Hydraulic Power Production Expenses	505,389	546,911	8.22%
Other Power Generation				
Operation				
546	Operation Supervision & Engineering	94	440	368.40%
547	Fuel	245	497,403	***********
548	Generation Expenses	35,277	89,588	153.96%
549	Miscellaneous Other Power Gen. Expenses	(488)	773	258.37%
550	Rents	0	0	
	TOTAL Operation - Other	35,128	588,204	1574.48%
Maintenance				
551	Maintenance Supervision & Engineering	93	442	376.38%
552	Maintenance of Structures	10	(11)	-208.79%
553	Maintenance of Generating & Electric Plant	(3)	(68)	-2304.17%
554	Maintenance of Misc. Other Power Gen. Plant	225	304	34.96%
	TOTAL Maintenance - Other	325	667	105.35%
	TOTAL Other Power Production Expenses	35,452	588,871	1561.02%
Other Power Supply Expenses				
555	Purchased Power	10,583,227	25,140,794	137.55%
556	System Control & Load Dispatching	158,416	124,174	-21.62%
557	Other Expenses	202,349	169,948	-16.01%
	TOTAL Other Power Supply Expenses	10,943,992	25,434,916	132.41%
	TOTAL Power Production Expenses	23,716,641	39,201,820	65.29%

MONTANA OPERATION & MAINTENANCE EXPENSES

Line	Account Number & Title		Last Year	This Year	% Change
1		Transmission Expenses			
2	Operation				
3	560	Operation Supervision & Engineering	18,683	17,974	-3.80%
4	561	Load Dispatching	46,222	51,925	12.34%
5	562	Station Expenses	63,245	56,650	-10.43%
6	563	Overhead Line Expenses	26,416	28,616	8.33%
7	564	Underground Line Expenses	5	10	111.98%
8	565	Transmission of Electricity by Others	1,070,833	1,451,406	35.54%
9	566	Miscellaneous Transmission Expenses	26,006	24,578	-5.49%
10	567	Rents	12,216	14,019	14.76%
11					
12		TOTAL Operation - Transmission	1,263,627	1,645,178	30.19%
13	Maintenance				
14	568	Maintenance Supervision & Engineering	16,961	17,176	1.27%
15	569	Maintenance of Structures	3,544	3,329	-6.09%
16	570	Maintenance of Station Equipment	84,027	77,196	-8.13%
17	571	Maintenance of Overhead Lines	59,432	98,185	65.21%
18	572	Maintenance of Underground Lines	37	119	221.49%
19	573	Maintenance of Misc. Transmission Plant	12,197	17,720	45.28%
20					
21		TOTAL Maintenance - Transmission	176,198	213,725	21.30%
22					
23		TOTAL Transmission Expenses	1,439,825	1,858,903	29.11%
24					
25		Distribution Expenses			
26	Operation				
27	580	Operation Supervision & Engineering	48,221	56,566	17.31%
28	581	Load Dispatching	49,537	85,122	71.83%
29	582	Station Expenses	116,205	41,758	-64.06%
30	583	Overhead Line Expenses	209,312	187,061	-10.63%
31	584	Underground Line Expenses	220,937	210,685	-4.64%
32	585	Street Lighting & Signal System Expenses	11,807	18,184	54.01%
33	586	Meter Expenses	144,860	91,931	-36.54%
34	587	Customer Installations Expenses	25,323	10,001	-60.51%
35	588	Miscellaneous Distribution Expenses	217,415	274,012	26.03%
36	589	Rents	23,454	32,904	40.29%
37					
38		TOTAL Operation - Distribution	1,067,072	1,008,225	-5.51%
39	Maintenance				
40	590	Maintenance Supervision & Engineering	43,735	55,415	26.71%
41	591	Maintenance of Structures	2,183	3,058	40.08%
42	592	Maintenance of Station Equipment	33,542	114,961	242.74%
43	593	Maintenance of Overhead Lines	953,878	1,061,208	11.25%
44	594	Maintenance of Underground Lines	143,174	150,783	5.31%
45	595	Maintenance of Line Transformers	62,779	50,584	-19.43%
46	596	Maintenance of Street Lighting, Signal Systems	12,374	18,149	46.67%
47	597	Maintenance of Meters	24,099	5,623	-76.67%
48	598	Maintenance of Miscellaneous Dist. Plant	41,974	17,205	-59.01%
49					
50		TOTAL Maintenance - Distribution	1,317,737	1,476,987	12.09%
51					
52		TOTAL Distribution Expenses	2,384,808	2,485,212	4.21%

MONTANA OPERATION & MAINTENANCE EXPENSES

	Account Number & Title		Last Year	This Year	% Change
1		Customer Accounts Expenses			
2	Operation				
3	901	Supervision	140,688	114,204	-18.82%
4	902	Meter Reading Expenses	374,203	368,369	-1.56%
5	903	Customer Records & Collection Expenses	603,566	629,105	4.23%
6	904	Uncollectible Acçounts Expenses	86,653	667,888	670.76%
7	905	Miscellaneous Customer Accounts Expenses	22,561	18,068	-19.92%
8					
9		TOTAL Customer Accounts Expenses	1,227,671	1,797,634	46.43%
10					
11		Customer Service & Information Expenses			
12	Operation				
13	907	Supervision	2,436	2,640	8.37%
14	908	Customer Assistance Expenses	200,351	255,029	27.29%
15	909	Informational & Instructional Adv. Expenses	43,449	62,237	43.24%
16	910	Miscellaneous Customer Service & Info. Exp.	91,878	112,217	22.14%
17					
18		TOTAL Customer Service & Info Expenses	338,113	432,122	27.80%
19					
20		Sales Expenses			
21	Operation				
22	911	Supervision	31,190	19,917	-36.14%
23	912	Demonstrating & Selling Expenses	121,701	124,144	2.01%
24	913	Advertising Expenses	7,156	7,371	3.01%
25	916	Miscellaneous Sales Expenses	71,376	70,686	-0.97%
26					
27		TOTAL Sales Expenses	231,422	222,118	-4.02%
28					
29		Administrative & General Expenses			
30	Operation				
31	920	Administrative & General Salaries	1,768,977	2,096,762	18.53%
32	921	Office Supplies & Expenses	644,087	878,517	36.40%
33	922	(Less) Administrative Expenses Transferred - Cr.	0	0	
34	923	Outside Services Employed	313,569	487,746	55.55%
35	924	Property Insurance	208,570	220,381	5.66%
36	925	Injuries & Damages	193,391	211,046	9.13%
37	926	Employee Pensions & Benefits	2,830,488	2,883,453	1.87%
38	927	Franchise Requirements	741	734	-0.85%
39	928	Regulatory Commission Expenses	167,900	166,574	-0.79%
40	929	(Less) Duplicate Charges - Cr.	(3,016,819)	(3,021,703)	-0.16%
41	930.1	General Advertising Expenses	2,000	2,000	0.00%
42	930.2	Miscellaneous General Expenses	314,723	3,999,519	1170.81%
43	931	Rents	142,128	140,138	-1.40%
44					
45		TOTAL Operation - Admin. & General	3,569,755	8,065,164	125.93%
46	Maintenance				
47	935	Maintenance of General Plant	47,048	48,141	2.32%
48					
49		TOTAL Administrative & General Expenses	3,616,803	8,113,305	124.32%
50					
51		TOTAL Operation & Maintenance Expenses	32,955,283	54,111,113	64.20%

Sch. 11

MONTANA TAXES OTHER THAN INCOME

Description of Tax	Last Year	This Year	% Change
Property (Ad Valorem)	1,386,808	1,497,233	7.96%
Franchise and Occupation	656	1,689	157.47%
Federal - Excise Superfund	9,293	19,558	110.45%
Utah Gross Receipts Tax	69,014	10,930	-84.16%
Washington - Operating Revenue Fee	124,623	131,754	5.72%
Washington - Pollution Control Credit	(1,284)	(1,466)	-14.15%
Montana - Energy Proceeds	2,926	6,338	116.60%
Montana - Consumer Counsel	32,013	33,014	3.13%
Other - Miscellaneous Taxes & License	(805)	40	105.02%
TOTAL MT Taxes other than Income	1,623,244	1,699,090	4.67%

Sch. 12 PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Asplundh Tree Expert	Tree trimming	5,996,648	121,552	2.0270%
2	CAMCO Construction	Const./Maint. Contracts	3,994,707	80,972	2.0270%
3	COMSYS Technical Services	Consulting	4,693,735	95,142	2.0270%
4	Deloitte & Touche	Consulting	10,233,316	207,429	2.0270%
5	General Electric Co.	Const./Maint. Contracts	17,592,825	356,607	2.0270%
6	International Line	Const./Maint. Contracts	14,969,808	303,438	2.0270%
7	Irwin Industries	Const./Maint. Contracts	4,575,255	92,740	2.0270%
8	Oracle Corporation	Consulting	3,869,260	78,430	2.0270%
9	Plant Maintenance Service	Const./Maint. Contracts	5,710,957	115,761	2.0270%
10	SAP America Inc.	Consulting	10,765,486	218,216	2.0270%
11	Stoel Rives Boley Jones & Gray	Legal	10,006,344	202,829	2.0270%
12	Sturgeon Electric Co.	Const./Maint. Contracts	10,028,721	203,282	2.0270%
13	Trees, Inc.	Tree trimming	9,452,987	191,612	2.0270%
14	Westinghouse Electric	Const./Maint. Contracts	7,815,443	158,419	2.0270%
15					
16					
17					
18					
19					
20					
21	Total		119,705,492	2,426,429	
22					
23					
24					
25					
26	Costs assignable directly to Montana:				
27	Asplundh Tree Expert	Tree trimming	374,927	374,927	
28	Harp Line Construction Co.	Const./Maint. Contracts	1,461,022	1,461,022	
29	NW Energy Efficiency	Const./Maint. Contracts	137,854	137,854	
30	S E Incorporated	Const./Maint. Contracts	93,688	93,688	
31					
32					
33					
34					
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63					
64	TOTAL Payments for Services		2,067,491	2,067,491	

Sch. 13 POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS

	Description	Total Company	Montana (1)	% Montana
2	Legislative Expense	546,711	0	0.00%
4	PacifiCorp D.C., Ltd.	193,165	0	0.00%
6	Legal and Consulting	66,970	0	0.00%
8	Other Expenditures	262,369	0	0.00%
50	TOTAL	1,069,215	0	0.00%

(1) PAC contributions are charged to account 426.4 and are not allocated to Montana for rate making purposes.

Sch. 14 PENSION COSTS

	Description	Last Year	This Year	% Change
1				
2	Plan Name: PacifiCorp Retirement Plan			
3				
4	Defined Benefit Plan: yes			
5				
6	Defined Contribution Plan: yes			
7				
8	Is the Plan overfunded?: no			
9				
10	Actuarial Cost Method: Projected Unit Credit Method			
11				
12	IRS Code: 93-0246090			
13				
14	Annual Contribution by Employer: varies by year and			
15	funding status			
16				
17	Accumulated Benefit Obligation	N/A	868,722,356	
18	Projected Benefit Obligation	1,008,983,054	1,028,878,714	1.97%
19	Fair Value of Plan Assets	669,972,791	797,603,188	
20				
21	Discount Rate for Benefit Obligations	7.25%	7.50%	3.45%
22	Expected Long-Term Return on Assets	8.75%	8.75%	0.00%
23				
24	Net Periodic Pension Cost:			
25	Service Cost	26,655,430	23,135,961	-13.20%
26	Interest Cost	71,157,521	75,028,404	5.44%
27	Return on Plan Assets	(59,114,328)	(70,712,099)	-19.62%
28	Amortization of Transition Amount	8,213,148	8,343,647	1.59%
29	Amortization of Gains or Losses	0	0	
30	Total Net Periodic Pension Cost	46,911,771	35,795,913	-23.70%
31				
32	Minimum Required Contribution	61,123,570	49,764,302	-18.58%
33	Actual Contribution	64,000,000	49,764,302	-22.24%
34	Maximum Amount Deductible	196,431,636	96,304,207	-50.97%
35	Benefit Payments	55,550,657	62,432,000	12.39%
36				
37	Montana Intrastate Costs:			
38	Pension Costs	647,644	500,809	-22.67%
39	Pension Costs Capitalized	276,321	224,774	-18.65%
40	Accumulated Pension Asset (Liability) at Year End	(2,083,422)	(1,914,163)	8.12%
41				
42	Number of Company Employees:			
43	Covered by the Plan	13,298	13,221	-0.58%
44	Not Covered by the Plan	N/A	N/A	
45	Active	8,439	8,064	-4.44%
46	Retired	3,636	3,848	5.83%
47	Deferred Vested Terminated	1,223	1,309	

Sch. 15 OTHER POST EMPLOYMENT BENEFITS (OPEBS)

	Description	Last Year	This Year	% Change
1	**General Information**			
2				
3	Assumptions:			
4	Discount Rate for Benefit Obligations	7.25%	7.50%	3.45%
5	Expected Long-Term Return on Assets	8.75%	8.75%	0.00%
6	Medical Cost Inflation Rate	8.8% to4.5%	0.0% to4.5%	
7	Actuarial Cost Method	Projected Unit	Projected Unit	
8		Credit Method	Credit Method	
9	List each method used to fund OPEBs (ie: VEBA, 401(h)):			
10	Method - Tax Advantaged (Yes or No)			
11	VEBA - Yes			
12	401(h) - Yes			
13				
14				
15				
16	Describe Changes to the Benefit Plan:			
17	Contribution requirement for retirees changed in 1997.			
18				
19				
20	**Total Company**			
21				
22	Accumulated Post Retirement Benefit Obligation (APBO)	30[illegible]	[illegible]	-2.55%
23	Fair Value of Plan Assets	95[illegible]	[illegible]	46.43%
24	List the amount funded through each funding method:			
25	VEBA	14,5[illegible]	[illegible]3,407,605	-7.74%
26	401(h)	4,5[illegible],000	1,703,946	-62.13%
27	Other _VEBA 2_____	612,664	525,449	-14.24%
28	Total amount funded	19,644,346	15,637,000	-20.40%
29				
30	List amount that was tax deductible for each type of funding:			
31	VEBA	14,531,682	13,407,605	-7.74%
32	401(h)	4,500,000	1,703,946	-62.13%
33	Other _VEBA 2_____	612,664	525,449	-14.24%
34	Total amount that was tax deductible	19,644,346	15,637,000	-20.40%
35				
36	Net Periodic Post Retirement Benefit Cost:			
37	Service Cost	6,912,404	7,181,000	3.89%
38	Interest Cost	21,838,540	21,787,000	-0.24%
39	Return on Plan Assets	(9,098,424)	(12,502,000)	
40	Amortization of Transition Obligation	13,950,713	13,951,000	0.00%
41	Amortization of Gains or Losses	(1,390,562)	(2,072,000)	
42	Total Net Periodic Post Retirement Benefit Cost	32,212,671	28,345,000	-12.01%
43				
44	Benefit Cost Expensed	22,577,861	19,563,719	-13.35%
45	Benefit Cost Capitalized	9,634,810	8,781,281	-8.86%
46	Benefit Payments (The $55 m stated last year was	10,444,000	10,760,776	3.03%
47	incorrect.)			
48	Number of Company Employees:			
49	Covered by the Plan	12,280	12,108	-1.40%
50	Not Covered by the Plan	N/A	N/A	
51	Active	9,147	8,993	-1.68%
52	Retired	3,133	3,115	-0.57%
53	Spouse/Dependants covered by the Plan	3,191	3,365	5.45%

Parenthetical?
Line 46 amount?

Sch. 15 OTHER POST EMPLOYMENT BENEFITS (OPEBS) (cont.)

	Description	Last Year	This Year	% Change
1				
2	**Montana**			
3				
4	Accumulated Post Retirement Benefit Obligation (APBO)	5,927,446	5,944,400	0.29%
5	Fair Value of Plan Assets	1,878,677	2,831,131	50.70%
6	List the amount funded through each funding method:			
7	VEBA	286,216	271,772	-5.05%
8	401(h)	88,632	34,539	-61.03%
9	Other _VEBA 2_____	12,067	10,651	
10	Total amount funded	386,915	316,962	-18.08%
11				
12	List amount that was tax deductible for each type of funding:			
13	VEBA	286,216	271,772	-5.05%
14	401(h)	88,632	34,539	-61.03%
15	Other _VEBA 2_____	12,067	10,651	
16	Total amount that was tax deductible	386,915	316,962	-18.08%
17				
18	Net Periodic Post Retirement Benefit Cost:			
19	Service Cost	136,147	145,559	6.91%
20	Interest Cost	430,132	441,622	2.67%
21	Return on Plan Assets	(179,203)	(253,416)	
22	Amortization of Transition Obligation	274,773	282,787	2.92%
23	Amortization of Gains or Losses	(27,389)	(41,999)	0.00%
24	Total Net Periodic Post Retirement Benefit Cost	634,461	574,553	-9.44%
25				
26	Benefit Cost Expensed	444,694	396,557	-10.82%
27	Benefit Cost Capitalized	189,767	177,997	-6.20%
28	Benefit Payments	205,705	218,121	6.04%
29				
30	Number of Company Employees:			
31	Covered by the Plan	N/A	N/A	
32	Not Covered by the Plan	N/A	N/A	
33	Active	N/A	N/A	
34	Retired	N/A	N/A	
35	Spouse/Dependants covered by the Plan	N/A	N/A	
36				
37	Regulatory Treatment			
38				
39	Commission authorized - most recent			
40	Docket number: N/A			
41	Order number: N/A			
42				
43	Amount recovered through rates	N/A	N/A	

Sch. 16 TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1 Bennerr, Harold L.	75,678	15,923	3,000	94,601	107,685	-12%
Excess Life						
Vehicle Allowance			2,700			
Safety Award			300			
2 Redman, James M.	77,454	13,281	2,925	93,660	89,626	5%
Excess Life						
Vehicle Allowance			2,700			
Safety Award			225			
OT/ Premium Pay						
3 Jordan, Donald M.	78,122	13,003	225	91,350	80,433	14%
Excess Life						
Safety Award			225			
4 McDonald, Michael C.	54,688	1,616	34,531	90,835	70,363	29%
Excess Life			360			
Safety Award			80			
OT/ Premium Pay			34,091			
5 Gosney, Dennis L.	55,592	1,605	30,487	87,684	69,508	26%
Excess Life						
Safety Award			125			
Relocation			30,362			
6 Leuning, Clinton E.	55,282		31,563	86,845	73,753	18%
Excess Life						
Safety Award			1,829			
OT/ Premium Pay			29,734			
7 Walker, Ervin R.	55,530	9,115	19,181	83,826	65,646	28%
Excess Life						
Safety Award			70			
Relocation			19,111			
8 Bech, Steven D.	55,574	1,670	22,815	80,059	73,429	9%
Excess Life			519			
Safety Award			125			
OT/ Premium Pay			22,171			
9 Roe, Danial J.	50,489	1,564	26,902	78,955	67,947	16%
Excess Life			349			
Safety Award			150			
OT/ Premium Pay			26,403			
10 Trebas Jr, William F.	50,265	1,519	26,489	78,273	66,046	19%
Excess Life						
Safety Award			80			
OT/ Premium Pay			26,409			

Sch. 17 COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION

	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	Frederick W. Buckman	635,004		478,870	1,113,874	1,467,600	-24%
	Restricted Stock Awards			469,848			
	Employee Stock Plan			7,500			
	Term Life Insurance Prem.			1,522			
2	Richard T. O'Brien	287,500		135,220	422,720	863,995	-51%
	Restricted Stock Awards			127,530			
	Employee Stock Plan			7,500			
	Term Life Insurance Prem.			190			
3	John A. Bohling	285,000		155,521	440,521	508,721	-13%
	Restricted Stock Awards			145,429			
	Employee Stock Plan			7,500			
	Term Life Insurance Prem.			2,592			
4	Dennis P. Steinberg	280,002		153,439	433,441	829,117	-48%
	Restricted Stock Awards			145,429			
	Employee Stock Plan			7,500			
	Term Life Insurance Prem.			510			
5	Verl R. Topham	277,500		136,267	413,767	667,452	-38%
	Restricted Stock Awards			127,530			
	Employee Stock Plan			7,500			
	Term Life Insurance Prem.			1,237			

BALANCE SHEET

		Account Title	Last Year	This Year	% Change
1		Assets and Other Debits			
2	Utility Plant				
3	101	Electric Plant in Service	11,073,799,377	11,416,666,610	3.10%
4	101.1	Property Under Capital Leases	23,575,921	23,326,905	-1.06%
5	102	Electric Plant Purchased or Sold			
6	103	Experimental Electric Plant Unclassified			
7	104	Electric Plant Leased to Others			
8	105	Electric Plant Held for Future Use	5,331,033	5,249,037	-1.54%
9	106	Completed Constr. Not Classified - Electric	28,782,514	0	-100.00%
10	107	Construction Work in Progress - Electric	249,133,885	253,751,878	1.85%
11	108	(Less) Accumulated Depreciation	(3,599,037,424)	(3,889,032,390)	-8.06%
12	111	(Less) Accumulated Amortization	(88,780,996)	(110,935,810)	-24.95%
13	114	Electric Plant Acquisition Adjustments	132,320,435	126,446,168	-4.44%
14	115	(Less) Accum. Amort. Elec. Acq. Adj.			
15	118-119	Other Utility Plant - Net	0	0	ERR
16	120	Nuclear Fuel (Net)			
17		TOTAL Utility Plant	7,825,124,745	7,825,472,398	0.00%
18					
19	Other Property & Investments				
20	121	Nonutility Property	7,160,443	79,903,363	1015.90%
21	122	(Less) Accum. Depr. & Amort. for Nonutil. Prop.	(1,062,436)	(30,465,057)	-2767.47%
22	123	Investments in Associated Companies	6,107,928	6,107,928	0.00%
23	123.1	Investments in Subsidiary Companies	1,506,260,461	2,393,746,585	58.92%
24	124	Other Investments	14,785,310	13,773,399	-6.84%
25	125	Sinking Funds			
26	128	Other Special Funds	5,205,127	6,594,009	26.68%
27		TOTAL Other Property & Investments	1,538,456,833	2,469,660,227	60.53%
28	Current & Accrued Assets				
29	131	Cash	(29,551,513)	(5,675,621)	80.79%
30	132-134	Special Deposits	50,248	0	-100.00%
31	135	Working Funds	3,359,412	2,130,882	-36.57%
32	136	Temporary Cash Investments			
33	141	Notes Receivable	758,511	786,536	3.69%
34	142	Customer Accounts Receivable	316,339,978	426,987,458	34.98%
35	143	Other Accounts Receivable	44,057,769	33,428,107	-24.13%
36	144	(Less) Accum. Provision for Uncollectible Accts.	(7,669,344)	(16,936,916)	-120.84%
37	145	Notes Receivable - Associated Companies	6,985,207	10,005,250	
38	146	Accounts Receivable - Associated Companies	9,367,093	13,444,886	43.53%
39	151	Fuel Stock	49,964,811	49,529,918	-0.87%
40	152	Fuel Stock Expenses Undistributed			
41	153	Residuals			
42	154	Plant Materials and Operating Supplies	107,233,442	109,648,940	2.25%
43	155	Merchandise			
44	156	Other Material & Supplies			
45	157	Nuclear Materials Held for Sale			
46	163	Stores Expense Undistributed	4,457,950	0	-100.00%
47	165	Prepayments	29,426,140	21,599,215	-26.60%
48	171	Interest & Dividends Receivable	1,319,855	901,572	-31.69%
49	172	Rents Receivable	290,933	475,095	63.30%
50	173	Accrued Utility Revenues	136,580,390	154,467,085	13.10%
51	174	Miscellaneous Current & Accrued Assets	306,183	369,223	
52		TOTAL Current & Accrued Assets	673,277,065	801,161,630	18.99%

BALANCE SHEET

Line	Acct.	Account Title	This Year	This Year	% Change
1					
2		Assets and Other Debits (cont.)			
3					
4		Deferred Debits			
5					
6	181	Unamortized Debt Expense	36,188,006	42,779,665	18.22%
7	182.1	Extraordinary Property Losses			ERR
8	182.2	Unrecovered Plant & Regulatory Study Costs	26,850,724	22,971,771	-14.45%
9	182.3	Regulatory Asset	1,018,072,234	871,122,504	-14.43%
10	183	Prelim. Survey & Investigation Charges	3,242,666	1,831,480	-43.52%
11	184	Clearing Accounts			
12	185	Temporary Facilities	337,012	203,783	-39.53%
13	186	Miscellaneous Deferred Debits	94,074,145	91,536,603	-2.70%
14	187	Deferred Losses from Disposition of Util. Plant			
15	188	Research, Devel. & Demonstration Expend.			
16	189	Unamortized Loss on Reacquired Debt	68,415,542	60,616,543	-11.40%
17	190	Accumulated Deferred Income Taxes	76,728,727	117,072,212	52.58%
18		TOTAL Deferred Debits	1,323,909,056	1,208,134,561	-8.74%
19					
20		TOTAL Assets & Other Debits	11,360,767,699	12,304,428,816	8.31%

Line	Acct.	Account Title	This Year	This Year	% Change
21					
22		Liabilities and Other Credits			
23					
24		Proprietary Capital			
25					
26	201	Common Stock Issued	3,303,415,102	3,340,585,746	1.13%
27	202	Common Stock Subscribed			
28	204	Preferred Stock Issued	313,538,225	241,364,150	-23.02%
29	205	Preferred Stock Subscribed			
30	207	Premium on Capital Stock			
31	211	Miscellaneous Paid-In Capital			
32	212	Installments Received on Capital Stock	(144,324)	89,048	161.70%
33	213	(Less) Discount on Capital Stock			
34	214	(Less) Capital Stock Expense	(45,357,896)	(45,170,539)	0.41%
35	215	Appropriated Retained Earnings	3,044,555	3,575,811	17.45%
36	216	Unappropriated Retained Earnings	767,981,311	1,072,617,698	39.67%
37	217	(Less) Reacquired Capital Stock	(7,469,432)	(8,148,231)	-9.09%
38		TOTAL Proprietary Capital	4,335,007,541	4,604,913,683	6.23%
39					
40		Long Term Debt			
41					
42	221	Bonds	3,162,024,495	3,261,514,726	3.15%
43	222	(Less) Reacquired Bonds			
44	223	Advances from Associated Companies	276,185,605	430,561,880	55.90%
45	224	Other Long Term Debt	175,825,925	175,825,925	0.00%
46	225	Unamortized Premium on Long Term Debt	6,511,526	4,527,076	-30.48%
47	226	(Less) Unamort. Discount on L-Term Debt-Dr.	(1,913,536)	(2,705,176)	-41.37%
48		TOTAL Long Term Debt	3,618,634,015	3,869,724,431	6.94%

Account	BALANCE SHEET Account Title	Last Year	This Year	% Change
	Total Liabilities and Other Credits (cont.)			
	Other Noncurrent Liabilities			
227	Obligations Under Cap. Leases - Noncurrent	23,309,486	23,085,597	-0.96%
228.1	Accumulated Provision for Property Insurance	22,304	156,767	602.86%
228.2	Accumulated Provision for Injuries & Damages	5,903,779	4,634,140	-21.51%
228.3	Accumulated Provision for Pensions & Benefits	108,201,383	97,078,227	-10.28%
228.4	Accumulated Misc. Operating Provisions	14,774,085	13,993,079	-5.29%
229	Accumulated Provision for Rate Refunds			
	TOTAL Other Noncurrent Liabilities	152,211,037	138,947,810	-8.71%
	Current & Accrued Liabilities			
231	Notes Payable	675,007,000	303,179,000	-55.09%
232	Accounts Payable	293,668,806	401,934,797	36.87%
233	Notes Payable to Associated Companies	30,954,961	746,522,352	2311.64%
234	Accounts Payable to Associated Companies	10,059,514	10,707,233	6.44%
235	Customer Deposits	4,623,856	3,961,964	-14.31%
236	Taxes Accrued	75,298,250	81,806,898	8.64%
237	Interest Accrued	70,820,660	78,232,320	10.47%
238	Dividends Declared	86,336,660	85,238,635	-1.27%
239	Matured Long Term Debt			
240	Matured Interest			
241	Tax Collections Payable	7,833,896	7,104,569	-9.31%
242	Miscellaneous Current & Accrued Liabilities	37,009,949	38,008,752	2.70%
243	Obligations Under Capital Leases - Current	266,435	241,308	-9.43%
	TOTAL Current & Accrued Liabilities	1,291,879,987	1,756,937,828	36.00%
	Deferred Credits			
252	Customer Advances for Construction	16,781,741	18,198,806	8.44%
253	Other Deferred Credits	144,238,426	165,920,523	15.03%
254	Regulatory Liabilities	57,115,816	53,959,061	-5.53%
255	Accumulated Deferred Investment Tax Credit	141,265,333	133,261,629	-5.67%
256	Deferred Gains from Disposition Of Util. Plant			
257	Unamortized Gain on Reacquired Debt	2,279,025	1,862,353	-18.28%
281-283	Accumulated Deferred Income Taxes	1,601,354,778	1,560,702,692	-2.54%
	TOTAL Deferred Credits	1,963,035,119	1,933,905,064	-1.48%
	TOTAL Liabilities & Other Credits	11,360,767,699	12,304,428,816	8.31%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Account Number & Title		Last Year	This Year	% Change
	Intangible Plant			
301	Organization	441,908	441,908	0.00%
302	Franchises & Consents	90,214	254,169	181.74%
303	Miscellaneous Intangible Plant	3,471,286	4,375,856	26.06%
	TOTAL Intangible Plant	4,003,408	5,071,934	26.69%
	Production Plant			
Steam Production				
310	Land & Land Rights	942,735	1,009,369	7.07%
311	Structures & Improvements	11,219,407	12,024,023	7.17%
312	Boiler Plant Equipment	41,261,545	43,199,871	4.70%
313	Engines & Engine Driven Generators	0	0	
314	Turbogenerator Units	10,418,553	11,462,245	10.02%
315	Accessory Electric Equipment	5,021,418	5,008,106	-0.27%
316	Miscellaneous Power Plant Equipment	657,295	503,332	-23.42%
	TOTAL Steam Production Plant	69,520,954	73,206,946	5.30%
Nuclear Production				
320	Land & Land Rights	0	0	
321	Structures & Improvements	0	0	
322	Reactor Plant Equipment	0	0	
323	Turbogenerator Units	0	0	
324	Accessory Electric Equipment	0	0	
325	Miscellaneous Power Plant Equipment	0	0	
	TOTAL Nuclear Production Plant	0	0	
Hydraulic Production				
330	Land & Land Rights	420,087	440,488	4.86%
331	Structures & Improvements	1,936,397	1,584,094	-18.19%
332	Reservoirs, Dams & Waterways	6,415,334	6,806,204	6.09%
333	Water Wheels, Turbines & Generators	1,631,251	1,662,013	1.89%
334	Accessory Electric Equipment	488,933	472,269	-3.41%
335	Miscellaneous Power Plant Equipment	71,361	83,230	16.63%
336	Roads, Railroads & Bridges	283,045	246,139	-13.04%
	TOTAL Hydraulic Production	11,246,409	11,294,438	0.43%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Account Number & Title		Last Year	This Year	% Change
	Production Plant (cont.)			
Other Production				
340	Land & Land Rights	17,151	17,313	0.95%
341	Structures & Improvements	258,268	281,996	9.19%
342	Fuel Holders, Producers & Accessories	516	640	24.17%
343	Prime Movers	4,337	4,816	11.05%
344	Generators	2,620,510	2,673,649	2.03%
345	Accessory Electric Equipment	166,700	237,867	42.69%
346	Miscellaneous Power Plant Equipment	9,649	14,189	47.05%
	TOTAL Other Production Plant	3,077,130	3,230,469	4.98%
	TOTAL Production Plant	83,844,493	87,731,853	4.64%
	Transmission Plant			
350	Land & Land Rights	1,015,578	1,052,086	3.59%
352	Structures & Improvements	523,149	612,313	17.04%
353	Station Equipment	11,665,492	12,164,119	4.27%
354	Towers & Fixtures	6,222,388	6,478,066	4.11%
355	Poles & Fixtures	5,360,650	5,861,380	9.34%
356	Overhead Conductors & Devices	10,127,333	10,684,119	5.50%
357	Underground Conduit	258	350	35.27%
358	Underground Conductors & Devices	1,008	1,148	13.86%
359	Roads & Trails	223,336	237,773	6.46%
	TOTAL Transmission Plant	35,139,192	37,091,355	5.56%
	Distribution Plant			
360	Land & Land Rights	217,981	193,796	-11.10%
361	Structures & Improvements	695,645	945,156	35.87%
362	Station Equipment	12,462,123	12,374,423	-0.70%
363	Storage Battery Equipment	0	0	
364	Poles, Towers & Fixtures	13,323,050	15,885,339	19.23%
365	Overhead Conductors & Devices	11,733,516	13,080,314	11.48%
366	Underground Conduit	4,016,256	4,465,853	11.19%
367	Underground Conductors & Devices	4,686,778	5,634,662	20.22%
368	Line Transformers	16,347,514	16,814,678	2.86%
369	Services	8,372,093	9,169,297	9.52%
370	Meters	2,923,319	3,151,036	7.79%
371	Installations on Customers' Premises	166,583	166,201	-0.23%
372	Leased Property on Customers' Premises	0	0	
373	Street Lighting & Signal Systems	677,493	738,399	8.99%
	TOTAL Distribution Plant	75,622,351	82,619,154	9.25%

		Account Number & Title	Last Year	This Year	% Change
1		General Plant			
2					
3	389	Land & Land Rights	139,954	166,362	18.87%
4	390	Structures & Improvements	2,586,916	2,905,275	12.31%
5	391	Office Furniture & Equipment	1,746,481	2,075,636	18.85%
6	392	Transportation Equipment	733,296	949,103	29.43%
7	393	Stores Equipment	88,796	92,194	3.83%
8	394	Tools, Shop & Garage Equipment	703,169	792,898	12.76%
9	395	Laboratory Equipment	708,018	540,526	-23.66%
10	396	Power Operated Equipment	1,557,988	1,842,652	18.27%
11	397	Communication Equipment	1,673,971	1,885,883	12.66%
12	398	Miscellaneous Equipment	52,490	65,710	25.19%
13	399	Other Tangible Property	8,170,281	9,222,707	12.88%
14					
15		TOTAL General Plant	18,161,360	20,538,947	13.09%
16					
17		TOTAL Unclassified Plant	2,155,353	(53)	-100.00%
18					
19		TOTAL Electric Plant in Service	218,926,157	233,053,190	6.45%

Sch. 20 MONTANA DEPRECIATION SUMMARY

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	Accumulated Depreciation This Year Bal.	Current Avg. Rate
1					
2	Steam Production		28,004,646	30,475,493	2.45%
3	Nuclear Production		0	0	0.00%
4	Hydraulic Production		3,896,505	4,254,615	1.85%
5	Other Production		66,113	216,148	3.08%
6	Transmission		10,609,158	11,660,519	2.36%
7	Distribution		18,898,448	21,366,470	3.16%
8	General		5,778,238	7,506,619	5.83%
9	TOTAL		67,253,108	75,479,865	

Sch. 21 MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

		Account	Last Year Bal.	This Year Bal.	%Change
1					
2	151	Fuel Stock	905,972	1,014,336	11.96%
3	152	Fuel Stock Expenses Undistributed			
4	153	Residuals			
5	154	Plant Materials & Operating Supplies:			
6		Assigned to Construction (Estimated)			
7		Assigned to Operations & Maintenance			
8		Production Plant (Estimated)	1,324,526	1,303,941	-1.55%
9		Transmission Plant (Estimated)	180,009	196,780	9.32%
10		Distribution Plant (Estimated)	364,572	323,652	-11.22%
11		Assigned to Other	82,516	179,423	117.44%
12	155	Merchandise			
13	156	Other Materials & Supplies			
14	157	Nuclear Materials Held for Sale			
15	163	Stores Expense Undistributed	87,805	75,006	-14.58%
16					
17		TOTAL Materials & Supplies	2,945,400	3,093,138	5.02%

Sch. 22 MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

	Commission Accepted - Most Recent		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	89.6.17			
2	Order Number	5432			
3					
4	Common Equity		35.20%	12.30%	4.33%
5	Preferred Stock		7.60%	8.35%	0.63%
6	Long Term Debt		57.20%	8.45%	4.83%
7	Other		0.00%	0.00%	0.00%
8	TOTAL		100.00%		9.80%
9					
10	Actual at Year End				
11					
12	Common Equity		47.00%	12.30%	5.78%
13	Preferred Stock		6.00%	7.52%	0.45%
14	Long Term Debt		47.00%	6.02%	2.83%
15	Other		0.00%	0.00%	0.00%
16	TOTAL		100.00%		9.06%

Sch. 23 **STATEMENT OF CASH FLOWS**

Line	Description	This year	Last Year	% Change
1				
2	**Increase/(decrease) in Cash & Cash Equivalents:**			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	645,442,443	504,367,619	27.97%
6	Depreciation	360,510,615	312,878,983	15.22%
7	Amortization	44,006,653	30,516,067	44.21%
8	Deferred Income Taxes - Net	(67,692,795)	45,162,035	-249.89%
9	Investment Tax Credit Adjustments - Net	(8,003,704)	(8,991,006)	10.98%
10	Change in Operating Receivables - Net	(104,681,713)	(113,393,081)	7.68%
11	Change in Materials, Supplies & Inventories - Net	2,477,345	23,985,675	-89.67%
12	Change in Operating Payables & Accrued Liabilities - Net	115,351,477	67,901,273	69.88%
13	Allowance for Funds Used During Construction (AFUDC)			
14	Change in Other Assets & Liabilities - Net	162,109,025	(65,541,905)	347.34%
15	Other Operating Activities	(474,641,714)	(133,124,720)	-256.54%
16	Net Cash Provided by/(Used in) Operating Activities	674,877,632	663,760,940	1.67%
17				
18	Cash Inflows/Outflows From Investment Activities:			
19	Construction/Acquisition of Property, Plant and Equipment			
20	(net of AFUDC & Capital Lease Related Acquisitions)	(479,431,681)	(590,528,660)	18.81%
21	Acquisition of Other Noncurrent Assets			
22	Proceeds from Disposal of Noncurrent Assets	1,604,500	9,711,668	-83.48%
23	Investments In and Advances to Affiliates	(398,767,784)	(7,405,905)	-5284.46%
24	Contributions and Advances from Affiliates			
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)	15,989,060	6,444,060	148.12%
27	Net Cash Provided by/(Used in) Investing Activities	(860,605,905)	(581,778,837)	-47.93%
28				
29	Cash Flows from Financing Activities:			
30	Proceeds from Issuance of:			
31	Long-Term Debt	692,234,056	202,120,401	242.49%
32	Preferred Stock			
33	Common Stock	37,166,847	221,281,746	-83.20%
34	Other: Intercompany Borrowings	866,923,624	260,620,351	232.64%
35	Net Increase in Short-Term Debt			
36	Other:			
37	Payment for Retirement of:			
38	Long-Term Debt	(602,130,588)	(207,702,595)	-189.90%
39	Preferred Stock	(72,174,075)	(216,996,300)	66.74%
40	Common Stock	(678,800)	(2,303,888)	70.54%
41	Other: Redemption Premium/Intercompany Borrowing	(6,006)	(5,161,939)	99.88%
42	Net Decrease in Short-Term Debt	(371,828,000)	(6,887,000)	
43	Dividends on Preferred Stock	(21,461,423)	(31,448,754)	31.76%
44	Dividends on Common Stock	(319,720,248)	(314,971,082)	-1.51%
45	Other Financing Activities (explained on attached page)			
46	Net Cash Provided by (Used in) Financing Activities	208,325,387	(101,449,060)	305.35%
47				
48	Net Increase/(Decrease) in Cash and Cash Equivalents	22,597,114	(19,466,957)	216.08%
49	Cash and Cash Equivalents at Beginning of Year	(26,141,853)	(6,674,896)	-291.64%
50	Cash and Cash Equivalents at End of Year	(3,544,739)	(26,141,853)	86.44%

Sch. 24

LONG TERM DEBT

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1									
2	FIRST MORTGAGE BONDS:								
3	6-3/4% Series due 4/1/05	04/01/93	04/01/2005	150,000,000	144,118,206	150,000,000	7.24%	10,615,150	7.08%
4	8.271% Series due 10/1/10	04/15/92	10/01/2010	48,972,000	41,772,000	40,080,000	8.27%	3,315,017	8.27%
5	7.978% Series due 10/1/11	04/15/92	10/01/2011	4,422,000	3,794,000	3,654,000	7.98%	291,516	7.98%
6	8.493% Series due 10/1/12	04/15/92	10/01/2012	19,772,000	17,382,000	16,832,000	8.49%	1,429,542	8.49%
7	8.797% Series due 10/1/13	04/15/92	10/01/2013	16,203,000	14,457,000	14,059,000	8.80%	1,236,770	8.80%
8	8.734% Series due 10/1/14	04/15/92	10/01/2014	28,218,000	25,429,000	24,797,000	8.73%	2,165,770	8.73%
9	8.294% Series due 10/1/15	04/15/92	10/01/2015	46,946,000	42,510,000	41,516,000	8.29%	3,443,337	8.29%
10	8.635% Series due 10/1/16	04/15/92	10/01/2016	18,750,000	17,176,000	16,827,000	8.63%	1,453,011	8.64%
11	8.470% Series due 10/1/17	04/15/92	10/01/2017	19,609,000	18,069,000	17,730,000	8.47%	1,501,731	8.47%
12									
13	Total First Mortgage Bonds			$352,892,000	$324,707,206	$325,495,000		$25,451,844	7.82%
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									
32									

