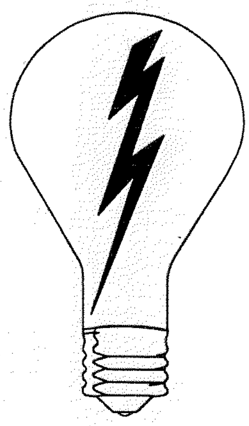
YEAR 1996

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

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) 464-5065
Address for Correspondence Concerning Report:	Pacific Power 1228 Public Service Building 920 S. W. Sixth Avenue Portland, Oregon 97204

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
1	Keith R. McKennon (Chairman)	Portland, Oregon	170,000
2	Frederick W. Buckman (1)	Portland, Oregon	(2)
3	Kathryn A. Braun	Irvine, Californiz	44,952
4	C. Todd Conover	Cupertino, California	50,768
5	Richard C. Edgley (3)	Salt Lake City, Utah	37,212
6	John C. Hampton (4)	Portland, Oregon	23,599
7	Nolan E. Karras	Roy, Utah	63,140
8	Robert G. Miller	Portland, Oregon	49,958
9	Verl R. Topham	Salt Lake City, Utah	(2)
10	Don M. Wheeler	Salt Lake City, Utah	55,489
11	Nancy Wilgenbusch	Marylhurst, Oregon	49,666
12	Peter I. Wold	Casper, Wyoming	53,925
13			
14			
15			
16			
17			
18	(1) President and Chief Executive Officer of the		
19	Company.		
20	(2) No remuneration as a director, officer of the		
21	Company during 1996		
22	(3) Resigned May 1996		
23	(4) Retired February 1996		

Sch. 3

OFFICERS

	Title	Department Supervised	Name
1	President and Chief Executive Officer		Frederick W. Buckman
2			
3	Senior Vice President		Paul G. Lorenzini
4			
5	Senior Vice President and General Counsel		Verl R. Topham
6			
7	Senior Vice President		Daniel L. Spalding
8			
9	Senior Vice President		John A. Bohling
10			
11	Senior Vice President		John E. Mooney
12			
13	Senior Vice President		Dennis P. Steinberg
14			
15	Senior Vice President		Shelley R. Faigle'
16			
17	Senior Vice President and Chief Financial Officer		Richard T. O'Brien
18			
19	Senior Vice President		William C. Brauer (1)
20			
21	Vice President		Brett Harvey
22			
23	Vice President		David P. Hoffman
24			
25	Vice President		Thomas J. Imeson
26			
27	Vice President		Robert F. Lanz (2)
28			
29	Vice President and Corporate Secretary		Sally A. Nofziger
30			
31	Vice President		Edwin J. O'Mara
32			
33	Vice President		Michael J. Pittman
34			
35	Vice President		Paul W. Pechersky
36			
37	Vice President		Ernest E. Wessman
38			
39	Vice President		Thomas W. Forsgren
40			
41	Vice President		Thomas A. Lockhart
42			
43	Vice President		Richard D. Westerberg
44			
45	Vice President		Michael C. Henderson
46			
47	Vice President and Treasurer		William E. Peressini (3)
48			
49	Controller		Donald A. Bloodworth (4)
50			

Sch. 3

OFFICERS

Title	Department Supervised	Name
Controller		Jacqueline S. Bell (5)

(1) Elected Senior Vice President May 8, 1996; formerly Vice President.
(2) Terminated Officer Status on December 2, 1996.
(3) Elected Vice President and Treasurer May 8, 1996; formerly Treasurer.
(4) Elected Controller August 14, 1996.
(5) Reassigned Assistant Controller December 31, 1996.

Sch. 4

CORPORATE STRUCTURE

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1	PacifiCorp Holdings, Inc.	Holding company	133,033,474	100.16%
2				
3	Demand Side Receivable	Demand Side loan		
4		holder	(214,849)	-0.16%
5				
6				
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48				
49				
50	TOTAL		132,818,625	100%

Sch. 5

CORPORATE ALLOCATIONS

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Corporate Management Fee		Three Factor Method			
2	$18,643,338	January - December	69.4% to Electric Utility Operations			
3						
4						
5	Electric Utility Portion					
6	$12,938,478					
7				254,836	1.9696%	12,683,642
8						
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33						
34	TOTAL			254,836	1.9696%	12,683,642

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	66,378	0.01%	1,234
2		Customer Billing	Cost	159,202	0.03%	2,960
3		Telephone Svc & Pole Attach	Cost	120,828	0.02%	8,878
4						
5	PacifiCorp Trans	Air Transportation	Cost	6,705,652	81.44%	136,667
6						
7	Centralia Mining	Coal & Mine Mgt	Cost	50,249,644	(a)	941,729
8						
9	Energy West	Coal & Mine Mgt	Cost	140,652,806	(a)	2,635,974
10						
11	Glenrock Coal	Coal & Mine Mgt	Cost	30,913,504	(a)	579,350
12						
13	Williams Fork	Coal & Mine Mgt	Cost	7,039,575	(a)	131,929
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27	(a) This company is not evaluated on a stand-alone basis. No balance sheet or income statement is available.					
28						
29						
30						
31						
32	TOTAL			235,907,589		4,438,721

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	4,689	0.0011%	0
2		Pole Contact Rental	Cost	117,751	0.0264%	0
3						
4	Pacific Generation	Printing Service	Cost	612	0.0024%	0
5		Consulting Service	Cost	389,346	1.4982%	0
6						
7	PacifiCorp Trans	Accounting Service	Cost	9,000	0.1249%	0
8		Office Rent	Cost	2,846	0.0395%	0
9		Printing Service	Cost	3,016	0.0419%	0
10						
11	PacifiCorp Holdings, Inc.	Printing Service	Cost	2	0.0000%	0
12		Consulting Service	Cost	232,869	0.0194%	0
13						
14	PacifiCorp Energy, Inc	Printing & Payroll Processing	Cost	1,751	0.0268%	0
15		Consulting Service	Cost	898,749	13.7713%	0
16						
17	PacifiCorp Power Marketing, Inc.	Printing & Payroll Processing	Cost	9,049	0.2383%	0
18		Consulting Service	Cost	959,915	25.2819%	0
19						
20	PacifiCorp Kentucky Energy	Printing Service	Cost	206	0.1219%	0
21		Consulting Service	Cost	139,847	82.7693%	0
22						
23	Powercor	Consulting Service	Cost	456,522	N/A	0
24						0
25	Hazelwood	Consulting Service	Cost	85,160	N/A	0
26						
27						
28						
29	Note: Transactions involving services goods and services to affiliated companies are recorded in account 186, Miscellaneous Deferred Debits.					
30	Billings to affiliates do not result in charges to accounts affecting ratepayers.					
31						
32	TOTAL			3,311,330		0

Sch. 8 MONTANA UTILITY INCOME STATEMENT

	Account Number & Title		Last Year	This Year	% Change
1	400	Operating Revenues	47,111,260	55,819,015	18.48%
2					
3		Operating Expenses			
4	401	Operation Expenses	23,444,610	29,536,256	25.98%
5	402	Maintenance Expenses	3,168,622	3,419,027	7.90%
6	403	Depreciation Expenses	4,846,045	5,411,909	11.68%
7	404-405	Amortization of Electric Plant	357,189	474,007	32.70%
8	406	Amort. of Plant Acquisition Adjustments	104,038	111,510	7.18%
9	407	Amort. of Property Losses, Unrecovered Plant	38,181	33,663	-11.83%
10		& Regulatory Study Costs			
11	408.1	Taxes Other Than Income Taxes	1,669,507	1,623,244	-2.77%
12	409.1	Income Taxes - Federal	2,309,576	2,571,949	11.36%
13		- Other	337,622	364,199	7.87%
14	410.1	Provision for Deferred Income Taxes	2,630,213	2,832,047	7.67%
15	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	(1,475,666)	(1,730,322)	-17.26%
16	411.4	Investment Tax Credit Adjustment	0	0	
17	411.6	(Less) Gains from Disposition of Utility Plant	(11,915)	0	
18	411.7	Losses from Disposition of Utility Plant	0	0	
19	411.8	(Less) Gains from Sales of Emmission Allow.	(110,367)	(133,438)	
20		TOTAL Utility Operating Expenses	37,307,655	44,514,051	19.32%
21		NET UTILITY OPERATING INCOME	9,803,604	11,304,964	15.31%

Sch. 9 MONTANA REVENUES

	Account Number & Title		Last Year	This Year	% Change
22		Sales of Electricity			
23	440	Residential	16,852,868	18,161,798	7.77%
24	442	Commercial & Industrial - Small	11,580,152	12,549,315	8.37%
25		Commercial & Industrial - Large	9,216,688	10,858,213	17.81%
26	444	Public Street & Highway Lighting	145,920	157,610	8.01%
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	37,795,628	41,726,936	10.40%
32	447	Sales for Resale	8,597,128	13,302,591	54.73%
33					
34		TOTAL Sales of Electricity	46,392,756	55,029,527	18.62%
35	449.1	(Less) Provision for Rate Refunds	0	0	
36					
37		TOTAL Revenue Net of Provision for Refunds	46,392,756	55,029,527	18.62%
38		Other Operating Revenues			
39	450	Forfeited Discounts & Late Payment Revenues	24,371	50,600	107.63%
40	451	Miscellaneous Service Revenues	(17,931)	6,742	137.60%
41	453	Sales of Water & Water Power	0	0	
42	454	Rent From Electric Property	336,781	248,231	-26.29%
43	455	Interdepartmental Rents	0	0	
44	456	Other Electric Revenues	375,282	483,916	28.95%
45					
46		TOTAL Other Operating Revenues	718,504	789,488	9.88%
47		Total Electric Operating Revenues	47,111,260	55,819,015	18.48%

MONTANA OPERATION & MAINTENANCE EXPENSES

		Account Number & Title	Last Year	This Year	% Change
1		**Power Production Expenses**			
2					
3		**Steam Power Generation**			
4		Operation			
5	500	Operation Supervision & Engineering	255,564	235,052	-8.03%
6	501	Fuel	8,383,122	9,015,410	7.54%
7	502	Steam Expenses	452,068	456,696	1.02%
8	503	Steam from Other Sources	57,251	98,130	71.40%
9	504	(Less) Steam Transferred - Cr.	0	0	
10	505	Electric Expenses	237,047	249,856	5.40%
11	506	Miscellaneous Steam Power Expenses	414,799	470,228	13.36%
12	507	Rents	78	(48)	-161.94%
13					
14		TOTAL Operation - Steam	9,799,928	10,525,323	7.40%
15					
16		Maintenance			
17	510	Maintenance Supervision & Engineering	296,759	264,535	-10.86%
18	511	Maintenance of Structures	127,586	119,652	-6.22%
19	512	Maintenance of Boiler Plant	837,638	842,599	0.59%
20	513	Maintenance of Electric Plant	183,679	217,224	18.26%
21	514	Maintenance of Miscellaneous Steam Plant	178,765	262,474	46.83%
22					
23		TOTAL Maintenance - Steam	1,624,427	1,706,484	5.05%
24					
25		TOTAL Steam Power Production Expenses	11,424,355	12,231,807	7.07%
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	

MONTANA OPERATION & MAINTENANCE EXPENSES

Line	Account Number & Title		Last Year	This Year	% Change
1	**Power Production Expenses -continued**				
2	**Hydraulic Power Generation**				
3	Operation				
4	535	Operation Supervision & Engineering	22,589	22,264	-1.44%
5	536	Water for Power	1,053	1,242	17.94%
6	537	Hydraulic Expenses	66,003	90,202	36.66%
7	538	Electric Expenses	76,929	84,278	9.55%
8	539	Miscellaneous Hydraulic Power Gen. Expenses	90,886	135,866	49.49%
9	540	Rents	59	301	411.31%
10					
11		TOTAL Operation - Hydraulic	257,520	334,153	29.76%
12					
13	Maintenance				
14	541	Maintenance Supervision & Engineering	11,100	16,902	52.27%
15	542	Maintenance of Structures	6,162	8,460	37.28%
16	543	Maint. of Reservoirs, Dams & Waterways	29,464	34,925	18.54%
17	544	Maintenance of Electric Plant	58,528	74,563	27.40%
18	545	Maintenance of Miscellaneous Hydro Plant	39,379	36,386	-7.60%
19					
20		TOTAL Maintenance - Hydraulic	144,633	171,236	18.39%
21					
22		TOTAL Hydraulic Power Production Expenses	402,153	505,389	25.67%
23					
24	**Other Power Generation**				
25	Operation				
26	546	Operation Supervision & Engineering	322	94	-70.77%
27	547	Fuel	43,083	245	-99.43%
28	548	Generation Expenses	2,793	35,277	1163.27%
29	549	Miscellaneous Other Power Gen. Expenses	1,311	(488)	-137.23%
30	550	Rents	0	0	
31					
32		TOTAL Operation - Other	47,508	35,128	-26.06%
33					
34	Maintenance				
35	551	Maintenance Supervision & Engineering	320	93	-71.05%
36	552	Maintenance of Structures	3	10	197.86%
37	553	Maintenance of Generating & Electric Plant	366	(3)	-100.77%
38	554	Maintenance of Misc. Other Power Gen. Plant	412	225	-45.33%
39					
40		TOTAL Maintenance - Other	1,101	325	-70.50%
41					
42		TOTAL Other Power Production Expenses	48,609	35,452	-27.07%
43					
44	**Other Power Supply Expenses**				
45	555	Purchased Power	5,841,166	10,583,227	81.18%
46	556	System Control & Load Dispatching	124,090	158,416	27.66%
47	557	Other Expenses	119,913	202,349	68.75%
48					
49		TOTAL Other Power Supply Expenses	6,085,169	10,943,992	79.85%
50					
51		**TOTAL Power Production Expenses**	17,960,287	23,716,641	32.05%

MONTANA OPERATION & MAINTENANCE EXPENSES

Line	Account	Account Number & Title	Last Year	This Year	% Change
1		**Transmission Expenses**			
2	Operation				
3	560	Operation Supervision & Engineering	13,751	18,683	35.87%
4	561	Load Dispatching	59,472	46,222	-22.28%
5	562	Station Expenses	64,842	63,245	-2.46%
6	563	Overhead Line Expenses	24,081	26,416	9.70%
7	564	Underground Line Expenses	2	5	137.20%
8	565	Transmission of Electricity by Others	800,897	1,070,833	33.70%
9	566	Miscellaneous Transmission Expenses	16,533	26,006	57.30%
10	567	Rents	12,880	12,216	-5.15%
11					
12		TOTAL Operation - Transmission	992,458	1,263,627	27.32%
13	Maintenance				
14	568	Maintenance Supervision & Engineering	12,477	16,961	35.94%
15	569	Maintenance of Structures	3,711	3,544	-4.50%
16	570	Maintenance of Station Equipment	79,668	84,027	5.47%
17	571	Maintenance of Overhead Lines	57,841	59,432	2.75%
18	572	Maintenance of Underground Lines	15	37	152.90%
19	573	Maintenance of Misc. Transmission Plant	2,690	12,197	353.43%
20					
21		TOTAL Maintenance - Transmission	156,401	176,198	12.66%
22					
23		**TOTAL Transmission Expenses**	1,148,859	1,439,825	25.33%
24					
25		**Distribution Expenses**			
26	Operation				
27	580	Operation Supervision & Engineering	58,941	48,221	-18.19%
28	581	Load Dispatching	45,645	49,537	8.53%
29	582	Station Expenses	64,444	116,205	80.32%
30	583	Overhead Line Expenses	216,565	209,312	-3.35%
31	584	Underground Line Expenses	172,629	220,937	27.98%
32	585	Street Lighting & Signal System Expenses	23,199	11,807	-49.11%
33	586	Meter Expenses	199,011	144,860	-27.21%
34	587	Customer Installations Expenses	22,869	25,323	10.73%
35	588	Miscellaneous Distribution Expenses	248,851	217,415	-12.63%
36	589	Rents	24,710	23,454	-5.08%
37					
38		TOTAL Operation - Distribution	1,076,863	1,067,072	-0.91%
39	Maintenance				
40	590	Maintenance Supervision & Engineering	86,510	43,735	-49.45%
41	591	Maintenance of Structures	2,385	2,183	-8.47%
42	592	Maintenance of Station Equipment	78,728	33,542	-57.40%
43	593	Maintenance of Overhead Lines	782,417	953,878	21.91%
44	594	Maintenance of Underground Lines	91,337	143,174	56.75%
45	595	Maintenance of Line Transformers	83,751	62,779	-25.04%
46	596	Maintenance of Street Lighting, Signal Systems	14,190	12,374	-12.80%
47	597	Maintenance of Meters	23,700	24,099	1.68%
48	598	Maintenance of Miscellaneous Dist. Plant	17,791	41,974	135.92%
49					
50		TOTAL Maintenance - Distribution	1,180,810	1,317,737	11.60%
51					
52		**TOTAL Distribution Expenses**	2,257,673	2,384,808	5.63%