Sch. 24

LONG TERM DEBT

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1	8.75% Ser. B due 2/12/98	02/12/91	02/12/98	$15,000,000	$14,873,027	$15,000,000	8.92%	$1,330,637	8.87%
2	8.75% Ser. B due 2/12/98	02/12/91	02/12/98	15,000,000	14,873,027	15,000,000	8.92%	1,330,637	8.87%
3	8.75% Ser. B due 2/12/98	02/12/91	02/12/98	15,000,000	14,880,527	15,000,000	8.91%	1,329,566	8.86%
4	8.75% Ser. A due 2/12/98	02/12/91	02/12/98	10,000,000	9,915,352	10,000,000	8.92%	887,091	8.87%
5	8.75% Ser. A due 2/12/98	02/12/91	02/12/98	5,000,000	4,957,676	5,000,000	8.92%	443,546	8.87%
6	8.81% Ser. C due 3/5/98	08/05/91	03/05/98	7,000,000	6,948,089	7,000,000	8.96%	624,587	8.92%
7	8.94% Ser. A due 6/25/98	06/25/91	06/25/98	15,000,000	14,909,658	15,000,000	9.06%	1,353,905	9.03%
8	8.95% Ser. A due 6/30/98	06/26/91	06/30/98	20,000,000	19,879,544	20,000,000	9.07%	1,807,179	9.04%
9	8.95% Ser. A due 6/30/98	06/26/91	06/30/98	5,000,000	4,972,386	5,000,000	9.06%	451,438	9.03%
10	8.90% Ser. C due 6/30/98	06/27/91	06/30/98	25,000,000	24,802,102	25,000,000	9.06%	2,253,235	9.01%
11	8.96% Ser. A due 7/3/98	07/03/91	07/03/98	8,000,000	7,951,860	8,000,000	9.08%	723,676	9.05%
12	8.94% Ser. C due 7/6/98	07/05/91	07/06/98	5,000,000	4,960,420	5,000,000	9.10%	452,652	9.05%
13	8.89% Ser. C due 7/20/98	07/19/91	07/20/98	5,000,000	4,960,420	5,000,000	9.04%	450,152	9.00%
14	8.82% Ser. C due 8/3/98	08/02/91	08/03/98	5,000,000	4,960,420	5,000,000	8.97%	446,652	8.93%
15	8.83% Ser. C due 9/1/98	08/06/91	09/01/98	18,000,000	17,857,513	18,000,000	8.98%	1,609,548	8.94%
16	8.83% Ser. C due 9/1/98	08/06/91	09/01/98	4,000,000	3,968,336	4,000,000	8.98%	357,677	8.94%
17	8.83% Ser. C due 9/1/98	08/06/91	09/01/98	4,000,000	3,968,336	4,000,000	8.98%	357,677	8.94%
18	8.83% Ser. C due 9/1/98	08/06/91	09/01/98	4,000,000	3,970,336	4,000,000	8.97%	357,395	8.93%
19	7.45% Ser. D due 1/22/99	01/31/92	01/22/99	5,000,000	4,574,389	5,000,000	9.13%	433,510	8.67%
20	7.45% Ser. D due 1/22/99	01/31/92	01/22/99	10,000,000	8,548,779	10,000,000	10.43%	953,029	9.53%
21	7.35% Ser. D due 2/1/99	01/31/92	02/01/99	4,000,000	3,419,512	4,000,000	10.31%	376,886	9.42%
22	7.45% Ser. D due 2/4/99	02/14/92	02/04/99	20,000,000	18,828,651	20,000,000	8.58%	1,657,976	8.29%
23	7.46% Ser. D due 2/15/99	02/14/92	02/15/99	10,000,000	8,414,326	10,000,000	10.74%	972,414	9.72%
24	7.40% Ser. D due 2/15/99	02/14/92	02/15/99	5,000,000	4,707,163	5,000,000	8.53%	411,813	8.24%
25	7.40% Ser. D due 2/15/99	02/14/92	02/15/99	5,000,000	4,707,163	5,000,000	8.53%	411,813	8.24%
26	7.50% Ser. D due 2/15/99	02/14/92	02/15/99	5,000,000	4,707,163	5,000,000	8.63%	416,813	8.34%
27	7.49% Ser. D due 2/15/99	02/14/92	02/15/99	30,000,000	27,942,981	30,000,000	8.82%	2,540,716	8.47%
28	7.45% Ser. D due 2/15/99	02/14/92	02/15/99	20,000,000	18,728,651	20,000,000	8.68%	1,671,533	8.36%
29	7.54% Ser. D due 2/15/99	02/14/92	02/15/99	15,000,000	13,121,489	15,000,000	10.08%	1,399,228	9.33%
30	9-1/2% Ser. A due 5/20/99	05/19/89	05/20/99	60,000,000	59,177,495	60,000,000	9.72%	5,782,239	9.64%
31	9.48% Ser. A due 5/25/99	05/25/89	05/25/99	15,000,000	14,869,277	15,000,000	9.62%	1,435,074	9.57%
32	9-1/2% Ser. A due 6/1/99	05/25/89	06/01/99	15,000,000	14,794,374	15,000,000	9.72%	1,445,526	9.64%

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	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1	9-1/2% Ser. A due 6/1/99	05/25/89	06/01/99	$15,000,000	$14,930,177	$15,000,000	9.57%	$1,431,970	9.55%
2	9.40% Ser. A due 6/1/99	05/26/89	06/01/99	15,000,000	14,798,124	15,000,000	9.61%	1,430,157	9.53%
3	8.55% Ser. A due 8/10/99	08/04/89	08/10/99	2,000,000	1,982,570	2,000,000	8.68%	172,740	8.64%
4	8.59% Ser. A due 9/1/99	08/03/89	09/01/99	10,000,000	9,915,352	10,000,000	8.72%	867,399	8.67%
5	6.51% Ser. E due 9/23/99	09/23/92	09/23/99	15,000,000	13,195,463	15,000,000	8.85%	1,234,367	8.23%
6	6.54% Ser. E due 9/27/99	09/25/92	09/27/99	5,000,000	4,398,488	5,000,000	8.88%	412,888	8.26%
7	6.53% Ser. E due 9/27/99	09/25/92	09/27/99	5,000,000	4,398,488	5,000,000	8.87%	412,388	8.25%
8	6.55% Ser. E due 9/28/99	09/28/92	09/28/99	1,200,000	1,055,637	1,200,000	8.90%	99,229	8.27%
9	7.21% Ser. E due 1/19/00	01/19/93	01/19/2000	25,000,000	23,168,715	25,000,000	8.63%	2,064,189	8.26%
10	7.11% Ser. E due 1/20/00	01/20/93	01/20/2000	10,000,000	9,267,486	10,000,000	8.52%	815,676	8.16%
11	7.13% Ser. E due 1/20/00	01/20/93	01/20/2000	10,000,000	9,267,486	10,000,000	8.54%	817,676	8.18%
12	7.07% Ser. E due 1/25/00	01/22/93	01/25/2000	10,500,000	9,730,860	10,500,000	8.48%	852,131	8.12%
13	6.99% Ser. E due 1/25/00	01/25/93	01/25/2000	10,000,000	9,692,579	10,000,000	7.56%	742,930	7.43%
14	6.97% Ser. E due 1/28/00	01/28/93	01/28/2000	1,000,000	971,670	1,000,000	7.50%	73,748	7.37%
15	5.85% Ser. F due 4/17/00	08/02/93	04/17/2000	3,000,000	2,817,905	3,000,000	7.00%	202,647	6.75%
16	5.85% Ser. F due 4/17/00	08/02/93	04/17/2000	3,000,000	2,817,905	3,000,000	7.00%	202,647	6.75%
17	5.85% Ser. F due 4/17/00	08/02/93	04/17/2000	5,000,000	4,696,507	5,000,000	7.00%	337,745	6.75%
18	5.85% Ser. F due 4/17/00	08/02/93	04/17/2000	5,000,000	4,696,507	5,000,000	7.00%	337,745	6.75%
19	6.05% Ser. F due 4/17/00	08/13/93	04/17/2000	15,000,000	14,089,522	15,000,000	7.21%	1,043,848	6.96%
20	6.05% Ser. F due 4/17/00	08/13/93	04/17/2000	15,000,000	14,089,522	15,000,000	7.21%	1,043,848	6.96%
21	6.05% Ser. F due 4/17/00	08/13/93	04/17/2000	25,000,000	24,170,621	25,000,000	6.67%	1,636,703	6.55%
22	6.05% Ser. F due 4/17/00	08/13/93	04/17/2000	5,000,000	4,874,722	5,000,000	6.52%	321,261	6.43%
23	6.86% Ser. E due 9/11/00	09/10/92	09/11/2000	10,000,000	8,796,975	10,000,000	9.00%	836,327	8.36%
24	6.55% Ser. E due 9/15/00	09/16/92	09/15/2000	5,000,000	4,398,488	5,000,000	8.67%	402,715	8.05%
25	8.90% Ser. B due 2/15/01	02/12/91	02/15/2001	20,000,000	19,825,703	20,000,000	9.03%	1,797,413	8.99%
26	8.90% Ser. B due 2/15/01	02/12/91	02/15/2001	20,000,000	19,830,703	20,000,000	9.03%	1,796,913	8.98%
27	8.88% Ser. B due 2/15/01	02/12/91	02/15/2001	20,000,000	19,825,703	20,000,000	9.01%	1,793,413	8.97%
28	8.90% Ser. B due 2/15/01	02/13/91	02/15/2001	20,000,000	19,825,703	20,000,000	9.03%	1,797,418	8.99%
29	9.10% Ser. A due 3/1/01	06/25/91	03/01/2001	5,000,000	4,969,886	5,000,000	9.19%	458,110	9.16%
30	6.02% Ser. F due 5/15/01	07/27/93	05/15/2001	4,500,000	4,224,607	4,500,000	7.05%	306,206	6.80%
31	9.12% Ser. C due 7/5/01	07/05/91	07/05/2001	5,000,000	4,959,170	5,000,000	9.25%	460,082	9.20%
32	9.12% Ser. C due 7/5/01	07/05/91	07/05/2001	10,000,000	9,918,341	10,000,000	9.25%	920,165	9.20%

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	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1	9.06% Ser. B due 7/9/01	07/09/91	07/09/2001	$1,000,000	$993,982	$1,000,000	9.15%	$91,202	9.12%
2	9.15% Ser. C due 7/16/01	07/16/91	07/16/2001	3,000,000	2,975,502	3,000,000	9.28%	276,949	9.23%
3	9.17% Ser. B due 7/17/01	07/17/91	07/17/2001	1,000,000	993,732	1,000,000	9.27%	92,327	9.23%
4	9.06% Ser. C due 7/23/01	07/23/91	07/23/2001	1,000,000	991,834	1,000,000	9.19%	91,416	9.14%
5	9.09% Ser. C due 7/24/01	07/24/91	07/24/2001	1,000,000	991,834	1,000,000	9.22%	91,716	9.17%
6	9.10% Ser. C due 7/30/01	07/30/91	07/30/2001	5,000,000	4,959,170	5,000,000	9.23%	459,082	9.18%
7	7.50% Ser. E due 8/1/01	11/06/92	08/01/2001	2,000,000	1,853,064	2,000,000	8.72%	166,824	8.34%
8	8.99% Ser. C due 8/7/01	08/07/91	08/07/2001	3,000,000	2,975,502	3,000,000	9.12%	272,149	9.07%
9	9.00% Ser. C due 8/8/01	08/08/91	08/08/2001	500,000	495,917	500,000	9.13%	45,408	9.08%
10	9.00% Ser. B due 8/8/01	08/08/91	08/08/2001	2,500,000	2,484,331	2,500,000	9.10%	226,567	9.06%
11	7.20% Ser. D due 8/15/02	08/14/92	08/15/2002	12,000,000	11,318,967	12,000,000	8.04%	932,094	7.77%
12	7.20% Ser. D due 8/15/02	08/14/92	08/15/2002	6,500,000	6,131,108	6,500,000	8.04%	504,884	7.77%
13	7.20% Ser. D due 8/15/02	08/14/92	08/15/2002	10,000,000	9,432,473	10,000,000	8.04%	776,745	7.77%
14	7.20% Ser. D due 8/15/02	08/14/92	08/15/2002	6,000,000	5,659,483	6,000,000	8.04%	466,047	7.77%
15	7.18% Ser. D due 8/15/02	08/14/92	08/15/2002	10,000,000	9,432,473	10,000,000	8.02%	774,745	7.75%
16	7.18% Ser. D due 8/15/02	08/14/92	08/15/2002	3,500,000	3,301,365	3,500,000	8.02%	271,161	7.75%
17	7.12% Ser. D due 8/15/02	08/14/92	08/15/2002	4,000,000	3,772,989	4,000,000	7.95%	307,498	7.69%
18	7.25% Ser. E due 9/9/02	09/08/92	09/09/2002	20,000,000	18,842,236	20,000,000	8.11%	1,565,761	7.83%
19	7.25% Ser. E due 9/9/02	09/04/92	09/09/2002	20,000,000	17,591,269	20,000,000	9.11%	1,690,577	8.45%
20	7.21% Ser. E due 9/9/02	09/09/92	09/09/2002	10,000,000	8,794,475	10,000,000	9.07%	841,569	8.42%
21	7.14% Ser. E due 9/10/02	09/10/92	09/10/2002	1,500,000	1,319,171	1,500,000	8.99%	125,185	8.35%
22	6.98% Ser. E due 9/16/02	09/15/92	09/16/2002	10,000,000	8,794,475	10,000,000	8.82%	818,536	8.19%
23	6.97% Ser. E due 9/16/02	09/15/92	09/16/2002	2,000,000	1,758,895	2,000,000	8.81%	163,507	8.18%
24	6.95% Ser. E due 9/16/02	09/16/92	09/16/2002	10,000,000	8,794,475	10,000,000	8.79%	815,569	8.16%
25	7.00% Ser. E due 9/17/02	09/17/92	09/17/2002	1,000,000	879,448	1,000,000	8.84%	82,057	8.21%
26	6.97% Ser. E due 9/23/02	09/21/92	09/23/2002	1,500,000	1,319,171	1,500,000	8.81%	122,625	8.18%
27	7.40% Ser. E due 1/22/03	01/22/93	01/22/2003	1,000,000	926,499	1,000,000	8.51%	81,351	8.14%
28	7.36% Ser. E due 1/27/03	01/26/93	01/27/2003	3,000,000	2,914,260	3,000,000	7.78%	229,373	7.65%
29	6.34% Ser. F due 7/28/03	07/28/93	07/28/2003	19,000,000	17,832,478	19,000,000	7.21%	1,321,368	6.95%
30	6.34% Ser. F due 7/28/03	07/28/93	07/28/2003	4,000,000	3,754,206	4,000,000	7.21%	278,183	6.95%
31	6.34% Ser. F due 7/28/03	07/28/93	07/28/2003	2,000,000	1,877,103	2,000,000	7.21%	139,091	6.95%
32	6.34% Ser. F due 7/28/03	07/28/93	07/28/2003	2,000,000	1,877,103	2,000,000	7.21%	139,091	6.95%

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LONG TERM DEBT

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1	6.34% Ser. F due 7/28/03	07/21/93	07/28/2003	$10,000,000	$9,385,515	$10,000,000	7.21%	$695,339	6.95%
2	6.31% Ser. F due 7/28/03	07/28/93	07/28/2003	6,000,000	5,631,308	6,000,000	7.18%	415,474	6.92%
3	6.31% Ser. F due 7/28/03	07/28/93	07/28/2003	18,000,000	16,893,926	18,000,000	7.18%	1,246,423	6.92%
4	6.31% Ser. F due 7/28/03	07/28/93	07/28/2003	18,000,000	16,893,926	18,000,000	7.18%	1,246,423	6.92%
5	6.31% Ser. F due 7/28/03	07/28/93	07/28/2003	1,000,000	938,552	1,000,000	7.18%	69,246	6.92%
6	9.00% Ser. C due 9/1/03	06/10/91	09/01/2003	55,226,000	29,720,726	25,344,380	6.89%	4,366,933	17.23%
7	7.03% Ser. E due 10/15/03	10/15/92	10/15/2003	5,000,000	4,630,369	5,000,000	8.06%	385,109	7.70%
8	7.27% Ser. E due 10/21/03	10/21/92	10/21/2003	2,000,000	1,852,147	2,000,000	8.31%	158,844	7.94%
9	7.39% Ser. E due 10/21/03	10/21/92	10/21/2003	5,000,000	4,630,369	5,000,000	8.43%	403,109	8.06%
10	7.30% Ser. E due 10/22/03	10/22/92	10/22/2003	2,000,000	1,852,147	2,000,000	8.34%	159,444	7.97%
11	7.86% Ser. D due 2/16/04	02/14/92	02/16/2004	2,500,000	2,136,570	2,500,000	9.96%	226,772	9.07%
12	7.81% Ser. D due 2/16/04	02/14/92	02/16/2004	20,000,000	17,245,673	20,000,000	9.78%	1,791,423	8.96%
13	7.79% Ser. D due 2/16/04	02/14/92	02/16/2004	6,000,000	5,647,095	6,000,000	8.58%	496,795	8.28%
14	7.75% Ser. D due 2/16/04	02/14/92	02/16/2004	3,000,000	2,823,548	3,000,000	8.54%	247,198	8.24%
15	6.75% Ser. H due 7/15/04	07/15/97	07/15/2004	175,000,000	171,821,174	175,000,000	7.08%	12,266,574	7.01%
16									
17	7.32% Ser. E due 9/3/04	09/04/92	09/03/2004	7,500,000	7,065,838	7,500,000	8.08%	585,188	7.80%
18	7.11% Ser. E due 9/24/04	09/24/92	09/24/2004	6,500,000	5,716,409	6,500,000	8.75%	527,449	8.11%
19	7.30% Ser. E due 10/22/04	10/22/92	10/22/2004	10,000,000	9,260,737	10,000,000	8.28%	791,605	7.92%
20	7.30% Ser. E due 10/22/04	10/22/92	10/22/2004	10,000,000	9,260,737	10,000,000	8.28%	791,605	7.92%
21	7.66% Ser. E due 10/22/04	11/06/92	10/22/2004	5,000,000	4,631,411	5,000,000	8.66%	413,821	8.28%
22	7.53% Ser. E due 10/26/04	10/26/92	10/26/2004	750,000	694,555	750,000	8.53%	61,095	8.15%
23	7.71% Ser. E due 10/27/04	10/27/92	10/27/2004	3,000,000	2,778,221	3,000,000	8.72%	249,782	8.33%
24	7.71% Ser. E due 10/27/04	10/27/92	10/27/2004	3,250,000	3,009,740	3,250,000	8.72%	270,597	8.33%
25	7.60% Ser. E due 11/1/04	11/06/92	11/01/2004	1,000,000	926,282	1,000,000	8.60%	82,150	8.22%
26	7.72% Ser. E due 11/2/04	11/02/92	11/02/2004	1,500,000	1,389,423	1,500,000	8.72%	125,015	8.33%
27	7.43% Ser. E due 1/24/05	01/22/93	01/24/2005	1,000,000	926,499	1,000,000	8.41%	80,422	8.04%
28	7.43% Ser. E due 1/24/05	01/22/93	01/24/2005	2,500,000	2,316,247	2,500,000	8.41%	201,056	8.04%
29	7.34% Ser. E due 10/17/05	10/15/92	10/17/2005	5,000,000	4,630,369	5,000,000	8.28%	395,423	7.91%
30	7.36% Ser. E due 10/17/05	10/15/92	10/17/2005	5,000,000	4,630,369	5,000,000	8.30%	396,423	7.93%
31	6.12% Ser. G due 1/15/06	01/22/96	01/15/2006	100,000,000	96,289,728	100,000,000	6.63%	6,491,689	6.49%
32	7.67% Ser. C due 1/10/07	01/10/92	01/10/2007	5,724,000	4,903,598	5,724,000	9.48%	493,722	8.63%

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LONG TERM DEBT

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1	6.625% Ser. G due 6/1/07	06/09/95	06/01/2007	100,000,000	97,220,876	100,000,000	6.97%	6,857,017	6.86%
2									
3	7.43% Ser. E due 9/11/07	09/11/92	09/11/2007	2,000,000	1,758,395	2,000,000	8.90%	164,709	8.24%
4	7.22% Ser. E due 9/18/07	09/18/92	09/18/2007	$2,500,000	$2,197,994	$2,500,000	8.68%	$200,636	8.03%
5	7.27% Ser. E due 9/24/07	09/22/92	09/24/2007	4,000,000	3,516,790	4,000,000	8.73%	323,007	8.08%
6	7.00% Ser. H due 7/15/09	07/15/97	07/15/2009	125,000,000	122,573,160	125,000,000	7.24%	8,952,237	7.16%
7									
8	9.15% Ser. C due 8/9/11	08/09/91	08/09/2011	8,000,000	7,924,673	8,000,000	9.25%	735,766	9.20%
9	8.95% Ser. C due 9/1/11	08/16/91	09/01/2011	25,000,000	24,824,602	25,000,000	9.03%	2,246,251	8.99%
10	8.95% Ser. C due 9/1/11	08/16/91	09/01/2011	20,000,000	19,867,882	20,000,000	9.02%	1,796,591	8.98%
11	8.92% Ser. C due 9/1/11	08/16/91	09/01/2011	20,000,000	19,811,682	20,000,000	9.02%	1,793,395	8.97%
12	8.29% Ser. C due 12/30/11	12/31/91	12/30/2011	3,000,000	2,566,175	3,000,000	9.97%	270,394	9.01%
13	8.26% Ser. C due 1/10/12	01/09/92	01/10/2012	1,000,000	855,423	1,000,000	9.94%	89,828	8.98%
14	8.28% Ser. C due 1/10/12	01/10/92	01/10/2012	2,000,000	1,712,847	2,000,000	9.95%	179,958	9.00%
15	8.25% Ser. C due 2/1/12	01/15/92	02/01/2012	3,000,000	2,566,270	3,000,000	9.92%	269,136	8.97%
16	8.13% Ser. E due 1/22/13	01/20/93	01/22/2013	10,000,000	9,252,486	10,000,000	8.94%	850,365	8.50%
17	7.25% Ser. F due 8/1/13	07/28/93	08/01/2013	10,000,000	9,373,015	10,000,000	7.88%	756,332	7.56%
18	7.25% Ser. F due 8/1/13	07/28/93	08/01/2013	10,000,000	9,373,015	10,000,000	7.88%	756,332	7.56%
19	7.25% Ser. F due 8/1/13	07/28/93	08/01/2013	10,000,000	9,373,015	10,000,000	7.88%	756,332	7.56%
20	7.25% Ser. F due 8/1/13	07/28/93	08/01/2013	10,000,000	9,373,015	10,000,000	7.88%	756,332	7.56%
21	8.53% Ser. C due 12/16/21	12/16/91	12/16/2021	15,000,000	12,830,877	15,000,000	10.07%	1,351,801	9.01%
22	8.375% Ser. C due 12/31/21	12/31/91	12/31/2021	5,000,000	4,276,959	5,000,000	9.88%	442,850	8.86%
23	8.26% Ser. C due 1/7/22	01/08/92	01/07/2022	5,000,000	4,282,117	5,000,000	9.74%	436,931	8.74%
24	8.27% Ser. C due 1/10/22	01/09/92	01/10/2022	4,000,000	3,421,693	4,000,000	9.77%	350,074	8.75%
25	8.05% Ser. E due 9/1/22	09/18/92	09/01/2022	15,000,000	13,172,963	15,000,000	9.26%	1,268,499	8.46%
26	8.07% Ser. E due 9/9/22	09/09/92	09/09/2022	8,000,000	7,025,580	8,000,000	9.28%	678,082	8.48%
27	8.12% Ser. E due 9/9/22	09/11/92	09/09/2022	50,000,000	43,909,875	50,000,000	9.34%	4,263,050	8.53%
28	8.11% Ser. E due 9/9/22	09/11/92	09/09/2022	12,000,000	10,538,370	12,000,000	9.32%	1,021,932	8.52%
29	8.05% Ser. E due 9/14/22	09/14/92	09/14/2022	10,000,000	8,781,975	10,000,000	9.26%	845,603	8.46%
30	8.08% Ser. E due 10/14/22	10/15/92	10/14/2022	26,000,000	22,852,821	26,000,000	9.28%	2,205,720	8.48%
31	8.08% Ser. E due 10/14/22	10/15/92	10/14/2022	25,000,000	22,738,182	25,000,000	8.95%	2,095,404	8.38%
32	8.23% Ser. E due 1/20/23	01/20/93	01/20/2023	5,000,000	4,626,243	5,000,000	8.95%	423,959	8.48%

Sch. 24

LONG TERM DEBT

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1	8.23% Ser. E due 1/20/23	01/29/93	01/20/2023	4,000,000	3,962,241	4,000,000	8.32%	330,460	8.26%
2									
3	7.26% Ser. F due 7/21/23	07/22/93	07/21/2023	27,000,000	25,307,139	27,000,000	7.80%	2,016,636	7.47%
4	7.26% Ser. F due 7/21/23	07/22/93	07/21/2023	11,000,000	10,310,316	11,000,000	7.80%	821,593	7.47%
5	7.40% Ser. F due 7/28/23	07/28/93	07/28/2023	2,000,000	1,874,603	2,000,000	7.95%	152,180	7.61%
6	7.37% Ser. F due 8/11/23	08/11/93	08/11/2023	15,500,000	14,528,173	15,500,000	7.92%	1,174,746	7.58%
7	7.23% Ser. F due 8/16/23	08/16/93	08/16/2023	$15,000,000	$14,594,165	$15,000,000	7.46%	$1,098,028	7.32%
8	7.24% Ser. F due 8/16/23	08/16/93	08/16/2023	30,000,000	29,188,329	30,000,000	7.47%	2,199,057	7.33%
9	6.75% Ser. F due 9/14/23	09/14/93	09/14/2023	5,000,000	4,927,581	5,000,000	6.86%	339,914	6.80%
10	6.75% Ser. F due 9/14/23	09/14/93	09/14/2023	2,000,000	1,984,700	2,000,000	6.81%	135,510	6.78%
11	6.72% Ser. F due 9/14/23	09/14/93	09/14/2023	2,000,000	1,984,700	2,000,000	6.78%	134,910	6.75%
12	6.75% Ser. F due 10/26/23	10/26/93	10/26/2023	20,000,000	19,847,674	20,000,000	6.81%	1,355,078	6.78%
13	6.75% Ser. F due 10/26/23	10/26/93	10/26/2023	16,000,000	15,878,139	16,000,000	6.81%	1,084,062	6.78%
14	6.75% Ser. F due 10/26/23	10/26/93	10/26/2023	12,000,000	11,908,604	12,000,000	6.81%	813,047	6.78%
15	8.625% Ser. F due 12/13/24	12/13/94	12/13/2024	20,000,000	19,350,375	20,000,000	8.94%	1,746,653	8.73%
16	6.71% Ser. G due 1/15/26	01/23/96	01/15/2026	100,000,000	99,095,533	100,000,000	6.78%	6,740,170	6.74%
17									
18	Total Secured Medium-Term Notes			$2,236,650,000	$2,109,665,467	$2,206,768,380		$177,271,891	8.03%
19									
20	POLL. CTRL. OBLIGATIONS SECURED BY PLEDGED FIRST MORTGAGE BONDS:								
21	Var. Rate Moffat 1994	11/17/94	05/01/2013	$40,655,000	$39,705,929	$40,655,000	3.73%	$1,497,327	3.68%
22	5-5/8% Series due 11/21 Linco	11/15/93	11/01/2021	8,300,000	7,459,117	8,300,000	6.41%	496,948	5.99%
23	5.65% Series due 11/23 Emery	11/15/93	11/01/2023	46,500,000	42,033,154	46,500,000	6.37%	2,776,342	5.97%
24	5-5/8% Series due 11/23 Emer	11/15/93	11/01/2023	16,400,000	14,565,392	16,400,000	6.48%	983,735	6.00%
25	Var. Rate Sweetwater 1994	11/17/94	11/01/2024	21,260,000	20,661,169	21,260,000	3.70%	773,337	3.64%
	Var. Rate Converse 1994	11/17/94	11/01/2024	8,190,000	7,893,899	8,190,000	3.75%	300,170	3.67%
26	Var. Rate Emery 1994	11/17/94	11/01/2024	121,940,000	116,739,987	121,940,000	3.72%	4,421,847	3.63%
27	Var. Rate Carbon 1994	11/17/94	11/01/2024	9,365,000	9,099,907	9,365,000	3.71%	341,915	3.65%
28	Var. Rate Lincoln 1994	11/17/94	11/01/2024	15,060,000	14,556,007	15,060,000	3.73%	550,475	3.66%
29									
30	Total PCRB's Secured by Pledged FMB's			$287,670,000	$272,714,561	$287,670,000		$12,142,096	4.22%
31									
32									

Sch. 24

LONG TERM DEBT

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1	POLLUTION CONTROL REVENUE BONDS:								
2	Var. Rate Sweetwater 1992A	09/29/92	04/01/2005	$9,335,000	$9,053,264	$9,335,000	3.87%	$355,465	3.81%
3	Var. Rate Sweetwater 1992B	09/29/92	12/01/2005	6,305,000	6,068,787	6,305,000	3.94%	243,085	3.86%
4	Var. Rate Converse 1992	09/29/92	07/01/2006	22,485,000	21,987,426	22,485,000	3.80%	844,315	3.76%
5	Var. Rate Sweetwater 1988B	01/01/88	01/01/2014	11,500,000	11,022,928	11,500,000	3.75%	421,216	3.66%
6	Var. Rate Converse 1988	01/01/88	01/01/2014	17,000,000	16,264,181	17,000,000	3.76%	622,891	3.66%
7	Var. Rate Sweetwater C	12/01/84	12/01/2014	$15,000,000	$14,772,113	$15,000,000	3.53%	$524,377	3.50%
8									
9	Var. Rate Sweetwater 1990A	07/25/90	07/01/2015	70,000,000	68,544,128	70,000,000	3.82%	2,642,720	3.78%
10	Var. Rate Emery Co. 1991	05/23/91	07/01/2015	45,000,000	51,180,533	45,000,000	2.86%	4,276,774	9.50%
11	Var. Rate Lincoln Co. 1991	01/17/91	01/01/2016	45,000,000	51,446,459	45,000,000	2.74%	4,201,195	9.34%
12	Var. Rate Forsyth 1986	12/01/86	12/01/2016	8,500,000	8,195,176	8,500,000	3.86%	320,708	3.77%
13	Var. Rate Sweetwater A	01/01/88	01/01/2017	50,000,000	48,695,456	50,000,000	3.67%	1,806,381	3.61%
14	Var. Rate Forsyth 1988	01/01/88	01/01/2018	45,000,000	43,606,519	45,000,000	3.74%	3,386,831	7.53%
15	Var. Rate Gillette (Wyodak)	01/01/88	01/01/2018	63,000,000	39,842,082	41,200,000	6.25%	3,799,892	9.22%
16	Var. Rate Converse 1995	11/17/95	11/01/2025	5,300,000	5,167,957	5,300,000	3.93%	205,294	3.87%
17	Var. Rate Lincoln 1995	11/17/95	11/01/2025	22,000,000	21,595,738	22,000,000	3.89%	847,360	3.85%
18	Var. Rate Sweetwater 1995	12/14/95	11/01/2025	24,400,000	23,746,531	24,400,000	3.94%	946,700	3.88%
19	6.15% Series due 9/30 Emery	09/24/96	09/01/2030	12,675,000	11,985,368	12,675,000	6.55%	799,834	6.31%
20									
21	Total Pollution Control Revenue Bonds			$472,500,000	$453,174,646	$450,700,000		$26,245,038	5.82%
22									
23	OTHER LONG-TERM DEBT:								
24	8.25% Debenture Series C	06/11/96	06/30/2036	223,712,000	216,339,676	223,712,000	8.54%	18,640,309	8.33%
25	7.70% Debenture Series D	08/04/97	09/30/2037	139,176,000	134,745,722	139,176,000	7.96%	10,826,879	7.78%
26									
27	8.55% QUIDS Series B	10/05/95	12/31/2025	55,825,925	53,978,103	55,825,925	8.86%	4,834,223	8.66%
28	8.375% QUIDS Series A	05/31/95	06/30/2035	$120,000,000	$115,676,396	$120,000,000	8.70%	$10,157,869	8.46%
29									
30	Total Other Long-Term Debt			$538,713,925	$520,739,897	$538,713,925		$44,459,279	8.25%
31									
32	Total Long-Term Debt			$3,888,425,925	$3,681,001,777	$3,809,347,305		$285,570,148	7.50%

Sch. 25

PREFERRED STOCK

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value(a)	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1	5% cumulative preferred	(b)	126,533	100.00	110.00	12,555,021	5.04%	12,653,300	637,617	5.08%
2	Serial preferred, cumulative:									
3	4.52% Series	11/55	2,065	100.00	103.50	196,824	4.74%	206,500	9,793	4.98%
4	7.00% Series	(c)	18,060	100.00	None	1,806,000	7.00%	1,806,000	126,420	7.00%
5	6.00% Series	(c)	5,932	100.00	None	593,200	6.00%	593,200	35,592	6.00%
6	5.00% Series	(c)	42,000	100.00	100.00	4,200,000	5.00%	4,200,000	210,000	5.00%
7	5.40% Series	(c)	65,960	100.00	101.00	6,596,000	5.40%	6,596,000	356,184	5.40%
8	4.72% Series	8/63	69,890	100.00	103.50	6,958,651	4.74%	6,989,000	331,320	4.76%
9	4.56% Series	2/65	84,592	100.00	102.34	8,410,129	4.59%	8,459,200	387,990	4.61%
10										
11										
12	No par serial preferred cumulative:									
13	$1.28 Series	9/60	381,220	25.00	26.35	9,530,500	5.12%	9,530,500	487,962	5.12%
14	$1.18 Series	5/62	420,116	25.00	26.15	10,502,900	4.72%	10,502,900	495,737	4.72%
15	$1.16 Series	8/64	193,102	25.00	26.11	4,827,550	4.64%	4,827,550	223,998	4.64%
16	$7.70 Series	8/91	1,000,000	100.00	N. A.	99,088,493	7.77%	100,000,000	7,770,832	7.84%
17	$7.48 Series	6/92	750,000	100.00	N. A.	74,159,567	7.56%	75,000,000	5,673,577	7.65%
18										
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32										
33	TOTAL		3,159,470			239,424,835		241,364,150	16,747,021	6.99%

(a) Par or Stated Value
(b) Replaced preferred stock issues sold in the 1920's and 1930's.
(c) Replaced an issue of The California Oregon Power Company as a result of merger with Pacific Power.

Sch. 26

COMMON STOCK

Line		Avg. Number of Shares Outstanding	Book Value Per Share	Earnings Per Share	Dividends Per Share	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
4	January	295,157,376	14.08	0.14			21.375	21.000	
6	February	295,614,180	13.61	0.10			21.375	21.500	
8	March	295,638,426	13.77	0.15	0.27	30.82%	20.125	21.875	13.5
10	April	295,659,516	13.85	0.08			21.250	19.250	
12	May	296,126,685	13.68	0.10			20.875	19.375	
14	June	296,147,965	13.81	0.12	0.27	10.36%	22.375	19.750	17.5
16	July	296,162,794	13.95	0.13			21.438	23.500	
18	August	296,525,751	13.62	(0.06)			22.063	20.063	
20	September	296,537,648	13.78	0.15	0.27	-19.42%	23.125	20.625	24.2
22	October	296,551,651	13.91	0.14			23.250	20.938	
24	November	296,893,381	13.84	0.19			23.313	21.250	
26	December	296,908,110	14.7	0.85	0.27	77.18%	27.250	23.000	5.3
32	TOTAL Year End	292,423,918		2.10	1.08	48.60%	21.125	20.500	10.1

MONTANA EARNED RATE OF RETURN

Account	Description	Last Year	This Year	% Change
	Rate Base			
101	Plant in Service	212,596,088	227,717,309	7.11%
108	(Less) Accumulated Depreciation	(67,314,616)	(74,095,476)	-10.07%
	NET Plant in Service	145,281,472	153,621,833	5.74%
	Additions			
154, 156	Materials & Supplies	3,187,232	3,113,563	-2.31%
165	Prepayments	448,748	351,352	-21.70%
	Other Additions	8,909,355	11,105,858	24.65%
	TOTAL Additions	12,545,335	14,570,773	16.14%
	Deductions			
190	Accumulated Deferred Income Taxes	(12,031,930)	(11,954,687)	0.64%
252	Customer Advances for Construction	(39,392)	(17,608)	55.30%
255	Accumulated Def. Investment Tax Credits	(449,497)	(420,953)	6.35%
	Other Deductions	(1,874,190)	(1,787,651)	4.62%
	TOTAL Deductions	(14,395,009)	(14,180,899)	1.49%
	TOTAL Rate Base	143,431,798	154,011,707	7.38%
	Net Earnings	11,304,965	7,281,256	-35.59%
	Rate of Return on Average Rate Base	7.88%	4.73%	-40.02%
	Rate of Return on Average Equity	8.58%	-0.09%	-101.08%
	Major Normalizing Adjustments & Commission Ratemaking adjustments to Utility Operations			
	Commission Ordered / Allowed Ratemaking Adjustments			
	- Malin Midpoint Adj.	15,759	25,504	61.84%
	- Advertising Expense Adj.	0	195	ERR
	- Present Rates Adj.	(49,112)	6,170	112.56%
	- Weather Normalization Adj.	(681,874)	(18,378)	97.30%
	- Production Cost Study Adj.	(81,939)	(60,920)	25.65%
	- Interest Expense Adj.	847,240	159,183	-81.21%
	- Clean Air Credits	(22,349)	(254,426)	-1038.42%
	- DSM Third Party Financing	281	(35)	-112.46%
	Other Company Ratemaking Adjustments			
	- Other Adjustments	(636,000)	3,403,436	635.13%
	Adjusted Rate of Return on Average Rate Base	7.18%	6.79%	-5.33%
	Adjusted Rate of Return on Average Equity	6.57%	5.77%	-12.12%

PACIFICORP
State of Montana - Electric Utility
Schedule 27 Detail for Other Rate Base Additions / Deductions

		Last Year	This Year
1	Rate Base:		
2	Plant Held for Future Use	101,645	86,352
3	Misc Deferred Debits	2,184,017	2,601,995
4	Acquisition Adjustment	2,686,491	2,759,520
5	Nuclear Fuel	0	0
6	Working Capital (1)	1,530,202	3,270,560
7	Weatherization Loans	1,650,279	1,658,013
8	Unrecovered Plant - Trojan	756,721	729,418
9	Total Other Additions	8,909,355	11,105,858
10			
11	Deductions:		
12	Accumulated Prov. - Trojan	(413,571)	(410,699)
13	Accumulated Prov. - Injuries	(128,045)	(106,802)
14	Accumulated Prov. - Proprety Ins	(37,416)	(1,815)
15	Other Deferred Credits	(1,295,158)	(1,268,335)
16	Total Other Deductions	(1,874,190)	(1,787,651)

(1) The Company does not have a specific Commission order authorizing the inclusion of cash working capital in rate base. However, cash working capital has been allowed in Company's previously authorized results (reference rate filings for Docket No. 87.12.80, Order No. 5326 and for Docket No. 89.6.17, Order No. 5432).

MONTANA COMPOSITE STATISTICS

		Description		Amount
1				
2		**Plant (Intrastate Only) (000 Omitted)**		
3				
4	101	Plant in Service		349,386
5	107	Construction Work in Progress		3,695
6	114	Plant Acquisition Adjustments		-
7	105	Plant Held for Future Use		-
8	154, 156	Materials & Supplies		441
9		(Less):		
10	108, 111	Depreciation & Amortization Reserves		(111,405)
11	252	Contributions in Aid of Construction		(4,496)
12				
13		**NET BOOK COSTS**		237,621
14				
15		**Revenues & Expenses (000 Omitted)**		
16				
17	400	Operating Revenues		74,245
18				
19	403 - 407	Depreciation & Amortization Expenses		7,562
20		Federal & State Income Taxes		6,314
21		Other Taxes		1,699
22		Other Operating Expenses	KWS 945,763 ←	51,822
23		TOTAL Operating Expenses		67,397
24			$54.79 ←	
25		Net Operating Income		6,848
26				
27	415-421.1	Other Income		0
28	421.2-426.	Other Deductions		(433)
29				
30		**NET INCOME**		7,281
31				
32		**Customers (Intrastate Only)**		
33				
34		Year End Average:		
35		Residential		28,199
36		Commercial		5,673
37		Industrial		300
38		Other		58
39				
40		**TOTAL NUMBER OF CUSTOMERS**		34,230
41				
42		**Other Statistics (Intrastate Only)**		
43				
44		Average Annual Residential Use (Kwh)		12,797
45		Average Annual Residential Cost per (Kwh) (Cents) *		5.03
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use		
47		Average Residential Monthly Bill		$53.67
48		Gross Plant per Customer		$10,207

Sch. 29 MONTANA CUSTOMER INFORMATION

	City/Town	Population (Include Rural	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Bigfork	N.A.	2,530	539	39	3,108
2	Columbia Falls	N.A.	2,976	503	35	3,514
3	Kalispell	N.A.	11,114	2,318	200	13,632
4	Kila	N.A.	259	38		297
5	Lakeside	N.A.	1,058	212	6	1,276
6	Libby	N.A.	4,263	944	53	5,260
7	Rollins	N.A.	282	41	5	328
8	Somers	N.A.	591	107	8	706
9	Swan Lake	N.A.	182	25	1	208
10	Whitefish	N.A.	4,945	946	21	5,912
11	Cooke City	N.A.	136	52	3	191
12	Silver Gate	N.A.	70	15		85
13						0
14						0
15						0
16						0
17						0
18						0
19						0
20						0
21						0
22						0
23						0
24						0
25						0
26						0
27						0
28						0
29						0
30						0
31						0
32	TOTAL Montana Customers	0	28,406	5,740	371	34,517

Sch. 30 MONTANA EMPLOYEE COUNTS

	Department	Year Beginning	Year End	Average
1	Big Fork	2	1	2
2	Kalispell District	49	45	47
3	Libby District	7	7	7
4	Montana Area	3	2	3
5	Whitefish District	4	3	4
6				
7				
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43				
44				
45				
46	TOTAL Montana Employees	65	58	62

Sch. 31 MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)

	Project Description	Total Company (in 000's)	Total Montana (in 000's)
1			
2	CENTRALIA MINE-PURCHASE (3) 190 TON HAUL TRU	3,361	70
3	CENTRALIA MINE - REBUILD B.E. DRAGLINE	2,267	47
4	YALE RELICENSING	2,108	43
5	CENTRALIA MINE- MOVE DRAGLINE	1,154	24
6	BSIP IMPLEMENTATION	62,504	1,267
7	FOOTE CREEK WIND PROJECT - CAPIT	44,690	919
8	REPLACE LONGWALL MINING SYSTEM	22,073	459
9	LCT RELOCATION	20,298	411
10	HAYDEN PLANT EMISSIONS CONTROLS	13,047	268
11	WAN/LAN CORPORATE UPGRADE	8,557	173
12	RMT TRADING SYSTEM	6,740	137
13	HUNTER 303---TURBINE UPRATE	6,392	131
14	NEW CPU, ISV S/W & PRINTERS	4,759	96
15	MIDVALLEY SUB-INSTALL 2ND 345/13	3,999	82
16	HG U2 GE ADVANCED AERO DESIGN	3,665	75
17	BILLING SYSTEM FOR CUSTOMER SERVICE	3,271	66
18	NAUGHTON 273: CONSTRUCT 2ND FGD	3,029	62
19	BUSINESS CENTER TECHNOLOGY	3,004	61
20	PROJECT SERVER INTEGRATION	2,935	59
21	AUTOMATED MAPPING PROJECT	2,649	54
22	MIDWAY - SILVER CREEK 138 KV LINE	2,330	48
23	HUNTER UNIT 3 MCR MODIFICATION.	2,275	47
24	DISPATCHING CONSOLIDATION	2,273	46
25	JB UNIT #4 TURBINE UPGRADE	2,258	46
26	NORTH UMPQUA RELICENSING	2,146	44
27	HUNTER 303 SCRUBBER RECYCLE	1,866	38
28	HUNTER UNIT 1 TURBINE PROJECT	1,851	38
29	JB UNIT #1 CONDENSER TITANIUM	1,730	36
30	INFRASTRUCTURE MANAGEMENT	1,643	33
31	DEER CREEK MINE-MINE EXTENSION-1	1,633	34
32	JB UNIT 1 TURBINE UPGRADE	1,557	32
33	TRAIL MTN MINE-LONGWALL INCLINE	1,505	31
34	HT UNIT 2 LOW NOX BURNER & WINDB	1,440	30
35	DEV. GLOBAL SALES & MKTG SYSTEM	1,308	27
36	MIDVALLEY-COTTONWOOD 138/46 KV	1,166	24
37	DATA CENTER_TAPE DRIVES	1,138	23
38	ROCS-D2000+ DEVELOPMENT	1,115	23
39	RECORDS MANAGEMENT TRACKING SYST	1,110	23
40	DATA CENTER MOVE	1,025	21
41			
42	ALL OTHER	301,629	N/A
43			
44			
45			
46			
47			
48			
49			
50	TOTAL	553,500	5,148

Sch. 32 TOTAL SYSTEM & MONTANA PEAK AND ENERGY

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	14	08:00	7,960	8,148,378	3,515,581
2	Feb.	6	08:00	7,454	7,222,606	3,182,549
3	Mar.	4	08:00	7,153	7,689,300	3,495,487
4	Apr.	11	08:00	6,775	7,348,516	3,459,310
5	May	16	15:00	6,598	7,896,636	3,936,017
6	Jun.	26	15:00	6,968	8,471,834	4,420,549
7	Jul.	21	14:00	7,552	9,358,600	4,935,917
8	Aug.	22	16:00	7,456	9,588,984	5,100,075
9	Sep.	9	16:00	7,020	9,220,159	5,268,244
10	Oct.	24	08:00	6,848	11,463,300	7,250,337
11	Nov.	17	18:00	7,242	11,317,971	7,203,196
12	Dec.	11	18:00	7,596	12,036,801	7,189,190
13	TOTAL				109,763,085	58,956,452

Montana

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
14	Jan.	13	09:00	196	104,370	0
15	Feb.	10	09:00	173	87,025	0
16	Mar.	14	08:00	169	88,450	0
17	Apr.	6	09:00	150	79,194	0
18	May	2	09:00	128	68,700	0
19	Jun.	11	10:00	128	66,481	0
20	Jul.	28	12:00	120	68,729	0
21	Aug.	5	12:00	124	70,320	0
22	Sep.	22	08:00	118	67,171	0
23	Oct.	14	09:00	137	74,684	0
24	Nov.	13	08:00	155	80,523	0
25	Dec.	12	09:00	161	92,476	0
26	TOTAL				948,123	0

Sch. 33 TOTAL SYSTEM Sources & Disposition of Energy

	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	48,880,532	Sales to Ultimate Consumers	
3	Nuclear	(465)	(Include Interdepartmental)	46,148,733
4	Hydro - Conventional	5,746,233		
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	0	for Resale	186,692
7	(Less) Energy for Pumping			
8	NET Generation	54,626,300	Non-Requirements Sales	
9	Purchases	55,116,668	for Resale	58,956,453
10	Power Exchanges			
11	Received	12,358,000	Energy Furnished	
12	Delivered	11,941,542	Without Charge	
13	NET Exchanges	416,458		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	8,938,554	Electric Utility	69,876
16	Delivered	8,938,554		
17	NET Transmission Wheeling	0	Total Energy Losses	4,401,331
18	Transmission by Others Losses	(396,341)		
19	TOTAL	109,763,085	TOTAL	109,763,085

SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Thermal	Cholla Unit No. 4	Joseph City, Arizona	385.0	2,433,537
2	Thermal	Craig Units #1 & #2	Craig, Colorado	165.0	1,365,293
3	Thermal	Hayden Plant	Hayden, Colorado	78.0	583,645
4	Thermal	Colstrip Unit #3 & #4	Colstrip, Montana	167.0	1,019,592
5	Thermal	Hermiston Plant	Hermiston, Oregon	243.0	961,743
6	Thermal	Carbon Plant	Castle Gate, Utah	184.0	1,405,087
7	Thermal	Gadsby Plant	Salt Lake City, Utah	225.0	181,486
8	Thermal	Hunter Plant	Castle Dale, Utah	1,245.0	7,717,335
9	Thermal	Huntington Plant	Huntington, Utah	857.0	6,142,165
10	Thermal	Centralia Plant	Centralia, Washington	646.0	3,382,223
11	Thermal	James River	Camas, Washington	54.0	360,852
12	Thermal	Dave Johnston Plant	Glenrock, Wyoming	807.0	5,983,492
13	Thermal	Jim Bridger Plant	Rock Springs, Wyoming	1,555.0	9,786,354
14	Thermal	Wyodak Plant	Gillette, Wyoming	338.0	2,299,922
15	Thermal	Naughton Plant	Kemmerer, Wyoming	726.0	5,089,288
16	Geothermal	Blundell Plant	Milford, Utah	24.0	168,518
17					
18	Nuclear	Trojan Plant	Rainier, Oregon		(465)
19					
20	Hydro	Cutler	Collinston, Utah	57.0	170,790
21	Hydro	Grace	Grace, Idaho	64.0	232,477
22	Hydro	Olmsted	Orem, Utah	9.0	49,121
23	Hydro	Oneida	Preston, Idaho	39.0	111,591
24	Hydro	Soda	Soda, Idaho	20.0	49,870
25	Hydro	Merwin	Ariel, Washington	150.0	705,881
26	Hydro	Yale	Amboy, Washington	161.0	803,615
27	Hydro	Swift #1	Cougar, Washington	261.0	956,149
28	Hydro	Copco #1	Copco, California	27.0	106,750
29	Hydro	Copco #2	Copco, California	29.0	149,096
30	Hydro	John C. Boyle	Keno, Oregon	91.0	386,267
31	Hydro	Iron Gate	Hornbrook, California	19.0	130,512
32	Hydro	Soda Springs	Toketee Falls, Oregon	14.0	77,958
33	Hydro	Slide Creek	Toketee Falls, Oregon	19.0	113,409
34	Hydro	Fish Creek	Toketee Falls, Oregon	14.0	67,380
35	Hydro	Clearwater #1	Toketee Falls, Oregon	15.0	78,340
36	Hydro	Clearwater #2	Toketee Falls, Oregon	25.0	94,482
37	Hydro	Lemolo #1	Toketee Falls, Oregon	28.0	202,642
38	Hydro	Lemolo #2	Toketee Falls, Oregon	36.0	222,979
39	Hydro	Toketee	Toketee Falls, Oregon	45.0	299,324
40	Hydro	Prospect #2	Prospect, Oregon	38.0	216,531
41					
42	Hydro	American Fork	American Fork, Utah	1.0	290
43	Hydro	Ashton	Ashton, Idaho	7.0	49,196
44	Hydro	Beaver - Upper	Beaver, Utah	2.0	13,513
45	Hydro	Bend	Bend, Oregon	1.0	6,884
46	Hydro	Bigfork	Bigfork, Montana	4.0	26,728
47	Hydro	Cline Falls	Redmond, Oregon	1.0	4,692
48	Hydro	Condit	Underwood, Washington	15.0	105,468
49	Hydro	Cove	Grace, Idaho	8.0	49,461

SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
50	Hydro	Drop	Naches, Washington	20.0	8,457
51	Hydro	Eagle Point	Eagle Point, Oregon	3.0	7,948
52	Hydro	East Side	Klamath Falls, Oregon	4.0	18,348
53	Hydro	Fall Creek	Copco, California	3.0	10,703
54	Hydro	Fountain Green	Fountain Green, Utah		664
55	Hydro	Granite	Salt Lake City, Utah	1.0	6,656
56	Hydro	Gunlock	Gunlock, Utah		1,165
57	Hydro	Last Chance	Grace, Idaho	1.0	9,718
58	Hydro	Naches	Naches, Washington	6.0	32,005
59	Hydro	Paris	Paris, Idaho	8.0	3,629
60	Hydro	Pioneer	Ogden, Utah	6.0	30,154
61	Hydro	Powerdale	Hood River, Oregon	6.0	28,319
62	Hydro	Prospect #1	Prospect, Oregon	4.0	36,989
63	Hydro	Prospect #3	Prospect, Oregon	7.0	13,800
64	Hydro	Prospect #4	Prospect, Oregon	1.0	7,192
65	Hydro	Sand Cove	Sand Cove, Utah		1,054
66	Hydro	Snake Creek	Midway, Utah	1.0	4,600
67	Hydro	Stairs	Salt Lake City, Utah	1.0	6,573
68	Hydro	St. Anthony	St. Anthony, Idaho	1.0	4,103
69	Hydro	Veyo	Veyo, Utah	1.0	685
70	Hydro	Viva Naughton	Kemmerer, Wyoming	1.0	1,987
71	Hydro	Wallowa Falls	Joseph, Oregon	1.0	3,162
72	Hydro	Weber	Uintah, Utah	4.0	25,787
73	Hydro	West Side	Klamath Falls, Oregon	1.0	2,753
74	Pumping	Lifton	Lifton, Idaho		(1,614)
75					
76		Total Net Generation		8,980.0	54,626,300
77					
78	POWER PURCHASES - ACCOUNT 555				
79					
80	Power Purchases				
81	AIG Trading Corp.		(4)		25,065
82	AIG Trading Corp.		(4)		232,800
83	American Hunter Electric		(4)		1,600
84	American Hunter Electric		(4)		252,400
85	Amoco Energy Trading		(4)		30,800
86	Anaheim, City of		(4)		3,300
87	Aquila Power Corp.		(4)		88,469
88	Aquila Power Corp.		(4)		2,162,170
89	Arizona Power Pool Association		(4)		2,510
90	Arizona Public Service Company		October 31, 2020		2,410
91	Arizona Public Service Company		(4)		55,158
92	Arizona Public Service Company		(4)		157,425
93	Avista Energy, Inc.		(4)		181,058
94	Avista Energy, Inc.		(4)		200,625
95	Azusa, City of		(4)		29,280
96	BC Hydro		(4)		517,336
97	BC Hydro		(4)		494,225
98	Beaver City		(3)		90

SOURCES OF ELECTRIC SUPPLY

	Type / Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
99	Bell Mountain Power	(1)		1,964
100	Benton County Public Utility Dist. No. 1	(4)		720
101	Biomass One, Limited Partnership	(1)		127,219
102	Birch Creek Hydro	(1)		16,092
103	Black Hills Power & Light Company	December 31, 2000		214,879
104	Black Hills Power & Light Company	(1)		3,305
105	Blanding City	(3)		978
106	Bogus Creek	(1)		1,273
107	Boise Cascade Corporation	(4)		10
108	Bonneville Power Administration	(2)		
109	Bonneville Power Administration	(2)		146,350
110	Bonneville Power Administration	March 31, 2003		
111	Bonneville Power Administration	(4)		2,316,864
112	Bonneville Power Administration	(4)		4,513,140
113	Boston Power	(1)		188
114	Boyd, James	(1)		1,837
115	Buffalo Hydro Inc.	(1)		1,326
116	California Dept. of Water Resources	(4)		209,341
117	California Dept. of Water Resources	(4)		132,913
118	Calpine Power Marketing Inc.	(4)		1,600
119	Calpine Power Marketing Inc.	(4)		11,200
120	CDM Hydro	(1)		39,133
121	Central Oregon Irrigation District	(1)		38,706
122	Chelan County Public Utility Dist. No. 1	(1)		583,414
123	Chelan County Public Utility Dist. No. 1	(4)		83,639
124	Chevron Chemical	(4)		2,967
125	Cinergy Services Inc.	(4)		9,440
126	Cinergy Services Inc.	(4)		616,800
127	Citizens Lehman Power Sales	(4)		118,424
128	Citizens Lehman Power Sales	(4)		506,490
129	City of Buffalo	(1)		828
130	Clark County Public Utility District	December 12, 2007		139,355
131	CNG Energy Services Corp.	(4)		10,800
132	CNG Energy Services Corp.	(4)		421,000
133	Colorado Springs	(4)		4,950
134	Colorado Springs	(4)		960
135	Columbia Storage Power Exchange	March 31, 2003		209,590
136	Commercial Energy Management	(1)		3,472
137	ConAgra Energy Services	(4)		109,123
138	ConAgra Energy Services	(4)		790,500
139	Cook Electric	(1)		5,160
140	Coral Power	(4)		9,200
141	Coral Power	(4)		102,000
142	Cowlitz County Public Utility Dist. No. 1	(4)		22,080
143	Curtiss Livestock	(1)		313
144	Davis County Waste Management	(1)		2,200
145	Delhi Energy Service	(4)		4,000
146	Delhi Energy Service	(4)		49,200
147	Deseret Generation & Trans. Coop.	December 31, 1997		264,174

SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
148	Deseret Generation & Trans. Coop.		June 30, 2001		2,008,586
149	Deseret Generation & Trans. Coop.		(5)		(429)
150	Destec Power Service		(4)		114
151	Douglas County Public Utility Dist. No. 1		(1)		372,236
152	Douglas County Public Utility Dist. No. 1		(4)		160,384
153	DR Johnson Lumber Company		(1)		62,992
154	Duke Louis Dreyfus		(4)		158,733
155	Duke Louis Dreyfus		(4)		2,903,028
156	Dupont Power Marketing Inc.		(4)		47,338
157	Dupont Power Marketing Inc.		(4)		353,550
158	Eagle Point Irrigation		(1)		1,990
159	Eastern Power Distribution		(4)		223,903
160	Eastern Power Distribution		(4)		457,660
161	Edison Source		(4)		3,600
162	Edison Source		(4)		
163	Edison Source		(4)		99,200
164	El Paso Electric Company		(4)		24,332
165	El Paso Electric Company		(4)		16,400
166	El Paso Energy Marketing		(4)		26,752
167	El Paso Energy Marketing		(4)		101,600
168	Electric Clearinghouse, Inc.		(4)		146,110
169	Electric Clearinghouse, Inc.		(4)		1,273,172
170	Energy Services, Inc.		(4)		35,000
171	Energy Services, Inc.		(4)		18,600
172	Engage Energy US, L.P.		(4)		6,960
173	Engage Energy US, L.P.		(4)		639,530
174	Englehard Power Marketing, Inc.		(4)		14,400
175	Englehard Power Marketing, Inc.		(4)		11,600
176	Enron Power Marketing, Inc.		(4)		548,694
177	Enron Power Marketing, Inc.		(4)		3,212,508
178	Entergy Power, Inc.		(4)		13,440
179	Entergy Power, Inc.		(4)		180,800
180	E'Prime Inc.		(4)		7,200
181	Equitable Power Services Co.		(4)		400
182	Equitable Power Services Co.		(4)		44,800
183	Eugene Water & Electric Board		(4)		23,042
184	Falls Creek		(1)		16,813
185	Farmers Irrigation #2		(1)		25,577
186	Farmington, City of		(4)		5,145
187	Fery, Loyd		(1)		274
188	Fillmore City		(3)		65
189	Fox, Marion		(1)		2
190	Galesville Dam		(1)		5,040
191	Garland Canal		(1)		10,015
192	General Chemical Company		(4)		1,843
193	Georgetown Power		(1)		3,071
194	Glendale, City of		(4)		50
195	Glendale, City of		(4)		37,200
196	Grand Valley Rural Power		(3)		100

SOURCES OF ELECTRIC SUPPLY

	Type / Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
197	Grant County Public Utility Dist. No. 2	(3)		87,600
198	Grant County Public Utility Dist. No. 2	(1)		1,162,359
199	Grant County Public Utility Dist. No. 2	(1)		765,274
200	Grant County Public Utility Dist. No. 2	(4)		469,874
201	Grays Harbor	(4)		4,100
202	Great Salt Lake Minerals	(1)		32,736
203	Heber Light & Power	(3)		1,445
204	Hermiston Generating Company, L.P.	(1)		961,677
205	Hurricane, City of	(3)		651
206	Idaho Falls, City of	(1)		67,938
207	Idaho Power Company	(4)		515,461
208	Idaho Power Company	(4)		755,878
209	Illinova Power Marketing, Inc.	(4)		52,599
210	Illinova Power Marketing, Inc.	(4)		1,479,481
211	Imperial Irrigation District	(4)		50,665
212	Imperial Irrigation District	(4)		9,600
213	Ingram Warm Springs Ranch	(1)		3,416
214	Intermountain Power Project	(1)		540,399
215	Intermountain Power Project	(4)		8,833
216	K N Marteting, Inc.	(4)		20,400
217	K N Marteting, Inc.	(4)		126,400
218	Kennecott	(1)		4,853
219	Koch Power Services, Inc.	(4)		35,420
220	Koch Power Services, Inc.	(4)		173,600
221	Lacomb Irrigation	(1)		4,429
222	Lake Siskiyou	(1)		15,650
223	LG&E Power Marketing Inc.	(4)		37,378
224	LG&E Power Marketing Inc.	(4)		175,008
225	Los Angeles, City of	(4)		187,791
226	Los Angeles, City of	(4)		368,000
227	Los Angeles, City of	(4)		3,200
228	Luckey, Paul	(1)		337
229	Manitoba Hydro	(4)		10,327
230	Marsh Valley Hydro Electric Company	(1)		9,508
231	McMinnville Water and Light	(4)		1,849
232	Middlefork Irrigation District	(1)		25,840
233	Mink Creek Hydro	(1)		12,538
234	Minnesota Power	(4)		4,267
235	Modesto Irrigation Distrist	(4)		10,000
236	Montana Power Company	(4)		152,767
237	Morgan City	(3)		40
238	Morgan Stanley Capitol Group Inc.	(4)		10,000
239	Morgan Stanley Capitol Group Inc.	(4)		30,400
240	Mountain Energy	(1)		133
241	Municipal Energy Agency of Nebraska	(4)		210
242	Murray City	(3)		338
243	National Gas & Electric L.P.	(4)		13,520
244	National Gas & Electric L.P.	(4)		50,000
245	Nebraska Public Power District	(4)		39,830
246	Nephi City	(3)		18

SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
247	Nevada Power Company		(4)		20,897
248	Nicholson Sunnybar Ranch		(1)		2,305
249	Noram Energy Services, Inc.		(4)		54,809
250	Noram Energy Services, Inc.		(4)		505,200
251	North Fork Sprague		(1)		3,218
252	Northern California Power Agency		(4)		2,480
253	Northern California Power Agency		(5)		(10,779)
254	Northern States Power		(4)		3,950
255	NP Energy Inc.		(4)		115,800
256	NP Energy Inc.		(4)		223,200
257	O.J. Power Company		(1)		1,152
258	Odell Creek		(1)		50
259	Omaha Public Power District		(4)		7,305
260	Omaha Public Power District		(4)		25,732
261	Opal Springs		(1)		32,396
262	Ormsby, Leslie		(1)		13
263	Pacific Gas & Electric Company		(4)		77,099
264	Pacific Gas & Electric Company		(4)		196,818
265	Pancheri, Inc.		(1)		112
266	Panenergy		(4)		14,230
267	Panenergy		(4)		62,664
268	Pasadena, City of		(4)		4,727
269	PECO Energy		(4)		230,073
270	PECO Energy		(4)		148,400
271	Phibro Inc.		(4)		4,128
272	Phibro Inc.		(4)		19,991
273	Plains Electric Generation and Trans		(4)		31,961
274	Plains Electric Generation and Trans		(4)		9,775
275	Platte River Power Authority		(4)		3,750
276	Portland General Electric Company		December 18, 2001		24,000
277	Portland General Electric Company		(4)		143,815
278	Portland General Electric Company		(4)		1,652,825
279	Power Exchange Corporation		(4)		16,000
280	Preston City Hydro		(1)		3,201
281	Provo City		(3)		141
282	Public Service Company of Colorado		(4)		112,735
283	Public Service Company of Colorado		(4)		66,140
284	Public Service Company of New Mexico		(4)		185,922
285	Public Service Company of New Mexico		(4)		19,950
286	Public Utility Dist. No. 1 of Okanogan Co		(4)		150
287	Puget Sound Power & Light Company		(4)		889,363
288	Puget Sound Power & Light Company		(4)		335,400
289	Questar Energy Trading		(4)		1,600
290	Questar Energy Trading		(4)		39,200
291	Ralphs Ranches, Inc.		(1)		310
292	Redding, City of		May 31, 2014		376,571
293	Redding, City of		(4)		3,327
294	Rocky Mountain Generation Cooperative		(4)		141,231
295	Rocky Mountain Generation Cooperative		(4)		111,301

SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
296	Rousch, Neil		(1)		466
297	Royal Oak		(1)		
298	Sacramento Municipal Utility District		(4)		3,360
299	Salt River Project		(4)		175,325
300	Salt River Project		(4)		114,125
301	San Diego Gas & Electric		(4)		25,293
302	San Diego Gas & Electric		(4)		599,200
303	Santa Clara, City of		(4)		26,071
304	Santa Clara, City of		(4)		88,450
305	Santiam Water Control District		(1)		1,319
306	SaskPower		(4)		2,972
307	SaskPower		(4)		1,520
308	Scana Energy Marketing, Inc.		(4)		400
309	Seattle City Light		(4)		206,722
310	Seattle City Light		(4)		54,800
311	Sierra Pacific Power Company		(4)		49,736
312	Sierra Pacific Power Company		(4)		30,000
313	Slate Creek		(1)		8,075
314	Snohomish Public Utility District		(4)		121,207
315	Snohomish Public Utility District		(4)		129,691
316	Southern California Edison Company		March 15, 2003		
317	Southern California Edison Company		(4)		55,602
318	Southern California Edison Company		(4)		10,400
319	Southern Energy Marketing Co.		(4)		81,468
320	Southern Energy Marketing Co.		(4)		1,900,950
321	Southwestern Public Service Company		(4)		1,622
322	Spanish Fork City		(3)		47
323	Springfield Utility District		(4)		45
324	Springville City		(3)		47
325	Stauffer Dry Creek		(1)		12,650
326	Strawberry Electric Service District		(4)		93
327	Sunnyside		(1)		366,435
328	Tacoma City Light		(4)		26,484
329	Thayne Ranch Hydro		(1)		1,662
330	The Power Company of America		(4)		32,000
331	The Power Company of America		(4)		441,200
332	Tillamook People's Utility District		(4)		1,043
333	Tractebel Energy Marketing, Inc.		(4)		20,800
334	TransAlta Energy Marketing Corp.		(4)		53,803
335	TransAlta Energy Marketing Corp.		(4)		951,440
336	TransCanada Power		(4)		1,200
337	TransCanada Power		(4)		40,800
338	Tri-State Generation & Transmission		December 31, 2020		273,838
339	Tri-State Generation & Transmission		(4)		117
340	Tucson Electric Power		(4)		56,348
341	Tucson Electric Power		(4)		44,600
342	Turlock Irrigation District		(4)		8,616
343	United States Bureau of Reclamation		(1)		75,862
344	USGen Power Services, L.P.		(4)		32,400

SOURCES OF ELECTRIC SUPPLY

	Type / Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
345	USGen Power Services, L.P.	(4)		320,800
346	Utah Assoc. Municipal Power Systems	(4)		900
347	Utah Assoc. Municipal Power Systems	(4)		10,294
348	Utah Municipal Power Agency	(4)		25,465
349	Valero Power Services Company	(4)		31,200
350	Valero Power Services Company	(4)		286,329
351	Vantus Energy	(4)		10,800
352	Vantus Energy	(4)		102,400
353	Vastar Power Marketing	(4)		131,200
354	Vitol Gas & Electric	(4)		149,179
355	Vitol Gas & Electric	(4)		2,050,128
356	Walla Walla, City of	(1)		15,987
357	Warm Springs Forest Products	(4)		564
358	Warm Springs Power Enterprises	(1)		97,151
359	Washington City	(3)		30
360	Washington Water Power Company	December 31, 1997		148,920
361	Washington Water Power Company	September 15, 2003		82,200
362	Washington Water Power Company	(4)		443,745
363	Washington Water Power Company	(4)		339,524
364	West Kootenay Power & Light Company	(4)		8,836
365	West Plains	(4)		10,742
366	West Plains	(4)		2,400
367	Western Area Power Administration	(4)		302,244
368	Western Power Services, Inc.	(4)		17,760
369	Western Resources	(4)		1,280
370	Whitmore Oxygen	(4)		1,902
371	Whitney, A. C.	(1)		1
372	Wiggins, Duane	(1)		42
373	Williams Energy Services Company	(4)		109,308
374	Williams Energy Services Company	(4)		265,380
375	Yakima Tieton	(1)		7,221
376	System Deviation			14,499
377				
378	Total Purchases			55,116,668
379				
380	Net Exchanges			416,458
381				
382	Transmission by Others Losses			(396,341)
383				
384	Total Sources			109,763,085
385				
386				
387				
388				
389				
390				
391				
392				
393				

Notes:
1. Non-firm
2. Under electric service agreement subject to termination upon timely notification.
3. Upon 2 years written notice.
4. Contract duration less than one year.
5. Out of period adjustment.

Sch. 35 MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (MW & MWH)		Achieved Savings (MW & MWH)		Difference (MW & MWH)	
1	**Residential Weatherization**									
2	Zero Interest Program									
3	Initiated - 1978	$2,308	$866	166.51%				8		8
4	Projected Life - to be rolled into SGC HIP in 1994									
5	Low Income Program									
6	Initiated - 1987	$41,845	$40,340	3.73%				64		
7	Projected Life - Indefinite									
8										
9										
10										
11	**Residential Appliance**									
12	Efficient Water Heaters									
13	Initiated - 1987	$4,081						27		
14	Projected Life - Indefinite									
15	SERP									
16	Initiated - 1994							8		
17	Projected Life - 1997									
18										
19										
20										
21	**New Residential**									
22	Super Good Cents									
23	Initiated - 1988	$16,458	$59,006	-72.11%				12		
24	Projected Life - 1997									
25	Manufactured Aquisition Program (MAP)									
26	Initiated - 1991	$2,800	$378,250	-99.26%				6		
27	Projected Life - 1997									
28										
29										
30	Total Residential	$67,492	$478,462	-85.89%	0.05	392	0.02	125	(0)	(267)
31										
32										

Sch. 35 MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (MW & MWH)		Achieved Savings (MW & MWH)		Difference (MW & MWH)	
1	New Commercial									
2	Energy FinAnswer									
3	Initiated - 1991	$12,705	$24,949	-49.08%				76		76
4	Projected Life - Indefinite									
5	Energy FinAnswer 12,000									
6	Initiated - 1992	$78	$186	-58.06%				0		
7	Projected Life - Indefinite									
8										
9	Total cOMMERCIAL	$12,783	$25,135	-49.14%	0.21	1,646	0.01	76	(0.20)	(1,570)
10										
11										
12	Industrial									
13	Industrial FinAnwser									
14	Initiated - 1995	$0	$0		0.04	324	0.00	0	(0)	
15	Projected Life - Indefinite									
16										
17										
18										
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	TOTAL	$80,275	$503,597	-84.06%	0.30	2,363	0.03	202	(0.27)	(2,161)

MONTANA CONSUMPTION AND REVENUES

	Sales of Electricity	Operating Revenues Current Year	Operating Revenues Previous Year	MegaWatt Hours Sold Current Year	MegaWatt Hours Sold Previous Year	Avg. No. of Customers Current Year	Avg. No. of Customers Previous Year
1	Residential	$18,160,261	$18,161,798	360,867	362,264	28,200	28,275
2	Commercial - Small	12,521,172	12,549,315	270,596	269,661	5,673	5,545
3	Commercial - Large						
4	Industrial - Small	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
5	Industrial - Large	12,723,215	10,858,213	312,041	322,279	300	262
6	Interruptible Industrial						
7	Public Street & Highway Lightin	149,049	157,610	2,259	2,392	58	49
8	Other Sales to Public Authorities						
9	Sales to Cooperatives						
10	Sales to Other Utilities	29,260,533	13,302,591	1,213,874	552,343	3	1
11	Interdepartmental						
12							
13	TOTAL	$72,814,230	$55,029,527	2,159,637	1,508,939	34,234	34,132

Excludes Other Electric Revenues.

825 N.E. Multnomah
Portland, Oregon 97232
(503) 464-5000

PACIFICORP
PACIFIC POWER UTAH POWER

June 10, 1998

Montana Public Service Commission
Attn: Laura J. Calkin
Accounting & Support Services
P.O. Box 202601
Helena, Montana 59620-2601

RE: Annual Reports for 1997

Dear Ms. Calkin:

Enclosed is a copy of our Annual State Report. If you have any questions, please don't hesitate to call me at (503) 813-6081.

Very truly yours,

Brian K. Hedman
Manager, Regulation

Enclosure

Notes
to
Financial
Statements

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PacifiCorp (the "Company") is an integrated electric utility that conducts its retail electric utility operations through Pacific Power and Utah Power, and engages in wholesale electric transactions under the name PacifiCorp. The Company is the indirect owner, through its wholly owned subsidiary, PacifiCorp Group Holdings Company, formerly PacifiCorp Holdings, Inc. ("Holdings"). Wholly owned subsidiaries of Holdings include Powercor Australia Limited ("Powercor"), an Australian electricity distributor purchased December 12, 1995; PacifiCorp Financial Services, Inc. ("PFS"), a financial services business; PacifiCorp Power Marketing, engaged in wholesale electricity trading in the eastern United States energy markets; and TPC Corporation ("TPC"), a natural gas marketing and storage company, purchased April 15, 1997.

The Company sold its telecommunications operation, Pacific Telecom, Inc. ("PTI") on December 1, 1997. See Note 14. The Company disposed of Pacific Generation Company ("PGC") on November 1, 1997, and the natural gas gathering and processing assets of TPC on December 1, 1997. See Note 15. In addition, the Company has signed letters of intent to sell the real estate assets held by its financial services business.

These regulatory basis financial statements have been prepared for the purpose of complying with, and on the basis of accounting practices specified by the Federal Energy Regulatory Commission ("FERC"). Accordingly, investments in subsidiaries are accounted for and reported on the equity basis of accounting and these regulatory basis financial statements do not include debt of the Leveraged ESOP Trust established under the PacifiCorp K Plus Employee Savings and Stock Ownership Plan ("K Plus Plan") which is guaranteed by Holdings and do not present financial position, results of operations and changes in cash flows in accordance with generally accepted accounting principles, which would require that the accounts of the subsidiaries be consolidated with those of PacifiCorp.

Name of Respondent PacifiCorp	This Report Is: (1) [X]An Original (2) [ ]A Resubmission	Date of Report (Mo,Da,Yr)	Year of Report Dec. 31, 1997

NOTES TO FINANCIAL STATEMENTS (Continued)

The following schedule shows increases and decreases had the accounts of the subsidiaries been consolidated with those of the Company:

THOUSANDS OF DOLLARS	CONSOLIDATED	FERC FORM 1 FINANCIALS	INCREASE/ (DECREASE)
AT DECEMBER 31, 1997			
Property, plant and equipment - net	$9,070,296	$7,825,472	$ 1,244,824
Investments in subsidiaries	-	2,393,747	(2,393,747)
Current assets	2,182,364	801,162	1,381,202
Other assets	2,627,577	1,284,048	1,343,529
Common stock	3,274,248	3,287,356	(13,108)
Retained earnings	1,106,268	1,076,194	30,074
Cumulative currency translation adj	(59,596)	-	(59,596)
Preferred stock	241,364	241,364	-
Long-term debt	4,414,476	4,008,672	405,804
Guaranteed Preferred Beneficial Interests in Company's Junior Subordinated Debentures	340,409	-	340,409
Current liabilities	2,105,519	1,756,938	348,581
Deferred credits	2,457,549	1,933,905	523,644
AT DECEMBER 31, 1996			
Property, plant and equipment - net	$9,267,114	$7,825,125	$ 1,441,989
Investments in subsidiaries	-	1,506,260	(1,506,260)
Current assets	1,661,926	673,277	988,649
Other assets	2,883,292	1,356,106	1,527,186
Common stock	3,236,756	3,250,444	(13,688)
Retained earnings	782,836	771,026	11,810
Cumulative currency translation adjustment	12,718	-	12,718
Preferred stock	313,538	313,538	-
Long-term debt	4,829,385	3,770,845	1,058,540
Guaranteed Preferred Beneficial Interests in Company's Junior Subordinated Debentures	209,732	-	209,732
Current liabilities	1,755,336	1,291,880	463,456
Deferred credits	2,672,031	1,963,035	708,996

NOTES TO FINANCIAL STATEMENTS (Continued)

THOUSANDS OF DOLLARS	CONSOLIDATED	FERC FORM 1 FINANCIALS	INCREASE/ (DECREASE)
FOR THE YEAR ENDED DECEMBER 31, 1997			
Operating revenues	$ 6,277,989	$3,683,921	$ 2,594,068
Operating expenses	5,475,491	3,200,919	2,274,572
Net cash provided by oper. activities	834,088	674,878	159,210
Net cash provided by (used in) investing activities	922,028	(860,606)	1,782,634
Net cash provided by (used in) financing activities	(1,023,191)	208,325	1,231,516
FOR THE YEAR ENDED DECEMBER 31, 1996			
Operating revenues	3,803,712	2,961,321	842,391
Operating expenses	2,717,334	2,309,175	408,159
Net cash provided by oper. activities	925,683	663,761	261,922
Net cash used in investing activities	(781,571)	(581,779)	(199,792)
Net cash used in financing activities	(151,540)	(101,449)	(50,091)

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements. Actual results could differ from those estimates.

Regulation

Accounting for the Company conforms with generally accepted accounting principles as applied to regulated public utilities and as prescribed by the Federal Energy Regulatory Commission and the regulatory agencies and the commissions of the various states in which the Company operates. The Company prepares its financial statements in accordance with Statement of Financial Accounting Standards ("SFAS") 71, "Accounting for the Effects of Certain Types of Regulation." See Note 2.

Asset Impairment

Long-lived assets and certain identifiable intangibles to be held and used by the Company are reviewed for impairment whenever events or circumstances indicate costs may not be recoverable. Impairment losses on long-lived assets are recognized when book values exceed expected undiscounted cash flows. If impairment exists, the asset's book value will be written down to its fair value.

NOTES TO FINANCIAL STATEMENTS (Continued)

Cash and Cash Equivalents

For the purposes of these financial statements, the Company considers all liquid investments with original maturities of three months or less to be cash equivalents.

Property, Plant and Equipment

Property, plant and equipment is stated at original cost of contracted services, direct labor and material, interest capitalized during construction and indirect charges for engineering, supervision and similar overhead items. The cost of depreciable utility properties retired, including the cost of removal, less salvage, is charged to accumulated depreciation.

Depreciation and Amortization

At December 31, 1997, the average depreciable life of property, plant and equipment by category was: Production, 35 years; Transmission, 42 years; Distribution, 31 years and Other, 16 years.

Depreciation and amortization is computed generally by the straight-line method in the following manner: As prescribed by the Company's various regulatory jurisdictions for regulated assets; and over the estimated useful lives of the related assets for nonregulated generation resource assets and for other nonregulated assets. Provisions for depreciation (excluding amortization of capital leases) were 3.2 and 3.1 percent of average depreciable assets in 1997 and 1996, respectively.

Mine Reclamation and Closure Costs

The Company expenses current mine reclamation costs and accrues for estimated final mine reclamation and closure costs using the units-of-production method.

Inventory Valuation

Inventories are generally valued at the lower of average cost or market.

Derivatives

Gains and losses on hedges of existing assets and liabilities are included in the carrying amounts of those assets or liabilities and are recognized in income as part of those carrying amounts. Gains and losses related to hedges of anticipated transactions and firm commitments are deferred on the balance sheet and recognized in income when the transaction occurs.

Interest Capitalized

Costs of debt and equity funds applicable to utility properties are capitalized during construction. Generally, the composite capitalization rates allowed were 5.7 percent for 1997 and 5.6 percent for 1996.

Income Taxes

The Company uses the liability method of accounting for deferred income taxes. Deferred tax liabilities and assets reflect the expected future tax consequences, based on enacted tax law, of temporary differences between the tax bases of assets and liabilities and their financial reporting amounts.

Prior to 1980, the Company did not provide deferred taxes on many of the timing differences between book and tax depreciation. In prior years, these benefits were flowed through to the utility customer as prescribed by the Company's various regulatory jurisdictions. Deferred income tax liabilities and regulatory assets have been established for those flow through tax benefits. See Note 2.

Investment tax credits are deferred and amortized to income over periods prescribed by the Company's various regulatory jurisdictions.

Revenue Recognition

The Company accrues estimated unbilled revenues for electric services provided after cycle billing to month-end.

Preferred Stock Retired

Amounts paid in excess of the net carrying value of preferred stock retired are amortized in accordance with regulatory orders.

Stock Based Compensation

The Company has elected to follow Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees ("APB 25") and related interpretations in accounting for its employee stock options. Under APB 25, because the exercise price of employee stock options equals the market price of the underlying stock on the date of grant, no compensation expense is recorded.

New Accounting Standards

In June 1997, the Financial Accounting Standards Board (the "FASB") issued SFAS 130, "Reporting Comprehensive Income," and SFAS 131, "Disclosures About Segments of an Enterprise and Related Information." SFAS 130 establishes standards for reporting and display of comprehensive income in financial statements. SFAS 131 requires that companies disclose segment data based on how management makes decisions about allocating resources to segments and measuring performance. In February 1998, the FASB issued SFAS 132, "Employers' Disclosures About Pensions and Other Postretirement Benefits." These standards are effective for fiscal years beginning after December 15, 1997. Adoption of these standards may result in additional financial disclosure but will not have an effect on the Company's financial position or results of operations.

Reclassification

Certain amounts from the prior year have been reclassified to conform with the 1997 method of presentation. These reclassifications had no effect on previously reported net income.

NOTE 2. ACCOUNTING FOR THE EFFECTS OF REGULATION

Regulated utilities have historically applied the provisions of SFAS 71 which is based on the premise that regulators will set rates that allow for the recovery of a utility's costs, including cost of capital. Accounting under SFAS 71 is appropriate as long as: rates are established by or subject to approval by independent, third-party regulators; rates are designed to recover the specific enterprise's cost-of-service; and in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be collected from customers. In applying SFAS 71, the Company must give consideration to changes in the level of demand or competition during the cost recovery period. In accordance with SFAS 71, the Company capitalizes certain costs, regulatory assets, in accordance with regulatory authority whereby those costs will be expensed and recovered in future periods.

The Emerging Issues Task Force of the Financial Accounting Standards Board (the EITF) concluded in 1997 that SFAS 71 should be discontinued when detailed legislation or regulatory order regarding competition is issued. Additionally, the EITF concluded that regulatory assets and liabilities applicable to businesses being deregulated should be written off unless their recovery is provided for through future regulated cash flows.

In 1996, legislation was passed in California restructuring its electric utility industry. The restructuring is scheduled to begin March 31, 1998, at which time customers will be able to buy their electricity from sources other than the local utility. The local utility will continue to provide distribution services. Legislation was also passed in Montana in 1997 which established a phased process to introduce price-based competition into the supply of electricity in Montana. As a result of these legislative actions, prices for the supply of electric generation in

California and Montana are, or are expected to be, in transition from cost-based regulated rates to rates determined by competitive market forces.

Regulatory assets-net at December 31, 1997 and 1996 included the following:

THOUSANDS OF DOLLARS/DECEMBER 31	1997	1996
Deferred taxes - net (a)	$650,145	$ 675,984
Deferred pension costs	-	102,888
Demand-side resource costs	108,303	118,773
Unamortized net loss on reacquired debt	60,617	68,415
Unrecovered Trojan Plant and regulatory study costs	22,972	26,851
Various other costs	58,715	63,312
Total	$900,752	$1,056,223

(a) Excludes $133,261 of investment tax audit regulatory liabilities.

The Company has evaluated its regulatory assets and liabilities related to the generation portion of its business allocable to the states of California and Montana based upon future regulated cash flows. Accordingly, the Company ceased the application of SFAS 71 to its generation business allocable to the states of California and Montana in 1997. The Company recorded an extraordinary loss of $15,994,000 for the write off of these regulatory assets and liabilities.

The Company operates in five other states (Oregon, Utah, Wyoming, Washington and Idaho) which are at various stages of addressing the issue of deregulating the electricity industry. At December 31, 1997, $382,000,000 of the $900,752,000 total regulatory assets - net was applicable to the generation assets allocable to these five states. Because of the potential regulatory and/or legislative actions in these other state jurisdictions, the Company may have additional regulatory asset write offs and charges for impairment of long-lived assets in future periods relating to the generation portion of its business.

Also in 1997, the Company evaluated all its regulatory assets and liabilities applicable to deferred pension costs which relate primarily to a deferred compensation plan and early retirement incentive programs in 1987 and 1990 and determined that recovery of these costs was not probable. As a result, the Company recorded an $86,887,000 write off of its deferred regulatory pension asset, since the Company does not intend to seek recovery of these costs. However, the Company will seek recovery for its current and future pension costs.