MONTANA OPERATION & MAINTENANCE EXPENSES

		Account Number & Title	Last Year	This Year	% Change
1		**Customer Accounts Expenses**			
2	Operation				
3	901	Supervision	132,050	140,688	6.54%
4	902	Meter Reading Expenses	373,902	374,203	0.08%
5	903	Customer Records & Collection Expenses	756,758	603,566	-20.24%
6	904	Uncollectible Accounts Expenses	107,530	86,653	-19.41%
7	905	Miscellaneous Customer Accounts Expenses	24,103	22,561	-6.40%
8					
9		**TOTAL Customer Accounts Expenses**	1,394,343	1,227,671	-11.95%
10					
11		**Customer Service & Information Expenses**			
12	Operation				
13	907	Supervision	6,897	2,436	-64.68%
14	908	Customer Assistance Expenses	188,802	200,351	6.12%
15	909	Informational & Instructional Adv. Expenses	34,160	43,449	27.19%
16	910	Miscellaneous Customer Service & Info. Exp.	107,044	91,878	-14.17%
17					
18		**TOTAL Customer Service & Info Expenses**	336,903	338,113	0.36%
19					
20		**Sales Expenses**			
21	Operation				
22	911	Supervision	23,036	31,190	35.39%
23	912	Demonstrating & Selling Expenses	191,960	121,701	-36.60%
24	913	Advertising Expenses	6,369	7,156	12.35%
25	916	Miscellaneous Sales Expenses	71,549	71,376	-0.24%
26					
27		**TOTAL Sales Expenses**	292,915	231,422	-20.99%
28					
29		**Administrative & General Expenses**			
30	Operation				
31	920	Administrative & General Salaries	1,597,284	1,768,977	10.75%
32	921	Office Supplies & Expenses	645,374	644,087	-0.20%
33	922	(Less) Administrative Expenses Transferred - Cr.	0	0	
34	923	Outside Services Employed	131,683	313,569	138.12%
35	924	Property Insurance	190,005	208,570	9.77%
36	925	Injuries & Damages	199,102	193,391	-2.87%
37	926	Employee Pensions & Benefits	3,059,811	2,830,488	-7.49%
38	927	Franchise Requirements	1,124	741	-34.11%
39	928	Regulatory Commission Expenses	181,655	167,900	-7.57%
40	929	(Less) Duplicate Charges - Cr.	(3,261,157)	(3,016,819)	7.49%
41	930.1	General Advertising Expenses	2,000	2,000	0.00%
42	930.2	Miscellaneous General Expenses	280,743	314,723	12.10%
43	931	Rents	133,378	142,128	6.56%
44					
45		**TOTAL Operation - Admin. & General**	3,161,001	3,569,755	12.93%
46	Maintenance				
47	935	Maintenance of General Plant	61,250	47,048	-23.19%
48					
49		**TOTAL Administrative & General Expenses**	3,222,251	3,616,803	12.24%
50					
51		**TOTAL Operation & Maintenance Expenses**	26,613,231	32,955,283	23.83%

MONTANA TAXES OTHER THAN INCOME

Description of Tax	Last Year	This Year	% Change
Property (Ad Valorem)	1,433,072	1,386,808	-3.23%
Franchise and Occupation	1,089	656	-39.76%
Federal - Excise Superfund	10,522	9,293	-11.68%
Washington - Operating Revenue Fee	116,162	124,623	7.28%
Washington - Pollution Control Credit	(17,165)	(1,284)	92.52%
Montana - Energy Proceeds	3,802	2,926	-23.04%
Montana - Consumer Counsel	29,119	32,013	9.94%
Utah Gross Receipts Tax	92,578	69,014	-25.45%
Other - Miscellaneous Taxes & License	328	(805)	-345.43%
TOTAL MT Taxes other than Income	1,669,507	1,623,244	-2.77%

Sch. 12 PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Arizona Public Service	Const./Maint. Contracts	9,505,000	187,210	1.9696%
2	Asplundh Tree Expert	Tree trimming	4,004,160	78,866	1.9696%
3	Bonneville Power Admin	Const./Maint. Contracts	4,594,147	90,486	1.9696%
4	General Electric Co.	Const./Maint. Contracts	13,643,536	268,723	1.9696%
5	International Line Builders, Inc	Const./Maint. Contracts	16,318,181	321,403	1.9696%
6	James River Corp	Const./Maint. Contracts	11,801,456	232,441	1.9696%
7	New Harbor Incorporation	Legal	4,739,390	93,347	1.9696%
8	Stoel Rives Boley Jo	Legal	7,995,202	157,473	1.9696%
9	Sturgeon Electric Co	Const./Maint. Contracts	5,111,495	100,676	1.9696%
10	Tree, Inc.	Tree Triming	8,488,820	167,196	1.9696%
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Total		86,201,387	1,697,821	
22					
23					
24					
25					
26	Costs assignable directly to Montana:				
27	Bonneville Power Admin	Const./Maint. Contracts	101,950	101,950	
28	Harp Line Construction Co.	Const./Maint. Contracts	1,294,811	1,294,811	
29	Hawkeye Construction, Inc.	Const./Maint. Contracts	436,619	436,619	
30	Trees, Inc	Tree trimming	260,625	260,625	
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49					
50	**TOTAL Payments for Services**		2,094,005	2,094,005	

Sch. 13 **POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS**

Description	Total Company	Montana (1)	% Montana
Legislative Expense	503,984	0	0.00%
PacifiCorp D.C., Ltd.	250,790	0	0.00%
Westerberg & Associates - legislative legal fees	149,668	0	0.00%
Other Expenditures	487,070	0	0.00%
(1) PAC contributions are charged to account 426.4 and are not allocated to Montana for rate making purposes.			
TOTAL	1,391,512	0	0.00%

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	871,588,826	N/A	-100.00%
18	Projected Benefit Obligation	1,007,974,122	1,008,983,054	0.10%
19	Fair Value of Plan Assets	668,867,831	669,972,791	
20				
21	Discount Rate for Benefit Obligations	7.25%	7.25%	0.00%
22	Expected Long-Term Return on Assets	8.75%	8.75%	0.00%
23				
24	Net Periodic Pension Cost:			
25	Service Cost	20,211,919	26,655,430	31.88%
26	Interest Cost	68,369,468	71,157,521	4.08%
27	Return on Plan Assets	120,704,768	59,114,328	-51.03%
28	Amortization of Transition Amount	9,968,828	7,076,156	-29.02%
29	Amortization of Gains or Losses	0	0	
30	Total Net Periodic Pension Cost	219,254,983	164,003,435	-25.20%
31				
32	Minimum Required Contribution	59,960,511	61,123,570	1.94%
33	Actual Contribution	78,613,355	64,000,000	-18.59%
34	Maximum Amount Deductible	204,645,649	196,431,636	-4.01%
35	Benefit Payments	56,178,388	55,550,657	-1.12%
36				
37	Montana Intrastate Costs:			
38	Pension Costs	2,865,548	2,264,184	-20.99%
39	Pension Costs Capitalized	1,210,402	966,027	-20.19%
40	Accumulated Pension Asset (Liability) at Year End	(3,388,574)	(2,083,422)	38.52%
41				
42	Number of Company Employees:			
43	Covered by the Plan	13,163	13,298	1.03%
44	Not Covered by the Plan	N/A	N/A	
45	Active	8,736	8,439	-3.40%
46	Retired	3,641	3,636	-0.14%
47	Deferred Vested Terminated	786	1,223	

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

P. 1 of 2

	Description	Last Year	This Year	% Chang
1	General Information			
2				
3	**Assumptions:**			
4	**Discount Rate for Benefit Obligations**	8.50%	7.25%	-14.71%
5	**Expected Long-Term Return on Assets**	8.75%	8.75%	0.00%
6	**Medical Cost Inflation Rate**	11% to 5.5%	8.8% to4.5%	
7	**Actuarial Cost Method**	Projected Unit Credit Method	Projected Unit Credit Method	
8				
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)**	314,570,203	300,946,674	-4.33%
23	**Fair Value of Plan Assets**	60,265,083	95,383,690	58.27%
24	**List the amount funded through each funding method:**			
25	**VEBA**	21,626,559	14,531,682	-32.81%
26	**401(h)**	5,013,000	4,500,000	-10.23%
27	**Other _VEBA 2_____**		612,664	
28	**Total amount funded**	26,639,559	19,644,346	-26.26%
29				
30	**List amount that was tax deductible for each type of funding:**			
31	**VEBA**	21,626,559	14,531,682	-32.81%
32	**401(h)**	5,013,000	4,500,000	-10.23%
33	**Other _VEBA 2_____**		612,664	
34	**Total amount that was tax deductible**	26,639,559	19,644,346	-26.26%
35				
36	**Net Periodic Post Retirement Benefit Cost:**			
37	**Service Cost**	6,238,694	6,912,404	10.80%
38	**Interest Cost**	26,660,978	21,838,540	-18.09%
39	**Return on Plan Assets**	(6,193,898)	(9,098,424)	
40	**Amortization of Transition Obligation**	13,950,713	13,950,713	0.00%
41	**Amortization of Gains or Losses**	0	(1,390,562)	
42	**Total Net Periodic Post Retirement Benefit Cost**	40,656,487	32,212,671	-20.77%
43				
44	**Benefit Cost Expensed**	28,581,510	22,577,861	-21.01%
45	**Benefit Cost Capitalized**	12,074,977	9,634,810	-20.21%
46	**Benefit Payments (The $55 m stated last year was**	14,016,928	12,568,325	-10.33%
47	**incorrect.)**			
48	**Number of Company Employees:**			
49	**Covered by the Plan**	12,325	12,280	-0.37%
50	**Not Covered by the Plan**	N/A	N/A	
51	**Active**	9,123	9,147	0.26%
52	**Retired**	3,202	3,133	-2.15%
53	**Spouse/Dependants covered by the Plan**	N/A	N/A	

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

	Description	Last Year	This Year	% Chang
1				
2	Montana			
3				
4	**Accumulated Post Retirement Benefit Obligation (APBO)**	5,847,860	5,927,446	1.36%
5	**Fair Value of Plan Assets**	1,120,328	1,878,677	67.69%
6	**List the amount funded through each funding method:**			
7	**VEBA**	402,038	286,216	-28.81%
8	**401(h)**	93,192	88,632	-4.89%
9	**Other _VEBA 2___**		12,067	
10	**Total amount funded**	495,229	386,915	-21.87%
11				
12	**List amount that was tax deductible for each type of funding:**			
13	**VEBA**	402,038	286,216	-28.81%
14	**401(h)**	93,192	88,632	-4.89%
15	**Other _VEBA 2____**		12,067	
16	**Total amount that was tax deductible**	495,229	386,915	-21.87%
17				
18	**Net Periodic Post Retirement Benefit Cost:**			
19	**Service Cost**	115,977	136,147	17.39%
20	**Interest Cost**	495,628	430,132	-13.21%
21	**Return on Plan Assets**	(115,145)	(179,203)	
22	**Amortization of Transition Obligation**	259,344	274,773	5.95%
23	**Amortization of Gains or Losses**	0	(27,389)	0.00%
24	**Total Net Periodic Post Retirement Benefit Cost**	755,804	634,461	-16.05%
25				
26	**Benefit Cost Expensed**	531,330	444,694	-16.31%
27	**Benefit Cost Capitalized**	224,474	189,767	-15.46%
28	**Benefit Payments**	1,024,165	247,546	-75.83%
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	Redman, James M	74,856	5,224	9,546	89,626	87,237	3%
	Excess Life			1,221			
	Vehicle Allowance			8,100			
	Safety Award			225			
2	Coon, Larry G	52,641	400	32,429	85,471	68,689	24%
	Excess Life			1,203			
	Safety Award			75			
	Relocation			23,680			
	OT/ Premium Pay			7,471			
3	Jordan, Donald M	72,744	6,524	1,165	80,433	79,232	2%
	Excess Life			965			
	Safety Award			200			
4	Leuning, Clinton E	54,250	400	19,104	73,753	73,712	0%
	Excess Life			482			
	Safety Award			75			
	OT/ Premium Pay			18,547			
5	Grigsby Jr, Hershel	54,048	400	19,228	73,676	59,864	23%
	Excess Life			1,363			
	Safety Award			150			
	OT/ Premium Pay			17,715			
6	Bech, Steven D	54,511	400	18,519	73,429	73,733	-0%
	Excess Life			1,326			
	Safety Award			100			
	OT/ Premium Pay			17,093			
7	Hall, Daniel M.	49,526	400	22,210	72,136	69,833	3%
	Excess Life			694			
	Safety Award			45			
	OT/ Premium Pay			21,471			
8	McDonald, Michael C	53,053	400	16,910	70,363	62,016	13%
	Excess Life			861			
	Safety Award			55			
	OT/ Premium Pay			15,994			
9	Gosney, Dennis L	49,076	400	20,032	69,508	70,561	-1%
	Excess Life			444			
	Safety Award			100			
	Relocation			19,487			
10	Hedges, Randy D.	49,491	400	19,267	69,158	68,156	1%
	Excess Life			288			
	Safety Award			45			
	OT/ Premium Pay			18,935			

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	590,000	486,750	390,850	1,467,600	955,666	54%
	Restricted Stock Awards			382,500			
	Employee Stock Plan			7,500			
	Term Life Insurance Prem.			850			
2	Charles E. Robinson	412,000	309,000	221,188	942,188	997,876	-6%
	Restricted Stock Awards			212,500			
	Employee Stock Plan			7,500			
	Term Life Insurance Prem.			1,188			
3	Verl R. Topham	270,000	162,000	235,452	667,452	391,666	70%
	Restricted Stock Awards			227,563			
	Employee Stock Plan			7,500			
	Term Life Insurance Prem.			389			
4	John A. Bohling	240,000	144,000	124,721	508,721	352,617	44%
	Restricted Stock Awards			116,875			
	Employee Stock Plan			7,500			
	Term Life Insurance Prem.			346			
5	Paul G. Lorenzini	240,000	126,000	92,846	458,846	332,502	38%
	Restricted Stock Awards			85,000			
	Employee Stock Plan			7,500			
	Term Life Insurance Prem.			346			

BALANCE SHEET

		Account Title	Last Year	This Year	% Change
1		**Assets and Other Debits**			
2		**Utility Plant**			
3	101	Electric Plant in Service	10,559,802,213	11,073,799,377	4.87%
4	101.1	Property Under Capital Leases	24,660,964	23,575,921	-4.40%
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	7,529,316	5,331,033	-29.20%
9	106	Completed Constr. Not Classified - Electric	36,755,712	28,782,514	-21.69%
10	107	Construction Work in Progress - Electric	306,180,306	249,133,885	-18.63%
11	108	(Less) Accumulated Depreciation	(3,399,411,578)	(3,599,037,424)	-5.87%
12	111	(Less) Accumulated Amortization	(95,450,413)	(88,780,996)	6.99%
13	114	Electric Plant Acquisition Adjustments	138,194,702	132,320,435	-4.25%
14	115	(Less) Accum. Amort. Elec. Acq. Adj.			
15	118-119	Other Utility Plant - Net	1,936,827	0	-100.00%
16	120	Nuclear Fuel (Net)			
17		**TOTAL Utility Plant**	7,580,198,049	7,825,124,745	3.23%
18					
19		**Other Property & Investments**			
20	121	Nonutility Property	6,322,584	7,160,443	13.25%
21	122	(Less) Accum. Depr. & Amort. for Nonutil. Prop.	(821,148)	(1,062,436)	-29.38%
22	123	Investments in Associated Companies	6,107,928	6,107,928	0.00%
23	123.1	Investments in Subsidiary Companies	1,352,846,625	1,506,260,461	11.34%
24	124	Other Investments	12,122,436	14,785,310	21.97%
25	125	Sinking Funds			
26	128	Other Special Funds	4,041,138	5,205,127	28.80%
27		**TOTAL Other Property & Investments**	1,380,619,563	1,538,456,833	11.43%
28					
29		**Current & Accrued Assets**			
30	131	Cash	(27,443,470)	(29,551,513)	-7.68%
31	132-134	Special Deposits	18,600,000	50,248	-99.73%
32	135	Working Funds	2,168,574	3,359,412	54.91%
33	136	Temporary Cash Investments			
34	141	Notes Receivable	43,815,119	758,511	-98.27%
35	142	Customer Accounts Receivable	221,351,262	316,339,978	42.91%
36	143	Other Accounts Receivable	32,389,096	44,057,769	36.03%
37	144	(Less) Accum. Provision for Uncollectible Accts.	(6,546,654)	(7,669,344)	-17.15%
38	145	Notes Receivable - Associated Companies	3,446,633	6,985,207	
39	146	Accounts Receivable - Associated Companies	4,501,397	9,367,093	108.09%
40	151	Fuel Stock	62,683,966	49,964,811	-20.29%
41	152	Fuel Stock Expenses Undistributed			
42	153	Residuals			
43	154	Plant Materials and Operating Supplies	117,108,828	107,233,442	-8.43%
44	155	Merchandise			
45	156	Other Material & Supplies			
46	157	Nuclear Materials Held for Sale			
47	163	Stores Expense Undistributed	5,849,084	4,457,950	-23.78%
48	165	Prepayments	30,088,262	29,426,140	-2.20%
49	171	Interest & Dividends Receivable	1,486,028	1,319,855	-11.18%
50	172	Rents Receivable	141,149	290,933	106.12%
51	173	Accrued Utility Revenues	89,852,585	136,580,390	52.00%
52	174	Miscellaneous Current & Accrued Assets		306,183	
53		**TOTAL Current & Accrued Assets**	599,491,859	673,277,065	12.31%

BALANCE SHEET

	Account Title	Last Year	This Year	% Change
1				
2	**Assets and Other Debits (cont.)**			
3				
4	**Deferred Debits**			
5				
6	181 Unamortized Debt Expense	28,619,157	36,188,006	26.45%
7	182.1 Extraordinary Property Losses	706,613		-100.00%
8	182.2 Unrecovered Plant & Regulatory Study Costs	28,420,850	26,850,724	-5.52%
9	182.3 Regulatory Asset	1,028,354,099	1,018,072,234	-1.00%
10	183 Prelim. Survey & Investigation Charges	3,261,619	3,242,666	-0.58%
11	184 Clearing Accounts			
12	185 Temporary Facilities	102,775	337,012	227.91%
13	186 Miscellaneous Deferred Debits	151,332,869	94,074,145	-37.84%
14	187 Deferred Losses from Disposition of Util. Plant			
15	188 Research, Devel. & Demonstration Expend.			
16	189 Unamortized Loss on Reacquired Debt	74,472,179	68,415,542	-8.13%
17	190 Accumulated Deferred Income Taxes	64,798,113	76,728,727	18.41%
18	**TOTAL Deferred Debits**	1,380,068,274	1,323,909,056	-4.07%
19				
20	**TOTAL Assets & Other Debits**	10,940,377,745	11,360,767,699	3.84%

	Account Title	Last Year	This Year	% Change
21				
22	**Liabilities and Other Credits**			
23				
24	**Proprietary Capital**			
25				
26	201 Common Stock Issued	3,076,430,917	3,303,415,102	7.38%
27	202 Common Stock Subscribed			
28	204 Preferred Stock Issued	530,534,525	313,538,225	-40.90%
29	205 Preferred Stock Subscribed			
30	207 Premium on Capital Stock			
31	211 Miscellaneous Paid-In Capital			
32	212 Installments Received on Capital Stock	236,505	(144,324)	-161.02%
33	213 (Less) Discount on Capital Stock			
34	214 (Less) Capital Stock Expense	(42,584,776)	(45,357,896)	-6.51%
35	215 Appropriated Retained Earnings	3,253,538	3,044,555	-6.42%
36	216 Unappropriated Retained Earnings	617,896,520	767,981,311	24.29%
37	217 (Less) Reacquired Capital Stock	(5,165,543)	(7,469,432)	-44.60%
38	**TOTAL Proprietary Capital**	4,180,601,686	4,335,007,541	3.69%
39				
40	**Long Term Debt**			
41				
42	221 Bonds	3,156,777,872	3,162,024,495	0.17%
43	222 (Less) Reacquired Bonds			
44	223 Advances from Associated Companies	41,063,554	276,185,605	572.58%
45	224 Other Long Term Debt	175,825,925	175,825,925	0.00%
46	225 Unamortized Premium on Long Term Debt	8,495,975	6,511,526	-23.36%
47	226 (Less) Unamort. Discount on L-Term Debt-Dr.	(1,845,774)	(1,913,536)	-3.67%
48	**TOTAL Long Term Debt**	3,380,317,552	3,618,634,015	7.05%

Sch. 18 cont.

BALANCE SHEET

Line	Acct.	Account Title	Last Year	This Year	% Change
1					
2		**Total Liabilities and Other Credits (cont.)**			
3					
4		**Other Noncurrent Liabilities**			
5					
6	227	Obligations Under Cap. Leases - Noncurrent	23,728,125	23,309,486	-1.76%
7	228.1	Accumulated Provision for Property Insurance	3,777,119	22,304	-99.41%
8	228.2	Accumulated Provision for Injuries & Damages	7,098,496	5,903,779	-16.83%
9	228.3	Accumulated Provision for Pensions & Benefits	190,944,689	108,201,383	-43.33%
10	228.4	Accumulated Misc. Operating Provisions	15,193,956	14,774,085	-2.76%
11	229	Accumulated Provision for Rate Refunds			
12		**TOTAL Other Noncurrent Liabilities**	240,742,385	152,211,037	-36.77%
13					
14		**Current & Accrued Liabilities**			
15					
16	231	Notes Payable	681,894,000	675,007,000	-1.01%
17	232	Accounts Payable	200,631,951	293,668,806	46.37%
18	233	Notes Payable to Associated Companies	1,918,085	30,954,961	1513.85%
19	234	Accounts Payable to Associated Companies	10,389,051	10,059,514	-3.17%
20	235	Customer Deposits	7,651,984	4,623,856	-39.57%
21	236	Taxes Accrued	99,205,072	75,298,250	-24.10%
22	237	Interest Accrued	66,257,592	70,820,660	6.89%
23	238	Dividends Declared	85,640,802	86,336,660	0.81%
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	12,922,638	7,833,896	-39.38%
27	242	Miscellaneous Current & Accrued Liabilities	36,542,753	37,009,949	1.28%
28	243	Obligations Under Capital Leases - Current	932,839	266,435	-71.44%
29		**TOTAL Current & Accrued Liabilities**	1,203,986,767	1,291,879,987	7.30%
30					
31		**Deferred Credits**			
32					
33	252	Customer Advances for Construction	13,183,732	16,781,741	27.29%
34	253	Other Deferred Credits	144,200,211	144,238,426	0.03%
35	254	Regulatory Liabilities	60,803,020	57,115,816	-6.06%
36	255	Accumulated Deferred Investment Tax Credit	150,256,339	141,265,333	-5.98%
37	256	Deferred Gains from Disposition Of Util. Plant			
38	257	Unamortized Gain on Reacquired Debt	2,695,697	2,279,025	-15.46%
39	281-283	Accumulated Deferred Income Taxes	1,563,590,356	1,601,354,778	2.42%
40		**TOTAL Deferred Credits**	1,934,729,355	1,963,035,119	1.46%
41					
42		**TOTAL Liabilities & Other Credits**	10,940,377,745	11,360,767,699	3.84%

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, 1996

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.

2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility.Give also a brief explanation of any dividends in arrears on cumulative preferred stock.

3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.

4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.

5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.

6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.

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SEE PAGE 123 FOR REQUIRED INFORMATION

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 power production and sales on a wholesale basis under the name PacifiCorp. The Company is the indirect owner, through its wholly owned subsidiary PacifiCorp Holdings, Inc. ("Holdings"), of wholly owned subsidiaries including an Australian electricity distributor (Powercor Australia Limited), acquired on December 12, 1995, see Note 14, a telecommunications company (PTI), formerly 87 percent owned, see Note 14, and a financial services company (PacifiCorp Financial Services, Inc.).

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 Powercor Australia Limited and all non-electric subsidiaries are accounted for and reported on the equity basis of accounting 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.

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, 1996			
Property, plant and equipment - net	$10,215,679	$7,825,125	$2,390,554
Investments in subsidiaries	-	1,506,260	(1,506,260)
Current assets	1,058,525	673,277	385,248
Other assets	3,360,344	1,356,106	2,004,238
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	5,323,792	3,770,845	1,552,947
Guaranteed Preferred Beneficial Interests in Company's Junior Subordinated Debentures	209,732	-	209,732
Current liabilities	1,862,876	1,291,880	570,996
Deferred credits	2,860,431	1,963,035	897,396
Minority interest	31,869	-	31,869
AT DECEMBER 31, 1995			
Property, plant and equipment - net	$ 9,952,296	$7,580,198	$2,372,098
Investments in subsidiaries	-	1,352,847	(1,352,847)
Current assets	912,224	599,492	312,732
Other assets	3,150,686	1,407,841	1,742,845
Common stock	3,012,927	3,028,917	(15,990)
Retained earnings	632,420	621,150	11,270
Guaranty of Employee Stock Ownership Plan borrowings	(12,240)	-	(12,240)
Preferred stock	530,535	530,535	-
Long-term debt	4,968,175	3,621,060	1,347,115
Current liabilities	2,004,917	1,203,987	800,930
Deferred credits	2,855,468	1,934,729	920,739
Minority interest	23,004	-	23,004

THOUSANDS OF DOLLARS	CONSOLIDATED	FERC FORM 1 FINANCIALS	INCREASE/ (DECREASE)
FOR THE YEAR ENDED DECEMBER 31, 1996			
Operating revenues	$ 4,293,774	$2,961,321	$1,332,453
Operating expenses	3,048,664	2,309,175	739,489
Net cash provided by oper. activities	1,077,272	663,761	413,511
Net cash used in investing activities	(903,255)	(581,779)	(321,476)
Net cash used in financing activities	(178,355)	(101,449)	(76,906)
FOR THE YEAR ENDED DECEMBER 31, 1995			
Operating revenues	$ 3,416,970	$2,616,914	$ 800,056
Operating expenses	2,361,115	2,023,053	338,062
Net cash provided by oper. activities	911,953	671,022	240,931
Net cash used in investing activities	(2,332,920)	(662,723)	(1,670,197)
Net cash provided by (used in) financing activities	1,419,838	(4,319)	1,424,157

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 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

Effective January 1, 1996, the Company adopted SFAS 121 "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." This Statement requires that long-lived assets and certain identifiable intangibles to be held and used by an entity be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The Company evaluated all its assets based upon SFAS 121 and within the context of SFAS 71 and concluded that no material adjustments were required. See Note 2.

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, 1996, the average depreciable life of property, plant and equipment by category was: Production, 42 years; Transmission, 49 years; Distribution, 34 years and Other, 15 years.

Depreciation and amortization is computed generally by the straight-line method over the estimated useful lives of the related assets after giving effect to requirements as prescribed by the Company's various regulatory jurisdictions. Provisions for depreciation (excluding amortization of capital leases) were 3.1 and 3.0 percent of average depreciable assets in 1996 and 1995, 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

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, 1996

NOTES TO FINANCIAL STATEMENTS (Continued)

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 5.60 percent for 1996 and 6.15 percent for 1995.

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.

Investment tax credits are deferred and amortized to income over the average estimated lives of the related properties.

Revenue Recognition

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

Reclassification

Certain amounts from the prior year have been reclassified to conform with the 1996 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

NOTES TO FINANCIAL STATEMENTS (Continued)

level of demand or competition during the cost recovery period. In accordance with SFAS 71, the Company capitalizes certain costs and regulatory assets, in accordance with regulatory authority, whereby those costs will be expensed and recovered in future periods. Regulatory assets-net at December 31, 1996 and 1995 included the following:

THOUSANDS OF DOLLARS/DECEMBER 31	1996	1995
Deferred taxes - net	$ 675,984	$ 695,312
Deferred pension costs	102,888	116,772
Demand-side resource costs	118,773	109,972
Unamortized net loss on reacquired debt	68,415	71,776
Unrecovered Trojan Plant and regulatory study costs	26,851	28,421
Various other costs	63,312	46,202
Total	$1,056,223	$1,068,455

If the Company, at some point in the future, determines that all or a portion of its operations no longer meet the criteria for continued application of SFAS 71, the Company would be required to adopt the provisions of SFAS 101, "Regulated Enterprises -- Accounting for the Discontinuation of Application of FASB Statement No. 71." Adoption of SFAS 101 would require the Company to write off the regulatory assets and liabilities relating to those operations not meeting SFAS 71 requirements.

The utility industry will also be impacted by the application of SFAS 121 as a result of deregulation. This accounting statement requires the recognition of impairment on long-lived assets when book values exceed expected future cash flows. Integral parts of future cash flow estimates include estimated future prices to be received, the expected future cash cost of operations, sales and load growth forecasts and the nature of any legislative cost recovery mechanisms.

Restructuring bills are being considered in all states in which the Company provides retail service. The Company expects any legislation passed to provide an opportunity to recover costs which have been placed at risk.

NOTE 3. SHORT-TERM DEBT AND BORROWING ARRANGEMENTS

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

THOUSANDS OF DOLLARS	DECEMBER 31 BALANCE	DECEMBER 31 AVERAGE INTEREST RATE (a)	FOR THE YEAR AVERAGE OUTSTANDING	FOR THE YEAR AVERAGE INTEREST RATE (b)
1996	$675,007	5.6%	$424,400	5.4%
1995	$681,894	5.9%	$407,210	5.9%

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

(b) Computed by dividing the total interest expense for the period by the average daily principal amount outstanding for the period.

At December 31, 1996, the Company's commercial paper and bank line borrowings were supported by revolving credit agreements totaling $700 million.

Commitment fees were approximately $623,000 in 1996 and $555,000 in 1995.

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, 1996

NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 4. COMMON AND PREFERRED STOCK

THOUSANDS OF SHARES/DOLLARS	SHARES COMMON STOCK	SHARES PREFERRED STOCK	COMMON SHARE-HOLDERS' CAPITAL
At January 1, 1995	284,251	10,532	$3,029,200
Sales through Employees' Stock Plans	26	-	487
Dividend Reinvestment Plan			(43)
Junior subordinated debentures exchanged for preferred stock	-	(2,233)	1,854
Stock expense, redemption and repurchases	-	-	(2,581)
At December 31, 1995	284,277	8,299	3,028,917
Dividend Reinvestment Plan	2,082	-	43,291
Stock Compensation Plans	(9)	-	(2,482)
Sales to Public	8,790	-	177,788
Preferred Stock Redemption	-	(2,342)	2,929
At December 31, 1996	295,140	5,957	$3,250,443

At December 31, 1996, there were 7,506,217 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.

Name of Respondent	This Report Is:	Date of Report	Year of Report
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NOTES TO FINANCIAL STATEMENTS (Continued)

PREFERRED STOCK OUTSTANDING
THOUSANDS OF SHARES/DOLLARS

DECEMBER 31 SERIES	1996 SHARES	1996 AMOUNT	1995 SHARES	1995 AMOUNT
SUBJECT TO MANDATORY REDEMPTION				
No Par Serial Preferred, ($100 stated value), 16,000 Shares Authorized				
$7.12	30	$ 3,000	440	$ 44,000
7.70	1,000	100,000	1,000	100,000
7.48	750	75,000	750	75,000
TOTAL		$178,000		$219,000
NOT SUBJECT TO MANDATORY REDEMPTION				
$1.16 ($25 stated value)	193	$ 4,828	193	$ 4,828
1.18 ($25 stated value)	420	10,503	420	10,503
1.28 ($25 stated value)	381	9,530	381	9,530
1.76 ($25 stated value)	-	-	394	9,847
1.98 ($25 stated value)	-	-	502	12,550
2.13 ($25 stated value)	-	-	666	16,655
1.98, Series 1992 ($25 st. val.)	2,767	69,175	2,767	69,175
Auction Rate ($100,000 stated value)	-	-	1	100,000
Serial Preferred $100 Stated Value Per Share, 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
7.96	-	-	135	13,518
8.92	-	-	69	6,938
9.08	-	-	165	16,489
% Preferred, $100 Stated Value, 127 Shares Authorized and Outstanding	127	12,653	127	12,653
AL		$135,538		$311,535

datory redemption requirements at stated value plus accrued dividends on
Par Serial Preferred Stock are as follows: beginning in 1997, 15,000
res of the $7.12 series are redeemable annually; 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 $7.12 series or the $7.48 series, it may not pay cash dividends on common stock.

NOTE 5. LONG-TERM DEBT

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

THOUSANDS OF DOLLARS	1996	1995
First mortgage and collateral trust bonds		
Maturing 1997 through 2001/5.9%-9.5% (a)	$ 946,500	$1,112,050
Maturing 2002 through 2006/6.1%-9%	600,981	519,835
Maturing 2007 through 2011/6.6%-9.2%	235,790	237,483
Maturing 2012 through 2016/7.3%-8.8%	172,954	175,648
Maturing 2017 through 2021/8.4%-8.5%	38,069	38,381
Maturing 2022 through 2026/6.7%-8.6%	441,500	341,500
Guaranty of pollution control revenue bonds		
5.6%-5.7% due 2021 through 2023 (b)	71,200	71,200
Variable rate due 2013 through 2024 (b)(c)	216,470	216,470
Variable rate due 2005 through 2030 (c)	450,700	456,625
Funds held by trustees	(12,140)	(12,414)
8.4%-8.6% Junior subordinated debentures due 2025 through 2035	175,826	175,826
Advances from associated companies	276,186	41,064
Unamortized premium and discount	4,598	6,650
Capital lease obligations	23,576	24,661
Total	3,642,210	3,404,979
Less current maturities	203,797	176,802
TOTAL	$3,438,413	$3,228,177

(a) Includes $50 million of 9.4 percent bonds issued to secure obligations under an equivalent 10-year yen loan. A currency swap converted the fixed rate yen liability to a floating rate U.S. dollar liability based on six-month LIBOR plus .02 percent (interest rate 5.9 percent at December 31, 1996).

(b) 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.

(c) 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 $4.6 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 bonds, pollution control revenue bonds, commercial paper, capital lease obligations and any future senior indebtedness.

The Company has guaranteed all of the obligations of PacifiCorp Capital I, a wholly owned subsidiary trust of the Company. See Note 13.

The annual maturities of long-term debt and redeemable preferred stock outstanding are $203,797,000, $194,958,000, $297,652,000, $168,492,000 and $236,077,000 in 1997 through 2001, respectively.

NOTE 6. 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, exchange 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 ratings. The Company's credit policy provides that counterparties satisfy minimum credit ratings. The credit exposure of interest rate foreign exchange 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 manage its interest rate risk. The swaps are used to adjust the characteristics of its liability portfolio from variable to fixed interest rates, allowing the Company to establish a mix of fixed or variable interest rates on its outstanding debt.

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.

	1996	1995
Pay-fixed swaps		
Average pay rate	8.2%	8.0%
Average receive rate	5.0	3.7

FOREIGN EXCHANGE RISK MANAGEMENT - At December 31, 1996, the Company held a foreign currency exchange agreement, which provides for the exchange of $50 million for 7.4 billion yen to meet a 1997 yen-denominated obligation of an equivalent amount.

COMMODITY RISK MANAGEMENT - Electricity futures contracts are used to hedge the Company's excess or shortage of net electricity for future months. At December 31, 1996, the Company had 67 NYMEX futures contracts to sell electricity with notional quantities amounting to approximately 49,300 MWh all expiring in 1997. The average fixed price to be received by the Company was $19.33 per MWh compared to the NYMEX average spot market price of $15.78 per MWh.

NOTE 7. FAIR VALUE OF FINANCIAL INSTRUMENTS

	DECEMBER 31, 1996		DECEMBER 31, 1995	
THOUSANDS OF DOLLARS	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
Long-term debt	$3,618,634	$3,686,098	$3,380,318	$3,589,834
Preferred stock subject to mandatory redemption	178,000	195,800	219,000	240,260
Derivatives relating to				
Interest	(10,788)	(38,991)	-	(33,198)
Electricity futures	-	(175)	-	-

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NOTES TO FINANCIAL STATEMENTS (Continued)

The carrying value of cash and cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates 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 and capital lease obligations were excluded. The fair value of redeemable preferred stock was based on bid prices from an investment bank.

The fair value of interest rate derivatives, currency swaps and electricity futures is the estimated amount the Company would have to pay to terminate the agreements, taking into account current interest and currency exchange rates, electricity market prices and the current creditworthiness of the agreement counterparties.

NOTE 8. 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, 1996 and 1995 was $10,484,000 and $12,368,000, respectively.

Future minimum lease payments under noncancellable operating leases are $2,923,000, $2,058,000, $1,952,000, $1,866,000, $1,754,000 and $7,333,000 for 1997 through 2001 and years thereafter, respectively.

NOTE 9. COMMITMENTS AND CONTINGENCIES

Construction and Other

Construction and acquisitions are estimated at $478 million for 1997. As part of these programs, substantial commitments have been made.

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, 1996, principally the Superfund sites where the Company has been or may be designated as a potentially responsible party and violations under the Clean Air Act, 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. This is consistent with industry practices, and the Company believes its reclamation obligations are adequately provided for.

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.