In early 1997, the Division of Public Utilities (the "DPU") and the Committee of Consumer Services (the "CCS") in Utah filed a joint petition with the Utah Public Service Commission (the "PSC") requesting the PSC to commence proceedings to establish new rates for Utah customers. The DPU indicated that rates could be reduced by approximately $54,000,000. Subsequently in March 1997, the Utah Legislature passed a bill that created a legislative task force to study electrical restructuring and customer choice issues in the State of Utah. The bill precluded the PSC from holding hearings on rate changes and froze prices at January 31, 1997 levels until May 1998, but allowed for retroactive price changes. The Company agreed to an interim price decrease to Utah customers of $12,400,000 annually beginning on April 15, 1997.

During the freeze period, the PSC proceeded with hearings on the proper method for cost allocation among PacifiCorp's seven jurisdictions that would be used in the 1998 rate case. The DPU recommended an allocation method that would reduce prices by $56,000,000 over five years, of which $14,000,000 was included in its original estimate of $54,000,000. During these hearings,the CCS recommended a method that would reduce prices by $96,000,000 or $42,000,000 more than the original DPU estimate. The Company advocated a method that would result in a decrease of approximately $3,000,000 per year. The PSC held hearings in December and an order is expected in early 1998. An allocation order by itself will not decrease revenues, but will be incorporated into subsequent rate proceedings which are expected to occur in mid-1998 and will be combined with other cost increases and determine the overall impact to customer rates decreases to.

NOTE 3. SPECIAL CHARGES

In December 1997,the Company recorded in operating income special charges of $170,436,000 ($105,756,000 after-tax). The pretax special charges included write off of $86,887,000 of deferred regulatory pension assets (see Note 2), a $19,096,000 write off of certain information system assets associated with the Company's decision to proceed with an installation of SAP enterprise-wide software and $64,453,000 of costs associated with the write down of assets and acceleration of reclamation costs due to the early closure of the Glenrock coal mine. The inability of the mine to remain competitive has caused it to be uneconomic under current and expected market conditions due to increased mining stripping ratios, coal quality and related costs.

Also, in January 1998, the Company announced a plan to reduce its work force by approximately 600 positions, or 7 percent of the work force in 1998. This reduction will be accomplished through a combination of voluntary early retirement and special severance. Employees are not required to finalize their acceptance of offers until March 31, 1998. Based upon the current acceptance rate, the pretax costs are estimated to be $104,000,000, which will be recorded in the first quarter of 1998. The current acceptance rate has exceeded the Company's original estimate.

NOTE 4. SHORT-TERM DEBT AND BORROWING ARRANGEMENTS

Information concerning short-term debt and borrowing arrangements is as follows:

THOUSANDS OF DOLLARS	BALANCE	AVERAGE INTEREST RATE (a)
12/31/1997	$303,179	6.5%
12/31/1996	$675,007	5.6%

(a) Computed by dividing the total interest on principal amounts outstanding the end of the period by the weighted daily principal amounts outstanding

At December 31, 1997, the Company's commercial paper and bank line borrowings were supported by revolving credit agreements totaling $700 million.

NOTE 5. LONG-TERM DEBT

The Company's long-term debt at December 31 was as follows:

THOUSANDS OF DOLLARS	1997	1996
First mortgage and collateral trust bonds		
Maturing 1998 through 2002/5.9%-9.5%	$ 882,200	$1,074,500
Maturing 2003 through 2007/6.1%-9%	756,068	587,205
Maturing 2008 through 2012/7%-9.2%	267,566	144,948
Maturing 2013 through 2017/7.3%-8.8%	164,929	167,641
Maturing 2018 through 2022/8.1%-8.5%	175,000	175,000
Maturing 2023 through 2026/6.7%-8.6%	286,500	286,500
Guaranty of pollution control revenue bonds		
5.6%-5.7% due 2021 through 2023 (a)	71,200	71,200
Variable rate due 2013 through 2024 (a)(b)	216,470	216,470
Variable rate due 2005 through 2030 (b)	450,700	450,700
Funds held by trustees	(9,119)	(12,140)
8.4%-8.6% Junior subordinated debentures due 2025 through 2035	175,826	175,826
Advances fom associated companies	430,562	276,186
Unamortized premium and discount	1,822	4,598
Capital lease obligations	23,327	23,576
Total	3,893,051	3,642,210
Less current maturities	194,927	203,797
TOTAL	$3,698,124	$3,438,413

NOTES TO FINANCIAL STATEMENTS (Continued)

(a) Secured by pledged first mortgage and collateral trust bonds generally at the same interest rates, maturity dates and redemption provisions as the secured pollution control revenue bonds.

(b) Interest rates fluctuate based on various rates, primarily on certificate of deposit rates, interbank borrowing rates, prime rates or other short-term market rates.

Approximately $4.8 billion of the assets of the Company secure long-term debt. First mortgage and collateral trust bonds of the Company may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures.

The junior subordinated debentures are unsecured obligations of the Company and are subordinated to the Company's first mortgage and collateral trust bonds, pollution control revenue bonds, commercial paper, bank debt and any future senior indebtedness.

The Company has guaranteed all of the obligations of PacifiCorp Capital I and PacifiCorp Capital II, wholly owned subsidiary trusts of the Company. See Note 12.

The annual maturities of long-term debt and redeemable preferred stock outstanding are $194,927,000, $297,620,000, $168,459,000, $236,042,000 and 144,025,000 in 1998 through 2002, respectively.

NOTE 6. COMMON AND PREFERRED STOCK

THOUSANDS OF SHARES/DOLLARS	SHARES COMMON STOCK	SHARES PREFERRED STOCK	COMMON SHARE-HOLDERS' CAPITAL
At January 1, 1996	284,277	8,299	$3,028,917
Dividend Reinvestment Plan	2,082	-	43,291
Stock Compensation Plan	(9)	-	(2,482)
Sales to Public	8,790	-	177,788
Redemptions and Repurchases	-	(2,343)	2,929
At December 31, 1996	295,140	5,956	3,250,443
Dividend Reinvestment Plan	1,779	-	37,607
Stock Compensation Plan	(11)	-	(881)
Redemptions and Repurchases	-	(2,797)	187
At December 31, 1997	296,908	3,159	$3,287,356

At December 31, 1997, there were 30,227,513 authorized but unissued shares of common stock reserved for issuance under the Dividend Reinvestment and Stock Purchase Plan and the Employee Savings and Stock Ownership Plans and for sales to the public. Eligible employees under the employee plans may direct their pretax elective contributions into the purchase of the Company's common stock. The Company makes matching contributions, equal to a percentage of employee contributions, which are invested in the Company's common stock. Employee contributions eligible for matching contributions are limited to 6 percent of compensation.

Generally, preferred stock is redeemable at stipulated prices plus accrued dividends, subject to certain restrictions. Upon involuntary liquidation, all preferred stock is entitled to stated value or a specified preference amount per share plus accrued dividends.

Next Page is 200

Name of Respondent PacifiCorp	This Report Is: (1) [X]An Original (2) [ ]A Resubmission	Date of Report (Mo,Da,Yr)	Year of Report Dec. 31, 1997

NOTES TO FINANCIAL STATEMENTS (Continued)

PREFERRED STOCK OUTSTANDING
THOUSANDS OF SHARES/DECEMBER 31

DECEMBER 31 SERIES	1997 SHARES	1997 AMOUNT	1996 SHARES	1996 AMOUNT
SUBJECT TO MANDATORY REDEMPTION				
No Par Serial Preferred, $100 stated value, 16,000 Shares authorized				
$7.12	-	$ -	30	$ 3,000
7.70	1,000	100,000	1,000	100,000
7.48	750	75,000	750	75,000
TOTAL	1,750	$175,000	1,780	$178,000
NOT SUBJECT TO MANDATORY REDEMPTION				
No Par Serial Preferred, $25 stated value				
$1.16	193	4,828	193	4,828
1.18	420	10,503	420	10,503
1.28	381	9,531	381	9,530
1.98, Series 1992	-	-	2,767	69,175
Serial Preferred, $100 stated value, 3,500 Shares authorized				
4.52%	2	206	2	206
4.56	85	8,459	85	8,459
4.72	70	6,989	70	6,989
5.00	42	4,200	42	4,200
5.40	66	6,596	66	6,596
6.00	6	593	6	593
7.00	18	1,806	18	1,806
5% Preferred, $100 stated value, 127 Shares authorized and outstanding	127	12,653	127	12,653
TOTAL	1,410	$66,364	4,177	$135,538

Mandatory redemption requirements at stated value plus accrued dividends on No Par Serial Preferred Stock are as follows: the $7.70 series is redeemable in its entirety on August 15, 2001; and 37,500 shares of the $7.48 series are redeemable on each June 15 from 2002 through 2006, with all shares outstanding on June 15, 2007 redeemable on that date. If the Company is in default in its obligation to make any future redemptions on the $7.48 series, it may not pay cash dividends on common stock.

NOTE 7. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company seeks to reduce net income and cash flow exposure to changing interest and currency exchange rates and commodity price risks through the use of derivative financial instruments. The Company's participation in derivative transactions involves instruments that have a close correlation with its portfolio of liabilities, thereby managing its risk. Derivatives have been designed for hedging purposes and are not held or issued for speculative purposes.

Notional Amounts and Credit Exposure of Derivatives

The notional amounts of derivatives summarized below do not represent amounts exchanged and, therefore, are not a measure of the exposure of the Company through its use of derivatives. The amounts exchanged are calculated on the basis of the notional amounts and other terms of the derivatives, which relate to interest rates or other indexes.

The Company is exposed to credit-related losses in the event of nonperformance by counterparties to financial instruments, but it does not expect any counterparties to fail to meet their obligations given their high credit rating requirements. The Company's credit policy provides that counterparties satisfy minimum credit ratings. The credit exposure of interest rate and forward contracts is represented by the fair value of contracts with a positive fair value at the reporting date.

Interest Rate Risk Management

The Company enters into interest rate swaps to adjust the characteristics of its liability portfolio, allowing the Company to establish a mix of fixed or variable interest rates on its outstanding debt. The Company had outstanding interest rate contracts with notional amounts of $210,645,000 and $273,422,000 at December 31, 1997 and 1996, respectively.

Under the various swap agreements, the Company agrees with other parties to exchange, at specified intervals, the difference between fixed-rate and floating-rate interest amounts calculated by reference to an agreed notional principal amount. The following table indicates the weighted-average interest rates of the swaps. Average variable rates are based on rates implied in the yield curve at December 31; these may change significantly, affecting future cash flows. Swap contracts are principally between one and fifteen years in duration.

	1997	1996
PAY-FIXED SWAPS		
Average pay rate	8.2%	8.2%
Average receive rate	4.9	4.9

Commodity Risk Management

At December 31, 1997 and 1996, the Company had open NYMEX futures contracts as follows:

	1997	1996
OPEN CONTRACTS (number)		
Purchase	489	67
Sell	110	-
NOTIONAL QUANTITIES (mWh)		
Purchase	359,904	49,300
Sell	80,960	-
FAIR MARKET VALUE (thousands of dollars)		
Purchase	$(691)	$(175)
Sell	69	-

8. FAIR VALUE OF FINANCIAL INSTRUMENTS

	DECEMBER 31, 1997		DECEMBER 31, 1996	
THOUSANDS OF DOLLARS	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
Long-term debt	$3,869,724	$4,013,940	$3,618,634	$3,686,098
Preferred stock subject to mandatory redemption	175,000	194,125	178,000	195,800
Derivatives relating to interest	-	(31,902)	(10,788)	(38,991)

The carrying value of cash and cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximate fair value because of the short-term maturity of these instruments.

The fair value of the Company's long-term debt has been estimated by discounting projected future cash flows, using the current rate at which similar loans would be made to borrowers with similar credit ratings and for the same maturities. Current maturities of long-term debt were included. The fair value of redeemable preferred stock was based on bid prices from an investment bank.

The fair value of interest rate derivatives and electricity futures is the estimated amount the Company would have to receive (pay) to terminate the agreements, taking into account current interest rates and the current creditworthiness of the agreement counterparties.

NOTE 9. COMMITMENTS AND CONTINGENCIES

The Company is subject to numerous environmental laws including: the Federal Clean Air Act, as enforced by the Environmental Protection Agency and various state agencies; the 1990 Clean Air Act Amendments; the Endangered Species Act as it relates to certain potentially endangered species of salmon; the Comprehensive Environmental Response, Compensation and Liability Act, relating to environmental cleanups; along with the Federal Resource Conservation and Recovery Act and the Clean Water Act relating to water quality. These laws could potentially impact future operations. For those contingencies identified at December 31, 1997, principally the Superfund sites where the Company has been or may be designated as a potentially responsible party and the Clean Air Act matters, future costs associated with the disposition of these matters are not expected to be material to the Company's regulatory basis financial statements.

The Company's mining operations are subject to reclamation and closure requirements. The Company monitors these requirements and periodically revises its cost estimates to meet existing legal and regulatory requirements of the various jurisdictions in which it operates. Costs for reclamation are accrued using the units-of-production method such that estimated final mine reclamation and closure costs are fully accrued at completion of mining activities, except where the Company has decided to close a mine. When a mine is closed, the Company records the estimated cost to complete the mine closure. This is consistent with industry practices and, the Company believes that it has adequately provided for its reclamation obligations.

The Company is party to various legal claims, actions and complaints, certain of which involve material amounts. Although the Company is unable to predict with certainty whether or not it will ultimately be successful in these legal proceedings or, if not, what the impact might be, management currently believes that disposition of these matters will not have a materially adverse effect on the Company's regulatory basis financial statements.

Construction and Other

Construction and acquisitions are estimated at $550,000,000 for 1998. As part of these programs, substantial commitments have been made.

Leases

The Company leases certain properties under leases with various expiration dates and renewal options. Rentals on lease renewals are subject to negotiation. Certain leases provide for options to purchase at fair market value. The Company is also committed to pay all taxes, expenses of operation (other than depreciation) and maintenance applicable to the leased property.

Net rent expense for the years ending December 31, 1997 and 1996 was $12,470,000 and $10,484,000, respectively.

Future minimum lease payments under noncancellable operating leases are $2,127,000, $1,281,000, $1,764,000, $1,698,000, $1,472,000 and $6,007,000 for 1998 through 2002 and years thereafter, respectively.

Jointly Owned Plants

At December 31, 1997, the Company's participation in jointly owned plants was as follows:

THOUSANDS OF DOLLARS	COMPANY'S SHARE	PLANT IN SERVICE	ACCUMULATED DEPRECIATION	CONSTRUCTION WORK IN PROGRESS
Centralia	47.5%	$181,513	$111,120	$ 527
Jim Bridger Units 1,2,3 and 4	67.7	796,096	320,340	4,532
Trojan(a)	2.5	-	-	-
Colstrip Units 3 and 4	10.0	205,214	68,042	57
Hunter Unit 1	93.8	260,954	107,104	1,362
Hunter Unit 2	60.3	188,620	71,247	10,314
Wyodak	80.0	304,856	102,918	388
Craig Station Units 1 and 2	19.3	150,550(b)	59,439	1,077
Hayden Station Unit 1	24.5	18,556(b)	12,021	6,043
Hayden Station Unit 2	12.6	15,638(b)	8,827	3,404
Hermiston(c)	50.0	156,721	10,932	40

(a)Plant, inventory, fuel and decommissioning costs totaling $23 million relating to the Trojan Plant were included in regulatory assets-net at December 31, 1997.

(b)Excludes unallocated acquisition adjustments of $114 million.

(c)Additionally, the Company has contracted to purchase the remaining 50 percent of the output of this plant.

Under the joint agreements, each participating utility is responsible for financing its share of construction, operating and leasing costs. The Company's portion is recorded in its applicable operations, maintenance and tax accounts.

Long-term Wholesale Sales and Purchased Power Contracts

The Company manages its energy resource requirements by integrating long-term firm, short-term and spot market purchases with its own generating resources to economically dispatch the system and meet commitments for wholesale sales and retail load growth. The long-term wholesale sales commitments include contracts with minimum sales requirements of $484,900,000 in 1998, $449,700,000 in 1999, $415,100,000 in 2000, $315,600,000 in 2001 and $308,500,000 in 2002. As part of its energy resources portfolio, the Company acquires power through long-term purchases and/or exchange agreements which require minimum fixed payments of $320,000,000 in 1998, $316,400,000 in 1999, $313,700,000 in 2000, $290,100,000 in 2001 and $298,000,000 in 2002. The contracts include agreements with the Bonneville Power Administration, the Hermiston Plant and a number of cogenerating facilities

Excluded from the minimum fixed annual payments above, are commitments to purchase power from several hydroelectric projects under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of project output and for a like percentage of project annual costs (operating expenses and debt service). These costs are included in operations expense. The Company is required to pay its portion of the debt service, whether or not any power is produced. The arrangements provide for nonwithdrawable power and the majority also provide for additional power, withdrawable by the districts upon one to five years' notice. For 1997, such purchases approximated 3 percent of energy requirements.

At December 31, 1997, the Company's share of long-term arrangements with public utility districts was as follows:

GENERATING FACILITY (THOUSANDS OF DOLLARS)	YEAR CONTRACT EXPIRES	CAPACITY (kW)	PERCENTAGE OF OUTPUT	ANNUAL COSTS (a)
Wanapum	2009	155,444	18.7%	$ 4,400
Priest Rapids	2005	109,602	13.9	3,500
Rocky Reach	2011	64,297	5.3	2,900
Wells	2018	59,617	7.7	2,000
TOTAL		388,960		$12,800

(a)Annual costs include debt service of $7 million.

The Company has a 4 percent interest in the Intermountain Power Project (the Project), located in central Utah. The Company and the city of Los Angeles have agreed that the City will purchase capacity and energy from Company plants equal to the Company's 4 percent entitlement of the Project at a price equivalent to 4 percent of the expenses and debt service of the Project.

Fuel Contracts

The Company has take or pay coal and natural gas contracts which require minimum fixed payments of $83,000,000 for 1998 and 1999, $90,000,000 for 2000, $62,000,000 for 2001 and $64,000,000 for 2002.

NOTE 10. INCOME TAXES

Excluding equity in subsidiaries' earnings, the Company's effective combined federal and state income tax rate from continuing operations was 37 percent in both 1997 and 1996. The difference between taxes calculated as if the statutory federal tax rate of 35 percent was applied to income from continuing operations before income taxes and the recorded tax expense is reconciled as follows:

THOUSANDS OF DOLLARS	1997	1996
COMPUTED FEDERAL INCOME TAXES	$104,363	$205,894
INCREASE (REDUCTION) IN TAX RESULTING FROM		
Depreciation differences (flow-through basis)	14,282	12,726
Investment tax credits	(7,938)	(8,926)
Depletion	(2,570)	(3,717)
Other items capitalized and miscellaneous differences	(7,129)	(6,780)
Total	(3,355)	(6,697)
FEDERAL INCOME TAX	101,008	199,197
STATE INCOME TAX, NET OF FEDERAL INCOME TAX BENEFIT	10,378	17,828
TOTAL INCOME TAX EXPENSE	$111,386	$217,025

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1997

NOTES TO FINANCIAL STATEMENTS (Continued)

The provision for income taxes is summarized as follows:

THOUSANDS OF DOLLARS	1997	1996
CURRENT		
Federal	$164,133	$157,722
State	20,615	23,131
Total	184,748	180,853
DEFERRED		
Federal	(60,775)	40,800
State	(4,649)	4,297
Total	(65,424)	45,097
INVESTMENT TAX CREDITS	(7,938)	(8,925)
TOTAL INCOME TAX EXPENSE	$111,386	$217,025

The tax effects of significant items comprising the Company's net deferred tax liability at December 31 are as follows:

THOUSANDS OF DOLLARS	1997	1996
Property, plant and equipment	$ 859,001	$ 855,445
Regulatory asset	704,104	733,100
Other deferred liabilities	31,116	54,275
DEFERRED TAX ASSETS		
Regulatory liability	(53,959)	(57,116)
Book reserves not deductible for tax	(11,403)	(6,365)
Pension accrual	(39,919)	(8,132)
Other deferred assets	(45,309)	(46,581)
NET DEFERRED TAX LIABILITY	$1,443,631	$1,524,626

During 1996, the Company received an examination report for 1989 and 1990 proposing adjustments. The Company filed a protest of certain proposed adjustments on July 30, 1996 and is currently holding discussions with the Appeals Division of the IRS. The Company's 1991, 1992, and 1993 federal income tax returns are currently under examination by the IRS.

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Name of Respondent	This Report Is:	Date of Report	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo,Da,Yr)	Dec. 31, 1997

NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 11. EMPLOYMENT PLANS

Retirement Plans

The Company has a pension plan covering substantially all of its employees. Benefits under this plan are generally based on the employee's years of service and average monthly pay in the 60 consecutive months of highest pay out of the last 120 months, with adjustments, to reflect benefits estimated to be received from Social Security. Pension costs are funded annually by no more than the maximum amount of pension expense which can be deducted for federal income tax purposes. Unfunded prior service costs are amortized over the remaining service period of employees expected to receive benefits. At December 31, 1997, plan assets were primarily invested in common stocks, bonds and United States government obligations.

Net pension cost for the years ended December 31 is summarized as follows:

THOUSANDS OF DOLLARS	1997	1996
Service cost - benefits earned	$ 24,697	$ 27,597
Interest cost on projected benefit obligation	77,211	72,193
Actual gain on plan assets	(70,997)	(59,114)
Net amortization and deferral	9,468	8,881
Regulatory deferral (see Note 2)	-	14,212
NET PENSION COST	$ 40,379	$ 63,769

Name of Respondent	This Report Is:	Date of Report	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1997

NOTES TO FINANCIAL STATEMENTS (Continued)

The funded status, net pension liability and significant assumptions at December 31 are as follows:

THOUSANDS OF DOLLARS	1997	1996
Actuarial present value of benefit obligations		
Vested benefit obligation	$ 930,296	$ 837,016
Accumulated benefit obligation	$ 988,800	$ 910,333
Projected benefit obligation	$1,144,969	$1,027,416
Plan assets at fair value	929,804	786,947
Projected benefit obligation in excess of plan assets	215,165	240,469
Unrecognized prior service cost	(15,237)	(13,697)
Unrecognized net loss	(9,825)	(87,038)
Unrecognized net obligation	(79,986)	(10,113)
Minimum liability adjustment	5,514	2,891
NET PENSION LIABILITY	$ 115,631	$ 132,512
Discount rate	7%	7.5%
Expected long-term rate of return on assets	9.25%	9%
Rate of increase in compensation levels	4%	4.5%

Other Postretirement Benefits

The Company provides health care and life insurance benefits through various plans for eligible retirees on a basis substantially similar to those who are active employees. The cost of postretirement benefits are accrued over the active service period of employees. The transition obligation represents the unrecognized prior service cost and is being amortized over a period of 20 years. For those employees retired at January 1, 1993, the Company funds postretirement benefit expense on a pay-as-you-go basis and has an unfunded accrued liability of $58,343,000 at December 31, 1997. For those employees retiring after January 1, 1993, the Company funds postretirement benefit expense through a combination of funding vehicles. The Company funded $15,637,000 and $28,011,000 of postretirement benefit expense during 1997 and 1996, respectively. These funds are invested in common stocks, bonds and United States government obligations

NOTES TO FINANCIAL STATEMENTS (Continued)

The net periodic postretirement benefit cost for the years ended December 31, 1997 and 1996 are summarized as follows:

THOUSANDS OF DOLLARS	1997	1996
Service costs - benefits earned	$ 7,181	$ 6,912
Interest cost on accumulated postretirement benefit obligation	21,787	21,838
Amortization of transition obligation	11,879	12,560
Regulatory deferral	6,392	3,400
Net asset gain during the period deferred for future recognition	18,963	3,514
Actual gain on plan assets	(31,465)	(12,612)
NET PERIODIC POSTRETIREMENT BENEFIT COST	$ 34,737	$ 35,612

The accumulated postretirement benefit obligation ("APBO") at December 31 was as follows:

THOUSANDS OF DOLLARS	1997	1996
Retirees and dependents	$172,248	$ 167,958
Fully eligible active plan participants	11,973	10,113
Other active plan participants	143,157	131,014
APBO	327,378	309,085
Plan assets at fair value	179,773	135,063
APBO in excess of plan assets	147,605	174,022
Unrecognized transition obligation	(209,260)	(223,211)
Unrecognized net gain	64,300	51,199
ACCRUED POSTRETIREMENT BENEFIT OBLIGATION	$ 2,645	$ 2,010

Discount rate	7%	7.5%
Estimated long-term rate of return on assets	9.25%	9%
Initial health care cost trend rate-under 65	8.3%	8.8%
Initial health care cost trend rate-over 65	8.3%	8.4%
Ultimate health care cost trend rate	4.5%	4.5%

The assumed health care cost trend rate gradually decreases over eight years. The health care cost trend rate assumption has a significant effect on the amounts reported. Increasing the assumed health care cost trend rate by one percentage point would have increased the APBO as of December 31, 1997 by $29,347,000 and the annual net periodic postretirement benefit cost by $2,732,000.

Name of Respondent	This Report Is:	Date of Report	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1997

NOTES TO FINANCIAL STATEMENTS (Continued)

Postemployment Benefits

The Company provides certain postemployment benefits to former employees and their dependents during the period following employment but before retirement. The costs of these benefits are accrued as they are incurred. Benefits include salary continuation, severance benefits, disability benefits and continuation of health care benefits for terminated and disabled employees and workers compensation benefits. Accrued costs for postemployment benefits were $12,600,000 and $4,500,000 in 1997 and 1996, respectively.

Pending Early Retirement Offer

The Company has offered enhanced early retirement to approximately 1,200 employees who have until March 31, 1998 to accept the offer. The cost of the enhancement will have an impact on the funding status of the retirement and other postretirement benefit plans. However, the Company intends to fund a substantial portion of the increase in the accumulated benefit obligation.

Stock Incentive Plan

During 1997, the Company formalized a Stock Incentive Plan (the "Plan") under which selected employees, officers and directors and selected nonemployee agents, consultants, advisors and independent contractors may be granted options to purchase the Company's common stock. Options generally become exercisable in three equal installments on each of the first through third anniversaries of the grant date and have a maximum term of ten years. As of December 31, 1997, options have been granted to 193 officers and employees. Under the Plan 1,322,500 options were granted on June 3, 1997 and 193,500 options were granted on August 12, 1997 at prices of $19.75 and $21.25, respectively. The weighted average estimated fair value of options granted was $2.78 per share. These options to purchase the Company's common stock were issued at 100 percent of market price on the dates the options were granted. None of the options were exercisable as of December 31, 1997. During 1997, options for 19,000 shares relating to the June 3, 1997 grant were forfeited. As permitted by SFAS 123, the Company has elected to account for the Plan under APB 25. Accordingly, no compensation expense has been recognized for the Plan. Had compensation cost for the Plan been determined based on the fair value at the grant date consistent with SFAS 123, there would have been no impact on the Company's net income.

The fair value of each option grant was estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions used: dividend yield of 5.5 percent, risk-free interest rate of 6.8 percent, expected life of the options of 10 years and volatility of 15 percent.

NOTE 12. RELATED PARTY TRANSACTIONS

The Company and its subsidiaries participate in a consolidated cash management program. Any funds advanced to/from the Company are included in accounts and notes payable/receivable-affiliated companies and advances from affiliated companies. The notes and advances are due upon demand and bear interest at a short-term rate as defined under intercompany loan agreements and a contractual understanding agreement between the Company and its subsidiaries. Net interest expense on these advances was $5,350,000 and $2,225,000 in 1997 and 1996, respectively.

PacifiCorp Capital I and PacifiCorp Capital II, wholly owned subsidiary trusts of the Company (the "Trusts") have issued, in public offerings, redeemable preferred securities representing preferred undivided beneficial interests in the assets of the Trusts. The sole assets of the Trusts are $223,712,000 and $139,176,000 of Junior Subordinated Deferrable Interest Debentures of the Company due 2036 and 2037 (the Debentures) that bear interest at 8.25 percent and 7.7 percent, respectively. The Company paid interest expense on the Debentures of $22,830,000 and $10,202,000 in 1997 and 1996, respectively.

The Company provides certain management services, such as corporate and financial advice and consultation, to subsidiaries at cost. The amounts charged to the subsidiaries were $5,559,000 and $5,705,000 in 1997 and 1996, respectively.

All of the coal production of the Bridger mine ("Bridger") is sold to a steam electric generating plant owned by the Company and Idaho Power Company ("Idaho"). Sales to the plant were $121,545,000 in 1997 and $117,668,000 in 1996. The Company provided Bridger with management, administrative, engineering services and electricity on an as-needed basis. The amount charged for these services was $5,661,000 and $4,521,000 in 1997 and 1996, respectively. In addition, Bridger paid overriding royalties to the Company and Idaho of $422,000 and $630,000 in 1997 and 1996, respectively, pursuant to coal lease agreements.

During 1996, the Company received a litigation settlement from its insurers for coverage of environmental liabilities. The Company transferred these environmental liabilities to an unregulated subsidiary, PacifiCorp Investment Management Inc. ("PIMI"), together with an amount of cash equivalent to the estimated net present value of resolving the liabilities, approximately $33,500,000. PIMI invested the cash received from the Company in long-term variable rate notes issued by PTI and transferred the environmental liabilities and long-term variable rate notes to a 90 percent owned unregulated subsidiary of the Company, PacifiCorp Environmental Remediation Company.

The Company has entered into an agreement with its wholly owned subsidiary, Demand Side Receivables, Inc. ("DSRI") to sell all of its demand side receivable loans to DSRI at their discounted present values. Transactions relating to sales of loans to DSRI resulted in net cash outflows of $2,283,000 and a net loss of $845,000 in 1997 compared to net cash proceeds of $5984,000 and a net gain of $1,134,000 in 1996. DSRI recorded a gain of $704,000 in 1997 and a loss of $758,000 in 1996 on sales of the loans to outside parties. The effects of the DSRI sales are included in equity in subsidiary earnings.

NOTE 13. PROPOSED ACQUISITION BY A SUBSIDIARY

On June 13, 1997, the Company announced a cash tender offer by Holdings for The Energy Group PLC ("TEG"). TEG is a diversified international energy group with operations in the United Kingdom (the "UK"), the United States and Australia and includes Eastern Group PLC, one of the leading integrated electricity and gas groups in the UK and Peabody Holding Company, Inc., the world's largest private producer of coal. Holdings' initial offer lapsed on August 1, 1997 when it was referred to the Monopolies and Mergers Commission (the "MMC") by the President of the Board of Trade in the UK. The proposed acquisition of TEG by the Company was subsequently cleared by the President of the Board of Trade on December 19, 1997.

On February 3, 1998, the Company announced the terms of a renewed cash tender offer by Holdings for TEG of 765 pence for each ordinary share. On March 2, 1998, Texas Utilities Company ("TU") announced an offer of 810 pence for each TEG share. Following TU's announcement, the Company announced an increased cash offer of 820 pence for each TEG share. This increased offer values the transaction at $11.1 billion, including the purchase of 521 million shares and the assumption of $4.1 billion of TEG's debt. The acquisition was to be financed with cash raised through sales of noncore assets of subsidiaries of Holdings (See Notes 14 and 15) and borrowings by subsidiaries of Holdings. The Company's announcement of the increased offer followed the acquisition on March 2, 1998 by a subsidiary of Holdings of approximately 46 million TEG shares at a price of 820 pence per share. These shares represent approximately 8.8 percent of the outstanding share capital of TEG.

On March 3, 1998, TU announced that it was increasing its offer to 840 pence for each TEG share. TU's offer is subject to clearance by the UK Secretary of State for Trade and Industry and certain other regulatory bodies. TU has also announced that it has acquired approximately 15 percent of the outstanding share capital of TEG.

Upon initiation of the original tender offer in June 1997, Holdings entered into foreign currency exchange contracts. The financing facilities associated with the June 1997 offer for TEG terminated upon referral to the MMC and Holdings initiated steps to unwind its foreign currency exchange positions consistent with its policies on derivatives. As a result of the termination of these positions and initial option costs, Holdings realized an after-tax loss of approximately $65,000,0000 in the third quarter of 1997, which was recorded in Equity in Subsidiary Earnings.

NOTE 14. DISCONTINUED OPERATIONS OF A SUBSIDIARY

On December 1, 1997, Holdings completed the sale of PTI to Century Telephone Enterprises, Inc. ("Century"). Pursuant with a Stock Purchase Agreement dated June 11, 1997, Century acquired all the stock of PTI for $1.5 billion in cash plus the assumption of PTI's debt. The sale resulted in an after-tax gain of $365,000,000. A portion of the proceeds from the sale of PTI was temporarily advanced to the Company for retirement of short-term debt. Holdings recorded income of $89,200,000 for the eleven months of operation in 1997 and $74,700,000 for all of 1996.

NOTE 15. ACQUISITIONS AND DISPOSITIONS BY SUBSIDIARIES

On April 15, 1997, Holdings, through a subsidiary, acquired all of the outstanding shares of common stock of TPC, a natural gas gathering, processing, storage and marketing company based in Houston, Texas, for approximately $265,000,000 in cash and assumed debt of approximately $140,000,000. Following completion of a tender offer, TPC became a wholly owned subsidiary of Holdings through a cash merger at the same price. During May 1997, TPC retired $131,000,000 of its outstanding long-term debt. These transactions were funded with capital contributions from the Company.

On December 1, 1997, TPC sold all of the capital stock of three subsidiaries that hold its natural gas gathering and processing systems to El Paso Field Services Company for $195,000,000 in cash, before tax payments of $23,000,000. No gain or loss was recognized by Holdings on the sale.

On November 5, 1997, Holdings completed the sale of PGC to NRG Energy for $150,000,000 in cash. An after-tax gain on the sale of $30,000,000 was recognized by Holdings in the fourth quarter of 1997.

In September 1996, a consortium, known as the Hazelwood Power Partnership, purchased a 1,600 megawatt, coal-fired generating station and associated coal mine in Victoria, Australia for approximately $1.9 billion. The consortium financed the acquisition of the Hazelwood plant and mine with approximately $858,000,000 in equity contributions from the partners and $1 billion of nonrecourse borrowings at the partnership level. Holdings, which has a 19.9% interest in the partnership, financed its $145,000,000 portion of the equity investment and the associated $12,000,000 advance with term borrowings in the United States.

On December 12, 1995, Holdings purchased Powercor, an electricity distributor in Australia, for $1.6 billion in cash. Powercor is the largest electricity distributrior in the State of Victoria. The acquisition was accounted for as a purchase and the results of operations of Powercor have been included in equity in subsidiary earnings since December 12, 1995.

In February 1998, PFS agreed to sell its investments in affordable housing for cash proceeds of approximately $81,000,000 and assumption of debt of approximately $161,000,000. This sale transaction will not have a material impact on 1998 earnings.

Plant Outages for 1997

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Carbon No. 1						
1.	01/05/97 18:35	-	01/05/97 21:10	Unplanned	2.58	180.83
	Descr: The unit had a boiler upset (plugged feeder). after d.a. level recov					
2.	01/05/97 23:32	-	01/07/97 19:00	Unplanned	43.47	3,042.67
	Descr: The unit had been on line for about two hours after tripping no.1 load					
3.	01/07/97 19:00	-	01/09/97 05:28	Unplanned	34.47	2,412.67
	Descr: The unit had been off line for a water wall tube leak. the tube leak					
4.	01/31/97 13:48	-	02/01/97 07:45	Unplanned	17.95	1,256.50
	Descr: The unit was taken off line to replace an expansion joint (north side,					
5.	02/02/97 00:56	-	02/04/97 07:00	Unplanned	54.07	3,784.67
	Descr: Unit was taken off line to repair condenser tube leak (unable to maint					
6.	02/11/97 05:10	-	02/13/97 22:04	Unplanned	64.90	4,543.00
	Descr: Unit was taken off line to repair a water wall tube leak (possible					
7.	03/18/97 23:35	-	03/21/97 16:00	Unplanned	64.42	4,509.17
	Descr: The unit was taken off line to do a chemical clean. the boiler had					
8.	03/21/97 16:00	-	03/22/97 09:00	Unplanned	17.00	1,190.00
	Descr: The unit was taken off line to do a chemical clean. the air preheater					
9.	03/22/97 09:00	-	03/24/97 16:08	Unplanned	55.13	3,859.33
	Descr: The unit was taken off line to do a chemical clean. the portabledemin					
10.	04/03/97 06:58	-	04/03/97 08:39	Unplanned	1.68	117.83
	Descr: Unit trip due to a fault on the helper 46kv line. a cross arm broke					
11.	05/04/97 16:50	-	05/04/97 19:13	Unplanned	2.38	166.83
	Descr: Operations was washing down and water entered a lighting panel. this					
12.	05/04/97 19:13	-	05/04/97 20:13	Unplanned	1.00	70.00
	Descr: Unit start up was delayed due to prblems with the igniters					
13.	05/31/97 22:39	-	06/02/97 02:47	Planned	28.13	1,969.33
	Descr: Unit was taken off line to clean the hydrogen coolers (hydrogen temper					
14.	06/09/97 23:39	-	06/10/97 13:47	Unplanned	14.13	989.33
	Descr: Economizer tube leak (right rear corner of the pent house, weld faile					
15.	06/25/97 00:48	-	06/27/97 21:08	Unplanned	68.33	4,783.33
	Descr: The unit was taken off line to replace the high side"u" bushings. the					
16.	06/28/97 00:30	-	06/28/97 21:48	Unplanned	21.30	1,491.00
	Descr: The unit had been off line to replace the main transformer bushings an					
17.	07/10/97 23:42	-	07/11/97 21:42	Unplanned	22.00	1,540.00
	Descr: The unit was taken off line to repair a leak in the high temperature					
18.	07/15/97 22:36	-	07/17/97 02:45	Unplanned	28.15	1,970.50
	Descr: The unit was taken off line to repair a leak in the high temperautre					
19.	09/18/97 03:34	-	09/19/97 18:00	Unplanned	38.43	2,690.33
	Descr: Unit was taken off line to repair an economizer tube leak (a sootblowe					
20.	09/19/97 18:00	-	09/20/97 00:50	Unplanned	6.83	478.33
	Descr: The unit was off line for an economizer tube leak, the unit remained					
21.	10/11/97 04:20	-	10/12/97 04:10	Unplanned	23.83	1,668.33
	Descr: Unit was taken off line to repair an economizer tube leak					
22.	10/12/97 13:00	-	10/12/97 14:59	Unplanned	1.98	138.83
	Descr: Unit tripped due to loss of d.a.level (a bad transmitter is suspected)					
23.	10/24/97 14:11	-	10/24/97 15:25	Unplanned	1.23	86.33
	Descr: 1-1 mill was out to replace the reject scraper. while 1-1 mill was					

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	- Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Carbon No. 1					
24.	10/25/97 14:21	- 10/26/97 10:31	Unplanned	21.17	1,481.67
	Descr: Unit was taken off line to repair an economzer tube leak				
25.	11/11/97 23:29	- 11/12/97 18:00	Unplanned	18.52	1,296.17
	Descr: Water cooled spacer tube leak (there was also a high temp. superheat				
26.	11/12/97 18:00	- 11/13/97 11:00	Unplanned	17.00	1,190.00
	Descr: High temp. superheat tube leak. a leak occurred in the water cooled s				
27.	11/13/97 11:00	- 11/13/97 23:55	Unplanned	12.92	904.17
	Descr: The unit was off line for two tube leaks (water cooled spacer and high				
28.	11/16/97 02:20	- 11/17/97 02:48	Unplanned	24.47	1,712.67
	Descr: The unit was taken off line for a leak in the main steam sample line.				
29.	12/21/97 13:24	- 12/22/97 09:00	Unplanned	19.60	1,372.00
	Descr: The unit was taken off line to repair a water cooled spacer tube leak.				
30.	12/22/97 09:00	- 12/23/97 00:54	Unplanned	15.90	1,113.00
	Descr: The unit was taken off line to repair a water cooled spacer tube leak.				
31.	12/28/97 21:44	- 12/30/97 00:25	Unplanned	26.68	1,867.83
	Descr: Low temperature superheat tube leak				
	*** * * Unit Summary for Carbon No. 1 for the year 1997 =**			769.65	53,876.65
Carbon No. 2					
1.	01/01/97 00:00	- 01/01/97 15:00	Unplanned	15.00	1,575.00
	Descr: Unit was taken off line due to #8 exciter bearing high temperature.				
2.	01/01/97 15:00	- 01/05/97 06:41	Unplanned	87.68	9,206.75
	Descr: The unit was off line to repair #8 exciter bearing. the left intercept				
3.	03/08/97 00:15	- 03/10/97 03:34	Unplanned	51.32	5,388.25
	Descr: The unit was taken off line to wash the economizer (high differential				
4.	04/07/97 11:44	- 04/07/97 12:48	Unplanned	1.07	112.00
	Descr: Unit ripped off line. both i.d. fans tripped on thermal overload.the t				
5.	04/07/97 12:48	- 04/07/97 13:48	Unplanned	1.00	105.00
	Descr: The unit had tripped off line. unit start-up was delayed due to the i				
6.	05/15/97 11:41	- 05/21/97 10:48	Unplanned	143.12	15,027.25
	Descr: Unit was taken off line to repair dead dead air space. the gas recirc				
7.	05/21/97 10:48	- 05/21/97 12:48	Unplanned	2.00	210.00
	Descr: The unit had been off line to repair coutant bottom/dead air space.				
8.	06/28/97 23:40	- 06/30/97 02:45	Planned	27.08	2,843.75
	Descr: The unit was taken off line to clean the hydrogen coolers. hydrogen				
9.	07/30/97 23:32	- 07/31/97 13:02	Unplanned	6.75	708.75
	Descr: The unit was taken off line to clean the economizer and high temp.				
10.	07/30/97 23:32	- 08/02/97 00:26	Unplanned	42.15	4,425.75
	Descr: The unit was taken off line to clean the economizer. the h.t.s.h. was				
11.	10/20/97 23:05	- 10/21/97 15:00	Unplanned	15.92	1,671.25
	Descr: Unit was taken off line for an economizer tube leak (weld failure at				
12.	10/21/97 15:00	- 10/22/97 04:52	Unplanned	13.87	1,456.00
	Descr: Unit was taken off line for an economizer tube leak. the unit remia				
13.	12/04/97 12:10	- 12/04/97 14:07	Unplanned	1.95	204.75
	Descr: Unit trip - generator field forcing alarm annunciated. the c.r.o. and				
14.	12/15/97 00:42	- 12/15/97 02:37	Unplanned	1.92	201.25
	Descr: 2-1 boiler feed pump tripped and 2-2 b.f.p. started as back-up, but				