Jointly Owned Plants

At December 31, 1996, the Company's participation in jointly owned plants was as follows:

THOUSANDS OF DOLLARS	THE COMPANY'S SHARE	PLANT IN SERVICE	ACCUMULATED DEPRECIATION	CONSTRUCTION WORK IN PROGRESS
Centralia	47.5%	$178,146	$108,010	$4,169
Jim Bridger Units 1,2,3 and 4	66.7	789,664	308,145	2,178
Trojan(a)	2.5	-	-	-
Colstrip Units 3 and 4	10.0	203,473	63,174	1,108
Hunter Unit 1	93.8	260,204	100,949	814
Hunter Unit 2	60.3	187,567	66,435	1,313
Wyodak	80.0	303,852	96,646	1,776
Craig Station Units 1 and 2	19.3	150,040(b)	56,871	1,100
Hayden Station Unit 1	24.5	17,081(b)	10,613	1,080
Hayden Station Unit 2	12.6	16,958(b)	9,928	808
Hermiston(c)	50.0	164,891	3,448	28

(a) Plant, inventory, fuel and decommissioning costs totaling $27 million relating to the Trojan Plant were included in regulatory assets-net at December 31, 1996.

(b) Excludes unallocated acquisition adjustments of $119 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.

PURCHASED POWER

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, including sales contracts with minimum payment requirements, and retail load growth. As part of its energy resource portfolio, the Company acquires power through long-term purchases and/or exchange agreements which require minimum fixed payments of $298,400,000 in 1997, $293,900,000 in 1998, $294,000,000 in 1999, $291,300,000 in 2000 and $251,800,000 in 2001.

These 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 1996, such purchases approximated 3.5% of energy requirements.

At December 31, 1996, 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%	$ 5,000
Priest Rapids	2005	109,602	13.9	3,700
Rocky Reach	2011	64,297	5.3	2,400
Wells	2018	59,617	7.7	1,900
TOTAL		388,960		$13,000

(a) Annual costs include debt service of $6 million.

The Company has a 4 percent interest in the Intermountain Power Project ("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.

NOTE 10.INCOME TAXES

Excluding equity in subsidiaries' earnings or losses, the Company's effective combined federal and state income tax rate was 37 percent and 40 percent in 1996 and 1995, respectively. The difference between taxes calculated as if the statutory federal tax rate of 35 percent in 1996 and 1995 was applied to income before income taxes and the recorded tax expense is reconciled as follows:

(THOUSANDS OF DOLLARS)	1996	1995
COMPUTED FEDERAL INCOME TAXES	$205,894	$184,237
INCREASE (REDUCTION) IN TAX RESULTING FROM		
Depreciation differences (flow-through basis)	12,726	9,679
Investment tax credits	(8,926)	(8,927)
Depletion	(3,717)	(1,600)
Audit settlements	(1,582)	14,535
Other items capitalized and misc. differences	(5,198)	(627)
Total	(6,697)	13,060
FEDERAL INCOME TAX	199,197	197,297
STATE INCOME TAX, NET OF FED. INCOME TAX BENEFIT	17,828	15,662
TOTAL INCOME TAX EXPENSE	$217,025	$212,959

NOTES TO FINANCIAL STATEMENTS (Continued)

The provision for income taxes is summarized as follows:

THOUSANDS OF DOLLARS	1996	1995
CURRENT		
Federal	$ 157,722	$ 166,722
State	23,131	19,252
Total	180,853	185,974
DEFERRED		
Federal	40,800	31,067
State	4,297	4,845
Total	45,097	35,912
INVESTMENT TAX CREDITS	(8,925)	(8,927)
TOTAL INCOME TAX EXPENSE	$ 217,025	$ 212,959

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

THOUSANDS OF DOLLARS	1996	1995
DEFERRED TAX LIABILITIES		
Property, plant and equipment	$ 855,445	$ 796,352
Regulatory asset	733,100	756,115
Other deferred liabilities	(438)	14,721
DEFERRED TAX ASSETS		
Regulatory liability	(57,116)	(60,803)
Book reserves not deductible for tax	(6,365)	(7,593)
NET DEFERRED TAX LIABILITY	$1,524,626	$1,498,792

During 1995, the Company and the Internal Revenue Service (the "IRS") agreed on a settlement of all issues related to the IRS examination of the Company's federal income tax returns for the years 1983 through 1988, including matters relating to the Company's abandonment of its 10 percent interest in Washington Public Power Supply System Unit No. 3.

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. The Company's 1991, 1992, and 1993 federal income tax returns are currently under examination by the IRS.

NOTE 11. 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, 1996, plan assets were primarily invested in common stocks, bonds and U.S. government obligations.

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

THOUSANDS OF DOLLARS	1996	1995
Service cost - benefits earned	$27,597	$ 20,476
Interest cost on projected benefit obligation	72,193	69,125
Actual gain on plan assets	(59,114)	(120,705)
Net amortization and deferral	8,881	81,523
Regulatory deferral (a)	14,212	29,446
NET PENSION COST	$63,769	$ 79,865

(a) The Company has received accounting orders from its primary and certain other regulatory authorities to defer the difference between pension cost as determined in accordance with SFAS 87 and 88 and that determined for funding purposes. See Note 2.

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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	1996	1995
Actuarial present value of benefit obligations		
Vested benefit obligation	$ 837,016	$ 827,031
Accumulated benefit obligation	$ 910,333	$ 880,993
Projected benefit obligation	$1,027,416	$1,018,821
Plan assets at fair value	786,947	668,868
Projected benefit obligation in excess of plan assets	240,469	349,953
Unrecognized prior service cost	(13,697)	(11,822)
Unrecognized net loss	(87,038)	(97,174)
Unrecognized net obligation at January 1, being amortized over 3 to 15 years	(10,113)	(94,011)
Minimum liability adjustment	2,891	65,179
NET PENSION LIABILITY	$ 132,512	$ 212,125
Discount rate	7.5%	7.25%
Expected long-term rate of return on assets	9%	8.75%
Rate of increase in compensation levels	4.5%	5-5.5%

NOTE 12. OTHER POSTRETIREMENT BENEFITS

The Company provides health care and life insurance benefits 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 Company funds postretirement benefit expense on a pay-as-you-go basis for those employees retired prior to January 1, 1993. The Company funds postretirement benefit expense through a combination of funding vehicles for those employees retiring after January 1, 1993. The Company funded $28,011,000 and $26,640,000 of postretirement benefit expense during 1996 and 1995, respectively. These funds are invested in common stock, bonds and U.S. Government obligations.

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NOTES TO FINANCIAL STATEMENTS (Continued)

The net periodic postretirement benefit cost for the years ended December 31, 1996 and 1995 are summarized as follows:

THOUSANDS OF DOLLARS	1996	1995
Service costs - benefits earned	$ 6,912	$ 6,239
Interest cost on accumulated postretirement benefit obligation	21,838	26,661
Amortization of transition obligation	12,560	13,950
Regulatory deferral	3,400	(4,460)
Net asset gain during the period deferred for future recognition	3,514	2,578
Actual return on plan assets	(12,612)	(8,772)
NET PERIODIC POSTRETIREMENT BENEFIT COST	$ 35,612	$ 36,196

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

(THOUSANDS OF DOLLARS)	1996	1995
Retirees and dependents	$167,958	$224,249
Fully eligible active plan participants	10,113	11,869
Other active plan participants	131,014	147,992
APBO	309,085	384,110
Plan assets at fair value	135,063	95,384
APBO in excess of plan assets	174,022	288,726
Unrecognized transition obligation at January 1, being amortized over 20 years	(223,211)	(237,162)
Unrecognized net gain (loss)	51,199	(43,197)
ACCRUED POSTRETIREMENT BENEFIT OBLIGATION	$ 2,010	$ 8,367
Discount rate	7.5%	7.25%
Estimated long-term rate of return on assets	9%	8.75%
Initial health care cost trend rate-under 65	8.8%	11%
Initial health care cost trend rate-over 65	8.4%	10%
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, 1996 by $26,945,000 and the annual net periodic postretirement benefit cost by $2,729,000.

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NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 13. 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 $2,225,000 and $4,539,000 in 1996 and 1995, respectively.

On June 11, 1996, PacifiCorp Capital I, a wholly owned subsidiary trust of the Company (the "Trust"), issued, in a public offering, 8,680,000 of its 8 1/4% Company Obligated Mandatorily Redeemable Preferred Securities (the "Preferred Securities"), representing preferred undivided beneficial interests in the assets of the Trust, with a liquidation preference of $25 per Preferred Security. The sole assets of the Trust are $224 million, in aggregate principal amount, of the Company's 8 1/4% Junior Subordinated Deferrable Interest Debentures, Series C, due June 30, 2036 and certain rights under a related guarantee by the Company. The Company's guarantee of the Preferred Securities, considered together with the other obligations of the Company with respect to Preferred Securities, constitutes a full and unconditional guarantee by the Company of the Trust's obligations with respect to the Preferred Securities. The Company paid interest expense of $10,202,000 to the Trust during 1996 on the 8 1/4% debentures.

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 $5,705,000 and $2,062,000 in 1996 and 1995, 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 $117,668,000 in 1996 and $136,411,000 in 1995. The Company provided Bridger with management, administrative and engineering services and electricity on an as-needed basis. The amount charged for these services was $4,521,000 and $4,764,000 in 1996 and 1995, respectively. In addition, Bridger paid overriding royalties to the Company and Idaho of $630,000 and $614,000 in 1996 and 1995, 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 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.

During 1995, the Company 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. The Company realized net proceeds of $5,984,000 in 1996 and $28,734,000 in 1995 and recorded a gain of $1,134,000 in 1996 and a loss of $3,508,000 in 1995, which are included in Miscellaneous Nonoperating Income. DSRI sold $4,225,000 and $23,400,000 of these receivables in 1996 and 1995, respectively, to outside parties and recorded a loss of $758,000 in 1996 and a gain of $2,644,000 in 1995, which are included in equity in subsidiary earnings

NOTE 14. ACQUISITIONS AND DISPOSITIONS BY SUBSIDIARIES

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 million 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 million portion of the equity investment and the associated $12 million advance with long-term borrowings in the United States. The other partners in the partnership are subsidiaries of National Power PLC (51.9%), Destec Energy (20%) and Commonwealth Bank Group of Australia (8.2%).

On December 12, 1995, Holdings purchased Powercor Australia Limited ("Powercor"), an electricity distributor in Australia, for $1.6 billion in cash. Powercor's service territory includes a portion of suburban Melbourne and the western and central regions of the State of Victoria and has approximately 547,000 customers. The acquisition has been accounted for as a purchase and the results of operations of Powercor have been included in equity in subsidiary earnings since December 12, 1995.

On September 27, 1995, holders of a majority of the 5,300,000 shares of outstanding common stock held by minority shareholders of PTI voted in favor of the merger of a wholly owned subsidiary of Holdings into PTI. Shareholders tendering shares pursuant to the merger were paid a total of $131 million, or $30 per share, and an accrued liability of $28 million was established by PTI to cover estimated amounts payable to dissenters.

During 1995, PTI purchased certain rural telephone exchange assets in Colorado, Washington and Oregon for approximately $376 million.

On August 7, 1995, PTI closed the sale of the stock of Alascom, Inc. ("Alascom") to AT&T Corp. A gain of $37 million from the sale of Alascom was included in equity in subsidiary earnings in 1995. Revenues and income from operations were $193 million and $37 million, respectively, for the seven months ended July 31, 1995.

NOTE 15. SUBSEQUENT EVENTS

On March 4, 1997, the Utah Legislature passed a bill which creates a legislative task force to study stranded cost issues and the timing of customer choice. The bill freezes rates at January 31, 1997 levels until 60 days following the conclusion of the 1998 legislative general session. The PSC is precluded from holding any hearings on rate changes during the freeze period. The Company has committed to reduce prices to Utah customers by $12 million annually on approximately May 1, 1997.

On March 11, 1997, Holdings entered into an agreement to acquire TPC Corporation, a natural gas gathering, processing, storage and marketing company. The acquisition is expected to cost approximately $288 million in cash plus assumed debt of approximately $149 million.

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	83,832	90,214	7.61%
303	Miscellaneous Intangible Plant	2,258,301	3,471,286	53.71%
TOTAL Intangible Plant		2,784,042	4,003,408	43.80%
Production Plant				
Steam Production				
310	Land & Land Rights	878,966	942,735	7.26%
311	Structures & Improvements	10,241,964	11,219,407	9.54%
312	Boiler Plant Equipment	38,120,667	41,261,545	8.24%
313	Engines & Engine Driven Generators	0	0	
314	Turbogenerator Units	9,068,283	10,418,553	14.89%
315	Accessory Electric Equipment	4,552,773	5,021,418	10.29%
316	Miscellaneous Power Plant Equipment	690,023	657,295	-4.74%
TOTAL Steam Production Plant		63,552,675	69,520,954	9.39%
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	380,030	420,087	10.54%
331	Structures & Improvements	1,733,809	1,936,397	11.68%
332	Reservoirs, Dams & Waterways	5,854,905	6,415,334	9.57%
333	Water Wheels, Turbines & Generators	1,435,302	1,631,251	13.65%
334	Accessory Electric Equipment	422,251	488,933	15.79%
335	Miscellaneous Power Plant Equipment	65,035	71,361	9.73%
336	Roads, Railroads & Bridges	249,214	283,045	13.58%
TOTAL Hydraulic Production		10,140,548	11,246,409	10.91%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Account Number & Title		Last Year	This Year	% Change
Production Plant (cont.)				
Other Production				
340	Land & Land Rights	0	17,151	
341	Structures & Improvements	176	258,268	
342	Fuel Holders, Producers & Accessories	0	516	
343	Prime Movers	1,452	4,337	198.70%
344	Generators	3,117	2,620,510	
345	Accessory Electric Equipment	940	166,700	
346	Miscellaneous Power Plant Equipment	0	9,649	
	TOTAL Other Production Plant	5,685	3,077,130	
	TOTAL Production Plant	73,698,907	83,844,493	13.77%
Transmission Plant				
350	Land & Land Rights	939,928	1,015,578	8.05%
352	Structures & Improvements	465,163	523,149	12.47%
353	Station Equipment	10,686,684	11,665,492	9.16%
354	Towers & Fixtures	5,807,524	6,222,388	7.14%
355	Poles & Fixtures	4,764,055	5,360,650	12.52%
356	Overhead Conductors & Devices	9,371,426	10,127,333	8.07%
357	Underground Conduit	226	258	14.37%
358	Underground Conductors & Devices	715	1,008	41.12%
359	Roads & Trails	208,506	223,336	7.11%
	TOTAL Transmission Plant	32,244,228	35,139,192	8.98%
Distribution Plant				
360	Land & Land Rights	217,981	217,981	0.00%
361	Structures & Improvements	640,593	695,645	8.59%
362	Station Equipment	9,926,542	12,462,123	25.54%
363	Storage Battery Equipment	0	0	
364	Poles, Towers & Fixtures	12,082,520	13,323,050	10.27%
365	Overhead Conductors & Devices	11,373,817	11,733,516	3.16%
366	Underground Conduit	3,644,594	4,016,256	10.20%
367	Underground Conductors & Devices	4,097,470	4,686,778	14.38%
368	Line Transformers	15,565,070	16,347,514	5.03%
369	Services	7,699,227	8,372,093	8.74%
370	Meters	2,791,675	2,923,319	4.72%
371	Installations on Customers' Premises	166,722	166,583	-0.08%
372	Leased Property on Customers' Premises	0	0	
373	Street Lighting & Signal Systems	605,522	677,493	11.89%
	TOTAL Distribution Plant	68,811,733	75,622,351	9.90%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

	Account Number & Title		Last Year	This Year	% Change
1	**General Plant**				
2					
3	389	Land & Land Rights	133,513	139,954	4.82%
4	390	Structures & Improvements	2,347,732	2,586,916	10.19%
5	391	Office Furniture & Equipment	2,414,744	1,746,481	-27.67%
6	392	Transportation Equipment	643,290	733,296	13.99%
7	393	Stores Equipment	111,160	88,796	-20.12%
8	394	Tools, Shop & Garage Equipment	710,395	703,169	-1.02%
9	395	Laboratory Equipment	693,578	708,018	2.08%
10	396	Power Operated Equipment	1,047,197	1,557,988	48.78%
11	397	Communication Equipment	1,488,091	1,673,971	12.49%
12	398	Miscellaneous Equipment	49,912	52,490	5.16%
13	399	Other Tangible Property	7,790,054	8,170,281	4.88%
14					
15	**TOTAL General Plant**		17,429,667	18,161,360	4.20%
16					
17	**TOTAL Unclassified Plant**		2,509,323	2,155,353	-14.11%
18					
19	**TOTAL Electric Plant in Service**		197,477,900	218,926,157	10.86%

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		24,763,472	28,004,646	2.45%
3	Nuclear Production		0	0	0.00%
4	Hydraulic Production		3,458,125	3,896,505	1.85%
5	Other Production		785	66,113	3.08%
6	Transmission		9,195,763	10,609,158	2.36%
7	Distribution		17,324,360	18,898,448	3.16%
8	General		5,981,019	5,778,238	5.83%
9	**TOTAL**		60,723,524	67,253,108	

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

	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock	1,088,620	905,972	-16.78%
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)	1,277,058	1,324,526	3.72%
9	Transmission Plant (Estimated)	155,687	180,009	15.62%
10	Distribution Plant (Estimated)	389,809	364,572	-6.47%
11	Assigned to Other	224,247	82,516	-63.20%
12	155 Merchandise			
13	156 Other Materials & Supplies			
14	157 Nuclear Materials Held for Sale			
15	163 Stores Expense Undistributed	108,736	87,805	-19.25%
16				
17	**TOTAL Materials & Supplies**	3,244,157	2,945,400	-9.21%

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		7.00%	6.30%	0.44%
14	Long Term Debt		46.00%	7.66%	3.53%
15	Other		0.00%	0.00%	0.00%
16	**TOTAL**		100.00%		9.75%