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Carbon No. 2						
15.	12/28/97 11:35	-	12/28/97 12:40	Unplanned	1.08	113.75
	Descr: Unit tripped off line due to a boiler upset that was initiated by a					
	*** **Unit Summary for Carbon No. 2 for the year 1997 =**				411.91	43,249.50
Centralia No. 1						
1.	03/06/97 13:36	-	03/06/97 15:04	Unplanned	1.47	982.67
	Descr: Electrical trip caused by defective contact in relay 405y.					
2.	03/06/97 15:04	-	03/06/97 16:04	Unplanned	1.00	670.00
	Descr: Error in bechtel drawing delayed troubleshooting.					
3.	06/13/97 22:32	-	07/06/97 01:42	Planned	531.17	355,881.67
	Descr: Boiler maintenance inspection					
4.	07/06/97 01:42	-	07/06/97 03:42	Unplanned	2.00	1,340.00
	Descr: Lack of ss coordination with psd on generator clearance status.					
5.	07/06/97 03:42	-	07/06/97 14:42	Unplanned	11.00	7,370.00
	Descr: Id fan gearbox and inlet ema and damper stroke both id #12 and fd #11.					
6.	07/06/97 14:42	-	07/06/97 15:42	Unplanned	1.00	670.00
	Descr: Turbine latch problems.					
7.	07/06/97 15:42	-	07/06/97 16:42	Unplanned	1.00	670.00
	Descr: Turbine speed control problems.					
8.	07/12/97 22:26	-	07/13/97 21:37	Unplanned	5.80	3,883.21
	Descr: Repack bsp suction mov's.					
9.	07/12/97 22:26	-	07/13/97 21:37	Unplanned	5.80	3,883.21
	Descr: Repack #11 booster pump					
10.	07/12/97 22:26	-	07/13/97 21:37	Unplanned	5.80	3,883.21
	Descr: Fwh tube leak repairs					
11.	07/12/97 22:26	-	07/13/97 21:37	Unplanned	5.78	3,874.83
	Descr: Da hatch cover leak					
12.	08/11/97 12:39	-	08/13/97 09:10	Unplanned	22.27	14,918.67
	Descr: Superheat tube leak					
13.	08/11/97 12:39	-	08/13/97 09:10	Unplanned	22.26	14,913.08
	Descr: Reheater boiler tube leak					
14.	11/04/97 09:36	-	11/07/97 01:40	Unplanned	64.07	42,924.67
	Descr: Rh tube leak					
15.	11/23/97 07:54	-	11/25/97 20:49	Unplanned	60.92	40,814.17
	Descr: Waterwall tube leak at 5-1/2 level					
16.	11/26/97 20:30	-	11/26/97 22:10	Unplanned	1.67	1,116.67
	Descr: Operator error					
17.	11/26/97 22:27	-	11/26/97 23:30	Unplanned	1.05	703.50
	Descr: Operator error					
18.	12/05/97 23:22	-	12/07/97 09:24	Unplanned	34.03	22,802.33
	Descr: Tube leak					
19.	12/07/97 09:24	-	12/07/97 14:24	Unplanned	5.00	3,350.00
	Descr: High opacity so boiler was tripped early					
20.	12/07/97 14:24	-	12/07/97 22:24	Unplanned	8.00	5,360.00
	Descr: #12 id fan linkage repair					
21.	12/22/97 05:34	-	12/22/97 10:44	Unplanned	5.17	3,461.67
	Descr: Repair leaking thermal well at bcp injection water heat exchanger outl					
	*** **Unit Summary for Centralia No. 1 for the year 1997 =**				796.26	533,473.56

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Centralia No. 2						
1.	02/07/97 09:17	-	02/07/97 19:43	Unplanned	10.43	6,990.33
	Descr: #21 load center transformer fire					
2.	02/23/97 08:30	-	02/24/97 13:59	Unplanned	29.48	19,753.83
	Descr: #22 load center transformer failure. unit was ready for startup at					
3.	05/30/97 23:45	-	06/16/97 09:02	Planned	393.28	263,499.83
	Descr: Chemical cleaning					
4.	06/16/97 09:02	-	06/16/97 17:52	Unplanned	8.83	5,918.33
	Descr: Boiler tube leak "f" corner, 9-1/2 level					
5.	06/16/97 17:52	-	06/16/97 20:59	Unplanned	3.12	2,088.17
	Descr: #21 bfp discharge valve repack					
6.	07/03/97 18:00	-	07/07/97 07:37	Unplanned	85.62	57,363.17
	Descr: Repair #21 bcp suction valve					
7.	07/11/97 07:51	-	07/11/97 08:57	Unplanned	1.10	737.00
	Descr: Flameout					
8.	10/13/97 05:18	-	10/13/97 07:16	Unplanned	1.97	1,317.67
	Descr: Flameout					
9.	10/13/97 07:16	-	10/13/97 08:16	Unplanned	1.00	670.00
	Descr: Warmup guns/ignitors had trouble proving					
10.	10/23/97 06:11	-	10/24/97 16:27	Unplanned	34.27	22,958.67
	Descr: Economizer tube repairs					
	*** Unit Summary for Centralia No. 2 for the year 1997 =				569.10	381,297.00
Dave Johnston No. 1						
1.	01/05/97 03:50	-	01/09/97 02:54	Unplanned	95.07	10,077.07
	Descr: Tube leak and diaphragm repairs					
2.	04/02/97 08:27	-	04/03/97 13:28	Unplanned	29.02	3,075.77
	Descr: 480v circuit breaker					
3.	04/19/97 00:00	-	05/20/97 20:12	Planned	764.20	81,005.20
	Descr: Planned unit outage					
4.	05/21/97 23:15	-	05/22/97 00:18	Unplanned	1.05	111.30
	Descr: Mft on draft					
5.	05/22/97 01:18	-	05/22/97 03:09	Unplanned	1.85	196.10
	Descr: Generator lock out					
6.	05/24/97 01:32	-	05/25/97 03:31	Planned	25.98	2,754.23
	Descr: Balance turbine					
7.	05/29/97 23:06	-	05/30/97 04:03	Planned	4.95	524.70
	Descr: Turbine os tests					
8.	06/08/97 09:28	-	06/08/97 11:43	Unplanned	2.25	238.50
	Descr: Condensate pump tripped, no backup pump available					
9.	07/20/97 04:32	-	07/21/97 13:07	Unplanned	32.58	3,453.83
	Descr: Tube leak by ik 51					
10.	07/26/97 08:27	-	07/26/97 22:30	Unplanned	14.05	1,489.30
	Descr: Econ. block valve					
11.	07/26/97 22:30	-	07/27/97 02:20	Unplanned	3.83	406.33
	Descr: Purging econ block repair					
12.	07/27/97 02:20	-	07/28/97 18:25	Unplanned	40.08	4,248.83
	Descr: Tube leak					

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Dave Johnston No. 1						
13.	08/12/97 23:42	-	08/14/97 02:33	Unplanned	26.85	2,846.10
	Descr: Ww tube leak					
14.	10/27/97 01:47	-	10/29/97 07:48	Unplanned	54.02	5,725.77
	Descr: Water wall tube leak					
15.	10/29/97 07:58	-	10/30/97 19:00	Unplanned	35.03	3,713.53
	Descr: Water wall tube leak					
16.	10/30/97 19:00	-	11/04/97 01:00	Unplanned	102.00	10,812.00
	Descr: Turbine bearing					
17.	11/23/97 02:44	-	11/24/97 08:27	Unplanned	29.72	3,149.97
	Descr: Tube leak					
	*** Unit Summary for Dave Johnston No. 1 for the year 1997				1,262.53	133,828.53
Dave Johnston No. 2						
1.	05/30/97 23:03	-	06/01/97 07:40	Unplanned	32.62	3,457.37
	Descr: Work on safety valves					
2.	06/02/97 13:31	-	06/03/97 05:03	Unplanned	15.53	1,646.53
	Descr: 2b condenser oos					
	*** Unit Summary for Dave Johnston No. 2 for the year 1997				48.15	5,103.90
Dave Johnston No. 3						
1.	02/11/97 23:22	-	02/13/97 11:00	Unplanned	35.63	8,195.67
	Descr: Water wall tube leak					
2.	02/13/97 11:00	-	02/15/97 00:27	Unplanned	37.45	8,613.50
	Descr: Replacing burner impellers					
3.	04/10/97 23:28	-	04/12/97 13:33	Unplanned	38.08	8,759.17
	Descr: Tube leak					
4.	04/15/97 01:05	-	04/15/97 05:54	Unplanned	4.82	1,107.83
	Descr: Turbine lost vacuum					
5.	06/03/97 23:35	-	06/05/97 08:47	Unplanned	33.20	7,636.00
	Descr: Tube leak					
6.	06/05/97 10:12	-	06/05/97 16:05	Unplanned	5.88	1,353.17
	Descr: Boiler controls					
7.	06/10/97 13:11	-	06/11/97 23:52	Unplanned	34.68	7,977.17
	Descr: Tube leak					
8.	07/21/97 09:29	-	07/23/97 21:20	Unplanned	59.85	13,765.50
	Descr: Water wall tube leak					
9.	09/10/97 07:17	-	09/10/97 08:32	Unplanned	1.25	287.50
	Descr: Dc power supply					
10.	09/17/97 23:15	-	09/20/97 23:44	Unplanned	72.48	16,671.17
	Descr: Ww tube leak					
11.	10/19/97 23:57	-	10/21/97 00:15	Unplanned	24.30	5,589.00
	Descr: Economizer tube leak					
12.	10/22/97 06:22	-	10/22/97 07:28	Unplanned	1.10	253.00
	Descr: Volts to hertz problem					
13.	11/21/97 23:00	-	11/24/97 16:36	Unplanned	65.60	15,088.00
	Descr: W.w. tube leak					
14.	12/01/97 17:47	-	12/03/97 20:35	Unplanned	50.80	11,684.00
	Descr: Primary sh tube leak					

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	- Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Dave Johnston No. 3					
15.	12/17/97 03:48	- 12/19/97 01:37	Unplanned	45.82	10,537.83
	Descr: Lp turbineexp. joint				
16.	12/29/97 05:13	- 01/01/98 00:00	Unplanned	66.78	15,360.17
	Descr: Ww tube leak				
	*** * * Unit Summary for Dave Johnston No. 3 for the year 1997**			577.72	132,878.68
Dave Johnston No. 4					
1.	01/31/97 22:18	- 02/02/97 22:00	Unplanned	47.70	15,741.00
	Descr: Tube repair				
2.	02/02/97 22:00	- 02/03/97 03:00	Unplanned	5.00	1,650.00
	Descr: Hydrogen cooler gasket failed				
3.	02/03/97 03:00	- 02/03/97 14:40	Unplanned	11.67	3,850.00
	Descr: Both bfp would not start				
4.	02/19/97 14:30	- 02/23/97 10:58	Unplanned	92.47	30,514.00
	Descr: 8 tube leaks in primary superheater				
5.	03/13/97 20:01	- 03/14/97 19:08	Unplanned	23.12	7,628.50
	Descr: Water wall tube leak				
6.	03/14/97 19:08	- 03/14/97 23:08	Unplanned	4.00	1,320.00
	Descr: Warm up guns failure				
7.	03/14/97 23:08	- 03/15/97 03:08	Unplanned	4.00	1,320.00
	Descr: Pa fan delayed startup				
8.	06/14/97 21:18	- 06/16/97 05:46	Unplanned	32.47	10,714.00
	Descr: Ah locked up				
9.	06/20/97 22:59	- 06/22/97 00:00	Unplanned	25.02	8,255.50
	Descr: Psh tube leak				
10.	06/22/97 00:00	- 06/24/97 02:59	Unplanned	50.98	16,824.50
	Descr: Cleaning scrubber				
11.	06/30/97 14:18	- 07/06/97 03:15	Unplanned	132.95	43,873.50
	Descr: Deslag w/tube leak				
12.	07/14/97 15:02	- 07/14/97 16:55	Unplanned	1.88	621.50
	Descr: Pa fan tripped & boiler mft				
13.	08/10/97 00:27	- 08/11/97 09:10	Unplanned	32.72	10,796.50
	Descr: Clinker caused tube leak				
14.	08/13/97 12:30	- 08/13/97 18:10	Unplanned	5.67	1,870.00
	Descr: Circuit breakers in switchyard opened up.				
15.	09/06/97 00:23	- 09/12/97 00:00	Planned	143.62	47,393.50
	Descr: Boiler inspection				
16.	09/12/97 00:00	- 09/13/97 22:53	Planned	46.88	15,471.50
	Descr: Scrubber inspection				
17.	09/16/97 17:06	- 09/17/97 16:16	Unplanned	23.17	7,645.00
	Descr: Pa fan				
18.	11/14/97 08:55	- 11/15/97 01:59	Unplanned	17.07	5,632.00
	Descr: Ah drive motor				
19.	12/06/97 22:28	- 12/08/97 04:00	Unplanned	29.53	9,746.00
	Descr: Ah motor swap				
20.	12/08/97 20:48	- 12/09/97 04:59	Unplanned	8.18	2,700.50
	Descr: 4160 breaker				

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	- Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Dave Johnston No. 4					
21.	12/17/97 22:20	- 12/21/97 02:50	Unplanned	76.50	25,245.00
	Descr: Ww tube leak				
22.	12/21/97 08:20	- 12/21/97 09:54	Unplanned	1.57	517.00
	Descr: Boiler controls				
23.	12/21/97 13:49	- 12/25/97 15:23	Unplanned	97.57	32,197.00
	Descr: Water wall tube leak				
24.	12/30/97 05:23	- 12/30/97 11:16	Unplanned	5.88	1,941.50
	Descr: Testing valves low reheater flow				
25.	12/30/97 12:05	- 12/30/97 14:27	Unplanned	2.37	781.00
	Descr: Da tank level indication				
	*** * * Unit Summary for Dave Johnston No. 4 for the year 1997**			921.99	304,249.00
Hunter No. 1					
1.	01/23/97 03:36	- 01/23/97 20:06	Unplanned	16.50	6,847.50
	Descr: Unit trip, feedwater mov breaker trip				
2.	02/02/97 11:46	- 02/02/97 16:47	Unplanned	5.02	2,081.92
	Descr: Unit trip, 1-1 cw pump & bfpt's tripped				
3.	02/06/97 20:58	- 02/07/97 01:17	Unplanned	4.32	1,791.42
	Descr: Unit off line - both bfpt's tripped				
4.	02/20/97 14:14	- 02/22/97 18:00	Unplanned	51.77	21,483.17
	Descr: Boiler tube leak (reheat section)				
5.	02/28/97 00:12	- 03/01/97 00:00	Unplanned	23.80	9,877.00
	Descr: Boiler tube leak (reheat section)				
6.	03/01/97 00:00	- 03/05/97 06:10	Unplanned	102.17	42,399.17
	Descr: Boiler tube leak (reheat section)				
7.	03/05/97 06:10	- 03/05/97 11:00	Unplanned	4.83	2,005.83
	Descr: Ignitor problems				
8.	03/05/97 11:00	- 03/05/97 21:30	Unplanned	10.50	4,357.50
	Descr: Building pressure/temps				
9.	03/06/97 04:30	- 03/06/97 09:10	Unplanned	4.67	1,936.67
	Descr: Unit off line				
10.	03/20/97 09:58	- 03/20/97 15:01	Unplanned	5.05	2,095.75
	Descr: Unit trip - i&c working on deh				
11.	04/16/97 17:03	- 04/19/97 15:01	Unplanned	69.97	29,036.17
	Descr: Boiler tube leak (steam-cooled wall)				
12.	06/05/97 08:27	- 06/10/97 03:52	Unplanned	115.42	47,897.92
	Descr: Main transformer bushing failure				
13.	06/21/97 23:23	- 06/23/97 04:20	Unplanned	28.95	12,014.25
	Descr: Off to tie 1-1 main transformer				
14.	07/12/97 01:00	- 07/14/97 06:00	Unplanned	53.00	21,995.00
	Descr: Off line - btm ash door repair				
15.	08/30/97 23:47	- 08/31/97 10:39	Unplanned	10.87	4,509.67
	Descr: Unit trip (unknown cause)				
16.	09/23/97 23:23	- 09/26/97 01:30	Unplanned	50.12	20,798.42
	Descr: Off line - reheater plugged				
17.	10/29/97 01:15	- 10/29/97 09:15	Unplanned	8.00	3,320.00
	Descr: Unit trip - high drum level				
	*** * * Unit Summary for Hunter No. 1 for the year 1997 =**			564.96	234,447.36

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	- Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Hunter No. 2					
1.	02/04/97 15:30	- 02/06/97 11:35	Unplanned	44.08	18,294.58
	Descr: Unit off line to fix da leak				
2.	02/17/97 22:17	- 02/17/97 23:17	Unplanned	1.00	415.00
	Descr: Unit trip - valving lube oil coolers				
3.	05/17/97 02:00	- 05/19/97 20:05	Unplanned	66.08	27,424.58
	Descr: Unit off - air heater wash				
4.	07/19/97 00:00	- 07/20/97 12:30	Unplanned	36.50	15,147.50
	Descr: Unit off line - cleaning ash out of boiler				
5.	08/03/97 00:00	- 08/03/97 11:51	Unplanned	11.85	4,917.75
	Descr: Off line - drum door gasket leak				
6.	09/16/97 00:52	- 09/18/97 23:07	Unplanned	70.25	29,153.75
	Descr: Boiler tube leak (first superheat)				
7.	10/11/97 00:28	- 11/01/97 00:00	Planned	504.53	209,381.33
	Descr: Unit outage (turbine) (dst)				
8.	11/01/97 00:00	- 11/24/97 14:52	Planned	566.87	235,249.67
	Descr: Unit outage (turbine)				
9.	11/24/97 20:35	- 11/25/97 22:42	Unplanned	26.12	10,838.42
	Descr: Off line - turbine overspeed tests				
10.	11/26/97 01:59	- 11/26/97 03:05	Unplanned	1.10	456.50
	Descr: Trip - flame failure-scanner problem				
11.	11/27/97 01:49	- 11/27/97 06:25	Unplanned	4.60	1,909.00
	Descr: Unit trip - condenser vacuum low				
12.	12/11/97 11:25	- 12/11/97 15:14	Unplanned	3.82	1,583.92
	Descr: Unit trip - low eh pressure				
	*** * * Unit Summary for Hunter No. 2 for the year 1997 =**			1,336.80	554,772.00
Hunter No. 3					
1.	03/05/97 11:00	- 03/07/97 21:30	Unplanned	58.50	23,692.50
	Descr: Unit off line - exciter brush failure				
2.	03/12/97 22:08	- 03/18/97 11:50	Unplanned	133.70	54,148.50
	Descr: Lp turbine blade failure				
3.	03/31/97 14:08	- 04/01/97 00:00	Unplanned	9.87	3,996.00
	Descr: Boiler tube leak (waterwall)				
4.	04/01/97 00:00	- 04/01/97 11:41	Unplanned	11.68	4,731.75
	Descr: Boiler master handhole cap leak				
5.	04/05/97 00:30	- 04/05/97 03:12	Unplanned	2.70	1,093.50
	Descr: Unit off - repair overspeed sol				
6.	04/29/97 13:37	- 04/29/97 22:55	Unplanned	9.30	3,766.50
	Descr: Unit trip - low drum - lost 3-2 bfpt				
7.	06/28/97 21:30	- 06/29/97 03:20	Unplanned	5.83	2,362.50
	Descr: Low drum level - bfpt 3-1 tripped				
8.	07/04/97 22:05	- 07/11/97 17:30	Unplanned	163.42	66,183.75
	Descr: Unit off - turbine blade repair				
9.	07/17/97 10:19	- 07/17/97 12:18	Unplanned	1.98	803.25
	Descr: Unit trip - loss turb lube oil press				
10.	07/17/97 15:05	- 07/17/97 17:44	Unplanned	2.65	1,073.25
	Descr: Trip - on switch to high speed on fd's				

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Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	- Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Hunter No. 3					
11.	09/03/97 02:50	- 09/05/97 05:11	Unplanned	50.35	20,391.75
	Descr: Boiler tube leak (second superheater)				
12.	10/21/97 20:31	- 10/22/97 09:21	Unplanned	12.83	5,197.50
	Descr: Unit trip - id & fd fans tripped				
13.	12/20/97 00:00	- 12/22/97 09:30	Unplanned	57.50	23,287.50
	Descr: Unit off - repair ww heater supports				
14.	12/22/97 15:36	- 12/22/97 18:10	Unplanned	2.57	1,039.50
	Descr: Unit trip - circ pump trip				
	*** * * Unit Summary for Hunter No. 3 for the year 1997 =**			522.88	211,767.75
Huntington No. 1					
1.	01/19/97 07:29	- 01/21/97 10:23	Unplanned	50.90	21,378.00
	Descr: Leak				
2.	03/14/97 22:46	- 04/24/97 05:55	Planned	966.15	405,783.00
	Descr: Overhaul				
3.	04/24/97 15:10	- 04/24/97 22:39	Unplanned	7.48	3,143.00
	Descr:				
4.	05/01/97 00:00	- 05/03/97 13:58	Unplanned	61.97	26,026.00
	Descr: Rh rad wall tube leak				
5.	06/12/97 20:20	- 06/13/97 23:00	Unplanned	13.33	5,600.00
	Descr: Leak				
6.	06/12/97 20:20	- 06/17/97 04:11	Unplanned	90.52	38,017.00
	Descr: Replacement of seal				
7.	06/24/97 20:20	- 06/24/97 21:50	Unplanned	1.50	630.00
	Descr:				
8.	07/17/97 00:38	- 07/22/97 06:10	Unplanned	125.53	52,724.00
	Descr: Leak				
9.	07/22/97 00:38	- 07/22/97 13:41	Unplanned	7.52	3,157.00
	Descr: Turbine bearing problem				
10.	07/22/97 13:41	- 07/22/97 16:56	Unplanned	3.25	1,365.00
	Descr: Leak				
11.	07/24/97 00:37	- 07/25/97 00:35	Unplanned	23.97	10,066.00
	Descr: Leak				
12.	08/20/97 00:00	- 08/21/97 02:15	Unplanned	26.25	11,025.00
	Descr: Unit off line for horizontal s.h. tube leak				
13.	08/26/97 18:30	- 08/27/97 03:54	Unplanned	9.40	3,948.00
	Descr: Condenser tube leak				
14.	09/22/97 23:48	- 09/27/97 14:30	Unplanned	110.70	46,494.00
	Descr: Unit off line for boiler tube leak				
15.	10/07/97 02:00	- 10/08/97 16:24	Unplanned	38.40	16,128.00
	Descr: Tube leaks				
16.	10/21/97 01:32	- 10/22/97 00:00	Unplanned	22.47	9,436.00
	Descr: Boiler tube leak				
17.	10/22/97 00:00	- 10/22/97 07:00	Unplanned	7.00	2,940.00
	Descr: Unit off line for boiler tube leak				
18.	10/22/97 07:00	- 10/22/97 19:00	Unplanned	12.00	5,040.00
	Descr: Boiler tube leak				

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Huntington No. 1						
19.	10/22/97 19:00	-	10/24/97 11:43	Unplanned	40.72	17,101.00
	Descr: Unit off line/tube leak/boiler					
20.	10/24/97 11:43	-	10/24/97 18:00	Unplanned	6.28	2,639.00
	Descr: Circ water system ph problem					
21.	10/24/97 18:00	-	10/25/97 22:53	Unplanned	28.88	12,131.00
	Descr: Condenser tube leak					
22.	10/26/97 02:00	-	10/26/97 03:23	Unplanned	2.38	1,001.00
	Descr: Boiler and turbine trip from under voltage 86tt					
23.	10/26/97 05:04	-	10/26/97 06:34	Unplanned	1.50	630.00
	Descr: Turbine trip from 86tt					
24.	10/26/97 08:00	-	10/26/97 09:00	Unplanned	1.00	420.00
	Descr: Turbine trip					
25.	10/30/97 12:33	-	10/30/97 13:36	Unplanned	1.05	441.00
	Descr: Unit trip (gen relay)					
26.	11/04/97 11:50	-	11/06/97 06:00	Unplanned	42.17	17,710.00
	Descr: Economizer tube leak hanger					
27.	12/25/97 13:35	-	12/25/97 21:49	Unplanned	8.23	3,458.00
	Descr: Generator ground took unit off line					
28.	12/25/97 22:37	-	12/26/97 00:10	Unplanned	1.55	651.00
	Descr: Generator ground took unit off line					
	*** **Unit Summary for Huntington No. 1 for the year 1997 =**				1,712.10	719,082.00
Huntington No. 2						
1.	01/07/97 01:26	-	01/08/97 22:51	Unplanned	45.42	19,302.08
	Descr: Leak					
2.	02/04/97 20:54	-	02/08/97 10:13	Unplanned	85.32	36,259.58
	Descr: Tube leak					
3.	02/08/97 10:13	-	02/08/97 22:55	Unplanned	12.70	5,397.50
	Descr: High temperature alarm					
4.	02/08/97 22:55	-	02/09/97 09:54	Unplanned	10.98	4,667.92
	Descr: Tube leak					
5.	02/18/97 23:06	-	02/20/97 11:00	Unplanned	35.90	15,257.50
	Descr: Tube leak					
6.	02/20/97 11:00	-	02/20/97 12:10	Unplanned	1.17	495.83
	Descr: Misc problems					
7.	02/20/97 12:32	-	02/20/97 14:35	Unplanned	2.05	871.25
	Descr: Drum level trip ww drum drains					
8.	03/12/97 08:30	-	03/12/97 12:00	Unplanned	3.50	1,487.50
	Descr:					
9.	04/05/97 21:23	-	04/06/97 12:09	Unplanned	13.77	5,850.83
	Descr: Repair					
10.	05/16/97 02:51	-	05/19/97 10:00	Unplanned	79.15	33,638.75
	Descr: Tube leak					
11.	08/15/97 00:00	-	08/16/97 00:00	Unplanned	24.00	10,200.00
	Descr: Unit off line for econo wash					
12.	08/16/97 00:00	-	08/19/97 00:00	Unplanned	72.00	30,600.00
	Descr: Plugged economizer					

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Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	- Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Huntington No. 2					
13.	08/19/97 00:00	- 08/19/97 10:36	Unplanned	10.60	4,505.00
	Descr: Plugged economizer & tube leak				
14.	08/22/97 22:18	- 08/23/97 01:57	Unplanned	3.65	1,551.25
	Descr: Unit tripped off ine while testing power load imbalance on ehc panel				
15.	10/11/97 00:16	- 10/12/97 15:55	Unplanned	39.65	16,851.25
	Descr: Boiler & feedwater heaters 2-3, 2-5 & 2-7 have leaks				
	*** **Unit Summary for Huntington No. 2 for the year 1997 =**			439.86	186,936.24
Jim Bridger No. 1					
1.	01/03/97 11:15	- 01/04/97 21:47	Unplanned	34.53	17,957.33
	Descr: Unit off line to repair broken inlet vanes on 11 i.d. fan.				
2.	01/31/97 10:43	- 01/31/97 14:30	Unplanned	3.78	1,967.33
	Descr: Unit off line for safety repair (sh).				
3.	01/31/97 14:30	- 01/31/97 16:48	Unplanned	2.30	1,196.00
	Descr: Economizer inlet valve controls repair.				
4.	02/12/97 22:44	- 02/13/97 22:00	Unplanned	23.27	12,098.67
	Descr: Unit off line to repair waterwall tube leak.				
5.	02/13/97 22:00	- 02/14/97 00:00	Unplanned	2.00	1,040.00
	Descr: Turbine overspeed tests.				
6.	02/14/97 00:00	- 02/14/97 02:53	Unplanned	2.88	1,499.33
	Descr: Mechanical oil trip problems.				
7.	04/22/97 00:00	- 04/23/97 20:50	Unplanned	44.83	23,313.33
	Descr: Reheat and waterwall tube leaks.				
8.	06/04/97 00:00	- 06/08/97 14:43	Unplanned	110.72	57,572.67
	Descr: Unit off line for air preheater wash.				
9.	06/21/97 00:00	- 06/21/97 19:38	Unplanned	19.63	10,209.33
	Descr: Unit off line to repair superheater tube leak.				
10.	07/08/97 03:57	- 07/09/97 09:03	Unplanned	29.10	15,132.00
	Descr: Unit off line to repair finishing superheat tube leak.				
11.	08/06/97 23:59	- 08/07/97 17:24	Unplanned	17.42	9,056.67
	Descr: Unit off line to repair phosphate injection line.				
12.	08/18/97 05:51	- 08/18/97 20:11	Unplanned	14.33	7,453.33
	Descr: Gen. voltage indication.				
13.	09/12/97 00:38	- 09/12/97 17:41	Unplanned	17.05	8,866.00
	Descr: Unit off line to repair economizer inlet valve.				
14.	09/14/97 14:14	- 09/15/97 20:26	Unplanned	30.20	15,704.00
	Descr: Penthouse sh tube leak.				
15.	09/23/97 12:43	- 09/23/97 13:51	Unplanned	1.13	589.33
	Descr: Unit trip-bfpt controls-bcp delta p.				
16.	09/23/97 14:15	- 09/23/97 15:20	Unplanned	1.08	563.33
	Descr: Unit trip-bfpt controls-bcp delta p.				
17.	10/02/97 00:12	- 10/02/97 21:23	Unplanned	21.18	11,015.33
	Descr: Unit off line to repair waterwall tube leak.				
18.	10/24/97 14:10	- 10/24/97 15:24	Unplanned	1.23	641.33
	Descr: Kinport borah line trip.				
19.	10/31/97 12:47	- 11/01/97 08:00	Unplanned	19.22	9,992.67
	Descr: Unit off line toepair steam sodium sample line from drum-hanger broke				

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Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger No. 1						
20.	11/01/97 08:00	-	11/02/97 00:00	Unplanned	16.00	8,320.00
	Descr: Deslag boiler.					
21.	11/02/97 00:00	-	11/03/97 00:52	Unplanned	24.87	12,930.67
	Descr: Air preheater down-mechanically bound.					
22.	11/03/97 02:39	-	11/03/97 03:52	Unplanned	1.22	632.67
	Descr: Unit trip-maintenance working on aux. bus-relay bump					
23.	11/16/97 08:03	-	11/16/97 12:57	Unplanned	4.90	2,548.00
	Descr: Unit trip-boiler ph low-circ. water leaked in from #12 condensate sump					
24.	11/16/97 13:08	-	11/16/97 14:17	Unplanned	1.15	598.00
	Descr: Unit trip-boiler ph low-circ. water leaked in from #12 condensate sump					
25.	12/17/97 03:36	-	12/17/97 22:37	Unplanned	19.02	9,888.67
	Descr: Unit off line to repair sh steam cooled wrapper tube.					
	*** * * Unit Summary for Jim Bridger No. 1 for the year 1997 =**				463.04	240,785.99
Jim Bridger No. 2						
1.	02/18/97 00:00	-	02/18/97 21:27	Unplanned	21.45	11,154.00
	Descr: Unit off line to repair i.d. fan linkages.					
2.	03/08/97 00:00	-	03/08/97 20:55	Unplanned	20.92	10,876.67
	Descr: Unit off tube leak.					
3.	04/17/97 23:58	-	04/19/97 13:32	Unplanned	37.57	19,534.67
	Descr: Unit off line to repair rh tube leak.					
4.	04/26/97 00:27	-	05/26/97 00:00	Planned	719.55	374,166.00
	Descr: Planned overhaul.					
5.	05/26/97 00:00	-	06/02/97 04:06	Planned	172.10	89,492.00
	Descr: Planned turbine overhaul.					
6.	06/02/97 10:50	-	06/02/97 13:57	Unplanned	3.12	1,620.67
	Descr: Post outage testing. turbine overspeeds.					
7.	08/02/97 18:27	-	08/04/97 16:50	Unplanned	46.38	24,119.33
	Descr: Unit off line to deslag reheater.					
8.	12/02/97 00:24	-	12/02/97 05:17	Unplanned	4.88	2,539.33
	Descr: Deslagging pendant reheater.					
9.	12/08/97 23:51	-	12/11/97 15:43	Unplanned	63.87	33,210.67
	Descr: Unit off line to deslag reheater.					
10.	12/11/97 17:46	-	12/11/97 19:12	Unplanned	1.43	745.33
	Descr: High turbine vibrations.					
11.	12/16/97 01:35	-	12/17/97 01:12	Unplanned	23.62	12,280.67
	Descr: Unit off line to repair waterwall tube leak.					
12.	12/20/97 07:29	-	12/20/97 10:10	Unplanned	2.68	1,395.33
	Descr: Unit off line-boiler feed pump control failure.					
	*** * * Unit Summary for Jim Bridger No. 2 for the year 1997 =**				1,117.57	581,134.67
Jim Bridger No. 3						
1.	03/11/97 23:21	-	03/13/97 13:46	Unplanned	38.42	19,976.67
	Descr: Id fan (31) linkage repair.					
2.	04/08/97 21:42	-	04/09/97 00:21	Unplanned	2.65	1,378.00
	Descr: Low hot p.a. duct pressure trip.					
3.	04/27/97 00:41	-	04/28/97 21:00	Unplanned	44.32	23,044.67
	Descr: Unit off line to repair air preheater drive problems.					

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No.	Beginning Date Time	- Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger No. 3					
4.	04/28/97 21:00	- 05/04/97 00:00	Unplanned	123.00	63,960.00
	Descr: 32 i.d. fan inlet vanes.				
5.	05/04/97 00:00	- 05/07/97 13:34	Unplanned	85.57	44,494.67
	Descr: 31 air preheater bearing failure.				
6.	05/18/97 21:57	- 05/28/97 08:19	Unplanned	226.37	117,710.67
	Descr: Unit off line to repair 32 air preheater primary-secondary sector plat				
7.	07/11/97 06:01	- 07/12/97 14:13	Unplanned	32.20	16,744.00
	Descr: Unit off line to repair i.d. fan inlet vanes.				
8.	07/12/97 15:36	- 07/17/97 07:09	Unplanned	111.55	58,006.00
	Descr: Unit off line to repair 32 i.d. fans inlet vane and bearing.				
9.	07/17/97 10:10	- 07/17/97 11:14	Unplanned	1.07	554.67
	Descr: Unit off line-boiler controls.				
10.	07/28/97 23:26	- 07/31/97 05:54	Unplanned	54.47	28,322.67
	Descr: Unit off line to restore 32 i.d. fan.				
11.	09/22/97 00:02	- 09/23/97 14:23	Unplanned	38.35	19,942.00
	Descr: Unit off line to repair waterwall tube leak.				
12.	11/30/97 02:29	- 12/01/97 03:38	Unplanned	25.15	13,078.00
	Descr: Unit off line to repair waterwall tube leak.				
13.	12/14/97 15:51	- 12/15/97 10:05	Unplanned	18.23	9,481.33
	Descr: Unit off line to repair pendant platen superheater tube leak.				
14.	12/22/97 19:29	- 12/23/97 12:06	Unplanned	16.62	8,640.67
	Descr: Unit off line to repair cooling tower circ. water header.				
	*** * * Unit Summary for Jim Bridger No. 3 for the year 1997 =**			817.97	425,334.02
Jim Bridger No. 4					
1.	01/17/97 07:44	- 01/18/97 10:30	Unplanned	26.77	13,918.67
	Descr: 42 ccw pump-blew expansion joint,				
2.	01/18/97 10:30	- 01/19/97 00:19	Unplanned	13.82	7,184.67
	Descr: Deslag reheater/superheater.				
3.	02/07/97 21:50	- 02/08/97 00:19	Unplanned	2.48	1,291.33
	Descr: Turbine trip. no apparent root cause in logs.				
4.	02/08/97 11:01	- 02/08/97 12:10	Unplanned	1.15	598.00
	Descr: Thrust bearing wear detector.				
5.	02/08/97 15:02	- 02/09/97 00:00	Unplanned	8.97	4,662.67
	Descr: Thrust bearing wear detector.				
6.	02/09/97 00:00	- 02/09/97 01:18	Unplanned	1.30	676.00
	Descr: B corner warmup gun control wiring fried due to boiler casing leak.				
7.	03/19/97 23:17	- 04/21/97 18:22	Planned	786.08	408,763.33
	Descr: Unit overhaul.				
8.	04/22/97 01:37	- 04/22/97 03:22	Unplanned	1.75	910.00
	Descr: Unit off line for overspeed test.				
9.	04/22/97 07:23	- 04/22/97 13:29	Unplanned	6.10	3,172.00
	Descr: Unit off line-125vdc circuit check-maintenance error.				
10.	05/08/97 01:00	- 05/08/97 17:05	Unplanned	16.08	8,363.33
	Descr: Unit off line to repair 42 feedwater heater bypass line leak.				
11.	05/08/97 17:05	- 05/08/97 20:58	Unplanned	3.88	2,019.33
	Descr: Waterwall tube leak.				

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No.	Beginning Date Time	- Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger No. 4					
12.	05/08/97 20:58	- 05/09/97 08:34	Unplanned	11.60	6,032.00
	Descr: Dc system ground.				
13.	06/09/97 23:30	- 06/10/97 23:54	Unplanned	24.40	12,688.00
	Descr: Unit off line to repair waterwall tube leak.				
14.	07/30/97 13:36	- 08/01/97 07:54	Unplanned	42.30	21,996.00
	Descr: Unit off line to replace lpb 14th stage expansion joint.				
15.	08/09/97 05:34	- 08/09/97 08:52	Unplanned	3.30	1,716.00
	Descr: Unit off line condensate storage tank ran dry.				
16.	10/20/97 14:10	- 10/20/97 15:25	Unplanned	1.25	650.00
	Descr: Defective sedcdevice tripped unit while tech was working on it.				
17.	10/24/97 15:00	- 10/24/97 18:20	Unplanned	3.33	1,733.33
	Descr: Exciter master firing circuit.				
18.	12/06/97 01:05	- 12/08/97 15:01	Unplanned	61.93	32,205.33
	Descr: Unit off line to deslag boiler.				
	*** * * Unit Summary for Jim Bridger No. 4 for the year 1997 =**			1,016.49	528,579.99
Naughton No. 1					
1.	05/24/97 00:14	- 06/30/97 19:54	Planned	907.67	145,226.67
	Descr: Overhaul - major boiler clean/retubing, rebuilding turbine valves, reb				
2.	07/25/97 23:27	- 07/27/97 05:53	Unplanned	30.43	4,869.33
	Descr: Repair economizer tube leak				
3.	09/19/97 22:23	- 09/20/97 12:29	Unplanned	14.10	2,256.00
	Descr: Outage - dc emergency lube oil pump and repack valves on boiler				
	*** * * Unit Summary for Naughton No. 1 for the year 1997 =**			952.20	152,352.00
Naughton No. 2					
1.	03/28/97 23:14	- 03/30/97 06:31	Unplanned	31.28	6,569.50
	Descr: Unit off to repair feedwater control valve				
2.	04/27/97 02:11	- 04/27/97 04:11	Unplanned	2.00	420.00
	Descr: Down to 100 with 3 mills, lost mill to low-flow, unstable flame, cause				
3.	06/11/97 08:37	- 06/11/97 12:47	Unplanned	4.17	875.00
	Descr: Safety inspection testing transformer deluge system				
4.	06/11/97 13:54	- 06/11/97 20:33	Unplanned	6.65	1,396.50
	Descr: Unit trip ups system failed				
5.	06/12/97 16:48	- 06/12/97 21:06	Unplanned	4.30	903.00
	Descr: Unit trip ups sytem failed				
6.	06/14/97 11:28	- 06/17/97 19:50	Unplanned	80.37	16,877.00
	Descr: Reheat tube leak repaired				
7.	06/21/97 00:20	- 06/26/97 13:03	Unplanned	132.72	27,870.50
	Descr: Reheat tube leak				
8.	08/19/97 23:52	- 08/21/97 11:49	Unplanned	35.95	7,549.50
	Descr: Lp blade failure l-o; removed 2 blade tips; weld repair peformed;nde t				
9.	10/21/97 09:49	- 10/21/97 13:04	Unplanned	3.25	682.50
	Descr: No load timer; contacts welded together and generator ran down				
10.	11/08/97 00:13	- 11/08/97 08:18	Unplanned	8.08	1,697.50
	Descr: Timer relay mcc 2-6 burned up, lost indication, lost bearing cooling p				
11.	11/12/97 23:29	- 11/15/97 19:19	Unplanned	67.83	14,245.00
	Descr: Condenser tube leak repairs and also repaired mov1				

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	- Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Naughton No. 2					
12.	11/22/97 23:38	- 11/23/97 02:00	Unplanned	2.37	497.00
	Descr: Governor system (raising/lowering load) tripped				
13.	12/20/97 00:13	- 12/21/97 23:53	Unplanned	47.67	10,010.00
	Descr: Offline to rod slag in boiler tube areas				
	*** * * Unit Summary for Naughton No. 2 for the year 1997 =**			426.64	89,593.00
Naughton No. 3					
1.	01/17/97 06:41	- 01/18/97 00:00	Unplanned	17.32	5,714.50
	Descr: Tripped low drum level operator error,repair 3 superheat 1 waterwall t				
2.	01/18/97 00:00	- 01/20/97 07:31	Unplanned	55.52	18,320.50
	Descr: Unit off to repair 3 sh 1 ww tube leaks, clean scrubber absorbers				
3.	01/24/97 23:30	- 01/25/97 22:31	Unplanned	23.02	7,595.50
	Descr: Repair economizer tube leak				
4.	02/02/97 01:28	- 02/02/97 04:56	Unplanned	3.47	1,144.00
	Descr: 3-2 boiler feed pump trip trying to valve in 3-1 bfp belly drain				
5.	02/02/97 11:15	- 02/02/97 13:42	Unplanned	2.45	808.50
	Descr: 3-2 boiler feed pump trip				
6.	02/02/97 13:44	- 02/02/97 16:08	Unplanned	2.40	792.00
	Descr: 3-2 bfp trip, voltage regulator stuck				
7.	03/21/97 05:16	- 03/21/97 10:26	Unplanned	5.17	1,705.00
	Descr: Bfp trip - belly drain flooded caused by condensate reject valve				
8.	05/08/97 07:32	- 05/08/97 14:56	Unplanned	7.40	2,442.00
	Descr: Unit trip, 3-1 and 3-2 bfpt tripped				
9.	09/06/97 04:00	- 09/09/97 01:58	Unplanned	69.97	23,089.00
	Descr: Repair waterwall tube leaks (6)				
10.	10/04/97 01:22	- 10/11/97 23:18	Unplanned	189.93	62,678.00
	Descr: Turbine chemical clean, clean scrubber absorbers, fix 2 waterwall leak				
11.	11/05/97 00:13	- 11/05/97 01:59	Unplanned	1.77	583.00
	Descr: Unit trip flame scanners				
12.	11/05/97 02:52	- 11/05/97 04:35	Unplanned	1.72	566.50
	Descr: Unit trip - burner controls				
13.	11/16/97 01:30	- 11/16/97 02:56	Unplanned	1.43	473.00
	Descr: Doing sunday valve test and ran valves wrong way				
14.	11/19/97 02:59	- 11/19/97 04:25	Unplanned	1.43	473.00
	Descr: Big slab of ash fell				
15.	11/26/97 03:57	- 11/29/97 02:56	Unplanned	70.98	23,424.50
	Descr: Repaired 6 waterwall and 1 superheat tube leaks				
16.	11/29/97 03:12	- 11/30/97 04:57	Unplanned	25.75	8,497.50
	Descr: Burnt relays on fsss system				
17.	12/06/97 01:38	- 12/08/97 02:05	Unplanned	48.45	15,988.50
	Descr: Repair first superheater tube leaks				
	*** * * Unit Summary for Naughton No. 3 for the year 1997 =**			528.18	174,295.00
Wyodak					
1.	02/27/97 02:36	- 02/27/97 12:22	Unplanned	9.77	3,271.83
	Descr: Turbine controls, at full load, transfered operation from partial arc				
2.	04/07/97 01:05	- 04/07/97 07:30	Unplanned	6.42	2,149.58
	Descr: 1a1 station transformer feed breaker tripped when 6h455 was racked in				

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	- Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Wyodak					
3.	04/07/97 07:30	- 04/07/97 17:30	Unplanned	10.00	3,350.00
	Descr: Boiler purge for start up failed due to water in instrument air lines				
4.	04/07/97 17:30	- 04/08/97 19:07	Unplanned	25.62	8,581.58
	Descr: Servo unit for the id fan damper controls was faulty				
5.	05/14/97 12:53	- 05/14/97 14:19	Unplanned	1.43	480.17
	Descr: Calibrating 1st stage pressure transmitter- steam flow indication went				
6.	09/26/97 06:26	- 09/26/97 10:05	Unplanned	3.65	1,222.75
	Descr: Unit trip on low drum level while trying to increase load				
7.	09/26/97 10:05	- 09/26/97 11:07	Unplanned	1.03	346.17
	Descr: After generator sync the unit tripped on high drum level				
8.	09/26/97 11:07	- 09/26/97 12:11	Unplanned	1.07	357.33
	Descr: After generator sync the unit tripped on high drum level				
9.	10/16/97 00:01	- 10/18/97 14:15	Unplanned	62.23	20,848.17
	Descr: Unit brought off line to remove ash build up in the reheater section				
10.	10/29/97 05:10	- 10/30/97 08:54	Unplanned	27.73	9,290.67
	Descr: Tube leak in convection pass floor below the reheat section				
11.	10/31/97 05:54	- 10/31/97 23:38	Unplanned	17.73	5,940.67
	Descr: High velocity winds caused voltage lines in the switch yard to cross				
12.	11/03/97 01:06	- 11/03/97 03:00	Unplanned	1.90	636.50
	Descr: For unknown reason at this time, the furnace pressure went above 10 in				
13.	11/22/97 12:27	- 11/23/97 10:36	Unplanned	22.15	7,420.25
	Descr: Tube leak				
14.	11/25/97 13:29	- 11/26/97 06:25	Unplanned	16.93	5,672.67
	Descr: Tube leak				
	*** * * Unit Summary for Wyodak for the year 1997 =**			207.66	69,568.34
Cholla No. 4					
1.	02/20/97 12:31	- 02/23/97 14:37	Unplanned	74.10	28,158.00
	Descr: Reheater tube leak repairs				
2.	03/11/97 12:24	- 03/11/97 14:00	Unplanned	1.60	608.00
	Descr: B vacuum pump controls				
3.	03/25/97 11:33	- 03/25/97 13:48	Unplanned	2.25	855.00
	Descr: B vacuum pump controls				
4.	05/05/97 13:08	- 05/05/97 14:51	Unplanned	1.72	652.33
	Descr: Volts/hertz trip - var transducer malfunction				
5.	05/23/97 23:20	- 05/24/97 04:11	Unplanned	4.85	1,843.00
	Descr: 'a' vacuum pump motor burned up				
6.	05/24/97 06:45	- 05/24/97 08:39	Unplanned	1.90	722.00
	Descr: Feedwater flow upset				
7.	08/07/97 09:14	- 08/13/97 02:57	Unplanned	137.72	52,332.33
	Descr: Repair tube leak				
8.	09/18/97 11:06	- 09/18/97 15:35	Unplanned	4.48	1,703.67
	Descr: Lost instrument air pressure				
9.	10/06/97 15:25	- 10/08/97 13:48	Unplanned	46.38	17,625.67
	Descr: Boiler reheater tube leak repairs				
10.	10/27/97 09:24	- 10/27/97 11:42	Unplanned	2.30	874.00
	Descr: Exciter cubical trip				

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Cholla No. 4						
11.	11/22/97 00:26	-	12/01/97 01:59	Planned	217.55	82,669.00
	Descr: Stack turning vane repairs					
	* * * **Unit Summary for Cholla No. 4 for the year 1997 =**				494.85	188,043.00
Gadsby No. 2						
1.	07/07/97 11:33	-	07/07/97 16:11	Unplanned	4.63	347.50
	Descr: While bringing up load unit due to high burner fuel pressure. this wa					
	* * * **Unit Summary for Gadsby No. 2 for the year 1997 =**				4.63	347.50
Gadsby No. 3						
1.	09/12/97 07:58	-	09/13/97 00:44	Unplanned	16.77	1,676.67
	Descr: Primary superheat tube leak 20 tubes from south side of boiler. it ap					
2.	09/26/97 13:35	-	09/26/97 20:00	Unplanned	6.42	641.67
	Descr: Fd inlet damper drives 3-1 and 3-2 would not close and consequently wo					
	* * * **Unit Summary for Gadsby No. 3 for the year 1997 =**				23.19	2,318.34
Blundell						
1.	04/09/97 11:15	-	04/09/97 15:15	Unplanned	4.00	92.00
	Descr: System disturbance					
2.	04/09/97 15:15	-	04/19/97 00:25	Unplanned	225.17	5,178.83
	Descr: Maintenance outage					
3.	04/19/97 05:35	-	04/19/97 17:26	Unplanned	11.85	272.55
	Descr: Condenser screens plugged					
4.	06/12/97 11:29	-	06/12/97 16:39	Unplanned	5.17	118.83
	Descr: Clean hotwell screens in main condenser					
5.	07/05/97 19:10	-	07/06/97 18:10	Unplanned	23.00	529.00
	Descr: Main condenser screens plugged					
6.	08/19/97 10:56	-	08/19/97 15:11	Unplanned	4.25	97.75
	Descr: Br-5 tripped causing other probs at wells and tripped unit manually					
7.	09/15/97 23:47	-	09/16/97 02:00	Unplanned	2.22	50.98
	Descr: Br4 pump tripped on low flow. ig's 28-3 well shut in					
8.	09/16/97 10:40	-	09/17/97 00:53	Unplanned	14.22	326.98
	Descr: Repair leak in dielectric flange					
9.	10/30/97 08:21	-	10/30/97 15:00	Unplanned	6.65	152.95
	Descr: Clean condenser screens					
10.	12/02/97 13:48	-	12/02/97 16:50	Unplanned	3.03	69.77
	Descr: Unit tripped; emergency overspeed trip					
11.	12/22/97 11:44	-	12/22/97 13:31	Unplanned	1.78	41.02
	Descr: Problems with cw1c electrical leads tripped unit					
	* * * **Unit Summary for Blundell for the year 1997 =**				301.34	6,930.66
Little Mountain						
1.	12/17/97 08:42	-	12/17/97 17:48	Unplanned	9.10	127.40
	Descr: Pre-evaporator tube leak					
	* * * **Unit Summary for Little Mountain for the year 1997 =**				9.10	127.40

1997 FORCED OUTAGES REPORT
(Outages Which Exceed 24 Hours)

	Location / Date of Outage	Unit No. and Cause of Outage	Outage Duration (Hours)
Hydro East			
	American Fork - 696	Unit 1 - 1/1/97-12/10/97 Flowline failure occurred May 1993. Plant returned to service December 1997 following pipleline repair	8218
	Ashton - 2381	Unit 2 - 9/11/97 - 9/25/97 Generator circuit breaker failure / Replaced pivot pin	327
		Unit 3 - 9/12/97 - 9/25/97 Generator circuit breaker failure / Replaced pivot pin	303
	Cove - 2401	None	
	Cutler - 2426	None	
	Fountain Green - 10690	Unit 1 - 1/1/97 - 5/16/97 Generator winding failure / Repaired damaged coils	4008
		Unit 1 - 10/21/97 - 12/12/97 Exciter rheostat failure / Rebuilt equipment	1222
	Grace - 2401	None	
	Gunlock - 9281	Unit 1 - 11/5/97 - 11/8/97 Vicker valve trouble / Replaced burned up coil	120
	Last Chance - 4580	Unit 1 - 1/1/97 - 1/23/97 Turbine shaft failure / Fabriciated new shaft	555
	Oneida - 472	Unit 1 - 3/18/97 - 3/21/97 Govenor trouble / Repaired govenor	74
		Unit 3 - 4/15/97 - 4/15/97 Lube oil pump failure / Repaired pump	23
	Paris - 703	Unit 1 - 1/12/97 - 1/14/97 Canal blown in with snow	47

1997 FORCED OUTAGES REPORT
(Outages Which Exceed 24 Hours)

	Location / Date of Outage	Unit No. and Cause of Outage	Outage Duration (Hours)
	Pioneer - 2722	Units 3&6 4/14/97 - 4/18/97 Repaired draft tubes	120
	Sandcove - 9281	Unit 1 - 8/10/97 - 8/11/97 Station battery trouble / Corrected problem	35
	Stairs - 597	Unit 1 - 6/12/97 - 7/1/97 Land slide upstream increased debris loading on intake screen. Bent intake screen and jammed scroll case / Unit disassembled and cleaned out	443
	St. Anthony - 2381	None	
	Snakecreek -	Unit 2 - 1/2/97 - 1/21/97 Damaged gear box / Fabricated new gear box and shaft	432
		Unit 2 - 4/29/97 - 4/30/97 Relay trouble / Repaired relays	37
	Soda - 20	None	
	Upper Beaver - 814	None	
	Veyo - 9281	Unit 1 - 1/15/97 - 1/16/97 Hydraulic hose failure / Repaired hose	28
	Viva Naughton - 6509		
	Weber - 1744	None	
Hydro North			

1997 FORCED OUTAGES REPORT
(Outages Which Exceed 24 Hours)

Location / Date of Outage	Unit No. and Cause of Outage	Outage Duration (Hours)
Bend - Unlicensed	Unit 1 - 1/13/97 to 1/15/97, Icing problems	56
	Unit 2 - 1/13/97 to 1/15/97, Icing problems	56
	Unit 3 - 1/13/97 to 1/16/97, Icing problems	77
Bigfork - 2652	Unit 3 - 1/4/97 to 1/6/97, Field switch malfunction	49
	Unit 1 - 7/6/97 to 7/8/97, Repair broken gate link	37
	Unit 3 - 7/26/97 to 8/11/97, Packing leak	384
	Unit 1 - 8/18/97 to 8/26/97, Canal repairs	196
	Unit 2 - 8/18/97 to 8/26/97, Canal repairs	196
	Unit 3 - 8/18/97 to 8/26/97, Canal repairs	197
Cline Falls - Unlicensed	Unit 1 - 10/5/97 to 10/10/97, Transformer breaker failure	126
Condit - 2342	Unit 1 - 1/1/97 to 1/3/97, Bearing repair	58
	Unit 2 - 1/14/97 to 1/16/97, Thrust bearing repair	56
	Unit 1 - 3/23/97 to 3/29/97, Plugged sump outlet and field ground	152
	Unit 1 - 7/4/97 to 7/8/97, Broken wicket gate arm, vibration	89
Merwin - 935	None	
Naches - Unlicensed	None	
Naches Drop - Unlicensed	None	
Powerdale - 2659	None	
Yale - 2071	None	
Skookumchuck	None	
Swift - 2111	None	
Wallowa Falls - 308	Unit 1 - !2/1/97 to 12/31/97, Frozen penstock, turnbine repairs	744

1997 FORCED OUTAGES REPORT
(Outages Which Exceed 24 Hours)

Hydro South	Location / Date of Outage	Unit No. and Cause of Outage	Outage Duration (Hours)
	Klamath	West Side Unit 1- 5/27/31 to 5/31/97, Repair governor bearing	102
		West Side Unit 1- 6/3/97 to 6/3/97, Repair governor bearing	63
		West Side Unit 1 - 7/1/97 to 8/31/97, Repair governor bearing	593
		Copco Unit 11 - 1/1/97 to 2/24/97, Problems with turbine runner overhaul	1329
		Copco Unit 11 - 6/6/97 to 7/28/97, Repair bearings	1253
		Copco Unit 11 -8/23/97 to 8/25/97, Exciter problems	64
		Copco Unit 11 - 8/28/97 to 8/30/97, Exciter problems	39
		Copco Unit 12 - 9/18/97 to 9/21/97, Problems with turbine runner overhaul	82
		Copco Unit 22 - 7/23/97 to 9/1/97, Water in turbine bearing	960
		Fall Creek Unit 1 - 6/6/97 to 6/9/97, Water in plant from heavy rain	68
		Fall Creek Unit 2 - 6/6/97 to 6/9/97, Water in plant from heavy rain	68
		Fall Creek Unit 3 - 6/6/97 to 6/9/97, Water in plant from heavy rain	68
	North Umpqua	Slide Creek Unit 1 - 1/2/97 to 1/4/97, Intake racks plugged	57
		Lemolo Unit 2 - 2/14/97 to 2/16/97, Canal repair	41
		Toketee Unit 2 - 10/29/97 to 10/30/97, Unit tripped due to grid closure	29
	Prospect 3	None	
	Prospect 1,2,4	Prospect 1, Unit 1- 11/21/97 to 11/22/97, Repair governor drive shaft	28
		Prospect 2, Unit 2- 12/26/97 to 12/31/97, Problem with generator guide bearing	104
	Eagle Point	Unit 1 - 1/5/97 to 3/4/97, Remove large rock in canal	1400

825 N.E. Multnomah
Portland, Oregon 97232
(503) 464-5000

PACIFICORP
PACIFIC POWER UTAH POWER

June 10, 1998

Montana Public Service Commission
Attn: Laura J. Calkin
Accounting & Support Services
P.O. Box 202601
Helena, Montana 59620-2601

RE: Annual Reports for 1997

Dear Ms. Calkin:

Enclosed is a copy of our Annual State Report. If you have any questions, please don't hesitate to call me at (503) 813-6081.

Very truly yours,

Brian K. Hedman
Manager, Regulation

Enclosure

Notes to Financial Statements

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PacifiCorp (the "Company") is an integrated electric utility that conducts its retail electric utility operations through Pacific Power and Utah Power, and engages in wholesale electric transactions under the name PacifiCorp. The Company is the indirect owner, through its wholly owned subsidiary, PacifiCorp Group Holdings Company, formerly PacifiCorp Holdings, Inc. ("Holdings"). Wholly owned subsidiaries of Holdings include Powercor Australia Limited ("Powercor"), an Australian electricity distributor purchased December 12, 1995; PacifiCorp Financial Services, Inc. ("PFS"), a financial services business; PacifiCorp Power Marketing, engaged in wholesale electricity trading in the eastern United States energy markets; and TPC Corporation ("TPC"), a natural gas marketing and storage company, purchased April 15, 1997.

The Company sold its telecommunications operation, Pacific Telecom, Inc. ("PTI") on December 1, 1997. See Note 14. The Company disposed of Pacific Generation Company ("PGC") on November 1, 1997, and the natural gas gathering and processing assets of TPC on December 1, 1997. See Note 15. In addition, the Company has signed letters of intent to sell the real estate assets held by its financial services business.

These regulatory basis financial statements have been prepared for the purpose of complying with, and on the basis of accounting practices specified by the Federal Energy Regulatory Commission ("FERC"). Accordingly, investments in subsidiaries are accounted for and reported on the equity basis of accounting and these regulatory basis financial statements do not include debt of the Leveraged ESOP Trust established under the PacifiCorp K Plus Employee Savings and Stock Ownership Plan ("K Plus Plan") which is guaranteed by Holdings and do not present financial position, results of operations and changes in cash flows in accordance with generally accepted accounting principles, which would require that the accounts of the subsidiaries be consolidated with those of PacifiCorp.

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo,Da,Yr)	Year of Report Dec. 31, 1997

NOTES TO FINANCIAL STATEMENTS (Continued)

The following schedule shows increases and decreases had the accounts of the subsidiaries been consolidated with those of the Company:

THOUSANDS OF DOLLARS	CONSOLIDATED	FERC FORM 1 FINANCIALS	INCREASE/ (DECREASE)
AT DECEMBER 31, 1997			
Property, plant and equipment - net	$9,070,296	$7,825,472	$ 1,244,824
Investments in subsidiaries	-	2,393,747	(2,393,747)
Current assets	2,182,364	801,162	1,381,202
Other assets	2,627,577	1,284,048	1,343,529
Common stock	3,274,248	3,287,356	(13,108)
Retained earnings	1,106,268	1,076,194	30,074
Cumulative currency translation adj	(59,596)	-	(59,596)
Preferred stock	241,364	241,364	-
Long-term debt	4,414,476	4,008,672	405,804
Guaranteed Preferred Beneficial Interests in Company's Junior Subordinated Debentures	340,409	-	340,409
Current liabilities	2,105,519	1,756,938	348,581
Deferred credits	2,457,549	1,933,905	523,644
AT DECEMBER 31, 1996			
Property, plant and equipment - net	$9,267,114	$7,825,125	$ 1,441,989
Investments in subsidiaries	-	1,506,260	(1,506,260)
Current assets	1,661,926	673,277	988,649
Other assets	2,883,292	1,356,106	1,527,186
Common stock	3,236,756	3,250,444	(13,688)
Retained earnings	782,836	771,026	11,810
Cumulative currency translation adjustment	12,718	-	12,718
Preferred stock	313,538	313,538	-
Long-term debt	4,829,385	3,770,845	1,058,540
Guaranteed Preferred Beneficial Interests in Company's Junior Subordinated Debentures	209,732	-	209,732
Current liabilities	1,755,336	1,291,880	463,456
Deferred credits	2,672,031	1,963,035	708,996

THOUSANDS OF DOLLARS	CONSOLIDATED	FERC FORM 1 FINANCIALS	INCREASE/ (DECREASE)
FOR THE YEAR ENDED DECEMBER 31, 1997			
Operating revenues	$ 6,277,989	$3,683,921	$ 2,594,068
Operating expenses	5,475,491	3,200,919	2,274,572
Net cash provided by oper. activities	834,088	674,878	159,210
Net cash provided by (used in) investing activities	922,028	(860,606)	1,782,634
Net cash provided by (used in) financing activities	(1,023,191)	208,325	1,231,516
FOR THE YEAR ENDED DECEMBER 31, 1996			
Operating revenues	3,803,712	2,961,321	842,391
Operating expenses	2,717,334	2,309,175	408,159
Net cash provided by oper. activities	925,683	663,761	261,922
Net cash used in investing activities	(781,571)	(581,779)	(199,792)
Net cash used in financing activities	(151,540)	(101,449)	(50,091)

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements. Actual results could differ from those estimates.

Regulation

Accounting for the Company conforms with generally accepted accounting principles as applied to regulated public utilities and as prescribed by the Federal Energy Regulatory Commission and the regulatory agencies and the commissions of the various states in which the Company operates. The Company prepares its financial statements in accordance with Statement of Financial Accounting Standards ("SFAS") 71, "Accounting for the Effects of Certain Types of Regulation." See Note 2.

Asset Impairment

Long-lived assets and certain identifiable intangibles to be held and used by the Company are reviewed for impairment whenever events or circumstances indicate costs may not be recoverable. Impairment losses on long-lived assets are recognized when book values exceed expected undiscounted cash flows. If impairment exists, the asset's book value will be written down to its fair value.

NOTES TO FINANCIAL STATEMENTS (Continued)

Cash and Cash Equivalents

For the purposes of these financial statements, the Company considers all liquid investments with original maturities of three months or less to be cash equivalents.

Property, Plant and Equipment

Property, plant and equipment is stated at original cost of contracted services, direct labor and material, interest capitalized during construction and indirect charges for engineering, supervision and similar overhead items. The cost of depreciable utility properties retired, including the cost of removal, less salvage, is charged to accumulated depreciation.

Depreciation and Amortization

At December 31, 1997, the average depreciable life of property, plant and equipment by category was: Production, 35 years; Transmission, 42 years; Distribution, 31 years and Other, 16 years.

Depreciation and amortization is computed generally by the straight-line method in the following manner: As prescribed by the Company's various regulatory jurisdictions for regulated assets; and over the estimated useful lives of the related assets for nonregulated generation resource assets and for other nonregulated assets. Provisions for depreciation (excluding amortization of capital leases) were 3.2 and 3.1 percent of average depreciable assets in 1997 and 1996, respectively.

Mine Reclamation and Closure Costs

The Company expenses current mine reclamation costs and accrues for estimated final mine reclamation and closure costs using the units-of-production method.

Inventory Valuation

Inventories are generally valued at the lower of average cost or market.

Derivatives

Gains and losses on hedges of existing assets and liabilities are included in the carrying amounts of those assets or liabilities and are recognized in income as part of those carrying amounts. Gains and losses related to hedges of anticipated transactions and firm commitments are deferred on the balance sheet and recognized in income when the transaction occurs.

Interest Capitalized

Costs of debt and equity funds applicable to utility properties are capitalized during construction. Generally, the composite capitalization rates allowed were 5.7 percent for 1997 and 5.6 percent for 1996.

Income Taxes

The Company uses the liability method of accounting for deferred income taxes. Deferred tax liabilities and assets reflect the expected future tax consequences, based on enacted tax law, of temporary differences between the tax bases of assets and liabilities and their financial reporting amounts.

Prior to 1980, the Company did not provide deferred taxes on many of the timing differences between book and tax depreciation. In prior years, these benefits were flowed through to the utility customer as prescribed by the Company's various regulatory jurisdictions. Deferred income tax liabilities and regulatory assets have been established for those flow through tax benefits. See Note 2.

Investment tax credits are deferred and amortized to income over periods prescribed by the Company's various regulatory jurisdictions.

Revenue Recognition

The Company accrues estimated unbilled revenues for electric services provided after cycle billing to month-end.

Preferred Stock Retired

Amounts paid in excess of the net carrying value of preferred stock retired are amortized in accordance with regulatory orders.

Stock Based Compensation

The Company has elected to follow Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees ("APB 25") and related interpretations in accounting for its employee stock options. Under APB 25, because the exercise price of employee stock options equals the market price of the underlying stock on the date of grant, no compensation expense is recorded.

New Accounting Standards

In June 1997, the Financial Accounting Standards Board (the "FASB") issued SFAS 130, "Reporting Comprehensive Income," and SFAS 131, "Disclosures About Segments of an Enterprise and Related Information." SFAS 130 establishes standards for reporting and display of comprehensive income in financial statements. SFAS 131 requires that companies disclose segment data based on how management makes decisions about allocating resources to segments and measuring performance. In February 1998, the FASB issued SFAS 132, "Employers' Disclosures About Pensions and Other Postretirement Benefits." These standards are effective for fiscal years beginning after December 15, 1997. Adoption of these standards may result in additional financial disclosure but will not have an effect on the Company's financial position or results of operations.

Reclassification

Certain amounts from the prior year have been reclassified to conform with the 1997 method of presentation. These reclassifications had no effect on previously reported net income.

NOTE 2. ACCOUNTING FOR THE EFFECTS OF REGULATION

Regulated utilities have historically applied the provisions of SFAS 71 which is based on the premise that regulators will set rates that allow for the recovery of a utility's costs, including cost of capital. Accounting under SFAS 71 is appropriate as long as: rates are established by or subject to approval by independent, third-party regulators; rates are designed to recover the specific enterprise's cost-of-service; and in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be collected from customers. In applying SFAS 71, the Company must give consideration to changes in the level of demand or competition during the cost recovery period. In accordance with SFAS 71, the Company capitalizes certain costs, regulatory assets, in accordance with regulatory authority whereby those costs will be expensed and recovered in future periods.

The Emerging Issues Task Force of the Financial Accounting Standards Board (the EITF) concluded in 1997 that SFAS 71 should be discontinued when detailed legislation or regulatory order regarding competition is issued. Additionally, the EITF concluded that regulatory assets and liabilities applicable to businesses being deregulated should be written off unless their recovery is provided for through future regulated cash flows.

In 1996, legislation was passed in California restructuring its electric utility industry. The restructuring is scheduled to begin March 31, 1998, at which time customers will be able to buy their electricity from sources other than the local utility. The local utility will continue to provide distribution services. Legislation was also passed in Montana in 1997 which established a phased process to introduce price-based competition into the supply of electricity in Montana. As a result of these legislative actions, prices for the supply of electric generation in

California and Montana are, or are expected to be, in transition from cost-based regulated rates to rates determined by competitive market forces.

Regulatory assets-net at December 31, 1997 and 1996 included the following:

THOUSANDS OF DOLLARS/DECEMBER 31	1997	1996
Deferred taxes - net (a)	$650,145	$ 675,984
Deferred pension costs	-	102,888
Demand-side resource costs	108,303	118,773
Unamortized net loss on reacquired debt	60,617	68,415
Unrecovered Trojan Plant and regulatory study costs	22,972	26,851
Various other costs	58,715	63,312
Total	$900,752	$1,056,223

(a) Excludes $133,261 of investment tax audit regulatory liabilities.

The Company has evaluated its regulatory assets and liabilities related to the generation portion of its business allocable to the states of California and Montana based upon future regulated cash flows. Accordingly, the Company ceased the application of SFAS 71 to its generation business allocable to the states of California and Montana in 1997. The Company recorded an extraordinary loss of $15,994,000 for the write off of these regulatory assets and liabilities.

The Company operates in five other states (Oregon, Utah, Wyoming, Washington and Idaho) which are at various stages of addressing the issue of deregulating the electricity industry. At December 31, 1997, $382,000,000 of the $900,752,000 total regulatory assets - net was applicable to the generation assets allocable to these five states. Because of the potential regulatory and/or legislative actions in these other state jurisdictions, the Company may have additional regulatory asset write offs and charges for impairment of long-lived assets in future periods relating to the generation portion of its business.

Also in 1997, the Company evaluated all its regulatory assets and liabilities applicable to deferred pension costs which relate primarily to a deferred compensation plan and early retirement incentive programs in 1987 and 1990 and determined that recovery of these costs was not probable. As a result, the Company recorded an $86,887,000 write off of its deferred regulatory pension asset, since the Company does not intend to seek recovery of these costs. However, the Company will seek recovery for its current and future pension costs.

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NOTES TO FINANCIAL STATEMENTS (Continued)

In early 1997, the Division of Public Utilities (the "DPU") and the Committee of Consumer Services (the "CCS") in Utah filed a joint petition with the Utah Public Service Commission (the "PSC") requesting the PSC to commence proceedings to establish new rates for Utah customers. The DPU indicated that rates could be reduced by approximately $54,000,000. Subsequently in March 1997, the Utah Legislature passed a bill that created a legislative task force to study electrical restructuring and customer choice issues in the State of Utah. The bill precluded the PSC from holding hearings on rate changes and froze prices at January 31, 1997 levels until May 1998, but allowed for retroactive price changes. The Company agreed to an interim price decrease to Utah customers of $12,400,000 annually beginning on April 15, 1997.

During the freeze period, the PSC proceeded with hearings on the proper method for cost allocation among PacifiCorp's seven jurisdictions that would be used in the 1998 rate case. The DPU recommended an allocation method that would reduce prices by $56,000,000 over five years, of which $14,000,000 was included in its original estimate of $54,000,000. During these hearings,the CCS recommended a method that would reduce prices by $96,000,000 or $42,000,000 more than the original DPU estimate. The Company advocated a method that would result in a decrease of approximately $3,000,000 per year. The PSC held hearings in December and an order is expected in early 1998. An allocation order by itself will not decrease revenues, but will be incorporated into subsequent rate proceedings which are expected to occur in mid-1998 and will be combined with other cost increases and determine the overall impact to customer rates decreases to.

NOTE 3. SPECIAL CHARGES

In December 1997,the Company recorded in operating income special charges of $170,436,000 ($105,756,000 after-tax). The pretax special charges included write off of $86,887,000 of deferred regulatory pension assets (see Note 2), a $19,096,000 write off of certain information system assets associated with the Company's decision to proceed with an installation of SAP enterprise-wide software and $64,453,000 of costs associated with the write down of assets and acceleration of reclamation costs due to the early closure of the Glenrock coal mine. The inability of the mine to remain competitive has caused it to be uneconomic under current and expected market conditions due to increased mining stripping ratios, coal quality and related costs.

Also, in January 1998, the Company announced a plan to reduce its work force by approximately 600 positions, or 7 percent of the work force in 1998. This reduction will be accomplished through a combination of voluntary early retirement and special severance. Employees are not required to finalize their acceptance of offers until March 31, 1998. Based upon the current acceptance rate, the pretax costs are estimated to be $104,000,000, which will be recorded in the first quarter of 1998. The current acceptance rate has exceeded the Company's original estimate.

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NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 4. SHORT-TERM DEBT AND BORROWING ARRANGEMENTS

Information concerning short-term debt and borrowing arrangements is as follows:

THOUSANDS OF DOLLARS	BALANCE	AVERAGE INTEREST RATE (a)
12/31/1997	$303,179	6.5%
12/31/1996	$675,007	5.6%

(a) Computed by dividing the total interest on principal amounts outstanding the end of the period by the weighted daily principal amounts outstanding

At December 31, 1997, the Company's commercial paper and bank line borrowings were supported by revolving credit agreements totaling $700 million.

NOTE 5. LONG-TERM DEBT

The Company's long-term debt at December 31 was as follows:

THOUSANDS OF DOLLARS	1997	1996
First mortgage and collateral trust bonds		
Maturing 1998 through 2002/5.9%-9.5%	$ 882,200	$1,074,500
Maturing 2003 through 2007/6.1%-9%	756,068	587,205
Maturing 2008 through 2012/7%-9.2%	267,566	144,948
Maturing 2013 through 2017/7.3%-8.8%	164,929	167,641
Maturing 2018 through 2022/8.1%-8.5%	175,000	175,000
Maturing 2023 through 2026/6.7%-8.6%	286,500	286,500
Guaranty of pollution control revenue bonds		
5.6%-5.7% due 2021 through 2023 (a)	71,200	71,200
Variable rate due 2013 through 2024 (a)(b)	216,470	216,470
Variable rate due 2005 through 2030 (b)	450,700	450,700
Funds held by trustees	(9,119)	(12,140)
8.4%-8.6% Junior subordinated debentures due 2025 through 2035	175,826	175,826
Advances fom associated companies	430,562	276,186
Unamortized premium and discount	1,822	4,598
Capital lease obligations	23,327	23,576
Total	3,893,051	3,642,210
Less current maturities	194,927	203,797
TOTAL	$3,698,124	$3,438,413

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(a) Secured by pledged first mortgage and collateral trust bonds generally at the same interest rates, maturity dates and redemption provisions as the secured pollution control revenue bonds.

(b) Interest rates fluctuate based on various rates, primarily on certificate of deposit rates, interbank borrowing rates, prime rates or other short-term market rates.

Approximately $4.8 billion of the assets of the Company secure long-term debt. First mortgage and collateral trust bonds of the Company may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures.

The junior subordinated debentures are unsecured obligations of the Company and are subordinated to the Company's first mortgage and collateral trust bonds, pollution control revenue bonds, commercial paper, bank debt and any future senior indebtedness.

The Company has guaranteed all of the obligations of PacifiCorp Capital I and PacifiCorp Capital II, wholly owned subsidiary trusts of the Company. See Note 12.

The annual maturities of long-term debt and redeemable preferred stock outstanding are $194,927,000, $297,620,000, $168,459,000, $236,042,000 and 144,025,000 in 1998 through 2002, respectively.

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NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 6. COMMON AND PREFERRED STOCK

THOUSANDS OF SHARES/DOLLARS	SHARES COMMON STOCK	SHARES PREFERRED STOCK	COMMON SHARE-HOLDERS' CAPITAL
At January 1, 1996	284,277	8,299	$3,028,917
Dividend Reinvestment Plan	2,082	-	43,291
Stock Compensation Plan	(9)	-	(2,482)
Sales to Public	8,790	-	177,788
Redemptions and Repurchases	-	(2,343)	2,929
At December 31, 1996	295,140	5,956	3,250,443
Dividend Reinvestment Plan	1,779	-	37,607
Stock Compensation Plan	(11)	-	(881)
Redemptions and Repurchases	-	(2,797)	187
At December 31, 1997	296,908	3,159	$3,287,356

At December 31, 1997, there were 30,227,513 authorized but unissued shares of common stock reserved for issuance under the Dividend Reinvestment and Stock Purchase Plan and the Employee Savings and Stock Ownership Plans and for sales to the public. Eligible employees under the employee plans may direct their pretax elective contributions into the purchase of the Company's common stock. The Company makes matching contributions, equal to a percentage of employee contributions, which are invested in the Company's common stock. Employee contributions eligible for matching contributions are limited to 6 percent of compensation.

Generally, preferred stock is redeemable at stipulated prices plus accrued dividends, subject to certain restrictions. Upon involuntary liquidation, all preferred stock is entitled to stated value or a specified preference amount per share plus accrued dividends.

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NOTES TO FINANCIAL STATEMENTS (Continued)

PREFERRED STOCK OUTSTANDING
THOUSANDS OF SHARES/DECEMBER 31

DECEMBER 31 SERIES	1997 SHARES	1997 AMOUNT	1996 SHARES	1996 AMOUNT
SUBJECT TO MANDATORY REDEMPTION				
No Par Serial Preferred, $100 stated value, 16,000 Shares authorized				
$7.12	-	$ -	30	$ 3,000
7.70	1,000	100,000	1,000	100,000
7.48	750	75,000	750	75,000
TOTAL	1,750	$175,000	1,780	$178,000
NOT SUBJECT TO MANDATORY REDEMPTION				
No Par Serial Preferred, $25 stated value				
$1.16	193	4,828	193	4,828
1.18	420	10,503	420	10,503
1.28	381	9,531	381	9,530
1.98, Series 1992	-	-	2,767	69,175
Serial Preferred, $100 stated value, 3,500 Shares authorized				
4.52%	2	206	2	206
4.56	85	8,459	85	8,459
4.72	70	6,989	70	6,989
5.00	42	4,200	42	4,200
5.40	66	6,596	66	6,596
6.00	6	593	6	593
7.00	18	1,806	18	1,806
5% Preferred, $100 stated value, 127 Shares authorized and outstanding	127	12,653	127	12,653
TOTAL	1,410	$66,364	4,177	$135,538

Mandatory redemption requirements at stated value plus accrued dividends on No Par Serial Preferred Stock are as follows: the $7.70 series is redeemable in its entirety on August 15, 2001; and 37,500 shares of the $7.48 series are redeemable on each June 15 from 2002 through 2006, with all shares outstanding on June 15, 2007 redeemable on that date. If the Company is in default in its obligation to make any future redemptions on the $7.48 series, it may not pay cash dividends on common stock.

NOTE 7. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company seeks to reduce net income and cash flow exposure to changing interest and currency exchange rates and commodity price risks through the use of derivative financial instruments. The Company's participation in derivative transactions involves instruments that have a close correlation with its portfolio of liabilities, thereby managing its risk. Derivatives have been designed for hedging purposes and are not held or issued for speculative purposes.

Notional Amounts and Credit Exposure of Derivatives

The notional amounts of derivatives summarized below do not represent amounts exchanged and, therefore, are not a measure of the exposure of the Company through its use of derivatives. The amounts exchanged are calculated on the basis of the notional amounts and other terms of the derivatives, which relate to interest rates or other indexes.

The Company is exposed to credit-related losses in the event of nonperformance by counterparties to financial instruments, but it does not expect any counterparties to fail to meet their obligations given their high credit rating requirements. The Company's credit policy provides that counterparties satisfy minimum credit ratings. The credit exposure of interest rate and forward contracts is represented by the fair value of contracts with a positive fair value at the reporting date.

Interest Rate Risk Management

The Company enters into interest rate swaps to adjust the characteristics of its liability portfolio, allowing the Company to establish a mix of fixed or variable interest rates on its outstanding debt. The Company had outstanding interest rate contracts with notional amounts of $210,645,000 and $273,422,000 at December 31, 1997 and 1996, respectively.

Under the various swap agreements, the Company agrees with other parties to exchange, at specified intervals, the difference between fixed-rate and floating-rate interest amounts calculated by reference to an agreed notional principal amount. The following table indicates the weighted-average interest rates of the swaps. Average variable rates are based on rates implied in the yield curve at December 31; these may change significantly, affecting future cash flows. Swap contracts are principally between one and fifteen years in duration.

	1997	1996
PAY-FIXED SWAPS		
Average pay rate	8.2%	8.2%
Average receive rate	4.9	4.9

Commodity Risk Management

At December 31, 1997 and 1996, the Company had open NYMEX futures contracts as follows:

	1997	1996
OPEN CONTRACTS (number)		
Purchase	489	67
Sell	110	-
NOTIONAL QUANTITIES (mWh)		
Purchase	359,904	49,300
Sell	80,960	-
FAIR MARKET VALUE (thousands of dollars)		
Purchase	$(691)	$(175)
Sell	69	-

8. FAIR VALUE OF FINANCIAL INSTRUMENTS

	DECEMBER 31, 1997		DECEMBER 31, 1996	
THOUSANDS OF DOLLARS	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
Long-term debt	$3,869,724	$4,013,940	$3,618,634	$3,686,098
Preferred stock subject to mandatory redemption	175,000	194,125	178,000	195,800
Derivatives relating to interest	-	(31,902)	(10,788)	(38,991)

The carrying value of cash and cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximate fair value because of the short-term maturity of these instruments.

The fair value of the Company's long-term debt has been estimated by discounting projected future cash flows, using the current rate at which similar loans would be made to borrowers with similar credit ratings and for the same maturities. Current maturities of long-term debt were included. The fair value of redeemable preferred stock was based on bid prices from an investment bank.

The fair value of interest rate derivatives and electricity futures is the estimated amount the Company would have to receive (pay) to terminate the agreements, taking into account current interest rates and the current creditworthiness of the agreement counterparties.

NOTE 9. COMMITMENTS AND CONTINGENCIES

The Company is subject to numerous environmental laws including: the Federal Clean Air Act, as enforced by the Environmental Protection Agency and various state agencies; the 1990 Clean Air Act Amendments; the Endangered Species Act as it relates to certain potentially endangered species of salmon; the Comprehensive Environmental Response, Compensation and Liability Act, relating to environmental cleanups; along with the Federal Resource Conservation and Recovery Act and the Clean Water Act relating to water quality. These laws could potentially impact future operations. For those contingencies identified at December 31, 1997, principally the Superfund sites where the Company has been or may be designated as a potentially responsible party and the Clean Air Act matters, future costs associated with the disposition of these matters are not expected to be material to the Company's regulatory basis financial statements.

The Company's mining operations are subject to reclamation and closure requirements. The Company monitors these requirements and periodically revises its cost estimates to meet existing legal and regulatory requirements of the various jurisdictions in which it operates. Costs for reclamation are accrued using the units-of-production method such that estimated final mine reclamation and closure costs are fully accrued at completion of mining activities, except where the Company has decided to close a mine. When a mine is closed, the Company records the estimated cost to complete the mine closure. This is consistent with industry practices and, the Company believes that it has adequately provided for its reclamation obligations.

The Company is party to various legal claims, actions and complaints, certain of which involve material amounts. Although the Company is unable to predict with certainty whether or not it will ultimately be successful in these legal proceedings or, if not, what the impact might be, management currently believes that disposition of these matters will not have a materially adverse effect on the Company's regulatory basis financial statements.

Construction and Other

Construction and acquisitions are estimated at $550,000,000 for 1998. As part of these programs, substantial commitments have been made.

Leases

The Company leases certain properties under leases with various expiration dates and renewal options. Rentals on lease renewals are subject to negotiation. Certain leases provide for options to purchase at fair market value. The Company is also committed to pay all taxes, expenses of operation (other than depreciation) and maintenance applicable to the leased property.

Net rent expense for the years ending December 31, 1997 and 1996 was $12,470,000 and $10,484,000, respectively.

Future minimum lease payments under noncancellable operating leases are $2,127,000, $1,281,000, $1,764,000, $1,698,000, $1,472,000 and $6,007,000 for 1998 through 2002 and years thereafter, respectively.

Jointly Owned Plants

At December 31, 1997, the Company's participation in jointly owned plants was as follows:

THOUSANDS OF DOLLARS	COMPANY'S SHARE	PLANT IN SERVICE	ACCUMULATED DEPRECIATION	CONSTRUCTION WORK IN PROGRESS
Centralia	47.5%	$181,513	$111,120	$ 527
Jim Bridger Units 1,2,3 and 4	67.7	796,096	320,340	4,532
Trojan(a)	2.5	-	-	-
Colstrip Units 3 and 4	10.0	205,214	68,042	57
Hunter Unit 1	93.8	260,954	107,104	1,362
Hunter Unit 2	60.3	188,620	71,247	10,314
Wyodak	80.0	304,856	102,918	388
Craig Station Units 1 and 2	19.3	150,550(b)	59,439	1,077
Hayden Station Unit 1	24.5	18,556(b)	12,021	6,043
Hayden Station Unit 2	12.6	15,638(b)	8,827	3,404
Hermiston(c)	50.0	156,721	10,932	40

(a)Plant, inventory, fuel and decommissioning costs totaling $23 million relating to the Trojan Plant were included in regulatory assets-net at December 31, 1997.