Sch. 23	STATEMENT OF CASH FLOWS			
	Description	This year	Last Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	504,367,619	504,466,484	-0.02%
6	Depreciation	312,878,983	294,321,232	6.31%
7	Amortization	30,516,067	26,040,250	17.19%
8	Deferred Income Taxes - Net	45,162,035	35,977,348	25.53%
9	Investment Tax Credit Adjustments - Net	(8,991,006)	(8,990,996)	-0.00%
10	Change in Operating Receivables - Net	(113,393,081)	(44,759,623)	-153.34%
11	Change in Materials, Supplies & Inventories - Net	23,985,675	(13,580,555)	276.62%
12	Change in Operating Payables & Accrued Liabilities - Net	67,901,273	63,284,381	7.30%
13	Allowance for Funds Used During Construction (AFUDC)			
14	Change in Other Assets & Liabilities - Net	(65,541,905)	5,299,092	-1336.85%
15	Other Operating Activities (explained on attached page)	(133,124,720)	(191,035,459)	30.31%
16	Net Cash Provided by/(Used in) Operating Activities	663,760,940	671,022,154	-1.08%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipment			
20	(net of AFUDC & Capital Lease Related Acquisitions)	(590,528,660)	(441,609,263)	-33.72%
21	Acquisition of Other Noncurrent Assets			
22	Proceeds from Disposal of Noncurrent Assets	9,711,668	25,626,933	-62.10%
23	Investments In and Advances to Affiliates	(7,405,905)	(241,000,000)	96.93%
24	Contributions and Advances from Affiliates			
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)	6,444,060	(5,740,697)	212.25%
27	Net Cash Provided by/(Used in) Investing Activities	(581,778,837)	(662,723,027)	12.21%
28				
29	**Cash Flows from Financing Activities:**			
30	Proceeds from Issuance of:			
31	Long-Term Debt	202,120,401	305,730,880	-33.89%
32	Preferred Stock			
33	Common Stock	221,281,746	391,507	56420.51%
34	Other: Intercompany Borrowings	260,620,351		
35	Net Increase in Short-Term Debt		248,846,759	-100.00%
36	Other:			
37	Payment for Retirement of:			
38	Long-Term Debt	(207,702,595)	(100,200,032)	-107.29%
39	Preferred Stock	(216,996,300)	(55,825,925)	-288.70%
40	Common Stock	(2,303,888)	(2,580,641)	10.72%
41	Other: Redemption Premium/Intercompany Borrowing	(5,161,939)	(54,196,020)	90.48%
42	Net Decrease in Short-Term Debt	(6,887,000)		
43	Dividends on Preferred Stock	(31,448,754)	(39,437,684)	20.26%
44	Dividends on Common Stock	(314,971,082)	(307,048,376)	-2.58%
45	Other Financing Activities (explained on attached page)			
46	Net Cash Provided by (Used in) Financing Activities	(101,449,060)	(4,319,532)	-2248.61%
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	(19,466,957)	3,979,595	-589.17%
49	**Cash and Cash Equivalents at Beginning of Year**	(6,674,896)	(10,654,491)	37.35%
50	**Cash and Cash Equivalents at End of Year**	(26,141,853)	(6,674,896)	-291.64%

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	**FIRST MORTGAGE BONDS:**								
2	9-3/8% Yen Fin due 7/22/97	07/22/87	07/22/97	$50,000,000	$48,714,128	$50,000,000	6.24%	$3,076,070	6.15%
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	41,772,000	8.27%	3,454,962	8.27%
5	7.978% Series due 10/1/11	04/15/92	10/01/2011	4,422,000	3,794,000	3,794,000	7.98%	302,685	7.98%
6	8.493% Series due 10/1/12	04/15/92	10/01/2012	19,772,000	17,382,000	17,382,000	8.49%	1,476,253	8.49%
7	8.797% Series due 10/1/13	04/15/92	10/01/2013	16,203,000	14,457,000	14,457,000	8.80%	1,271,782	8.80%
8	8.734% Series due 10/1/14	04/15/92	10/01/2014	28,218,000	25,429,000	25,429,000	8.73%	2,220,969	8.73%
9	8.294% Series due 10/1/15	04/15/92	10/01/2015	46,946,000	42,510,000	42,510,000	8.29%	3,525,779	8.29%
10	8.635% Series due 10/1/16	04/15/92	10/01/2016	18,750,000	17,176,000	17,176,000	8.63%	1,483,148	8.64%
11	8.470% Series due 10/1/17	04/15/92	10/01/2017	19,609,000	18,069,000	18,069,000	8.47%	1,530,444	8.47%
12									
13	**Total First Mortgage Bonds**			$402,892,000	$373,421,334	$380,589,000		$28,957,242	7.61%
14									
15	**SECURED MEDIUM-TERM NOTES:**								
16	6.96% Ser. D due 1/22/97	02/14/92	01/22/97	$1,000,000	$942,433	$1,000,000	8.41%	$81,255	8.13%
17	7.00% Ser. D due 1/27/97	01/27/92	01/27/97	15,000,000	13,838,168	15,000,000	8.96%	1,282,271	8.55%
18	7.00% Ser. D due 1/27/97	01/31/92	01/27/97	20,000,000	18,117,558	20,000,000	9.41%	1,777,160	8.89%
19	6.99% Ser. D due 2/3/97	01/31/92	02/03/97	1,500,000	1,383,817	1,500,000	8.94%	128,039	8.54%
20	6.09% Ser. E due 4/15/97	10/21/92	04/15/97	2,000,000	1,855,647	2,000,000	8.04%	154,008	7.70%
21	8.87% Ser. A due 6/20/97	06/20/91	06/20/97	15,000,000	14,917,158	15,000,000	8.99%	1,344,304	8.96%
22	8.85% Ser. A due 6/20/97	06/20/91	06/20/97	20,000,000	19,909,544	20,000,000	8.95%	1,785,073	8.93%
23	8.78% Ser. B due 6/30/97	06/28/91	06/30/97	7,000,000	6,961,340	7,000,000	8.90%	621,036	8.87%
24	8.84% Ser. B due 7/2/97	07/02/91	07/02/97	2,000,000	1,988,965	2,000,000	8.96%	178,639	8.93%
25	6.12% Ser. E due 9/29/97	09/29/92	09/29/97	3,500,000	3,082,441	3,500,000	9.15%	297,723	8.51%
26	6.12% Ser. E due 9/29/97	09/29/92	09/29/97	10,000,000	8,806,975	10,000,000	9.15%	850,638	8.51%
27	6.12% Ser. E due 9/29/97	09/29/92	09/29/97	10,000,000	8,806,975	10,000,000	9.15%	850,638	8.51%
28	6.12% Ser. E due 9/29/97	09/29/92	09/29/97	10,000,000	8,806,975	10,000,000	9.15%	850,638	8.51%
29	6.14% Ser. E due 9/29/97	09/29/92	09/29/97	10,000,000	8,806,975	10,000,000	9.17%	852,638	8.53%
30	5.88% Ser. E due 10/15/97	10/15/92	10/15/97	12,000,000	11,127,884	12,000,000	7.66%	880,047	7.33%
31	5.88% Ser. E due 10/15/97	10/15/92	10/15/97	1,000,000	927,324	1,000,000	7.66%	73,337	7.33%
32	6.00% Ser. E due 10/15/97	10/15/92	10/15/97	2,300,000	2,132,845	2,300,000	7.78%	171,436	7.45%

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	9.05%	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%

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	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%

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	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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	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	31,481,118	9.79%	4,919,239	15.63%
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	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%
16	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%
17	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%
18	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%
19	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%
20	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%
21	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%
22	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%
23	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%
24	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%
25	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%
26	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%
27	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%
28	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%
29	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%
30	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%
31	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%
32	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%

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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	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%
2	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%
3	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%
4	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%
5	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%
6	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%
7	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%
8	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%
9	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%
10	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%
11	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%
12	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%
13	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%
14	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%
15	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%
16	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%
17	8.375% Ser. C due 12/31/21	12/31/91	12/31/2021	5,000,000	4,276,959	5,000,000	9.89%	442,850	8.86%
18	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%
19	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%
20	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%
21	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%
22	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%
23	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%
24	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%
25	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%
26	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%
27	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%
28	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%
29	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%
30	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%
31	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%
32	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%

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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	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%
2	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%
3	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%
4	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%
5	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%
6	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%
7	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%
8	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%
9	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%
10	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%
11									
12	**Total Secured Medium-Term Notes**			$2,078,950,000	$1,947,684,158	$2,055,205,118		$168,784,265	8.21%
13									
14	**POLL. CTRL. OBLIGATIONS SECURED BY PLEDGED FIRST MORTGAGE BONDS:**								
15	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%
16	5-5/8% Series due 11/21 Lincol	11/15/93	11/01/2021	8,300,000	7,459,117	8,300,000	6.41%	496,948	5.99%
17	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%
18	5-5/8% Series due 11/23 Emery	11/15/93	11/01/2023	16,400,000	14,565,392	16,400,000	6.48%	983,735	6.00%
19	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%
20	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%
21	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%
22	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%
23	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%
24									
25	**Total PCRB's Secured by Pledged FMB's**			$287,670,000	$272,714,561	$287,670,000		$12,142,096	4.22%
26									
27	**POLLUTION CONTROL REVENUE BONDS:**								
28	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%
29	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%
30	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%
31	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%
32	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%

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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	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%
2	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%
3	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%
4	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%
5	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%
6	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%
7	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%
8	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%
9	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%
10	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%
11	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%
12	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%
13									
14	**Total Pollution Control Revenue Bonds**			$472,500,000	$453,174,646	$450,700,000		$26,245,038	5.82%
15									
16	**OTHER LONG-TERM DEBT:**								
17	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%
18	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%
19	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%
20									
21	**Total Other Long-Term Debt**			$399,537,925	$385,994,175	$399,537,925		$33,632,400	8.42%
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									
32	**Total Long-Term Debt**			$3,641,549,925	$3,432,988,874	$3,573,702,043		$269,761,042	7.55%

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	No par serial preferred cumulative:									
12	$7.12 Series	3/87	30,000	100.00	104.75	2,962,038	7.21%	3,000,000	216,338	7.30%
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	$1.98 Series - 1992	5/92	2,766,963	25.00	N. A.	66,876,176	8.19%	69,174,075	5,666,834	8.47%
18	$7.48 Series	6/92	750,000	100.00	N. A.	74,159,567	7.56%	75,000,000	5,673,577	7.65%
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32										
33	TOTAL		5,956,433			309,263,049		313,538,225	22,630,192	7.32%

(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	284,276,709	13.01	0.16			22.000	21.000	
6	February	284,760,988	12.85	0.13			21.625	20.750	
8	March	293,297,279	13.21	0.13	0.27	36.00%	21.750	20.125	12.4
10	April	293,612,562	13.29	0.07			21.250	19.625	
12	May	294,111,663	13.12	0.10			20.625	19.625	
14	June	294,136,530	13.26	0.13	0.27	11.85%	22.500	19.875	17.3
16	July	294,157,368	13.44	0.19			22.375	20.250	
18	August	294,627,417	13.33	0.16			21.625	19.875	
20	September	294,647,675	13.45	0.12	0.27	41.77%	21.125	19.625	11.0
22	October	294,665,717	13.56	0.10			21.625	20.250	
24	November	295,114,702	13.40	0.11			22.000	20.750	
26	December	295,139,753	13.63	0.22	0.27	37.40%	21.125	19.875	11.9
32	**TOTAL Year End**	292,423,918		1.62	1.08	33.46%	21.125	20.500	13.0

Sch. 27

MONTANA EARNED RATE OF RETURN

		Description	Last Year	This Year	% Change
1		**Rate Base**			
2	101	Plant in Service	192,585,262	212,596,088	10.39%
3	108	(Less) Accumulated Depreciation	(59,869,358)	(67,314,616)	-12.44%
4		NET Plant in Service	132,715,904	145,281,472	9.47%
5					
6		**Additions**			
7	154, 156	Materials & Supplies	3,156,903	3,187,232	0.96%
8	165	Prepayments	537,515	448,748	-16.51%
9		Other Additions	7,825,849	8,909,355	13.85%
10		TOTAL Additions	11,520,267	12,545,335	8.90%
11					
12		**Deductions**			
13	190	Accumulated Deferred Income Taxes	(9,579,717)	(12,031,930)	-25.60%
14	252	Customer Advances for Construction	(37,481)	(39,392)	-5.10%
15	255	Accumulated Def. Investment Tax Credits	(556,848)	(449,497)	19.28%
16		Other Deductions	(1,233,066)	(1,874,190)	-51.99%
17		TOTAL Deductions	(11,407,112)	(14,395,009)	-26.19%
18		TOTAL Rate Base	132,829,059	143,431,798	7.98%
19					
20		Net Earnings	9,803,604	11,304,965	15.31%
21					
22		Rate of Return on Average Rate Base	7.38%	7.88%	6.79%
23					
24		Rate of Return on Average Equity	7.03%	8.58%	22.01%
25					
26		Major Normalizing Adjustments & Commission			
27		Ratemaking adjustments to Utility Operations			
28		Commission Ordered / Allowed Ratemaking Adjustments			
29		- Malin Midpoint Adj.	15,549	15,759	1.35%
30		- Advertising Expense Adj.	1,303	0	-100.00%
31		- Present Rates Adj.	5,517	(49,112)	-990.19%
32		- Weather Normalization Adj.	81,838	(681,874)	-933.20%
33		- Production Cost Study Adj.	(619,821)	(81,939)	86.78%
34		- Interest Expense Adj.	464,019	847,240	82.59%
35		- Miscellaneous Accounting Adj	(44,907)		100.00%
36		- Clean Air Credits	(35,166)	(22,349)	36.45%
37		- Pension Expense	133,472		-100.00%
38		- DSM Third Party Financing	(1,579)	281	117.80%
39		Other Company Ratemaking Adjustments			
40		- Other Adjustments	(159,315)	(636,000)	-299.21%
41					
42					
43					
44					
45					
46					
47		Adjusted Rate of Return on Average Rate Base	6.95%	7.18%	3.28%
48					
49		Adjusted Rate of Return on Average Equity	5.80%	6.57%	13.26%

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	115,331	101,645
3	Misc Deferred Debits	1,417,436	2,184,017
4	Acquisition Adjustment	2,611,239	2,686,491
5	Nuclear Fuel	0	0
6	Working Capital (1)	1,468,736	1,530,202
7	Weatherization Loans	1,481,375	1,650,279
8	Unrecovered Plant - Trojan	731,732	756,721
9	Total Other Additions	7,825,849	8,909,355
10			
11	Deductions:		
12	Accumulated Prov. - Trojan	(392,337)	(413,571)
13	Accumulated Prov. - Injuries	(130,368)	(128,045)
14	Accumulated Prov. - Proprety Ins	(73,756)	(37,416)
15	Other Deferred Credits	(636,605)	(1,295,158)
16	Total Other Deductions	(1,233,066)	(1,874,190)

(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).

Sch. 28

MONTANA COMPOSITE STATISTICS

Line	Account	Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	338,695
5	107	Construction Work in Progress	4,977
6	114	Plant Acquisition Adjustments	-
7	105	Plant Held for Future Use	-
8	154, 156	Materials & Supplies	559
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	(102,292)
11	252	Contributions in Aid of Construction	(3,540)
12			
13		NET BOOK COSTS	238,399
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	55,819
18			
19	403 - 407	Depreciation & Amortization Expenses	6,031
20		Federal & State Income Taxes	2,936
21		Other Taxes	1,623
22		Other Operating Expenses	34,057
23		TOTAL Operating Expenses	44,647
24			
25		Net Operating Income	11,172
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	(133)
29			
30		NET INCOME	11,305
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	28,217
36		Commercial	5,519
37		Industrial	261
38		Other	49
39			
40		TOTAL NUMBER OF CUSTOMERS	34,046
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh)	12,839
45		Average Annual Residential Cost per (Kwh) (Cents) *	5.01
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	$53.64
48		Gross Plant per Customer	$10,181

Sch. 29 **MONTANA CUSTOMER INFORMATION**

	City/Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Bigfork	N.A.	2,496	534	30	3,060
2	Columbia Falls	N.A.	2,934	498	35	3,467
3	Kalispell	N.A.	11,052	2,288	197	13,537
4	Kila	N.A.	258	39		297
5	Lakeside	N.A.	1,045	207	6	1,258
6	Libby	N.A.	4,262	946	54	5,262
7	Rollins	N.A.	288	38	5	331
8	Somers	N.A.	583	103	8	694
9	Swan Lake	N.A.	182	25	1	208
10	Whitefish	N.A.	4,922	937	20	5,879
11	Cooke City	N.A.	136	52	3	191
12	Silver Gate	N.A.	69	15		84
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	28,227	5,682	359	34,268

Sch. 30

MONTANA EMPLOYEE COUNTS

	Department	Year Beginning	Year End	Average
1	Big Fork	2	2	2
2	Facilities Engineering	1	0	1
3	Kalispell District	56	49	53
4	Libby District	9	7	8
5	Montana Area	2	3	3
6	Whitefish District	6	4	5
7				0
8				0
9				0
10				0
11				0
12				0
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				0
33				0
34				0
35				0
36				0
37				0
38				0
39				0
40				0
41				0
42				0
43				0
44				0
45				0
46				0
47				0
48				0
49				0
50	**TOTAL Montana Employees**	76	65	71

Sch. 31 MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)