(b)Excludes unallocated acquisition adjustments of $114 million.

(c)Additionally, the Company has contracted to purchase the remaining 50 percent of the output of this plant.

Under the joint agreements, each participating utility is responsible for financing its share of construction, operating and leasing costs. The Company's portion is recorded in its applicable operations, maintenance and tax accounts.

Long-term Wholesale Sales and Purchased Power Contracts

The Company manages its energy resource requirements by integrating long-term firm, short-term and spot market purchases with its own generating resources to economically dispatch the system and meet commitments for wholesale sales and retail load growth. The long-term wholesale sales commitments include contracts with minimum sales requirements of $484,900,000 in 1998, $449,700,000 in 1999, $415,100,000 in 2000, $315,600,000 in 2001 and $308,500,000 in 2002. As part of its energy resources portfolio, the Company acquires power through long-term purchases and/or exchange agreements which require minimum fixed payments of $320,000,000 in 1998, $316,400,000 in 1999, $313,700,000 in 2000, $290,100,000 in 2001 and $298,000,000 in 2002. The contracts include agreements with the Bonneville Power Administration, the Hermiston Plant and a number of cogenerating facilities

Excluded from the minimum fixed annual payments above, are commitments to purchase power from several hydroelectric projects under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of project output and for a like percentage of project annual costs (operating expenses and debt service). These costs are included in operations expense. The Company is required to pay its portion of the debt service, whether or not any power is produced. The arrangements provide for nonwithdrawable power and the majority also provide for additional power, withdrawable by the districts upon one to five years' notice. For 1997, such purchases approximated 3 percent of energy requirements.

At December 31, 1997, the Company's share of long-term arrangements with public utility districts was as follows:

GENERATING FACILITY (THOUSANDS OF DOLLARS)	YEAR CONTRACT EXPIRES	CAPACITY (kW)	PERCENTAGE OF OUTPUT	ANNUAL COSTS (a)
Wanapum	2009	155,444	18.7%	$ 4,400
Priest Rapids	2005	109,602	13.9	3,500
Rocky Reach	2011	64,297	5.3	2,900
Wells	2018	59,617	7.7	2,000
TOTAL		388,960		$12,800

(a) Annual costs include debt service of $7 million.

The Company has a 4 percent interest in the Intermountain Power Project (the Project), located in central Utah. The Company and the city of Los Angeles have agreed that the City will purchase capacity and energy from Company plants equal to the Company's 4 percent entitlement of the Project at a price equivalent to 4 percent of the expenses and debt service of the Project.

Fuel Contracts

The Company has take or pay coal and natural gas contracts which require minimum fixed payments of $83,000,000 for 1998 and 1999, $90,000,000 for 2000, $62,000,000 for 2001 and $64,000,000 for 2002.

NOTE 10. INCOME TAXES

Excluding equity in subsidiaries' earnings, the Company's effective combined federal and state income tax rate from continuing operations was 37 percent in both 1997 and 1996. The difference between taxes calculated as if the statutory federal tax rate of 35 percent was applied to income from continuing operations before income taxes and the recorded tax expense is reconciled as follows:

THOUSANDS OF DOLLARS	1997	1996
COMPUTED FEDERAL INCOME TAXES	$104,363	$205,894
INCREASE (REDUCTION) IN TAX RESULTING FROM		
Depreciation differences (flow-through basis)	14,282	12,726
Investment tax credits	(7,938)	(8,926)
Depletion	(2,570)	(3,717)
Other items capitalized and miscellaneous differences	(7,129)	(6,780)
Total	(3,355)	(6,697)
FEDERAL INCOME TAX	101,008	199,197
STATE INCOME TAX, NET OF FEDERAL INCOME TAX BENEFIT	10,378	17,828
TOTAL INCOME TAX EXPENSE	$111,386	$217,025

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The provision for income taxes is summarized as follows:

THOUSANDS OF DOLLARS	1997	1996
CURRENT		
Federal	$164,133	$157,722
State	20,615	23,131
Total	184,748	180,853
DEFERRED		
Federal	(60,775)	40,800
State	(4,649)	4,297
Total	(65,424)	45,097
INVESTMENT TAX CREDITS	(7,938)	(8,925)
TOTAL INCOME TAX EXPENSE	$111,386	$217,025

The tax effects of significant items comprising the Company's net deferred tax liability at December 31 are as follows:

THOUSANDS OF DOLLARS	1997	1996
Property, plant and equipment	$ 859,001	$ 855,445
Regulatory asset	704,104	733,100
Other deferred liabilities	31,116	54,275
DEFERRED TAX ASSETS		
Regulatory liability	(53,959)	(57,116)
Book reserves not deductible for tax	(11,403)	(6,365)
Pension accrual	(39,919)	(8,132)
Other deferred assets	(45,309)	(46,581)
NET DEFERRED TAX LIABILITY	$1,443,631	$1,524,626

During 1996, the Company received an examination report for 1989 and 1990 proposing adjustments. The Company filed a protest of certain proposed adjustments on July 30, 1996 and is currently holding discussions with the Appeals Division of the IRS. The Company's 1991, 1992, and 1993 federal income tax returns are currently under examination by the IRS.

NOTE 11. EMPLOYMENT PLANS

Retirement Plans

The Company has a pension plan covering substantially all of its employees. Benefits under this plan are generally based on the employee's years of service and average monthly pay in the 60 consecutive months of highest pay out of the last 120 months, with adjustments, to reflect benefits estimated to be received from Social Security. Pension costs are funded annually by no more than the maximum amount of pension expense which can be deducted for federal income tax purposes. Unfunded prior service costs are amortized over the remaining service period of employees expected to receive benefits. At December 31, 1997, plan assets were primarily invested in common stocks, bonds and United States government obligations.

Net pension cost for the years ended December 31 is summarized as follows:

THOUSANDS OF DOLLARS	1997	1996
Service cost - benefits earned	$ 24,697	$ 27,597
Interest cost on projected benefit obligation	77,211	72,193
Actual gain on plan assets	(70,997)	(59,114)
Net amortization and deferral	9,468	8,881
Regulatory deferral (see Note 2)	-	14,212
NET PENSION COST	$ 40,379	$ 63,769

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NOTES TO FINANCIAL STATEMENTS (Continued)

The funded status, net pension liability and significant assumptions at December 31 are as follows:

THOUSANDS OF DOLLARS	1997	1996
Actuarial present value of benefit obligations		
Vested benefit obligation	$ 930,296	$ 837,016
Accumulated benefit obligation	$ 988,800	$ 910,333
Projected benefit obligation	$1,144,969	$1,027,416
Plan assets at fair value	929,804	786,947
Projected benefit obligation in excess of plan assets	215,165	240,469
Unrecognized prior service cost	(15,237)	(13,697)
Unrecognized net loss	(9,825)	(87,038)
Unrecognized net obligation	(79,986)	(10,113)
Minimum liability adjustment	5,514	2,891
NET PENSION LIABILITY	$ 115,631	$ 132,512
Discount rate	7%	7.5%
Expected long-term rate of return on assets	9.25%	9%
Rate of increase in compensation levels	4%	4.5%

Other Postretirement Benefits

The Company provides health care and life insurance benefits through various plans for eligible retirees on a basis substantially similar to those who are active employees. The cost of postretirement benefits are accrued over the active service period of employees. The transition obligation represents the unrecognized prior service cost and is being amortized over a period of 20 years. For those employees retired at January 1, 1993, the Company funds postretirement benefit expense on a pay-as-you-go basis and has an unfunded accrued liability of $58,343,000 at December 31, 1997. For those employees retiring after January 1, 1993, the Company funds postretirement benefit expense through a combination of funding vehicles. The Company funded $15,637,000 and $28,011,000 of postretirement benefit expense during 1997 and 1996, respectively. These funds are invested in common stocks, bonds and United States government obligations

Name of Respondent PacifiCorp	This Report Is: (1) [X]An Original (2) [ ]A Resubmission	Date of Report (Mo,Da,Yr)	Year of Report Dec. 31, 1997

NOTES TO FINANCIAL STATEMENTS (Continued)

The net periodic postretirement benefit cost for the years ended December 31, 1997 and 1996 are summarized as follows:

THOUSANDS OF DOLLARS	1997	1996
Service costs - benefits earned	$ 7,181	$ 6,912
Interest cost on accumulated postretirement benefit obligation	21,787	21,838
Amortization of transition obligation	11,879	12,560
Regulatory deferral	6,392	3,400
Net asset gain during the period deferred for future recognition	18,963	3,514
Actual gain on plan assets	(31,465)	(12,612)
NET PERIODIC POSTRETIREMENT BENEFIT COST	$ 34,737	$ 35,612

The accumulated postretirement benefit obligation ("APBO") at December 31 was as follows:

THOUSANDS OF DOLLARS	1997	1996
Retirees and dependents	$172,248	$ 167,958
Fully eligible active plan participants	11,973	10,113
Other active plan participants	143,157	131,014
APBO	327,378	309,085
Plan assets at fair value	179,773	135,063
APBO in excess of plan assets	147,605	174,022
Unrecognized transition obligation	(209,260)	(223,211)
Unrecognized net gain	64,300	51,199
ACCRUED POSTRETIREMENT BENEFIT OBLIGATION	$ 2,645	$ 2,010
Discount rate	7%	7.5%
Estimated long-term rate of return on assets	9.25%	9%
Initial health care cost trend rate-under 65	8.3%	8.8%
Initial health care cost trend rate-over 65	8.3%	8.4%
Ultimate health care cost trend rate	4.5%	4.5%

The assumed health care cost trend rate gradually decreases over eight years. The health care cost trend rate assumption has a significant effect on the amounts reported. Increasing the assumed health care cost trend rate by one percentage point would have increased the APBO as of December 31, 1997 by $29,347,000 and the annual net periodic postretirement benefit cost by $2,732,000.

Postemployment Benefits

The Company provides certain postemployment benefits to former employees and their dependents during the period following employment but before retirement. The costs of these benefits are accrued as they are incurred. Benefits include salary continuation, severance benefits, disability benefits and continuation of health care benefits for terminated and disabled employees and workers compensation benefits. Accrued costs for postemployment benefits were $12,600,000 and $4,500,000 in 1997 and 1996, respectively.

Pending Early Retirement Offer

The Company has offered enhanced early retirement to approximately 1,200 employees who have until March 31, 1998 to accept the offer. The cost of the enhancement will have an impact on the funding status of the retirement and other postretirement benefit plans. However, the Company intends to fund a substantial portion of the increase in the accumulated benefit obligation.

Stock Incentive Plan

During 1997, the Company formalized a Stock Incentive Plan (the "Plan") under which selected employees, officers and directors and selected nonemployee agents, consultants, advisors and independent contractors may be granted options to purchase the Company's common stock. Options generally become exercisable in three equal installments on each of the first through third anniversaries of the grant date and have a maximum term of ten years. As of December 31, 1997, options have been granted to 193 officers and employees. Under the Plan 1,322,500 options were granted on June 3, 1997 and 193,500 options were granted on August 12, 1997 at prices of $19.75 and $21.25, respectively. The weighted average estimated fair value of options granted was $2.78 per share. These options to purchase the Company's common stock were issued at 100 percent of market price on the dates the options were granted. None of the options were exercisable as of December 31, 1997. During 1997, options for 19,000 shares relating to the June 3, 1997 grant were forfeited. As permitted by SFAS 123, the Company has elected to account for the Plan under APB 25. Accordingly, no compensation expense has been recognized for the Plan. Had compensation cost for the Plan been determined based on the fair value at the grant date consistent with SFAS 123, there would have been no impact on the Company's net income.

The fair value of each option grant was estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions used: dividend yield of 5.5 percent, risk-free interest rate of 6.8 percent, expected life of the options of 10 years and volatility of 15 percent.

NOTE 12. RELATED PARTY TRANSACTIONS

The Company and its subsidiaries participate in a consolidated cash management program. Any funds advanced to/from the Company are included in accounts and notes payable/receivable-affiliated companies and advances from affiliated companies. The notes and advances are due upon demand and bear interest at a short-term rate as defined under intercompany loan agreements and a contractual understanding agreement between the Company and its subsidiaries. Net interest expense on these advances was $5,350,000 and $2,225,000 in 1997 and 1996, respectively.

PacifiCorp Capital I and PacifiCorp Capital II, wholly owned subsidiary trusts of the Company (the "Trusts") have issued, in public offerings, redeemable preferred securities representing preferred undivided beneficial interests in the assets of the Trusts. The sole assets of the Trusts are $223,712,000 and $139,176,000 of Junior Subordinated Deferrable Interest Debentures of the Company due 2036 and 2037 (the Debentures) that bear interest at 8.25 percent and 7.7 percent, respectively. The Company paid interest expense on the Debentures of $22,830,000 and $10,202,000 in 1997 and 1996, respectively.

The Company provides certain management services, such as corporate and financial advice and consultation, to subsidiaries at cost. The amounts charged to the subsidiaries were $5,559,000 and $5,705,000 in 1997 and 1996, respectively.

All of the coal production of the Bridger mine ("Bridger") is sold to a steam electric generating plant owned by the Company and Idaho Power Company ("Idaho"). Sales to the plant were $121,545,000 in 1997 and $117,668,000 in 1996. The Company provided Bridger with management, administrative, engineering services and electricity on an as-needed basis. The amount charged for these services was $5,661,000 and $4,521,000 in 1997 and 1996, respectively. In addition, Bridger paid overriding royalties to the Company and Idaho of $422,000 and $630,000 in 1997 and 1996, respectively, pursuant to coal lease agreements.

During 1996, the Company received a litigation settlement from its insurers for coverage of environmental liabilities. The Company transferred these environmental liabilities to an unregulated subsidiary, PacifiCorp Investment Management Inc. ("PIMI"), together with an amount of cash equivalent to the estimated net present value of resolving the liabilities, approximately $33,500,000. PIMI invested the cash received from the Company in long-term variable rate notes issued by PTI and transferred the environmental liabilities and long-term variable rate notes to a 90 percent owned unregulated subsidiary of the Company, PacifiCorp Environmental Remediation Company.

The Company has entered into an agreement with its wholly owned subsidiary, Demand Side Receivables, Inc. ("DSRI") to sell all of its demand side receivable loans to DSRI at their discounted present values. Transactions relating to sales of loans to DSRI resulted in net cash outflows of $2,283,000 and a net loss of $845,000 in 1997 compared to net cash proceeds of $5984,000 and a net gain of $1,134,000 in 1996. DSRI recorded a gain of $704,000 in 1997 and a loss of $758,000 in 1996 on sales of the loans to outside parties. The effects of the DSRI sales are included in equity in subsidiary earnings.

NOTE 13. PROPOSED ACQUISITION BY A SUBSIDIARY

On June 13, 1997, the Company announced a cash tender offer by Holdings for The Energy Group PLC ("TEG"). TEG is a diversified international energy group with operations in the United Kingdom (the "UK"), the United States and Australia and includes Eastern Group PLC, one of the leading integrated electricity and gas groups in the UK and Peabody Holding Company, Inc., the world's largest private producer of coal. Holdings' initial offer lapsed on August 1, 1997 when it was referred to the Monopolies and Mergers Commission (the "MMC") by the President of the Board of Trade in the UK. The proposed acquisition of TEG by the Company was subsequently cleared by the President of the Board of Trade on December 19, 1997.

On February 3, 1998, the Company announced the terms of a renewed cash tender offer by Holdings for TEG of 765 pence for each ordinary share. On March 2, 1998, Texas Utilities Company ("TU") announced an offer of 810 pence for each TEG share. Following TU's announcement, the Company announced an increased cash offer of 820 pence for each TEG share. This increased offer values the transaction at $11.1 billion, including the purchase of 521 million shares and the assumption of $4.1 billion of TEG's debt. The acquisition was to be financed with cash raised through sales of noncore assets of subsidiaries of Holdings (See Notes 14 and 15) and borrowings by subsidiaries of Holdings. The Company's announcement of the increased offer followed the acquisition on March 2, 1998 by a subsidiary of Holdings of approximately 46 million TEG shares at a price of 820 pence per share. These shares represent approximately 8.8 percent of the outstanding share capital of TEG.

On March 3, 1998, TU announced that it was increasing its offer to 840 pence for each TEG share. TU's offer is subject to clearance by the UK Secretary of State for Trade and Industry and certain other regulatory bodies. TU has also announced that it has acquired approximately 15 percent of the outstanding share capital of TEG.

Upon initiation of the original tender offer in June 1997, Holdings entered into foreign currency exchange contracts. The financing facilities associated with the June 1997 offer for TEG terminated upon referral to the MMC and Holdings initiated steps to unwind its foreign currency exchange positions consistent with its policies on derivatives. As a result of the termination of these positions and initial option costs, Holdings realized an after-tax loss of approximately $65,000,0000 in the third quarter of 1997, which was recorded in Equity in Subsidiary Earnings.

NOTE 14. DISCONTINUED OPERATIONS OF A SUBSIDIARY

On December 1, 1997, Holdings completed the sale of PTI to Century Telephone Enterprises, Inc. ("Century"). Pursuant with a Stock Purchase Agreement dated June 11, 1997, Century acquired all the stock of PTI for $1.5 billion in cash plus the assumption of PTI's debt. The sale resulted in an after-tax gain of $365,000,000. A portion of the proceeds from the sale of PTI was temporarily advanced to the Company for retirement of short-term debt. Holdings recorded income of $89,200,000 for the eleven months of operation in 1997 and $74,700,000 for all of 1996.

NOTE 15. ACQUISITIONS AND DISPOSITIONS BY SUBSIDIARIES

On April 15, 1997, Holdings, through a subsidiary, acquired all of the outstanding shares of common stock of TPC, a natural gas gathering, processing, storage and marketing company based in Houston, Texas, for approximately $265,000,000 in cash and assumed debt of approximately $140,000,000. Following completion of a tender offer, TPC became a wholly owned subsidiary of Holdings through a cash merger at the same price. During May 1997, TPC retired $131,000,000 of its outstanding long-term debt. These transactions were funded with capital contributions from the Company.

On December 1, 1997, TPC sold all of the capital stock of three subsidiaries that hold its natural gas gathering and processing systems to El Paso Field Services Company for $195,000,000 in cash, before tax payments of $23,000,000. No gain or loss was recognized by Holdings on the sale.

On November 5, 1997, Holdings completed the sale of PGC to NRG Energy for $150,000,000 in cash. An after-tax gain on the sale of $30,000,000 was recognized by Holdings in the fourth quarter of 1997.

In September 1996, a consortium, known as the Hazelwood Power Partnership, purchased a 1,600 megawatt, coal-fired generating station and associated coal mine in Victoria, Australia for approximately $1.9 billion. The consortium financed the acquisition of the Hazelwood plant and mine with approximately $858,000,000 in equity contributions from the partners and $1 billion of nonrecourse borrowings at the partnership level. Holdings, which has a 19.9% interest in the partnership, financed its $145,000,000 portion of the equity investment and the associated $12,000,000 advance with term borrowings in the United States.

On December 12, 1995, Holdings purchased Powercor, an electricity distributor in Australia, for $1.6 billion in cash. Powercor is the largest

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electricity distributrior in the State of Victoria. The acquisition was accounted for as a purchase and the results of operations of Powercor have been included in equity in subsidiary earnings since December 12, 1995.

In February 1998, PFS agreed to sell its investments in affordable housing for cash proceeds of approximately $81,000,000 and assumption of debt of approximately $161,000,000. This sale transaction will not have a material impact on 1998 earnings.

Plant Outages for 1997

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Carbon No. 1						
1.	01/05/97 18:35	-	01/05/97 21:10	Unplanned	2.58	180.83
	Descr: The unit had a boiler upset (plugged feeder). after d.a. level recov					
2.	01/05/97 23:32	-	01/07/97 19:00	Unplanned	43.47	3,042.67
	Descr: The unit had been on line for about two hours after tripping no.1 load					
3.	01/07/97 19:00	-	01/09/97 05:28	Unplanned	34.47	2,412.67
	Descr: The unit had been off line for a water wall tube leak. the tube leak					
4.	01/31/97 13:48	-	02/01/97 07:45	Unplanned	17.95	1,256.50
	Descr: The unit was taken off line to replace an expansion joint (north side,					
5.	02/02/97 00:56	-	02/04/97 07:00	Unplanned	54.07	3,784.67
	Descr: Unit was taken off line to repair condenser tube leak (unable to maint					
6.	02/11/97 05:10	-	02/13/97 22:04	Unplanned	64.90	4,543.00
	Descr: Unit was taken off line to repair a water wall tube leak (possible					
7.	03/18/97 23:35	-	03/21/97 16:00	Unplanned	64.42	4,509.17
	Descr: The unit was taken off line to do a chemical clean. the boiler had					
8.	03/21/97 16:00	-	03/22/97 09:00	Unplanned	17.00	1,190.00
	Descr: The unit was taken off line to do a chemical clean. the air preheater					
9.	03/22/97 09:00	-	03/24/97 16:08	Unplanned	55.13	3,859.33
	Descr: The unit was taken off line to do a chemical clean. the portabledemin					
10.	04/03/97 06:58	-	04/03/97 08:39	Unplanned	1.68	117.83
	Descr: Unit trip due to a fault on the helper 46kv line. a cross arm broke					
11.	05/04/97 16:50	-	05/04/97 19:13	Unplanned	2.38	166.83
	Descr: Operations was washing down and water entered a lighting panel. this					
12.	05/04/97 19:13	-	05/04/97 20:13	Unplanned	1.00	70.00
	Descr: Unit start up was delayed due to prblems with the igniters					
13.	05/31/97 22:39	-	06/02/97 02:47	Planned	28.13	1,969.33
	Descr: Unit was taken off line to clean the hydrogen coolers (hydrogen temper					
14.	06/09/97 23:39	-	06/10/97 13:47	Unplanned	14.13	989.33
	Descr: Economizer tube leak (right rear corner of the pent house, weld faile					
15.	06/25/97 00:48	-	06/27/97 21:08	Unplanned	68.33	4,783.33
	Descr: The unit was taken off line to replace the high side"u" bushings. the					
16.	06/28/97 00:30	-	06/28/97 21:48	Unplanned	21.30	1,491.00
	Descr: The unit had been off line to replace the main transformer bushings an					
17.	07/10/97 23:42	-	07/11/97 21:42	Unplanned	22.00	1,540.00
	Descr: The unit was taken off line to repair a leak in the high temperature					
18.	07/15/97 22:36	-	07/17/97 02:45	Unplanned	28.15	1,970.50
	Descr: The unit was taken off line to repair a leak in the high temperautre					
19.	09/18/97 03:34	-	09/19/97 18:00	Unplanned	38.43	2,690.33
	Descr: Unit was taken off line to repair an economizer tube leak (a sootblowe					
20.	09/19/97 18:00	-	09/20/97 00:50	Unplanned	6.83	478.33
	Descr: The unit was off line for an economizer tube leak, the unit remained					
21.	10/11/97 04:20	-	10/12/97 04:10	Unplanned	23.83	1,668.33
	Descr: Unit was taken off line to repair an economizer tube leak					
22.	10/12/97 13:00	-	10/12/97 14:59	Unplanned	1.98	138.83
	Descr: Unit tripped due to loss of d.a.level (a bad transmitter is suspected)					
23.	10/24/97 14:11	-	10/24/97 15:25	Unplanned	1.23	86.33
	Descr: 1-1 mill was out to replace the reject scraper. while 1-1 mill was					

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	- Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Carbon No. 1					
24.	10/25/97 14:21	- 10/26/97 10:31	Unplanned	21.17	1,481.67
	Descr: Unit was taken off line to repair an economzer tube leak				
25.	11/11/97 23:29	- 11/12/97 18:00	Unplanned	18.52	1,296.17
	Descr: Water cooled spacer tube leak (there was also a high temp. superheat				
26.	11/12/97 18:00	- 11/13/97 11:00	Unplanned	17.00	1,190.00
	Descr: High temp. superheat tube leak. a leak occurred in the water cooled s				
27.	11/13/97 11:00	- 11/13/97 23:55	Unplanned	12.92	904.17
	Descr: The unit was off line for two tube leaks (water cooled spacer and high				
28.	11/16/97 02:20	- 11/17/97 02:48	Unplanned	24.47	1,712.67
	Descr: The unit was taken off line for a leak in the main steam sample line.				
29.	12/21/97 13:24	- 12/22/97 09:00	Unplanned	19.60	1,372.00
	Descr: The unit was taken off line to repair a water cooled spacer tube leak.				
30.	12/22/97 09:00	- 12/23/97 00:54	Unplanned	15.90	1,113.00
	Descr: The unit was taken off line to repair a water cooled spacer tube leak.				
31.	12/28/97 21:44	- 12/30/97 00:25	Unplanned	26.68	1,867.83
	Descr: Low temperature superheat tube leak				
	*** * * Unit Summary for Carbon No. 1 for the year 1997 =**			769.65	53,876.65
Carbon No. 2					
1.	01/01/97 00:00	- 01/01/97 15:00	Unplanned	15.00	1,575.00
	Descr: Unit was taken off line due to #8 exciter bearing high temperature.				
2.	01/01/97 15:00	- 01/05/97 06:41	Unplanned	87.68	9,206.75
	Descr: The unit was off line to repair #8 exciter bearing. the left intercept				
3.	03/08/97 00:15	- 03/10/97 03:34	Unplanned	51.32	5,388.25
	Descr: The unit was taken off line to wash the economizer (high differential				
4.	04/07/97 11:44	- 04/07/97 12:48	Unplanned	1.07	112.00
	Descr: Unit ripped off line. both i.d. fans tripped on thermal overload.the t				
5.	04/07/97 12:48	- 04/07/97 13:48	Unplanned	1.00	105.00
	Descr: The unit had tripped off line. unit start-up was delayed due to the i				
6.	05/15/97 11:41	- 05/21/97 10:48	Unplanned	143.12	15,027.25
	Descr: Unit was taken off line to repair dead dead air space. the gas recirc				
7.	05/21/97 10:48	- 05/21/97 12:48	Unplanned	2.00	210.00
	Descr: The unit had been off line to repair coutant bottom/dead air space.				
8.	06/28/97 23:40	- 06/30/97 02:45	Planned	27.08	2,843.75
	Descr: The unit was taken off line to clean the hydrogen coolers. hydrogen				
9.	07/30/97 23:32	- 07/31/97 13:02	Unplanned	6.75	708.75
	Descr: The unit was taken off line to clean the economizer and high temp.				
10.	07/30/97 23:32	- 08/02/97 00:26	Unplanned	42.15	4,425.75
	Descr: The unit was taken off line to clean the economizer. the h.t.s.h. was				
11.	10/20/97 23:05	- 10/21/97 15:00	Unplanned	15.92	1,671.25
	Descr: Unit was taken off line for an economizer tube leak (weld failure at				
12.	10/21/97 15:00	- 10/22/97 04:52	Unplanned	13.87	1,456.00
	Descr: Unit was taken off line for an economizer tube leak. the unit remia				
13.	12/04/97 12:10	- 12/04/97 14:07	Unplanned	1.95	204.75
	Descr: Unit trip - generator field forcing alarm annunciated. the c.r.o. and				
14.	12/15/97 00:42	- 12/15/97 02:37	Unplanned	1.92	201.25
	Descr: 2-1 boiler feed pump tripped and 2-2 b.f.p. started as back-up, but				

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Carbon No. 2						
15.	12/28/97 11:35	-	12/28/97 12:40	Unplanned	1.08	113.75
	Descr: Unit tripped off line due to a boiler upset that was initiated by a					
	*** **Unit Summary for Carbon No. 2 for the year 1997 =**				411.91	43,249.50
Centralia No. 1						
1.	03/06/97 13:36	-	03/06/97 15:04	Unplanned	1.47	982.67
	Descr: Electrical trip caused by defective contact in relay 405y.					
2.	03/06/97 15:04	-	03/06/97 16:04	Unplanned	1.00	670.00
	Descr: Error in bechtel drawing delayed troubleshooting.					
3.	06/13/97 22:32	-	07/06/97 01:42	Planned	531.17	355,881.67
	Descr: Boiler maintenance inspection					
4.	07/06/97 01:42	-	07/06/97 03:42	Unplanned	2.00	1,340.00
	Descr: Lack of ss coordination with psd on generator clearance status.					
5.	07/06/97 03:42	-	07/06/97 14:42	Unplanned	11.00	7,370.00
	Descr: Id fan gearbox and inlet ema and damper stroke both id #12 and fd #11.					
6.	07/06/97 14:42	-	07/06/97 15:42	Unplanned	1.00	670.00
	Descr: Turbine latch problems.					
7.	07/06/97 15:42	-	07/06/97 16:42	Unplanned	1.00	670.00
	Descr: Turbine speed control problems.					
8.	07/12/97 22:26	-	07/13/97 21:37	Unplanned	5.80	3,883.21
	Descr: Repack bsp suction mov's.					
9.	07/12/97 22:26	-	07/13/97 21:37	Unplanned	5.80	3,883.21
	Descr: Repack #11 booster pump					
10.	07/12/97 22:26	-	07/13/97 21:37	Unplanned	5.80	3,883.21
	Descr: Fwh tube leak repairs					
11.	07/12/97 22:26	-	07/13/97 21:37	Unplanned	5.78	3,874.83
	Descr: Da hatch cover leak					
12.	08/11/97 12:39	-	08/13/97 09:10	Unplanned	22.27	14,918.67
	Descr: Superheat tube leak					
13.	08/11/97 12:39	-	08/13/97 09:10	Unplanned	22.26	14,913.08
	Descr: Reheater boiler tube leak					
14.	11/04/97 09:36	-	11/07/97 01:40	Unplanned	64.07	42,924.67
	Descr: Rh tube leak					
15.	11/23/97 07:54	-	11/25/97 20:49	Unplanned	60.92	40,814.17
	Descr: Waterwall tube leak at 5-1/2 level					
16.	11/26/97 20:30	-	11/26/97 22:10	Unplanned	1.67	1,116.67
	Descr: Operator error					
17.	11/26/97 22:27	-	11/26/97 23:30	Unplanned	1.05	703.50
	Descr: Operator error					
18.	12/05/97 23:22	-	12/07/97 09:24	Unplanned	34.03	22,802.33
	Descr: Tube leak					
19.	12/07/97 09:24	-	12/07/97 14:24	Unplanned	5.00	3,350.00
	Descr: High opacity so boiler was tripped early					
20.	12/07/97 14:24	-	12/07/97 22:24	Unplanned	8.00	5,360.00
	Descr: #12 id fan linkage repair					
21.	12/22/97 05:34	-	12/22/97 10:44	Unplanned	5.17	3,461.67
	Descr: Repair leaking thermal well at bcp injection water heat exchanger outl					
	*** **Unit Summary for Centralia No. 1 for the year 1997 =**				796.26	533,473.56

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	- Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Centralia No. 2					
1.	02/07/97 09:17	- 02/07/97 19:43	Unplanned	10.43	6,990.33
	Descr: #21 load center transformer fire				
2.	02/23/97 08:30	- 02/24/97 13:59	Unplanned	29.48	19,753.83
	Descr: #22 load center transformer failure. unit was ready for startup at				
3.	05/30/97 23:45	- 06/16/97 09:02	Planned	393.28	263,499.83
	Descr: Chemical cleaning				
4.	06/16/97 09:02	- 06/16/97 17:52	Unplanned	8.83	5,918.33
	Descr: Boiler tube leak "f" corner, 9-1/2 level				
5.	06/16/97 17:52	- 06/16/97 20:59	Unplanned	3.12	2,088.17
	Descr: #21 bfp discharge valve repack				
6.	07/03/97 18:00	- 07/07/97 07:37	Unplanned	85.62	57,363.17
	Descr: Repair #21 bcp suction valve				
7.	07/11/97 07:51	- 07/11/97 08:57	Unplanned	1.10	737.00
	Descr: Flameout				
8.	10/13/97 05:18	- 10/13/97 07:16	Unplanned	1.97	1,317.67
	Descr: Flameout				
9.	10/13/97 07:16	- 10/13/97 08:16	Unplanned	1.00	670.00
	Descr: Warmup guns/ignitors had trouble proving				
10.	10/23/97 06:11	- 10/24/97 16:27	Unplanned	34.27	22,958.67
	Descr: Economizer tube repairs				
	*** * * Unit Summary for Centralia No. 2 for the year 1997 =**			569.10	381,297.00
Dave Johnston No. 1					
1.	01/05/97 03:50	- 01/09/97 02:54	Unplanned	95.07	10,077.07
	Descr: Tube leak and diaphragm repairs				
2.	04/02/97 08:27	- 04/03/97 13:28	Unplanned	29.02	3,075.77
	Descr: 480v circuit breaker				
3.	04/19/97 00:00	- 05/20/97 20:12	Planned	764.20	81,005.20
	Descr: Planned unit outage				
4.	05/21/97 23:15	- 05/22/97 00:18	Unplanned	1.05	111.30
	Descr: Mft on draft				
5.	05/22/97 01:18	- 05/22/97 03:09	Unplanned	1.85	196.10
	Descr: Generator lock out				
6.	05/24/97 01:32	- 05/25/97 03:31	Planned	25.98	2,754.23
	Descr: Balance turbine				
7.	05/29/97 23:06	- 05/30/97 04:03	Planned	4.95	524.70
	Descr: Turbine os tests				
8.	06/08/97 09:28	- 06/08/97 11:43	Unplanned	2.25	238.50
	Descr: Condensate pump tripped, no backup pump available				
9.	07/20/97 04:32	- 07/21/97 13:07	Unplanned	32.58	3,453.83
	Descr: Tube leak by ik 51				
10.	07/26/97 08:27	- 07/26/97 22:30	Unplanned	14.05	1,489.30
	Descr: Econ. block valve				
11.	07/26/97 22:30	- 07/27/97 02:20	Unplanned	3.83	406.33
	Descr: Purging econ block repair				
12.	07/27/97 02:20	- 07/28/97 18:25	Unplanned	40.08	4,248.83
	Descr: Tube leak				

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	- Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Dave Johnston No. 1					
13.	08/12/97 23:42	- 08/14/97 02:33	Unplanned	26.85	2,846.10
	Descr: Ww tube leak				
14.	10/27/97 01:47	- 10/29/97 07:48	Unplanned	54.02	5,725.77
	Descr: Water wall tube leak				
15.	10/29/97 07:58	- 10/30/97 19:00	Unplanned	35.03	3,713.53
	Descr: Water wall tube leak				
16.	10/30/97 19:00	- 11/04/97 01:00	Unplanned	102.00	10,812.00
	Descr: Turbine bearing				
17.	11/23/97 02:44	- 11/24/97 08:27	Unplanned	29.72	3,149.97
	Descr: Tube leak				
	*** Unit Summary for Dave Johnston No. 1 for the year 1997**			1,262.53	133,828.53
Dave Johnston No. 2					
1.	05/30/97 23:03	- 06/01/97 07:40	Unplanned	32.62	3,457.37
	Descr: Work on safety valves				
2.	06/02/97 13:31	- 06/03/97 05:03	Unplanned	15.53	1,646.53
	Descr: 2b condenser oos				
	*** Unit Summary for Dave Johnston No. 2 for the year 1997**			48.15	5,103.90
Dave Johnston No. 3					
1.	02/11/97 23:22	- 02/13/97 11:00	Unplanned	35.63	8,195.67
	Descr: Water wall tube leak				
2.	02/13/97 11:00	- 02/15/97 00:27	Unplanned	37.45	8,613.50
	Descr: Replacing burner impellers				
3.	04/10/97 23:28	- 04/12/97 13:33	Unplanned	38.08	8,759.17
	Descr: Tube leak				
4.	04/15/97 01:05	- 04/15/97 05:54	Unplanned	4.82	1,107.83
	Descr: Turbine lost vacuum				
5.	06/03/97 23:35	- 06/05/97 08:47	Unplanned	33.20	7,636.00
	Descr: Tube leak				
6.	06/05/97 10:12	- 06/05/97 16:05	Unplanned	5.88	1,353.17
	Descr: Boiler controls				
7.	06/10/97 13:11	- 06/11/97 23:52	Unplanned	34.68	7,977.17
	Descr: Tube leak				
8.	07/21/97 09:29	- 07/23/97 21:20	Unplanned	59.85	13,765.50
	Descr: Water wall tube leak				
9.	09/10/97 07:17	- 09/10/97 08:32	Unplanned	1.25	287.50
	Descr: Dc power supply				
10.	09/17/97 23:15	- 09/20/97 23:44	Unplanned	72.48	16,671.17
	Descr: Ww tube leak				
11.	10/19/97 23:57	- 10/21/97 00:15	Unplanned	24.30	5,589.00
	Descr: Economizer tube leak				
12.	10/22/97 06:22	- 10/22/97 07:28	Unplanned	1.10	253.00
	Descr: Volts to hertz problem				
13.	11/21/97 23:00	- 11/24/97 16:36	Unplanned	65.60	15,088.00
	Descr: W.w. tube leak				
14.	12/01/97 17:47	- 12/03/97 20:35	Unplanned	50.80	11,684.00
	Descr: Primary sh tube leak				

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	- Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Dave Johnston No. 3					
15.	12/17/97 03:48	- 12/19/97 01:37	Unplanned	45.82	10,537.83
	Descr: Lp turbineexp. joint				
16.	12/29/97 05:13	- 01/01/98 00:00	Unplanned	66.78	15,360.17
	Descr: Ww tube leak				
	*** **Unit Summary for Dave Johnston No. 3 for the year 1997**			577.72	132,878.68
Dave Johnston No. 4					
1.	01/31/97 22:18	- 02/02/97 22:00	Unplanned	47.70	15,741.00
	Descr: Tube repair				
2.	02/02/97 22:00	- 02/03/97 03:00	Unplanned	5.00	1,650.00
	Descr: Hydrogen cooler gasket failed				
3.	02/03/97 03:00	- 02/03/97 14:40	Unplanned	11.67	3,850.00
	Descr: Both bfp would not start				
4.	02/19/97 14:30	- 02/23/97 10:58	Unplanned	92.47	30,514.00
	Descr: 8 tube leaks in primary superheater				
5.	03/13/97 20:01	- 03/14/97 19:08	Unplanned	23.12	7,628.50
	Descr: Water wall tube leak				
6.	03/14/97 19:08	- 03/14/97 23:08	Unplanned	4.00	1,320.00
	Descr: Warm up guns failure				
7.	03/14/97 23:08	- 03/15/97 03:08	Unplanned	4.00	1,320.00
	Descr: Pa fan delayed startup				
8.	06/14/97 21:18	- 06/16/97 05:46	Unplanned	32.47	10,714.00
	Descr: Ah locked up				
9.	06/20/97 22:59	- 06/22/97 00:00	Unplanned	25.02	8,255.50
	Descr: Psh tube leak				
10.	06/22/97 00:00	- 06/24/97 02:59	Unplanned	50.98	16,824.50
	Descr: Cleaning scrubber				
11.	06/30/97 14:18	- 07/06/97 03:15	Unplanned	132.95	43,873.50
	Descr: Deslag w/tube leak				
12.	07/14/97 15:02	- 07/14/97 16:55	Unplanned	1.88	621.50
	Descr: Pa fan tripped & boiler mft				
13.	08/10/97 00:27	- 08/11/97 09:10	Unplanned	32.72	10,796.50
	Descr: Clinker caused tube leak				
14.	08/13/97 12:30	- 08/13/97 18:10	Unplanned	5.67	1,870.00
	Descr: Circuit breakers in switchyard opened up.				
15.	09/06/97 00:23	- 09/12/97 00:00	Planned	143.62	47,393.50
	Descr: Boiler inspection				
16.	09/12/97 00:00	- 09/13/97 22:53	Planned	46.88	15,471.50
	Descr: Scrubber inspection				
17.	09/16/97 17:06	- 09/17/97 16:16	Unplanned	23.17	7,645.00
	Descr: Pa fan				
18.	11/14/97 08:55	- 11/15/97 01:59	Unplanned	17.07	5,632.00
	Descr: Ah drive motor				
19.	12/06/97 22:28	- 12/08/97 04:00	Unplanned	29.53	9,746.00
	Descr: Ah motor swap				
20.	12/08/97 20:48	- 12/09/97 04:59	Unplanned	8.18	2,700.50
	Descr: 4160 breaker				