	Project Description	Total Company	Total Montana
1	CENTRALIA MINE - KOPIAH FIELD DEVLOPMENT	6,124	115
2	CENTRALIA MINE - REBUILD B.E. DRAGLINE	4,320	81
3	CENTRALIA MINE - HYDRAULIC EXCAVATOR	3,565	67
4	YALE RELICENSING	1,935	64
5	SLC BUSINESS CENTER DEVELOPMENT	12,518	307
6	BUTLERVILLE 138/46 KV SUBSTATION	5,815	111
7	LCT RELOC: OFFICE MOVE	5,797	114
8	HUNTINGTON U1 COOLING TOWER REPLACEMENT	5,044	96
9	COMMUNICATION EQUIPMENT FOR LCT	5,039	99
10	EIS / OLAP FINANCIAL SYSTEM	4,500	89
11	CLIENT/SERVER INFRASTRUCTURE BUILD	4,445	88
12	HUNTER UNIT 2 TURBINE & BALANCE	4,344	83
13	HUNTER 303---CONDENSATE POLISHER	3,923	75
14	HG PLANT GE ADVANCED AERO DESIGN	3,817	73
15	HG U1 ADVANCED AERO DESIGN	3,774	72
16	AUTOMATED MAPPING PROJECT	3,744	74
17	CSS ENHANCEMENTS	2,905	71
18	CORPORATE VIDEO CONFERENCE	2,265	45
19	DJ#1 U1 TURBINE-GENERATOR	2,220	42
20	NAU 271: U1 COOLING TOWER UPGRADE	2,090	40
21	JB UNIT 1 TURBINE UPGRADE	1,983	38
22	1997 FINANCE SYSTEMS CAPITAL ENHANCEMENTS	1,953	38
23	JB UNIT #2 CONDENSER TITANIUM	1,886	36
24	N UMPQUA RELICENSING	1,841	61
25	HUNTER 303---TURBINE UPRATE	1,757	33
26	NAUGHTON 273: CONSTRUCT 2ND FGD	1,676	32
27	GLEN CANYON - SIGURD:PURCHASE	1,594	30
28	HUNTER UNIT 3 MCR MODIFICATION.	1,524	29
29	DAVE JOHNSTON MINE - (1) 190 TON TRUCK	1,407	26
30	TROUTDALE 230 KV	1,357	26
31	GREEN CANYON 138KV SUB	1,327	25
32	NAU 271: U1 OVERHAUL BOILER	1,324	25
33	JB UNIT 2 TURBINE UPGRADE	1,213	23
34	SERVER CURRENT SUPPORT	1,200	24
35	WAN UPGRADE	1,105	22
36	BIG FORK RELICENSING	1,046	35
37	ALL OTHER	379,959	N/A
38			
39			
40			
41			
42			
43			
44			
45			
46			
47			
48			
49			
50	TOTAL	492,336	2,309

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.	31	08:00	7,922	6,065,750	1,494,642
2	Feb.	2	08:00	8,013	5,764,696	1,630,800
3	Mar.	1	08:00	7,132	6,276,661	2,206,116
4	Apr.	19	09:00	6,500	5,868,193	2,000,130
5	May	13	14:00	6,414	5,888,321	1,913,012
6	Jun.	10	13:00	7,043	6,214,474	2,161,985
7	Jul.	26	15:00	7,667	6,961,288	2,352,889
8	Aug.	14	15:00	7,564	6,964,137	2,585,870
9	Sep.	4	15:00	6,875	6,727,529	2,828,237
10	Oct.	21	08:00	6,926	7,312,916	3,087,935
11	Nov.	26	18:00	7,277	7,389,952	2,927,179
12	Dec.	18	08:00	7,782	7,823,088	3,126,221
13	TOTAL				79,257,005	28,315,016

Montana

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
14	Jan.	30	09:00	205	163,077	52,710
15	Feb.	2	09:00	198	144,266	50,283
16	Mar.	6	10:00	171	143,045	49,232
17	Apr.	1	10:00	143	119,766	42,102
18	May	9	10:00	134	112,713	41,663
19	Jun.	18	12:00	117	103,870	43,957
20	Jul.	29	12:00	121	113,594	41,688
21	Aug.	5	00:00	121	111,479	40,955
22	Sep.	25	08:00	132	109,897	42,058
23	Oct.	31	09:00	153	123,690	39,511
24	Nov.	19	19:00	167	141,249	44,377
25	Dec.	26	19:00	183	163,869	48,450
26	TOTAL				1,550,515	536,986

Sch. 33 TOTAL SYSTEM Sources & Disposition of Energy

	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	47,828,822	Sales to Ultimate Consumers	
3	Nuclear	(545)	(Include Interdepartmental)	45,288,066
4	Hydro - Conventional	5,191,626		
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	772,440	for Resale	1,340,070
7	(Less) Energy for Pumping			
8	**NET Generation**	53,792,343	Non-Requirements Sales	
9	Purchases	25,669,732	for Resale	28,315,016
10	Power Exchanges			
11	Received	13,851,763	Energy Furnished	
12	Delivered	13,674,779	Without Charge	
13	**NET Exchanges**	176,984		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	8,843,539	Electric Utility	75,785
16	Delivered	8,843,539		
17	**NET Transmission Wheeling**	0	Total Energy Losses	4,238,068
18	Transmission by Others Losses	(382,054)		
19	**TOTAL**	79,257,005	**TOTAL**	79,257,005

Sch. 34	SOURCES OF ELECTRIC SUPPLY				
	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Thermal	Cholla Unit No. 4	Joseph City, Arizona	414.0	1,368,806
2	Thermal	Craig Units #1 & #2	Craig, Colorado	381.0	1,356,516
3	Thermal	Hayden Plant	Hayden, Colorado	78.0	537,468
4	Thermal	Colstrip Unit #3 & #4	Colstrip, Montana	166.0	795,052
5	Thermal	Hermiston Plant	Hermiston, Oregon	248.0	772,440
6	Thermal	Carbon Plant	Castle Gate, Utah	189.0	1,411,250
7	Thermal	Gadsby Plant	Salt Lake City, Utah	234.0	155,593
8	Thermal	Hunter Plant	Castle Dale, Utah	1,124.0	8,086,054
9	Thermal	Huntington Plant	Huntington, Utah	841.0	6,408,968
10	Thermal	Centralia Plant	Centralia, Washington	642.0	3,972,798
11	Thermal	James River	Camas, Washington	54.0	319,881
12	Thermal	Dave Johnston Plant	Glenrock, Wyoming	801.0	5,958,080
13	Thermal	Jim Bridger Plant	Rock Springs, Wyoming	1,430.0	9,908,635
14	Thermal	Wyodak Plant	Gillette, Wyoming	280.0	2,276,898
15	Thermal	Naughton Plant	Kemmerer, Wyoming	712.0	5,080,911
16	Geothermal	Blundell Plant	Milford, Utah	24.0	191,912
17					
18	Nuclear	Trojan Plant	Rainier, Oregon		(545)
19	Hydro	Copco #1	Copco, California	24.0	120,853
20	Hydro	Copco #2	Copco, California	30.0	172,572
21	Hydro	Fall Creek	Copco, California	3.0	11,756
22	Hydro	Iron Gate	Hornbrook, California	20.0	139,612
23	Hydro	Ashton	Ashton, Idaho	7.0	44,905
24	Hydro	Cove	Grace, Idaho	7.0	21,479
25	Hydro	Grace	Grace, Idaho	31.0	109,351
26	Hydro	Last Chance	Grace, Idaho	1.0	5,008
27	Hydro	Oneida	Preston, Idaho	27.0	41,504
28	Hydro	Paris	Paris, Idaho	1.0	3,024
29	Hydro	Soda	Soda, Idaho	7.0	18,324
30	Hydro	St. Anthony	St. Anthony, Idaho	1.0	3,275
31	Hydro	Bigfork	Bigfork, Montana	5.0	24,955
32	Hydro	Bend	Bend, Oregon	1.0	5,894
33	Hydro	Clearwater #1	Toketee Falls, Oregon	15.0	65,355
34	Hydro	Clearwater #2	Toketee Falls, Oregon	21.0	68,482
35	Hydro	Cline Falls	Redmond, Oregon	1.0	2,636
36	Hydro	Eagle Point	Eagle Point, Oregon	4.0	13,269
37	Hydro	East Side	Klamath Falls, Oregon	4.0	19,912
38	Hydro	Fish Creek	Toketee Falls, Oregon	12.0	73,496
39	Hydro	John C. Boyle	Keno, Oregon	90.0	445,353
40	Hydro	Lemolo #1	Toketee Falls, Oregon	28.0	172,853
41	Hydro	Lemolo #2	Toketee Falls, Oregon	35.0	217,508
42	Hydro	Powerdale	Hood River, Oregon	6.0	32,742
43	Hydro	Prospect #1	Prospect, Oregon	4.0	25,458
44	Hydro	Prospect #2	Prospect, Oregon	36.0	280,880
45	Hydro	Prospect #3	Prospect, Oregon	8.0	40,487
46	Hydro	Prospect #4	Prospect, Oregon	1.0	4,601
47	Hydro	Slide Creek	Toketee Falls, Oregon	18.0	120,143
48	Hydro	Soda Springs	Toketee Falls, Oregon	12.0	77,754
49					

SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
50	Hydro	Toketee	Toketee Falls, Oregon	43.0	296,639
51	Hydro	Wallowa Falls	Joseph, Oregon	1.0	(72)
52	Hydro	West Side	Klamath Falls, Oregon	1.0	3,709
53	Hydro	American Fork	Plesant Grove, Utah		
54	Hydro	Beaver - Upper	Beaver, Utah	2.0	10,465
55	Hydro	Cutler	Collinston, Utah	30.0	94,589
56	Hydro	Fountain Green	Fountain Green, Utah		603
57	Hydro	Granite	Salt Lake City, Utah	1.0	6,669
58	Hydro	Gunlock	Gunlock, Utah	1.0	887
59	Hydro	Olmsted	Orem, Utah	9.0	35,409
60	Hydro	Pioneer	Ogden, Utah	5.0	26,982
61	Hydro	Sand Cove	Sand Cove, Utah	1.0	781
62	Hydro	Snake Creek	Midway, Utah	1.0	4,131
63	Hydro	Stairs	Salt Lake City, Utah	1.0	6,226
64	Hydro	Veyo	Veyo, Utah		642
65	Hydro	Weber	Uintah, Utah	3.0	24,675
66	Hydro	Condit	Underwood, Washington	16.0	65,501
67	Hydro	Drop	Naches, Washington	1.0	7,734
68	Hydro	Merwin	Ariel, Washington	148.0	641,976
69	Hydro	Naches	Naches, Washington	6.0	28,624
70	Hydro	Swift #1	Cougar, Washington	250.0	847,140
71	Hydro	Yale	Amboy, Washington	153.0	703,759
72	Hydro	Viva Naughton	Kemmerer, Wyoming	1.0	2,269
73	Pumping	Lifton	Lifton, Idaho		(1,153)
74					
75		Total Net Generation		8,752.0	53,792,343
76					
77					
78	POWER PURCHASES - ACCOUNT 555				
79					
80	AIG Trading Corp.		(1)		5,375
81	AIG Trading Corp.		(4)		19,600
82	Aquila Power Corp.		(1)		23,970
83	Aquila Power Corp.		(4)		20,800
84	Anaheim, City of		(1)		1,399
85	Arizona Power Pool Association		(1)		2,135
86	Arizona Public Service Company		31-Oct-2020		1,706
87	Arizona Public Service Company		(4)		17,200
88	Arizona Public Service Company		(1)		53,344
89	BC Hydro		(1)		399,931
90	BC Hydro		(4)		92,400
91	BMT Geneva				14
92	Basin Electric Power Coop.		(1)		1,650
93	Beaver City		(2)		68
94	Bell Mountain Power		31-Nov-2020		2,004
95	Benton County Public Utility Disrict		(1)		2,160
96	Biomass One, Limited Partnership		31-Dec-2011		134,053
97	Birch Creek Hydro		31-Nov-2020		15,117
98	Black Hills Power & Light Company		30-Jun-2012		4,254

Sch. 34	SOURCES OF ELECTRIC SUPPLY				
	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
99	Black Hills Power & Light Company		31-Dec-2000		176,850
100	Blanding City		(2)		2,159
101	Bogus Creek		31-Dec-2017		1,324
102	Boise Cascade Corporation		(1)		50
103	Bonneville Power Administration		31-Jul-98		146,350
104	Bonneville Power Administration		31-Aug-2011		
105	Bonneville Power Administration		31-Mar-2003		
106	Bonneville Power Administration		(4)		1,046,202
107	Bonneville Power Administration		(1)		3,555,366
108	Boston Power		31-Dec-2006		228
109	Boyd, James		41639		2,365
110	Buffalo Hydro Inc.		26-Jul-2014		1,828
111	Burbank, City of		(1)		132
112	CDM Hydro		31-Dec-2020		36,505
113	California Dept. of Water Resources		(1)		165,534
114	California Dept. of Water Resources		(4)		224,400
115	Calpine Power Marketing Inc.		(1)		3,200
116	Calpine Power Marketing Inc.		(4)		61,600
117	Central Oregon Irrigation District		31-Dec-2020		33,938
118	Chelan County Public Utility Dist. No. 1		til bonds paid off		472,386
119	Chelan County Public Utility Dist. No. 1		(4)		30,800
120	Chelan County Public Utility Dist. No. 1		(1)		121,120
121	Citizens Lehman Power Sales		(1)		141,000
122	Citizens Lehman Power Sales		(4)		156,901
123	CNG Power Services Corp.		(1)		1,280
124	CNG Power Services Corp.		(4)		72,160
125	Coastal Electric Services Co.		(1)		12,500
126	Coastal Electric Services Co.		(4)		110,400
127	Colorado Public Service Company		(1)		52,547
128	Colorado Public Service Company		(4)		180,050
129	Colorado Springs		(1)		9,575
130	Columbia Storage Power Exchange		37711		218,292
131	Commercial Energy Management		28-Feb-2020		2,478
132	Cook Electric		43100		8,932
133	Cowlitz County Public Utility Dist. No. 1		(1)		14,796
134	Curtiss Livestock		31-Dec-1998		179
135	Davis County Waste Management		6 mo. extensions		2,381
136	Deseret Generation & Trans. Coop.		31-Dec-1997		264,486
137	Deseret Generation & Trans. Coop.		(1)		30,313
138	Deseret Generation & Trans. Coop.		30-Jun-2001		619,548
139	Deseret Generation & Trans. Coop.		(4)		217,625
140	Douglas County Public Utility Dist. No. 1		31-Aug-2018		378,026
141	Douglas County Public Utility Dist. No. 1		(1)		115,342
142	DR Johnson Lumber Company		31-Dec-2006		58,110
143	Dupont Power Marketing Inc.		(1)		26,526
144	Dupont Power Marketing Inc.		(4)		106,400
145	Eagle Point		31-Dec-2021		2,554
146	El Paso Electric Company		(1)		72,360
147	El Paso Energy Marketing		(1)		13,200

Sch. 34	SOURCES OF ELECTRIC SUPPLY				
	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
148	El Paso Energy Marketing		(4)		29,600
149	Electric Clearinghouse, Inc.		(1)		54,807
150	Electric Clearinghouse, Inc.		(4)		234,125
151	Energy Services, Inc.		(4)		29,260
152	Englehard Power Marketing, Inc.		(1)		400
153	Englehard Power Marketing, Inc.		(4)		400
154	Enron Power Marketing, Inc.		(1)		122,003
155	Enron Power Marketing, Inc.		(4)		633,717
156	Equitable Power Services Co.		(1)		400
157	Equitable Power Services Co.		(4)		79,900
158	Eugene Water & Electric Board		(1)		23,308
159	Falls Creek		31-Dec-2019		18,185
160	Farmers Irrigation #2		31-Dec-2010		20,608
161	Fery, Lloyd		31-Dec-98		286
162	Fillmore City		(2)		84
163	Fox, Marion		07-Apr-97		6
164	Galesville Dam		31-Dec-2021		7,814
165	Garland Canal		31-Dec-2014		10,325
166	General Chemical Company		(1)		5,019
167	Georgetown Power		31-Dec-2021		2,625
168	Grand Valley Rural Power Lines		(2)		108
169	Grant County Public Utility Dist. No. 2		(3)		87,600
170	Grant County Public Utility Dist. No. 2		31-Dec-2005		770,502
171	Grant County Public Utility Dist. No. 2		31-Dec-2005		1,115,653
172	Grant County Public Utility Dist. No. 2		(1)		508,753
173	Grays Harbor		(1)		560
174	Great Salt Lake Minerals		31-Mar-2001		49,380
175	Heartland Energy Services, Inc.		(1)		480
176	Heber Light & Power		(2)		947
177	Hermiston		30-Jun-2016		1,273,105
178	Idaho Falls, City of		12-Apr-98		60,605
179	Idaho Power Company		(1)		525,334
180	Idaho Power Company		(4)		290,128
181	Illinova Power Marketing, Inc.		(1)		812
182	Illinova Power Marketing, Inc.		(4)		25,600
183	Imperial Irrigation District		(1)		11,540
184	Ingram Warm Springs Ranch		30-Apr-2021		3,897
185	Intermountain Power Project		(1)		7,280
186	Intermountain Power Project		31-May-2027		340,214
187	Kennecott		01-Jun-98		682
188	Koch Power Services, Inc.		(1)		7,200
189	Koch Power Services, Inc.		(4)		113,600
190	LG&E Power Marketing Inc.		(1)		36,242
191	LG&E Power Marketing Inc.		(4)		262,000
192	Lacomb Hydro		31-Dec-2022		2,840
193	Lagoon Corporation		updated annually		2
194	Lake Siskiyou		31-Dec-2020		20,727
195	Los Alamos, City of		(1)		35
196	Los Angeles, City of		(4)		184,000

Sch. 34	SOURCES OF ELECTRIC SUPPLY				
	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
197	Los Angeles, City of		(1)		91,323
198	Louis Dreyfus		(1)		90,184
199	Louis Dreyfus		(4)		662,799
200	Luckey, Paul		31-Dec-2013		338
201	Marsh Valley Hydro Electric Company		28-Feb-2023		7,066
202	Middlefork Irrigation District		31-Dec-2005		25,344
203	Mink Creek Hydro		30-Nov-2021		10,711
204	Montana Power Company		(1)		84,466
205	Montana Power Company		(4)		109,100
206	Morgan City		(2)		22
207	Morgan Stanley Capitol Group Inc.		(4)		20,000
208	Mountain Energy		31-Dec-2004		160
209	Municipal Electric of Nebraska		(1)		800
210	Murray City		(2)		359
211	National Gas & Electric L.P.		(1)		2,000
212	National Gas & Electric L.P.		(4)		1,600
213	Nebraska Public Power		(1)		74,152
214	Nephi City		(2)		19
215	Nevada Power Company		(1)		24,367
216	Nevada Power Company		(4)		10,320
217	New Mexico Public Service Company		(1)		87,279
218	New Mexico Public Service Company		(4)		82,050
219	Nicholson Sunnybar Ranch		31-May-2021		2,674
220	NorAm Energy Services, Inc.		(1)		800
221	North Fork Sprague		31-Dec-2023		4,483
222	Northern California Power Agency		(1)		19,414
223	Odell Creek		31-Dec-2010		165
224	Omaha Public Power		(1)		19,700
225	Opal Springs		31-Dec-2020		32,879
226	Ormsby, Leslie		31-Dec-98		12
227	O.J. Power Company		28-Feb-2021		869
228	Pacific Gas & Electric Company		(1)		83,068
229	Pancheri, Inc.		30-Apr-2013		140
230	Pasadena, City of		(1)		755
231	PECO		(1)		32,460
232	Phibro Inc.		(4)		20,000
233	Plains Electric		(1)		3,759
234	Plains Electric		(4)		81,096
235	Platte River Power Authority		(1)		15,677
236	Platte River Power Authority		(4)		218,004
237	Portland General Electric Company		18-Dec-2001		24,024
238	Portland General Electric Company		(1)		111,976
239	Portland General Electric Company		(4)		374,208
240	Preston City Hydro		30-Nov-2017		3,276
241	Provo City		(2)		125
242	Puget Sound Power & Light Company		(1)		834,771
243	Puget Sound Power & Light Company		(4)		19,200
244	Questar Energy Trading Company		(1)		1,127
245	Redding, City of		(1)		216
246	Redding, City of		31-May-2014		372,484

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SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
247	Riverside, City of		(1)		78
248	Rocky Mountain Generation Cooperative		(1)		94,831
249	Rocky Mountain Generation Cooperative		(4)		208,859
250	Rousch, Neil		31-Dec-98		372
251	Royal Oak		31-Dec-98		
252	SF Phosphates Limited		(1)		2,294
253	Salt River Project		(1)		69,069
254	Salt River Project		(4)		499,032
255	Sacramento Municipal Utility District		(1)		23,384
256	San Diego Gas & Electric Company		(1)		6,188
257	San Diego Gas & Electric Company		(4)		8,000
258	Santa Clara, City of		(1)		3,775
259	Santa Clara, City of		(4)		33,071
260	Santiam Water Control District		31-Dec-2019		1,343
261	Seattle City Light		(1)		108,480
262	Sierra Pacific Power Company		(1)		23,021
263	Slate Creek		31-Dec-2018		12,099
264	Snohomish Public Utility District		(1)		75,808
265	Snohomish Public Utility District		(4)		76,000
266	Sonat Power Marketing Inc.		(1)		15,600
267	Sonat Power Marketing Inc.		(4)		47,600
268	Southern California Edison Company		(1)		78,105
269	Southern California Edison Company		15-Mar-2003		10,791
270	Southern California Edison Company		(4)		10,000
271	Southern Energy Marketing Co.		(1)		2,400
272	Southern Energy Marketing Co.		(4)		36,800
273	Southwestern Public Service Company		(1)		450
274	Spanish Fork City		(2)		45
275	Springfield Utility District		(1)		3,595
276	Springville City		(2)		43
277	Stauffer Dry Creek		30-Nov-2022		10,370
278	Strawberry Electric Service District		(1)		19
279	Sunnyside Cogeneration Associates		31-Jul-2023		373,197
280	Tacoma City Light		(1)		7,450
281	Teton Generation Station		15-Jul-96		
282	Thayne Ranch Hydro		6 mo. extensions		2,007
283	TKO		01-Jan-2013		183
284	TransAlta Energy Marketing		(1)		2,701
285	TransAlta Energy Marketing		(4)		101,600
286	TransCanada Northridge Power Ltd.		(1)		925
287	TransCanada Northridge Power Ltd.		(4)		103,200
288	Tri-State Generation & Transmission		(1)		32,276
289	Tri-State Generation & Transmission		31-Dec-2020		543,713
290	Tucson Electric Power Company		(1)		63,701
291	Tucson Electric Power Company		(4)		8,800
292	Turlock Irrigation District		(1)		13,654
293	United States Bureau of Reclamation		06-Oct-2000		52,876
294	United States Bureau of Reclamation		(1)		28,339
295	USGen Power Services L.P.		(1)		4,840

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SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
296	USGen Power Services L.P.		(4)		5,200
297	Utah Assoc. Municipal Power Systems		(1)		5,872
298	Utah Municipal Power Agency		(1)		17,940
299	Utility-2000 Energy Corp.		(1)		9,541
300	Utility-Trade Corp.		(4)		10,800
301	Vitol Gas & Electric		(1)		56,404
302	Vitol Gas & Electric		(4)		312,765
303	Walla Walla, City of		31-Dec-2012		9,758
304	Warm Springs Forest Products Industry		(1)		
305	Warm Springs Power Enterprises		30-Nov-2016		71,969
306	Washington Public Power Supply System		30-Jun-96		279,000
307	Washington Water Power Company		31-Dec-97		289,873
308	Washington Water Power Company		15-Sep-2003		82,800
309	Washington Water Power Company		(4)		925,550
310	Washington Water Power Company		(1)		314,824
311	West Kootenay Power & Light Company		(1)		5,175
312	West Plains		(1)		12,630
313	Western Area Power Administration		(1)		24,390
314	Western Power Services, Inc.		(1)		1,050
315	Western Power Services, Inc.		(4)		20,800
316	Whitmore Oxygen		(1)		2,021
317	Whitney, A.C.		no term date		1
318	Wiggins, Duane		31-Dec-98		48
319	Yakima Tieton		31-Dec-2005		7,299
320					
321	System Deviation				1,041
322					
323	Total Purchases				25,669,732
324					
325	Net Exchanges				176,984
326					
327	Transmission by Others Losses				(382,054)
328					
329	Total Sources				79,257,005
330					
331					
332					
333					
334					
335	Notes:				
336	1. Non-firm				
337	2. Under electric service agreement subject to termination upon timely notification.				
338	3. Upon 2 years written notice.				
339	4. Contract duration less than one year.				
340					
341					
342					
343					
344					

1996 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. 1				
1.	02/03/96 23:44 - 02/07/96 12:37 **Descr:** Unit off line - plugged sh/rh	Unplanned	84.88	35,226.58
2.	03/07/96 23:30 - 03/10/96 03:50 **Descr:** Boiler tube leak (reheat section)	Unplanned	52.33	21,718.33
3.	05/03/96 04:32 - 05/03/96 14:20 **Descr:** Unit trip - unknown problem	Unplanned	9.80	4,067.00
4.	05/03/96 17:49 - 05/04/96 00:45 **Descr:** Unit trip (unknown problem)	Unplanned	6.93	2,877.33
5.	07/04/96 10:30 - 07/04/96 12:40 **Descr:** Unit trip - 1-1 circ pump tripped	Unplanned	2.17	899.17
6.	07/07/96 12:04 - 07/07/96 16:12 **Descr:** Unit trip - 1-1 circ pump tripped	Unplanned	4.13	1,715.33
7.	07/17/96 00:00 - 07/18/96 12:22 **Descr:** Boiler tube leak (reheat section)	Unplanned	36.37	15,092.17
8.	11/25/96 01:10 - 11/27/96 19:00 **Descr:** Boiler tube leak (reheat section)	Unplanned	65.83	27,320.83
9.	11/27/96 19:00 - 11/29/96 12:54 **Descr:** Right intercept valve broken	Unplanned	41.90	17,388.50
10.	11/30/96 20:46 - 11/30/96 22:10 **Descr:** Unit trip - 1/1 bfpt trip	Unplanned	1.40	581.00
11.	12/04/96 08:49 - 12/04/96 13:22 **Descr:** Unit trip - 1-2 bfpt trip	Unplanned	4.55	1,888.25
12.	12/04/96 15:18 - 12/04/96 16:36 **Descr:** Unit trip - flame failure	Unplanned	1.30	539.50
13.	12/06/96 23:42 - 12/08/96 12:14 **Descr:** Boiler tube leak (waterwall)	Unplanned	36.53	15,161.33
	*** **Unit Summary for Hunter No. 1 for the year 1996 =**		348.12	144,475.32
Hunter No. 2				
1.	02/01/96 12:43 - 02/03/96 06:02 **Descr:** Unit off line - boiler plugged	Unplanned	41.32	17,146.42
2.	04/12/96 22:45 - 04/14/96 03:39 **Descr:** Off to repair hw cool leaks	Unplanned	28.90	11,993.50
3.	06/06/96 08:53 - 06/06/96 10:10 **Descr:** Unit trip - furnace draft	Unplanned	1.28	532.58
4.	06/06/96 10:10 - 06/06/96 12:50 **Descr:** Bfp's will not start- los of vacuum	Unplanned	2.67	1,106.67
5.	06/12/96 00:10 - 06/14/96 00:51 **Descr:** Unit off - air heater clean	Unplanned	48.68	20,203.58
6.	07/19/96 10:12 - 07/19/96 12:19 **Descr:** Unit trip - 820 system ground	Unplanned	2.12	878.42
7.	08/18/96 11:53 - 08/18/96 14:38 **Descr:** Off line - fix bottom ash door	Unplanned	2.75	1,141.25
8.	12/07/96 19:16 - 12/12/96 20:37 **Descr:** Unit off line - coal pipe fire	Unplanned	121.35	50,360.25
	*** **Unit Summary for Hunter No. 2 for the year 1996 =**		249.07	103,362.67

1996 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. 3				
1.	02/18/96 07:55 - 02/18/96 15:45 **Descr:** Unit trip - low drum level	Unplanned	7.83	3,172.50
2.	02/20/96 13:35 - 02/20/96 16:36 **Descr:** Unit trip - black furnace	Unplanned	3.02	1,221.75
3.	02/20/96 18:27 - 02/20/96 20:34 **Descr:** Unit trip - drum level	Unplanned	2.12	857.25
4.	03/08/96 23:20 - 03/28/96 19:41 **Descr:** Unit outage (boiler)	Planned	476.35	192,921.75
5.	03/29/96 11:28 - 03/30/96 00:00 **Descr:** Boiler tube leak (economizer)	Unplanned	12.53	5,076.00
6.	03/30/96 00:00 - 03/30/96 07:00 **Descr:** Unit in start-up mode	Unplanned	7.00	2,835.00
7.	03/30/96 10:10 - 03/30/96 12:20 **Descr:** Unit trip, baghouse logic problem	Unplanned	2.17	877.50
8.	03/30/96 22:43 - 03/31/96 01:27 **Descr:** Unit off line - baghouse logic	Unplanned	2.73	1,107.00
9.	04/01/96 08:05 - 04/01/96 10:31 **Descr:** Unit trip - 125v buss trip	Unplanned	2.43	985.50
10.	04/22/96 07:40 - 04/22/96 11:13 **Descr:** Unit trip - furnace draft, 3-2 baghouse	Unplanned	3.55	1,437.75
11.	04/22/96 13:17 - 04/22/96 14:58 **Descr:** Unit trip - low drum level	Unplanned	1.68	681.75
12.	04/27/96 11:45 - 04/27/96 18:49 **Descr:** Unit trip - baghouse trouble	Unplanned	7.07	2,862.00
13.	05/14/96 14:36 - 05/14/96 18:59 **Descr:** Unit trip - baghouse controls	Unplanned	4.38	1,775.25
14.	05/22/96 11:00 - 05/22/96 13:48 **Descr:** Unit trip - loss of stator coolant	Unplanned	2.80	1,134.00
15.	07/05/96 09:14 - 07/05/96 13:27 **Descr:** Unit trip - flame scanner	Unplanned	4.22	1,707.75
16.	07/05/96 21:05 - 07/06/96 00:00 **Descr:** Unit trip - gen relay	Unplanned	2.92	1,181.25
17.	07/06/96 00:00 - 07/06/96 02:20 **Descr:** Unit trip - gen relay	Unplanned	2.33	945.00
18.	10/04/96 22:56 - 10/05/96 07:00 **Descr:** Unit off - overspeed trip circuits	Unplanned	8.07	3,267.00
19.	10/05/96 07:00 - 10/05/96 10:16 **Descr:** Waiting on turb lube oil temp	Unplanned	3.27	1,323.00
20.	11/04/96 08:18 - 11/04/96 12:30 **Descr:** Unit trip - baghouse problems	Unplanned	4.20	1,701.00
21.	11/04/96 12:30 - 11/04/96 15:12 **Descr:** I&c working on fan problems	Unplanned	2.70	1,093.50
22.	12/24/96 08:03 - 12/24/96 11:10 **Descr:** Unit trip - loss of stator cool flow	Unplanned	3.12	1,262.25
	*** **Unit Summary for Hunter No. 3 for the year 1996 =**		566.49	229,425.75

1996 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. 1						
1.	02/25/96 08:15	-	02/26/96 13:09	Unplanned	28.90	19,363.00
	Descr: Boiler tube leak - dead air space					
2.	05/23/96 15:05	-	05/23/96 21:44	Unplanned	6.65	4,455.50
	Descr: Bcp injection water leak-off to da leak					
3.	05/23/96 21:44	-	05/24/96 01:14	Unplanned	3.50	2,345.00
	Descr: Replace building heating system steam supply block valve bonnet gasket					
4.	05/28/96 02:11	-	05/28/96 04:11	Unplanned	2.00	1,340.00
	Descr: Could not get "no trip condition" start permissive on boiler					
5.	05/28/96 04:11	-	05/28/96 05:41	Unplanned	1.50	1,005.00
	Descr: Quincy air compressor #11 480v supply breaker problems					
6.	06/05/96 08:57	-	06/05/96 09:57	Unplanned	1.00	670.00
	Descr: Warmup oil pressure control problems					
7.	06/05/96 09:57	-	06/05/96 13:27	Unplanned	3.50	2,345.00
	Descr: Orifice ommitted from piping modification made to top of autostop/eh i					
8.	06/05/96 13:27	-	06/05/96 14:27	Unplanned	1.00	670.00
	Descr: Problem getting purge permissive on boiler					
9.	06/29/96 12:04	-	06/30/96 17:27	Unplanned	29.38	19,686.83
	Descr: Boiler tube leak					
10.	07/10/96 11:06	-	07/12/96 01:58	Unplanned	38.87	26,040.67
	Descr: Boiler tube leak					
11.	07/12/96 01:58	-	07/12/96 03:03	Unplanned	1.08	725.83
	Descr: Crl #114 unable to satisfy boiler purge permissive.					
12.	07/12/96 03:03	-	07/12/96 04:03	Unplanned	1.00	670.00
	Descr: Major problem restoring warmup guns and ignitor lvls.					
13.	09/19/96 09:03	-	09/20/96 18:25	Unplanned	33.37	22,355.67
	Descr: Boiler tube leak - reheat front pendant assy. #31.					
14.	09/20/96 18:25	-	09/21/96 00:19	Unplanned	5.90	3,953.00
	Descr: Reduced air flow in order to reduce stack emissions.					
15.	09/21/96 00:19	-	09/21/96 02:19	Unplanned	2.00	1,340.00
	Descr: Warmup guns and ignitor controls.					
	*** **Unit Summary for Centralia No. 1 for the year 1996 =**				159.65	106,965.50
Centralia No. 2						
1.	01/17/96 13:01	-	01/17/96 20:09	Unplanned	7.13	4,779.33
	Descr: Low voltage on #232 emergency bus caused by startup of quincy air comp					
2.	01/17/96 20:09	-	01/17/96 21:09	Unplanned	1.00	670.00
	Descr: Faulty secondary air flow transmitter 2f89d					
3.	02/07/96 00:11	-	02/07/96 23:02	Unplanned	22.85	15,309.50
	Descr: #21 aux turbine hp bearing vibration					
4.	02/07/96 23:02	-	02/08/96 00:02	Unplanned	1.00	670.00
	Descr: Erratic secondary air flow transmitters 2f89c and 2f89d					
5.	03/18/96 07:28	-	03/18/96 20:28	Unplanned	13.00	8,710.00
	Descr: Condensate pump suction plugged with piece of sheet metal causing low					
6.	03/29/96 16:00	-	03/30/96 06:31	Unplanned	14.52	9,726.17
	Descr: Valve packing blow out on #21 boiler circ pump east discharge valve					
7.	06/04/96 07:16	-	06/04/96 08:19	Unplanned	1.05	703.50
	Descr: Net 90 module configuration problem					

1996 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						
8.	06/04/96 08:19	-	06/04/96 10:04	Unplanned	1.75	1,172.50
	Descr: #22 id fan ema problem					
9.	06/04/96 10:04	-	06/04/96 13:39	Unplanned	3.58	2,400.83
	Descr: Right upper intercept valve linkage problem					
10.	06/04/96 13:39	-	06/04/96 14:54	Unplanned	1.25	837.50
	Descr: Turbine interface valve problem					
11.	07/06/96 03:41	-	07/07/96 10:52	Unplanned	31.18	20,892.83
	Descr: Reheat tube leak, front pendant assy. #9 n. half "b" loop.					
12.	07/07/96 10:52	-	07/07/96 13:18	Unplanned	2.43	1,630.33
	Descr: Bad warmup oil system relay.					
13.	07/07/96 13:18	-	07/07/96 14:18	Unplanned	1.00	670.00
	Descr: Bad coil in flame scanner relay.					
14.	07/15/96 00:13	-	07/15/96 05:57	Unplanned	5.73	3,841.33
	Descr: Failure of 480v load center #22 transformer.					
15.	07/15/96 05:57	-	07/15/96 12:27	Unplanned	6.50	4,355.00
	Descr: Main turbine turning gear motor breaker problems.					
16.	07/15/96 12:27	-	07/15/96 14:57	Unplanned	2.50	1,675.00
	Descr: Turbine rotor electricity.					
17.	09/21/96 17:48	-	09/23/96 11:38	Unplanned	41.83	28,028.33
	Descr: Reheat tube leak, assy. #15, n. "b" loop.					
18.	09/23/96 11:38	-	09/23/96 12:58	Unplanned	1.33	893.33
	Descr: Warmup & ignitor oil gun problems.					
19.	09/25/96 20:48	-	09/27/96 21:24	Unplanned	48.60	32,562.00
	Descr: Superheat tube leak caused by ik #15.					
20.	09/27/96 21:24	-	09/27/96 23:04	Unplanned	1.67	1,116.67
	Descr: Furnace pressure control problems related to new furnace pressure tran					
21.	10/07/96 17:45	-	10/08/96 18:30	Unplanned	24.75	16,582.50
	Descr: Superheat tube leak					
22.	10/08/96 18:30	-	10/11/96 16:30	Unplanned	70.00	46,900.00
	Descr: Repair 31 additional sh tubes					
23.	10/11/96 16:30	-	10/14/96 20:30	Unplanned	76.00	50,920.00
	Descr: Repair 33 rh tubes					
24.	10/14/96 20:30	-	10/15/96 04:30	Unplanned	8.00	5,360.00
	Descr: Boiler clinker					
	*** **Unit Summary for Centralia No. 2 for the year 1996 =**				388.65	260,406.65
Jim Bridger No. 1						
1.	01/05/96 12:10	-	01/06/96 00:00	Unplanned	11.83	6,153.33
	Descr: Unit off line to repair low-temp. superheat tube leak.					
2.	01/06/96 00:00	-	01/06/96 03:55	Unplanned	3.92	2,036.67
	Descr: Start up delayed-aux. air fuel air damper problems.					
3.	01/06/96 03:55	-	01/06/96 05:30	Unplanned	1.58	823.33
	Descr: Start up.					
4.	01/06/96 05:30	-	01/06/96 07:15	Unplanned	1.75	910.00
	Descr: Ignitor air filter plugged,					
5.	01/06/96 07:55	-	01/06/96 09:00	Unplanned	1.08	563.33
	Descr: Ignitor air filter plugged.					