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	- Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Dave Johnston No. 4					
21.	12/17/97 22:20	- 12/21/97 02:50	Unplanned	76.50	25,245.00
	Descr: Ww tube leak				
22.	12/21/97 08:20	- 12/21/97 09:54	Unplanned	1.57	517.00
	Descr: Boiler controls				
23.	12/21/97 13:49	- 12/25/97 15:23	Unplanned	97.57	32,197.00
	Descr: Water wall tube leak				
24.	12/30/97 05:23	- 12/30/97 11:16	Unplanned	5.88	1,941.50
	Descr: Testing valves low reheater flow				
25.	12/30/97 12:05	- 12/30/97 14:27	Unplanned	2.37	781.00
	Descr: Da tank level indication				
	*** * * Unit Summary for Dave Johnston No. 4 for the year 1997**			921.99	304,249.00
Hunter No. 1					
1.	01/23/97 03:36	- 01/23/97 20:06	Unplanned	16.50	6,847.50
	Descr: Unit trip, feedwater mov breaker trip				
2.	02/02/97 11:46	- 02/02/97 16:47	Unplanned	5.02	2,081.92
	Descr: Unit trip, 1-1 cw pump & bfpt's tripped				
3.	02/06/97 20:58	- 02/07/97 01:17	Unplanned	4.32	1,791.42
	Descr: Unit off line - both bfpt's tripped				
4.	02/20/97 14:14	- 02/22/97 18:00	Unplanned	51.77	21,483.17
	Descr: Boiler tube leak (reheat section)				
5.	02/28/97 00:12	- 03/01/97 00:00	Unplanned	23.80	9,877.00
	Descr: Boiler tube leak (reheat section)				
6.	03/01/97 00:00	- 03/05/97 06:10	Unplanned	102.17	42,399.17
	Descr: Boiler tube leak (reheat section)				
7.	03/05/97 06:10	- 03/05/97 11:00	Unplanned	4.83	2,005.83
	Descr: Ignitor problems				
8.	03/05/97 11:00	- 03/05/97 21:30	Unplanned	10.50	4,357.50
	Descr: Building pressure/temps				
9.	03/06/97 04:30	- 03/06/97 09:10	Unplanned	4.67	1,936.67
	Descr: Unit off line				
10.	03/20/97 09:58	- 03/20/97 15:01	Unplanned	5.05	2,095.75
	Descr: Unit trip - i&c working on deh				
11.	04/16/97 17:03	- 04/19/97 15:01	Unplanned	69.97	29,036.17
	Descr: Boiler tube leak (steam-cooled wall)				
12.	06/05/97 08:27	- 06/10/97 03:52	Unplanned	115.42	47,897.92
	Descr: Main transformer bushing failure				
13.	06/21/97 23:23	- 06/23/97 04:20	Unplanned	28.95	12,014.25
	Descr: Off to tie 1-1 main transformer				
14.	07/12/97 01:00	- 07/14/97 06:00	Unplanned	53.00	21,995.00
	Descr: Off line - btm ash door repair				
15.	08/30/97 23:47	- 08/31/97 10:39	Unplanned	10.87	4,509.67
	Descr: Unit trip (unknown cause)				
16.	09/23/97 23:23	- 09/26/97 01:30	Unplanned	50.12	20,798.42
	Descr: Off line - reheater plugged				
17.	10/29/97 01:15	- 10/29/97 09:15	Unplanned	8.00	3,320.00
	Descr: Unit trip - high drum level				
	*** * * Unit Summary for Hunter No. 1 for the year 1997 =**			564.96	234,447.36

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	- Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Hunter No. 2					
1.	02/04/97 15:30	- 02/06/97 11:35	Unplanned	44.08	18,294.58
	Descr: Unit off line to fix da leak				
2.	02/17/97 22:17	- 02/17/97 23:17	Unplanned	1.00	415.00
	Descr: Unit trip - valving lube oil coolers				
3.	05/17/97 02:00	- 05/19/97 20:05	Unplanned	66.08	27,424.58
	Descr: Unit off - air heater wash				
4.	07/19/97 00:00	- 07/20/97 12:30	Unplanned	36.50	15,147.50
	Descr: Unit off line - cleaning ash out of boiler				
5.	08/03/97 00:00	- 08/03/97 11:51	Unplanned	11.85	4,917.75
	Descr: Off line - drum door gasket leak				
6.	09/16/97 00:52	- 09/18/97 23:07	Unplanned	70.25	29,153.75
	Descr: Boiler tube leak (first superheat)				
7.	10/11/97 00:28	- 11/01/97 00:00	Planned	504.53	209,381.33
	Descr: Unit outage (turbine) (dst)				
8.	11/01/97 00:00	- 11/24/97 14:52	Planned	566.87	235,249.67
	Descr: Unit outage (turbine)				
9.	11/24/97 20:35	- 11/25/97 22:42	Unplanned	26.12	10,838.42
	Descr: Off line - turbine overspeed tests				
10.	11/26/97 01:59	- 11/26/97 03:05	Unplanned	1.10	456.50
	Descr: Trip - flame failure-scanner problem				
11.	11/27/97 01:49	- 11/27/97 06:25	Unplanned	4.60	1,909.00
	Descr: Unit trip - condenser vacuum low				
12.	12/11/97 11:25	- 12/11/97 15:14	Unplanned	3.82	1,583.92
	Descr: Unit trip - low eh pressure				
	*** **Unit Summary for Hunter No. 2 for the year 1997** =			1,336.80	554,772.00
Hunter No. 3					
1.	03/05/97 11:00	- 03/07/97 21:30	Unplanned	58.50	23,692.50
	Descr: Unit off line - exciter brush failure				
2.	03/12/97 22:08	- 03/18/97 11:50	Unplanned	133.70	54,148.50
	Descr: Lp turbine blade failure				
3.	03/31/97 14:08	- 04/01/97 00:00	Unplanned	9.87	3,996.00
	Descr: Boiler tube leak (waterwall)				
4.	04/01/97 00:00	- 04/01/97 11:41	Unplanned	11.68	4,731.75
	Descr: Boiler master handhole cap leak				
5.	04/05/97 00:30	- 04/05/97 03:12	Unplanned	2.70	1,093.50
	Descr: Unit off - repair overspeed sol				
6.	04/29/97 13:37	- 04/29/97 22:55	Unplanned	9.30	3,766.50
	Descr: Unit trip - low drum - lost 3-2 bfpt				
7.	06/28/97 21:30	- 06/29/97 03:20	Unplanned	5.83	2,362.50
	Descr: Low drum level - bfpt 3-1 tripped				
8.	07/04/97 22:05	- 07/11/97 17:30	Unplanned	163.42	66,183.75
	Descr: Unit off - turbine blade repair				
9.	07/17/97 10:19	- 07/17/97 12:18	Unplanned	1.98	803.25
	Descr: Unit trip - loss turb lube oil press				
10.	07/17/97 15:05	- 07/17/97 17:44	Unplanned	2.65	1,073.25
	Descr: Trip - on switch to high speed on fd's				

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Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Hunter No. 3						
11.	09/03/97 02:50	-	09/05/97 05:11	Unplanned	50.35	20,391.75
	Descr: Boiler tube leak (second superheater)					
12.	10/21/97 20:31	-	10/22/97 09:21	Unplanned	12.83	5,197.50
	Descr: Unit trip - id & fd fans tripped					
13.	12/20/97 00:00	-	12/22/97 09:30	Unplanned	57.50	23,287.50
	Descr: Unit off - repair ww heater supports					
14.	12/22/97 15:36	-	12/22/97 18:10	Unplanned	2.57	1,039.50
	Descr: Unit trip - circ pump trip					
	*** * * Unit Summary for Hunter No. 3 for the year 1997 =**				522.88	211,767.75
Huntington No. 1						
1.	01/19/97 07:29	-	01/21/97 10:23	Unplanned	50.90	21,378.00
	Descr: Leak					
2.	03/14/97 22:46	-	04/24/97 05:55	Planned	966.15	405,783.00
	Descr: Overhaul					
3.	04/24/97 15:10	-	04/24/97 22:39	Unplanned	7.48	3,143.00
	Descr:					
4.	05/01/97 00:00	-	05/03/97 13:58	Unplanned	61.97	26,026.00
	Descr: Rh rad wall tube leak					
5.	06/12/97 20:20	-	06/13/97 23:00	Unplanned	13.33	5,600.00
	Descr: Leak					
6.	06/12/97 20:20	-	06/17/97 04:11	Unplanned	90.52	38,017.00
	Descr: Replacement of seal					
7.	06/24/97 20:20	-	06/24/97 21:50	Unplanned	1.50	630.00
	Descr:					
8.	07/17/97 00:38	-	07/22/97 06:10	Unplanned	125.53	52,724.00
	Descr: Leak					
9.	07/22/97 00:38	-	07/22/97 13:41	Unplanned	7.52	3,157.00
	Descr: Turbine bearing problem					
10.	07/22/97 13:41	-	07/22/97 16:56	Unplanned	3.25	1,365.00
	Descr: Leak					
11.	07/24/97 00:37	-	07/25/97 00:35	Unplanned	23.97	10,066.00
	Descr: Leak					
12.	08/20/97 00:00	-	08/21/97 02:15	Unplanned	26.25	11,025.00
	Descr: Unit off line for horizontal s.h. tube leak					
13.	08/26/97 18:30	-	08/27/97 03:54	Unplanned	9.40	3,948.00
	Descr: Condenser tube leak					
14.	09/22/97 23:48	-	09/27/97 14:30	Unplanned	110.70	46,494.00
	Descr: Unit off line for boiler tube leak					
15.	10/07/97 02:00	-	10/08/97 16:24	Unplanned	38.40	16,128.00
	Descr: Tube leaks					
16.	10/21/97 01:32	-	10/22/97 00:00	Unplanned	22.47	9,436.00
	Descr: Boiler tube leak					
17.	10/22/97 00:00	-	10/22/97 07:00	Unplanned	7.00	2,940.00
	Descr: Unit off line for boiler tube leak					
18.	10/22/97 07:00	-	10/22/97 19:00	Unplanned	12.00	5,040.00
	Descr: Boiler tube leak					

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Huntington No. 1						
19.	10/22/97 19:00	-	10/24/97 11:43	Unplanned	40.72	17,101.00
	Descr: Unit off line/tube leak/boiler					
20.	10/24/97 11:43	-	10/24/97 18:00	Unplanned	6.28	2,639.00
	Descr: Circ water system ph problem					
21.	10/24/97 18:00	-	10/25/97 22:53	Unplanned	28.88	12,131.00
	Descr: Condenser tube leak					
22.	10/26/97 02:00	-	10/26/97 03:23	Unplanned	2.38	1,001.00
	Descr: Boiler and turbine trip from under voltage 86tt					
23.	10/26/97 05:04	-	10/26/97 06:34	Unplanned	1.50	630.00
	Descr: Turbine trip from 86tt					
24.	10/26/97 08:00	-	10/26/97 09:00	Unplanned	1.00	420.00
	Descr: Turbine trip					
25.	10/30/97 12:33	-	10/30/97 13:36	Unplanned	1.05	441.00
	Descr: Unit trip (gen relay)					
26.	11/04/97 11:50	-	11/06/97 06:00	Unplanned	42.17	17,710.00
	Descr: Economizer tube leak hanger					
27.	12/25/97 13:35	-	12/25/97 21:49	Unplanned	8.23	3,458.00
	Descr: Generator ground took unit off line					
28.	12/25/97 22:37	-	12/26/97 00:10	Unplanned	1.55	651.00
	Descr: Generator ground took unit off line					
	*** * * Unit Summary for Huntington No. 1 for the year 1997 =**				1,712.10	719,082.00
Huntington No. 2						
1.	01/07/97 01:26	-	01/08/97 22:51	Unplanned	45.42	19,302.08
	Descr: Leak					
2.	02/04/97 20:54	-	02/08/97 10:13	Unplanned	85.32	36,259.58
	Descr: Tube leak					
3.	02/08/97 10:13	-	02/08/97 22:55	Unplanned	12.70	5,397.50
	Descr: High temperature alarm					
4.	02/08/97 22:55	-	02/09/97 09:54	Unplanned	10.98	4,667.92
	Descr: Tube leak					
5.	02/18/97 23:06	-	02/20/97 11:00	Unplanned	35.90	15,257.50
	Descr: Tube leak					
6.	02/20/97 11:00	-	02/20/97 12:10	Unplanned	1.17	495.83
	Descr: Misc problems					
7.	02/20/97 12:32	-	02/20/97 14:35	Unplanned	2.05	871.25
	Descr: Drum level trip ww drum drains					
8.	03/12/97 08:30	-	03/12/97 12:00	Unplanned	3.50	1,487.50
	Descr:					
9.	04/05/97 21:23	-	04/06/97 12:09	Unplanned	13.77	5,850.83
	Descr: Repair					
10.	05/16/97 02:51	-	05/19/97 10:00	Unplanned	79.15	33,638.75
	Descr: Tube leak					
11.	08/15/97 00:00	-	08/16/97 00:00	Unplanned	24.00	10,200.00
	Descr: Unit off line for econo wash					
12.	08/16/97 00:00	-	08/19/97 00:00	Unplanned	72.00	30,600.00
	Descr: Plugged economizer					

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Huntington No. 2						
13.	08/19/97 00:00	-	08/19/97 10:36	Unplanned	10.60	4,505.00
	Descr: Plugged economizer & tube leak					
14.	08/22/97 22:18	-	08/23/97 01:57	Unplanned	3.65	1,551.25
	Descr: Unit tripped off ine while testing power load imbalance on ehc panel					
15.	10/11/97 00:16	-	10/12/97 15:55	Unplanned	39.65	16,851.25
	Descr: Boiler & feedwater heaters 2-3, 2-5 & 2-7 have leaks					
	*** Unit Summary for Huntington No. 2 for the year 1997 =				439.86	186,936.24
Jim Bridger No. 1						
1.	01/03/97 11:15	-	01/04/97 21:47	Unplanned	34.53	17,957.33
	Descr: Unit off line to repair broken inlet vanes on 11 i.d. fan.					
2.	01/31/97 10:43	-	01/31/97 14:30	Unplanned	3.78	1,967.33
	Descr: Unit off line for safety repair (sh).					
3.	01/31/97 14:30	-	01/31/97 16:48	Unplanned	2.30	1,196.00
	Descr: Economizer inlet valve controls repair.					
4.	02/12/97 22:44	-	02/13/97 22:00	Unplanned	23.27	12,098.67
	Descr: Unit off line to repair waterwall tube leak.					
5.	02/13/97 22:00	-	02/14/97 00:00	Unplanned	2.00	1,040.00
	Descr: Turbine overspeed tests.					
6.	02/14/97 00:00	-	02/14/97 02:53	Unplanned	2.88	1,499.33
	Descr: Mechanical oil trip problems.					
7.	04/22/97 00:00	-	04/23/97 20:50	Unplanned	44.83	23,313.33
	Descr: Reheat and waterwall tube leaks.					
8.	06/04/97 00:00	-	06/08/97 14:43	Unplanned	110.72	57,572.67
	Descr: Unit off line for air preheater wash.					
9.	06/21/97 00:00	-	06/21/97 19:38	Unplanned	19.63	10,209.33
	Descr: Unit off line to repair superheater tube leak.					
10.	07/08/97 03:57	-	07/09/97 09:03	Unplanned	29.10	15,132.00
	Descr: Unit off line to repair finishing superheat tube leak.					
11.	08/06/97 23:59	-	08/07/97 17:24	Unplanned	17.42	9,056.67
	Descr: Unit off line to repair phosphate injection line.					
12.	08/18/97 05:51	-	08/18/97 20:11	Unplanned	14.33	7,453.33
	Descr: Gen. voltage indication.					
13.	09/12/97 00:38	-	09/12/97 17:41	Unplanned	17.05	8,866.00
	Descr: Unit off line to repair economizer inlet valve.					
14.	09/14/97 14:14	-	09/15/97 20:26	Unplanned	30.20	15,704.00
	Descr: Penthouse sh tube leak.					
15.	09/23/97 12:43	-	09/23/97 13:51	Unplanned	1.13	589.33
	Descr: Unit trip-bfpt controls-bcp delta p.					
16.	09/23/97 14:15	-	09/23/97 15:20	Unplanned	1.08	563.33
	Descr: Unit trip-bfpt controls-bcp delta p.					
17.	10/02/97 00:12	-	10/02/97 21:23	Unplanned	21.18	11,015.33
	Descr: Unit off line to repair waterwall tube leak.					
18.	10/24/97 14:10	-	10/24/97 15:24	Unplanned	1.23	641.33
	Descr: Kinport borah line trip.					
19.	10/31/97 12:47	-	11/01/97 08:00	Unplanned	19.22	9,992.67
	Descr: Unit off line toepair steam sodium sample line from drum-hanger broke					

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger No. 1						
20.	11/01/97 08:00	-	11/02/97 00:00	Unplanned	16.00	8,320.00
	Descr: Deslag boiler.					
21.	11/02/97 00:00	-	11/03/97 00:52	Unplanned	24.87	12,930.67
	Descr: Air preheater down-mechanically bound.					
22.	11/03/97 02:39	-	11/03/97 03:52	Unplanned	1.22	632.67
	Descr: Unit trip-maintenance working on aux. bus-relay bump					
23.	11/16/97 08:03	-	11/16/97 12:57	Unplanned	4.90	2,548.00
	Descr: Unit trip-boiler ph low-circ. water leaked in from #12 condensate sump					
24.	11/16/97 13:08	-	11/16/97 14:17	Unplanned	1.15	598.00
	Descr: Unit trip-boiler ph low-circ. water leaked in from #12 condensate sump					
25.	12/17/97 03:36	-	12/17/97 22:37	Unplanned	19.02	9,888.67
	Descr: Unit off line to repair sh steam cooled wrapper tube.					
	*** * * Unit Summary for Jim Bridger No. 1 for the year 1997 =**				463.04	240,785.99
Jim Bridger No. 2						
1.	02/18/97 00:00	-	02/18/97 21:27	Unplanned	21.45	11,154.00
	Descr: Unit off line to repair i.d. fan linkages.					
2.	03/08/97 00:00	-	03/08/97 20:55	Unplanned	20.92	10,876.67
	Descr: Unit off tube leak.					
3.	04/17/97 23:58	-	04/19/97 13:32	Unplanned	37.57	19,534.67
	Descr: Unit off line to repair rh tube leak.					
4.	04/26/97 00:27	-	05/26/97 00:00	Planned	719.55	374,166.00
	Descr: Planned overhaul.					
5.	05/26/97 00:00	-	06/02/97 04:06	Planned	172.10	89,492.00
	Descr: Planned turbine overhaul.					
6.	06/02/97 10:50	-	06/02/97 13:57	Unplanned	3.12	1,620.67
	Descr: Post outage testing. turbine overspeeds.					
7.	08/02/97 18:27	-	08/04/97 16:50	Unplanned	46.38	24,119.33
	Descr: Unit off line to deslag reheater.					
8.	12/02/97 00:24	-	12/02/97 05:17	Unplanned	4.88	2,539.33
	Descr: Deslagging pendant reheater.					
9.	12/08/97 23:51	-	12/11/97 15:43	Unplanned	63.87	33,210.67
	Descr: Unit off line to deslag reheater.					
10.	12/11/97 17:46	-	12/11/97 19:12	Unplanned	1.43	745.33
	Descr: High turbine vibrations.					
11.	12/16/97 01:35	-	12/17/97 01:12	Unplanned	23.62	12,280.67
	Descr: Unit off line to repair waterwall tube leak.					
12.	12/20/97 07:29	-	12/20/97 10:10	Unplanned	2.68	1,395.33
	Descr: Unit off line-boiler feed pump control failure.					
	*** * * Unit Summary for Jim Bridger No. 2 for the year 1997 =**				1,117.57	581,134.67
Jim Bridger No. 3						
1.	03/11/97 23:21	-	03/13/97 13:46	Unplanned	38.42	19,976.67
	Descr: Id fan (31) linkage repair.					
2.	04/08/97 21:42	-	04/09/97 00:21	Unplanned	2.65	1,378.00
	Descr: Low hot p.a. duct pressure trip.					
3.	04/27/97 00:41	-	04/28/97 21:00	Unplanned	44.32	23,044.67
	Descr: Unit off line to repair air preheater drive problems.					

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	- Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger No. 3					
4.	04/28/97 21:00	- 05/04/97 00:00	Unplanned	123.00	63,960.00
	Descr: 32 i.d. fan inlet vanes.				
5.	05/04/97 00:00	- 05/07/97 13:34	Unplanned	85.57	44,494.67
	Descr: 31 air preheater bearing failure.				
6.	05/18/97 21:57	- 05/28/97 08:19	Unplanned	226.37	117,710.67
	Descr: Unit off line to repair 32 air preheater primary-secondary sector plat				
7.	07/11/97 06:01	- 07/12/97 14:13	Unplanned	32.20	16,744.00
	Descr: Unit off line to repair i.d. fan inlet vanes.				
8.	07/12/97 15:36	- 07/17/97 07:09	Unplanned	111.55	58,006.00
	Descr: Unit off line to repair 32 i.d. fans inlet vane and bearing.				
9.	07/17/97 10:10	- 07/17/97 11:14	Unplanned	1.07	554.67
	Descr: Unit off line-boiler controls.				
10.	07/28/97 23:26	- 07/31/97 05:54	Unplanned	54.47	28,322.67
	Descr: Unit off line to restore 32 i.d. fan.				
11.	09/22/97 00:02	- 09/23/97 14:23	Unplanned	38.35	19,942.00
	Descr: Unit off line to repair waterwall tube leak.				
12.	11/30/97 02:29	- 12/01/97 03:38	Unplanned	25.15	13,078.00
	Descr: Unit off line to repair waterwall tube leak.				
13.	12/14/97 15:51	- 12/15/97 10:05	Unplanned	18.23	9,481.33
	Descr: Unit off line to repair pendant platen superheater tube leak.				
14.	12/22/97 19:29	- 12/23/97 12:06	Unplanned	16.62	8,640.67
	Descr: Unit off line to repair cooling tower circ. water header.				
	*** **Unit Summary for Jim Bridger No. 3 for the year 1997 =**			817.97	425,334.02
Jim Bridger No. 4					
1.	01/17/97 07:44	- 01/18/97 10:30	Unplanned	26.77	13,918.67
	Descr: 42 ccw pump-blew expansion joint,				
2.	01/18/97 10:30	- 01/19/97 00:19	Unplanned	13.82	7,184.67
	Descr: Deslag reheater/superheater.				
3.	02/07/97 21:50	- 02/08/97 00:19	Unplanned	2.48	1,291.33
	Descr: Turbine trip. no apparent root cause in logs.				
4.	02/08/97 11:01	- 02/08/97 12:10	Unplanned	1.15	598.00
	Descr: Thrust bearing wear detector.				
5.	02/08/97 15:02	- 02/09/97 00:00	Unplanned	8.97	4,662.67
	Descr: Thrust bearing wear detector.				
6.	02/09/97 00:00	- 02/09/97 01:18	Unplanned	1.30	676.00
	Descr: B corner warmup gun control wiring fried due to boiler casing leak.				
7.	03/19/97 23:17	- 04/21/97 18:22	Planned	786.08	408,763.33
	Descr: Unit overhaul.				
8.	04/22/97 01:37	- 04/22/97 03:22	Unplanned	1.75	910.00
	Descr: Unit off line for overspeed test.				
9.	04/22/97 07:23	- 04/22/97 13:29	Unplanned	6.10	3,172.00
	Descr: Unit off line-125vdc circuit check-maintenance error.				
10.	05/08/97 01:00	- 05/08/97 17:05	Unplanned	16.08	8,363.33
	Descr: Unit off line to repair 42 feedwater heater bypass line leak.				
11.	05/08/97 17:05	- 05/08/97 20:58	Unplanned	3.88	2,019.33
	Descr: Waterwall tube leak.				

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Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger No. 4						
12.	05/08/97 20:58	-	05/09/97 08:34	Unplanned	11.60	6,032.00
	Descr: Dc system ground.					
13.	06/09/97 23:30	-	06/10/97 23:54	Unplanned	24.40	12,688.00
	Descr: Unit off line to repair waterwall tube leak.					
14.	07/30/97 13:36	-	08/01/97 07:54	Unplanned	42.30	21,996.00
	Descr: Unit off line to replace lpb 14th stage expansion joint.					
15.	08/09/97 05:34	-	08/09/97 08:52	Unplanned	3.30	1,716.00
	Descr: Unit off line condensate storage tank ran dry.					
16.	10/20/97 14:10	-	10/20/97 15:25	Unplanned	1.25	650.00
	Descr: Defective sedcdevice tripped unit while tech was working on it.					
17.	10/24/97 15:00	-	10/24/97 18:20	Unplanned	3.33	1,733.33
	Descr: Exciter master firing circuit.					
18.	12/06/97 01:05	-	12/08/97 15:01	Unplanned	61.93	32,205.33
	Descr: Unit off line to deslag boiler.					
	*** * * Unit Summary for Jim Bridger No. 4 for the year 1997 =**				1,016.49	528,579.99
Naughton No. 1						
1.	05/24/97 00:14	-	06/30/97 19:54	Planned	907.67	145,226.67
	Descr: Overhaul - major boiler clean/retubing, rebuilding turbine valves, reb					
2.	07/25/97 23:27	-	07/27/97 05:53	Unplanned	30.43	4,869.33
	Descr: Repair economizer tube leak					
3.	09/19/97 22:23	-	09/20/97 12:29	Unplanned	14.10	2,256.00
	Descr: Outage - dc emergency lube oil pump and repack valves on boiler					
	*** * * Unit Summary for Naughton No. 1 for the year 1997 =**				952.20	152,352.00
Naughton No. 2						
1.	03/28/97 23:14	-	03/30/97 06:31	Unplanned	31.28	6,569.50
	Descr: Unit off to repair feedwater control valve					
2.	04/27/97 02:11	-	04/27/97 04:11	Unplanned	2.00	420.00
	Descr: Down to 100 with 3 mills, lost mill to low-flow, unstable flame, cause					
3.	06/11/97 08:37	-	06/11/97 12:47	Unplanned	4.17	875.00
	Descr: Safety inspection testing transformer deluge system					
4.	06/11/97 13:54	-	06/11/97 20:33	Unplanned	6.65	1,396.50
	Descr: Unit trip ups system failed					
5.	06/12/97 16:48	-	06/12/97 21:06	Unplanned	4.30	903.00
	Descr: Unit trip ups sytem failed					
6.	06/14/97 11:28	-	06/17/97 19:50	Unplanned	80.37	16,877.00
	Descr: Reheat tube leak repaired					
7.	06/21/97 00:20	-	06/26/97 13:03	Unplanned	132.72	27,870.50
	Descr: Reheat tube leak					
8.	08/19/97 23:52	-	08/21/97 11:49	Unplanned	35.95	7,549.50
	Descr: Lp blade failure l-o; removed 2 blade tips; weld repair peformed;nde t					
9.	10/21/97 09:49	-	10/21/97 13:04	Unplanned	3.25	682.50
	Descr: No load timer; contacts welded together and generator ran down					
10.	11/08/97 00:13	-	11/08/97 08:18	Unplanned	8.08	1,697.50
	Descr: Timer relay mcc 2-6 burned up, lost indication, lost bearing cooling p					
11.	11/12/97 23:29	-	11/15/97 19:19	Unplanned	67.83	14,245.00
	Descr: Condenser tube leak repairs and also repaired mov1					

1997 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Naughton No. 2						
12.	11/22/97 23:38	-	11/23/97 02:00	Unplanned	2.37	497.00
	Descr: Governor system (raising/lowering load) tripped					
13.	12/20/97 00:13	-	12/21/97 23:53	Unplanned	47.67	10,010.00
	Descr: Offline to rod slag in boiler tube areas					
	*** **Unit Summary for Naughton No. 2 for the year 1997 =**				426.64	89,593.00
Naughton No. 3						
1.	01/17/97 06:41	-	01/18/97 00:00	Unplanned	17.32	5,714.50
	Descr: Tripped low drum level operator error,repair 3 superheat 1 waterwall t					
2.	01/18/97 00:00	-	01/20/97 07:31	Unplanned	55.52	18,320.50
	Descr: Unit off to repair 3 sh 1 ww tube leaks, clean scrubber absorbers					
3.	01/24/97 23:30	-	01/25/97 22:31	Unplanned	23.02	7,595.50
	Descr: Repair economizer tube leak					
4.	02/02/97 01:28	-	02/02/97 04:56	Unplanned	3.47	1,144.00
	Descr: 3-2 boiler feed pump trip trying to valve in 3-1 bfp belly drain					
5.	02/02/97 11:15	-	02/02/97 13:42	Unplanned	2.45	808.50
	Descr: 3-2 boiler feed pump trip					
6.	02/02/97 13:44	-	02/02/97 16:08	Unplanned	2.40	792.00
	Descr: 3-2 bfp trip, voltage regulator stuck					
7.	03/21/97 05:16	-	03/21/97 10:26	Unplanned	5.17	1,705.00
	Descr: Bfp trip - belly drain flooded caused by condensate reject valve					
8.	05/08/97 07:32	-	05/08/97 14:56	Unplanned	7.40	2,442.00
	Descr: Unit trip, 3-1 and 3-2 bfpt tripped					
9.	09/06/97 04:00	-	09/09/97 01:58	Unplanned	69.97	23,089.00
	Descr: Repair waterwall tube leaks (6)					
10.	10/04/97 01:22	-	10/11/97 23:18	Unplanned	189.93	62,678.00
	Descr: Turbine chemical clean, clean scrubber absorbers, fix 2 waterwall leak					
11.	11/05/97 00:13	-	11/05/97 01:59	Unplanned	1.77	583.00
	Descr: Unit trip flame scanners					
12.	11/05/97 02:52	-	11/05/97 04:35	Unplanned	1.72	566.50
	Descr: Unit trip - burner controls					
13.	11/16/97 01:30	-	11/16/97 02:56	Unplanned	1.43	473.00
	Descr: Doing sunday valve test and ran valves wrong way					
14.	11/19/97 02:59	-	11/19/97 04:25	Unplanned	1.43	473.00
	Descr: Big slab of ash fell					
15.	11/26/97 03:57	-	11/29/97 02:56	Unplanned	70.98	23,424.50
	Descr: Repaired 6 waterwall and 1 superheat tube leaks					
16.	11/29/97 03:12	-	11/30/97 04:57	Unplanned	25.75	8,497.50
	Descr: Burnt relays on fsss system					
17.	12/06/97 01:38	-	12/08/97 02:05	Unplanned	48.45	15,988.50
	Descr: Repair first superheater tube leaks					
	*** **Unit Summary for Naughton No. 3 for the year 1997 =**				528.18	174,295.00
Wyodak						
1.	02/27/97 02:36	-	02/27/97 12:22	Unplanned	9.77	3,271.83
	Descr: Turbine controls, at full load, transfered operation from partial arc					
2.	04/07/97 01:05	-	04/07/97 07:30	Unplanned	6.42	2,149.58
	Descr: 1a1 station transformer feed breaker tripped when 6h455 was racked in					

No.	Beginning Date Time	- Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Wyodak					
3.	04/07/97 07:30	- 04/07/97 17:30	Unplanned	10.00	3,350.00
	Descr: Boiler purge for start up failed due to water in instrument air lines				
4.	04/07/97 17:30	- 04/08/97 19:07	Unplanned	25.62	8,581.58
	Descr: Servo unit for the id fan damper controls was faulty				
5.	05/14/97 12:53	- 05/14/97 14:19	Unplanned	1.43	480.17
	Descr: Calibrating 1st stage pressure transmitter- steam flow indication went				
6.	09/26/97 06:26	- 09/26/97 10:05	Unplanned	3.65	1,222.75
	Descr: Unit trip on low drum level while trying to increase load				
7.	09/26/97 10:05	- 09/26/97 11:07	Unplanned	1.03	346.17
	Descr: After generator sync the unit tripped on high drum level				
8.	09/26/97 11:07	- 09/26/97 12:11	Unplanned	1.07	357.33
	Descr: After generator sync the unit tripped on high drum level				
9.	10/16/97 00:01	- 10/18/97 14:15	Unplanned	62.23	20,848.17
	Descr: Unit brought off line to remove ash build up in the reheater section				
10.	10/29/97 05:10	- 10/30/97 08:54	Unplanned	27.73	9,290.67
	Descr: Tube leak in convection pass floor below the reheat section				
11.	10/31/97 05:54	- 10/31/97 23:38	Unplanned	17.73	5,940.67
	Descr: High velocity winds caused voltage lines in the switch yard to cross				
12.	11/03/97 01:06	- 11/03/97 03:00	Unplanned	1.90	636.50
	Descr: For unknown reason at this time, the furnace pressure went above 10 in				
13.	11/22/97 12:27	- 11/23/97 10:36	Unplanned	22.15	7,420.25
	Descr: Tube leak				
14.	11/25/97 13:29	- 11/26/97 06:25	Unplanned	16.93	5,672.67
	Descr: Tube leak				
	*** Unit Summary for Wyodak for the year 1997 =			207.66	69,568.34
Cholla No. 4					
1.	02/20/97 12:31	- 02/23/97 14:37	Unplanned	74.10	28,158.00
	Descr: Reheater tube leak repairs				
2.	03/11/97 12:24	- 03/11/97 14:00	Unplanned	1.60	608.00
	Descr: B vacuum pump controls				
3.	03/25/97 11:33	- 03/25/97 13:48	Unplanned	2.25	855.00
	Descr: B vacuum pump controls				
4.	05/05/97 13:08	- 05/05/97 14:51	Unplanned	1.72	652.33
	Descr: Volts/hertz trip - var transducer malfunction				
5.	05/23/97 23:20	- 05/24/97 04:11	Unplanned	4.85	1,843.00
	Descr: 'a' vacuum pump motor burned up				
6.	05/24/97 06:45	- 05/24/97 08:39	Unplanned	1.90	722.00
	Descr: Feedwater flow upset				
7.	08/07/97 09:14	- 08/13/97 02:57	Unplanned	137.72	52,332.33
	Descr: Repair tube leak				
8.	09/18/97 11:06	- 09/18/97 15:35	Unplanned	4.48	1,703.67
	Descr: Lost instrument air pressure				
9.	10/06/97 15:25	- 10/08/97 13:48	Unplanned	46.38	17,625.67
	Descr: Boiler reheater tube leak repairs				
10.	10/27/97 09:24	- 10/27/97 11:42	Unplanned	2.30	874.00
	Descr: Exciter cubical trip				

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Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Cholla No. 4						
11.	11/22/97 00:26	-	12/01/97 01:59	Planned	217.55	82,669.00
	Descr: Stack turning vane repairs					
	* * * **Unit Summary for Cholla No. 4 for the year 1997 =**				494.85	188,043.00
Gadsby No. 2						
1.	07/07/97 11:33	-	07/07/97 16:11	Unplanned	4.63	347.50
	Descr: While bringing up load unit due to high burner fuel pressure. this wa					
	* * * **Unit Summary for Gadsby No. 2 for the year 1997 =**				4.63	347.50
Gadsby No. 3						
1.	09/12/97 07:58	-	09/13/97 00:44	Unplanned	16.77	1,676.67
	Descr: Primary superheat tube leak 20 tubes from south side of boiler. it ap					
2.	09/26/97 13:35	-	09/26/97 20:00	Unplanned	6.42	641.67
	Descr: Fd inlet damper drives 3-1 and 3-2 would not close and consequently wo					
	* * * **Unit Summary for Gadsby No. 3 for the year 1997 =**				23.19	2,318.34
Blundell						
1.	04/09/97 11:15	-	04/09/97 15:15	Unplanned	4.00	92.00
	Descr: System disturbance					
2.	04/09/97 15:15	-	04/19/97 00:25	Unplanned	225.17	5,178.83
	Descr: Maintenance outage					
3.	04/19/97 05:35	-	04/19/97 17:26	Unplanned	11.85	272.55
	Descr: Condenser screens plugged					
4.	06/12/97 11:29	-	06/12/97 16:39	Unplanned	5.17	118.83
	Descr: Clean hotwell screens in main condenser					
5.	07/05/97 19:10	-	07/06/97 18:10	Unplanned	23.00	529.00
	Descr: Main condenser screens plugged					
6.	08/19/97 10:56	-	08/19/97 15:11	Unplanned	4.25	97.75
	Descr: Br-5 tripped causing other probs at wells and tripped unit manually					
7.	09/15/97 23:47	-	09/16/97 02:00	Unplanned	2.22	50.98
	Descr: Br4 pump tripped on low flow. ig's 28-3 well shut in					
8.	09/16/97 10:40	-	09/17/97 00:53	Unplanned	14.22	326.98
	Descr: Repair leak in dielectric flange					
9.	10/30/97 08:21	-	10/30/97 15:00	Unplanned	6.65	152.95
	Descr: Clean condenser screens					
10.	12/02/97 13:48	-	12/02/97 16:50	Unplanned	3.03	69.77
	Descr: Unit tripped; emergency overspeed trip					
11.	12/22/97 11:44	-	12/22/97 13:31	Unplanned	1.78	41.02
	Descr: Problems with cw1c electrical leads tripped unit					
	* * * **Unit Summary for Blundell for the year 1997 =**				301.34	6,930.66
Little Mountain						
1.	12/17/97 08:42	-	12/17/97 17:48	Unplanned	9.10	127.40
	Descr: Pre-evaporator tube leak					
	* * * **Unit Summary for Little Mountain for the year 1997 =**				9.10	127.40

1997 FORCED OUTAGES REPORT
(Outages Which Exceed 24 Hours)

	Location / Date of Outage	Unit No. and Cause of Outage	Outage Duration (Hours)
Hydro East			
	American Fork - 696	Unit 1 - 1/1/97-12/10/97 Flowline failure occurred May 1993. Plant returned to service December 1997 following pipleline repair	8218
	Ashton - 2381	Unit 2 - 9/11/97 - 9/25/97 Generator circuit breaker failure / Replaced pivot pin	327
		Unit 3 - 9/12/97 - 9/25/97 Generator circuit breaker failure / Replaced pivot pin	303
	Cove - 2401	None	
	Cutler - 2426	None	
	Fountain Green - 10690	Unit 1 - 1/1/97 - 5/16/97 Generator winding failure / Repaired damaged coils	4008
		Unit 1 - 10/21/97 - 12/12/97 Exciter rheostat failure / Rebuilt equipment	1222
	Grace - 2401	None	
	Gunlock - 9281	Unit 1 - 11/5/97 - 11/8/97 Vicker valve trouble / Replaced burned up coil	120
	Last Chance - 4580	Unit 1 - 1/1/97 - 1/23/97 Turbine shaft failure / Fabriciated new shaft	555
	Oneida - 472	Unit 1 - 3/18/97 - 3/21/97 Govenor trouble / Repaired govenor	74
		Unit 3 - 4/15/97 - 4/15/97 Lube oil pump failure / Repaired pump	23
	Paris - 703	Unit 1 - 1/12/97 - 1/14/97 Canal blown in with snow	47

1997 FORCED OUTAGES REPORT
(Outages Which Exceed 24 Hours)

	Location / Date of Outage	Unit No. and Cause of Outage	Outage Duration (Hours)
	Pioneer - 2722	Units 3&6 4/14/97 - 4/18/97 Repaired draft tubes	120
	Sandcove - 9281	Unit 1 - 8/10/97 - 8/11/97 Station battery trouble / Corrected problem	35
	Stairs - 597	Unit 1 - 6/12/97 - 7/1/97 Land slide upstream increased debris loading on intake screen. Bent intake screen and jammed scroll case / Unit disassembled and cleaned out	443
	St. Anthony - 2381	None	
	Snakecreek -	Unit 2 - 1/2/97 - 1/21/97 Damaged gear box / Fabricated new gear box and shaft	432
		Unit 2 - 4/29/97 - 4/30/97 Relay trouble / Repaired relays	37
	Soda - 20	None	
	Upper Beaver - 814	None	
	Veyo - 9281	Unit 1 - 1/15/97 - 1/16/97 Hydraulic hose failure / Repaired hose	28
	Viva Naughton - 6509		
	Weber - 1744	None	
Hydro North			

1997 FORCED OUTAGES REPORT
(Outages Which Exceed 24 Hours)

Location / Date of Outage	Unit No. and Cause of Outage	Outage Duration (Hours)
Bend - Unlicensed	Unit 1 - 1/13/97 to 1/15/97, Icing problems	56
	Unit 2 - 1/13/97 to 1/15/97, Icing problems	56
	Unit 3 - 1/13/97 to 1/16/97, Icing problems	77
Bigfork - 2652	Unit 3 - 1/4/97 to 1/6/97, Field switch malfunction	49
	Unit 1 - 7/6/97 to 7/8/97, Repair broken gate link	37
	Unit 3 - 7/26/97 to 8/11/97, Packing leak	384
	Unit 1 - 8/18/97 to 8/26/97, Canal repairs	196
	Unit 2 - 8/18/97 to 8/26/97, Canal repairs	196
	Unit 3 - 8/18/97 to 8/26/97, Canal repairs	197
Cline Falls - Unlicensed	Unit 1 - 10/5/97 to 10/10/97, Transformer breaker failure	126
Condit - 2342	Unit 1 - 1/1/97 to 1/3/97, Bearing repair	58
	Unit 2 - 1/14/97 to 1/16/97, Thrust bearing repair	56
	Unit 1 - 3/23/97 to 3/29/97, Plugged sump outlet and field ground	152
	Unit 1 - 7/4/97 to 7/8/97, Broken wicket gate arm, vibration	89
Merwin - 935	None	
Naches - Unlicensed	None	
Naches Drop - Unlicensed	None	
Powerdale - 2659	None	
Yale - 2071	None	
Skookumchuck	None	
Swift - 2111	None	
Wallowa Falls - 308	Unit 1 - !2/1/97 to 12/31/97, Frozen penstock, turnbine repairs	744

1997 FORCED OUTAGES REPORT
(Outages Which Exceed 24 Hours)

Hydro South	Location / Date of Outage	Unit No. and Cause of Outage	Outage Duration (Hours)
	Klamath	West Side Unit 1- 5/27/31 to 5/31/97, Repair governor bearing	102
		West Side Unit 1- 6/3/97 to 6/3/97, Repair governor bearing	63
		West Side Unit 1 - 7/1/97 to 8/31/97, Repair governor bearing	593
		Copco Unit 11 - 1/1/97 to 2/24/97, Problems with turbine runner overhaul	1329
		Copco Unit 11 - 6/6/97 to 7/28/97, Repair bearings	1253
		Copco Unit 11 -8/23/97 to 8/25/97, Exciter problems	64
		Copco Unit 11 - 8/28/97 to 8/30/97, Exciter problems	39
		Copco Unit 12 - 9/18/97 to 9/21/97, Problems with turbine runner overhaul	82
		Copco Unit 22 - 7/23/97 to 9/1/97, Water in turbine bearing	960
		Fall Creek Unit 1 - 6/6/97 to 6/9/97, Water in plant from heavy rain	68
		Fall Creek Unit 2 - 6/6/97 to 6/9/97, Water in plant from heavy rain	68
		Fall Creek Unit 3 - 6/6/97 to 6/9/97, Water in plant from heavy rain	68
	North Umpqua	Slide Creek Unit 1 - 1/2/97 to 1/4/97, Intake racks plugged	57
		Lemolo Unit 2 - 2/14/97 to 2/16/97, Canal repair	41
		Toketee Unit 2 - 10/29/97 to 10/30/97, Unit tripped due to grid closure	29
	Prospect 3	None	
	Prospect 1,2,4	Prospect 1, Unit 1- 11/21/97 to 11/22/97, Repair governor drive shaft	28
		Prospect 2, Unit 2- 12/26/97 to 12/31/97, Problem with generator guide bearing	104
	Eagle Point	Unit 1 - 1/5/97 to 3/4/97, Remove large rock in canal	1400