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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				
6.	01/06/96 09:00 - 01/06/96 12:48	Unplanned	3.80	1,976.00
	Descr: Start up.			
7.	01/24/96 17:09 - 01/25/96 15:37	Unplanned	22.47	11,682.67
	Descr: Unit off line to repair tube leak-b.a. area.			
8.	01/25/96 15:37 - 01/25/96 21:34	Unplanned	5.95	3,094.00
	Descr: 12 air preheater won't start.			
9.	01/27/96 00:08 - 01/27/96 22:37	Unplanned	22.48	11,691.33
	Descr: Unit off line to repair s.h. pendant platen tube leak-panel 34.			
10.	02/01/96 10:46 - 02/02/96 04:38	Unplanned	17.87	9,290.67
	Descr: Unit off line to repair boiler tube leak-waterwall.			
11.	03/30/96 00:00 - 04/27/96 00:00	Planned	671.00	348,920.00
	Descr: Planned outage.			
12.	04/27/96 00:00 - 05/03/96 04:07	Planned	148.12	77,020.67
	Descr: Extended planned outage.			
13.	05/03/96 04:15 - 05/03/96 05:43	Unplanned	1.47	762.67
	Descr: Post outage testing-trip after start up.			
14.	05/03/96 11:55 - 05/03/96 14:22	Unplanned	2.45	1,274.00
	Descr: Overspeed testing.			
15.	05/03/96 15:15 - 05/03/96 21:04	Unplanned	5.82	3,024.67
	Descr: Unit start up.			
16.	05/03/96 21:32 - 05/05/96 12:12	Unplanned	38.67	20,106.67
	Descr: Generator electrical problems-current transformer burned up.			
17.	06/04/96 02:40 - 06/05/96 01:14	Unplanned	22.57	11,734.67
	Descr: Unit off to repair sh pendant platen tube leak.			
18.	06/07/96 19:54 - 06/08/96 17:08	Unplanned	21.23	11,041.33
	Descr: Unit off line to repair finishing sh tube leak.			
19.	06/08/96 17:08 - 06/09/96 08:31	Unplanned	15.38	7,999.33
	Descr: Unit off line to repair waterwall tube leak.			
20.	07/02/96 14:25 - 07/02/96 16:37	Unplanned	2.20	1,144.00
	Descr: Switchyard problems.			
21.	07/02/96 17:18 - 07/02/96 18:23	Unplanned	1.08	563.33
	Descr: Circ. pump delta p.			
22.	07/05/96 23:14 - 07/07/96 02:58	Unplanned	27.73	14,421.33
	Descr: Unit off line to repair main steam safety.			
23.	07/07/96 09:36 - 07/07/96 11:53	Unplanned	2.28	1,187.33
	Descr: Lost both bfp's.			
24.	08/23/96 06:24 - 08/23/96 07:45	Unplanned	1.35	702.00
	Descr: Ras trip.			
25.	10/10/96 23:00 - 10/12/96 15:06	Unplanned	40.10	20,852.00
	Descr: Unit off line for i.d. fan duct work inspection.			
26.	12/18/96 23:58 - 12/21/96 00:36	Unplanned	48.63	25,289.33
	Descr: Unit off line to deslag reheater/superheater.			
	*** **Unit Summary for Jim Bridger No. 1 for the year 1996 =**		1,142.81	594,264.66

1996 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. 2						
1.	01/28/96 09:42	-	01/28/96 16:00	Unplanned	6.30	3,276.00
	Descr: Unit off line to repair boiler tube leak and reheat spray block valve.					
2.	01/28/96 16:00	-	01/29/96 02:19	Unplanned	10.32	5,364.67
	Descr: Reheat spray block valves repairs.					
3.	02/20/96 17:09	-	02/25/96 19:45	Unplanned	122.60	63,752.00
	Descr: Unit off line to repair hydrogen leak.					
4.	04/13/96 23:13	-	04/14/96 16:00	Unplanned	16.78	8,727.33
	Descr: Unit off to repair sh tube leak.					
5.	04/14/96 16:00	-	04/15/96 05:21	Unplanned	13.35	6,942.00
	Descr: Repairs to cond/fw system.					
6.	05/01/96 23:29	-	05/03/96 00:35	Unplanned	25.10	13,052.00
	Descr: Unit off line to repair boiler tube leak.					
7.	06/26/96 23:09	-	06/29/96 21:20	Unplanned	70.18	36,495.33
	Descr: Unit off line for i.d. fan inlet vane repairs.					
8.	07/02/96 14:25	-	07/02/96 16:26	Unplanned	2.02	1,048.67
	Descr: Station trip.					
9.	09/04/96 03:41	-	09/04/96 07:48	Unplanned	4.12	2,140.67
	Descr: Unit trip-smf.					
10.	09/04/96 08:00	-	09/04/96 10:21	Unplanned	2.35	1,222.00
	Descr: Unit trip-low p.a. duct pressure-broken linkage on 22 p.a. fan feedbac					
11.	09/17/96 11:11	-	09/18/96 23:14	Unplanned	36.05	18,746.00
	Descr: Unit off line to repair waterwall tube leak.					
12.	09/27/96 03:58	-	09/28/96 00:00	Unplanned	20.03	10,417.33
	Descr: Unit off line to repair finishing superheat tube leak.					
13.	09/28/96 00:00	-	09/28/96 09:03	Unplanned	9.05	4,706.00
	Descr: I.d. fan duct work repairs.					
14.	10/01/96 23:12	-	10/03/96 05:12	Unplanned	30.00	15,600.00
	Descr: Unit off line to repair reheater tube leak.					
15.	10/05/96 16:21	-	10/05/96 18:27	Unplanned	2.10	1,092.00
	Descr: Unit off line to repair stator cooling leak.					
16.	11/08/96 23:18	-	11/09/96 22:21	Unplanned	23.05	11,986.00
	Descr: Unit off line to repair sh pendant platen tube leak.					
17.	11/13/96 01:26	-	11/13/96 02:30	Unplanned	1.07	554.67
	Descr: Unit trip-shaft oil pressure switch,					
18.	11/13/96 04:01	-	11/13/96 09:53	Unplanned	5.87	3,050.67
	Descr: Unit off line-no main steam safety-broke.					
19.	12/16/96 02:18	-	12/18/96 00:07	Unplanned	45.82	23,824.67
	Descr: Unit off line to repair reheater tube leak.					
	*** **Unit Summary for Jim Bridger No. 2 for the year 1996 =**				446.16	231,998.01
Jim Bridger No. 3						
1.	01/15/96 16:48	-	01/15/96 18:12	Unplanned	1.40	728.00
	Descr: Bcp tripped-lost unit.					
2.	02/01/96 07:39	-	02/01/96 08:59	Unplanned	1.33	693.33
	Descr: Unit off line-32 p.a. fan trip.					
3.	02/07/96 17:34	-	02/07/96 18:46	Unplanned	1.20	624.00
	Descr: 32 bfpt tripped-high drum level.					

1996 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.	02/15/96 06:16	-	02/16/96 20:07	Unplanned	37.85	19,682.00
	Descr: Unit off line to repair boiler electrical problems-burned electrical c					
5.	02/22/96 23:42	-	02/23/96 01:03	Unplanned	1.35	702.00
	Descr: Condenser tube leak.					
6.	03/15/96 16:42	-	03/15/96 18:09	Unplanned	1.45	754.00
	Descr: Boiler ph 6.95-condenser tube leak.					
7.	05/03/96 23:32	-	06/01/96 00:00	Planned	672.47	349,682.67
	Descr: Unit off line for planned outage.					
8.	06/01/96 00:00	-	06/01/96 22:36	Planned	22.60	11,752.00
	Descr: Extended time for start up after overhaul.					
9.	06/02/96 03:00	-	06/02/96 08:48	Unplanned	5.80	3,016.00
	Descr: 31 boiler circ. pump.					
10.	06/02/96 20:22	-	06/03/96 04:21	Unplanned	7.98	4,151.33
	Descr: Thrust bearing wear detector.					
11.	06/03/96 10:04	-	06/03/96 13:32	Unplanned	3.47	1,802.67
	Descr: Problems with m.t. thrust bearing wear detector.					
12.	06/03/96 14:54	-	06/04/96 00:47	Unplanned	9.88	5,139.33
	Descr: Problems with m.t. thrust bearing wear detector.					
13.	06/04/96 02:09	-	06/04/96 17:35	Unplanned	15.43	8,025.33
	Descr: Thrust bearing wear detector.					
14.	06/04/96 17:35	-	06/04/96 22:00	Unplanned	4.42	2,296.67
	Descr: Ignitor/scanner problems.					
15.	06/05/96 00:36	-	06/05/96 05:30	Unplanned	4.90	2,548.00
	Descr: Master turbine trip-thrust bearing wear detector.					
16.	06/05/96 08:09	-	06/05/96 15:53	Unplanned	7.73	4,021.33
	Descr: Thrust bearing wear detector.					
17.	06/06/96 12:41	-	06/06/96 17:03	Unplanned	4.37	2,270.67
	Descr: Both boiler feed pumps tripped-unit trip.					
18.	06/07/96 05:42	-	06/08/96 15:48	Unplanned	34.10	17,732.00
	Descr: Rh safety valve.					
19.	06/08/96 15:48	-	06/08/96 19:25	Unplanned	3.62	1,880.67
	Descr: Boiler damper problem.					
20.	06/08/96 19:25	-	06/09/96 00:06	Unplanned	4.68	2,435.33
	Descr: Start up.					
21.	06/10/96 23:53	-	06/11/96 01:39	Unplanned	1.77	918.67
	Descr: Scanner malfunction.					
22.	07/02/96 14:25	-	07/03/96 00:12	Unplanned	9.78	5,087.33
	Descr: Switchyard trip-system disturbance.					
23.	07/12/96 23:35	-	07/14/96 23:38	Unplanned	48.05	24,986.00
	Descr: Boiler tube leaks.					
24.	07/19/96 13:57	-	07/19/96 21:31	Unplanned	7.57	3,934.67
	Descr: Unit off line to inspect/repair 32 air preheater drives.					
25.	07/24/96 16:28	-	07/25/96 08:00	Unplanned	15.53	8,077.33
	Descr: Unit off line to deslag bottom ash hopper.					
26.	07/25/96 08:00	-	07/25/96 14:00	Unplanned	6.00	3,120.00
	Descr: Repair waterwall tube leaks.					

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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. 3						
27.	07/25/96 14:00	-	07/25/96 21:00	Unplanned	7.00	3,640.00
	Descr: Deslag boiler.					
28.	07/25/96 21:00	-	07/26/96 03:20	Unplanned	6.33	3,293.33
	Descr: Start up after bottom ash hopper deslag outage.					
29.	07/26/96 09:29	-	07/27/96 05:30	Unplanned	20.02	10,408.67
	Descr: 31 air preheater bound up.					
30.	09/21/96 00:00	-	09/22/96 17:00	Unplanned	41.00	21,320.00
	Descr: Unit off line to deslag rh/sh/boiler.					
31.	09/22/96 17:00	-	09/26/96 03:00	Unplanned	82.00	42,640.00
	Descr: 32 i.d. fan damaged on shutdown-gas duct wear plate fell on wheel.					
32.	09/26/96 03:00	-	09/29/96 16:48	Unplanned	85.80	44,616.00
	Descr: Repair boiler 6 inch drain valve.					
33.	10/09/96 05:01	-	10/09/96 06:13	Unplanned	1.20	624.00
	Descr: 500kv transmission line trip					
34.	10/29/96 13:17	-	10/29/96 17:01	Unplanned	3.73	1,941.33
	Descr: Unit trip, pa duct pressure (bad swtich).					
35.	11/03/96 13:38	-	11/05/96 06:01	Unplanned	40.38	20,999.33
	Descr: Unit off line-fan problems-both i.d.'s. #31 i.d. fan inlet vane drive					
36.	11/15/96 22:30	-	11/18/96 18:50	Unplanned	68.33	35,533.33
	Descr: Unit off line to return 32 i.d. fan to service.					
37.	12/12/96 02:35	-	12/12/96 21:11	Unplanned	18.60	9,672.00
	Descr: Unit off line to repair finishing superheat tube leak.					
	***** Unit Summary for Jim Bridger No. 3 for the year 1996 =**				1,309.12	680,749.32
Jim Bridger No. 4						
1.	01/02/96 22:58	-	01/03/96 22:00	Unplanned	23.03	11,977.33
	Descr: Unit off to repair aph. f.d. fan repairs.					
2.	01/03/96 22:03	-	01/04/96 01:04	Unplanned	3.02	1,568.67
	Descr: High drum level trip.					
3.	05/02/96 08:47	-	05/02/96 13:29	Unplanned	4.70	2,444.00
	Descr: Lost aux. steam control valve.					
4.	05/02/96 14:30	-	05/02/96 18:30	Unplanned	4.00	2,080.00
	Descr: Unit trip-high drum level.					
5.	05/09/96 17:11	-	05/12/96 19:00	Unplanned	73.82	38,384.67
	Descr: Unit off line to deslag reheater/superheater.					
6.	05/12/96 19:00	-	05/13/96 00:00	Unplanned	5.00	2,600.00
	Descr: Cold wash turbine.					
7.	05/13/96 00:00	-	05/13/96 05:00	Unplanned	5.00	2,600.00
	Descr: Boiler chemistry problems-ph low.					
8.	05/13/96 05:00	-	05/13/96 14:58	Unplanned	9.97	5,182.67
	Descr: Cold wash turbine.					
9.	06/28/96 13:01	-	06/29/96 14:07	Unplanned	25.10	13,052.00
	Descr: Unit off line to repair waterwall tube leak.					
10.	07/02/96 14:25	-	07/02/96 21:03	Unplanned	6.63	3,449.33
	Descr: Unit trip-system disturbance.					
11.	07/07/96 22:21	-	07/09/96 00:02	Unplanned	25.68	13,355.33
	Descr: Unit off line to repair 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.	07/09/96 01:19	-	07/09/96 04:03	Unplanned	2.73	1,421.33
	Descr: Unit trip-transferring to aux. transformer and aux. breakers not racke					
13.	07/09/96 04:33	-	07/09/96 05:55	Unplanned	1.37	710.67
	Descr: Unit trip-high drum level.					
14.	07/23/96 10:44	-	07/24/96 13:02	Unplanned	26.30	13,676.00
	Descr: Unit off line to repair waterwall tube leak.					
15.	11/30/96 10:53	-	12/01/96 10:00	Unplanned	23.12	12,020.67
	Descr: Unit off line to repair waterwall tube leaks.					
16.	12/01/96 10:00	-	12/01/96 19:06	Unplanned	9.10	4,732.00
	Descr: Start up failure-f.d. fan inlet vane problems.					
17.	12/01/96 22:48	-	12/02/96 09:16	Unplanned	10.47	5,442.67
	Descr: Unit off line to repair air preheater and f.d. fan problems.					
18.	12/02/96 13:32	-	12/02/96 15:47	Unplanned	2.25	1,170.00
	Descr: Operator tripped unit-feedwater control problems.					
19.	12/15/96 20:24	-	12/15/96 21:55	Unplanned	1.52	788.67
	Descr: Unit trip-thrust bearing wear detector.					
20.	12/16/96 01:45	-	12/16/96 03:57	Unplanned	2.20	1,144.00
	Descr: Unit trip-thrust bearing wear detector-low oil pressure.					
	***** Unit Summary for Jim Bridger No. 4 for the year 1996 =**				265.01	137,800.01
Cholla No. 4						
1.	01/26/96 04:00	-	01/27/96 05:03	Unplanned	25.05	9,519.00
	Descr: Water box isolation valves seats rebuilt					
2.	01/27/96 06:07	-	01/27/96 08:37	Unplanned	2.50	950.00
	Descr: Feedwater flow upset					
3.	02/05/96 16:08	-	02/05/96 21:43	Unplanned	5.58	2,121.67
	Descr: Debris in water box caused high back pressure					
4.	02/06/96 07:41	-	02/06/96 14:43	Unplanned	7.03	2,672.67
	Descr: Debris in water box caused high back pressure					
5.	02/27/96 06:00	-	02/27/96 21:00	Unplanned	15.00	5,700.00
	Descr: Fuel oil controls problem					
6.	02/27/96 22:04	-	02/28/96 03:31	Unplanned	5.45	2,071.00
	Descr: False drum level indication					
7.	02/28/96 03:42	-	02/28/96 08:02	Unplanned	4.33	1,646.67
	Descr: False drum level indication					
8.	03/09/96 02:04	-	07/01/96 00:00	Planned	2,732.93	1,038,514.67
	Descr: Off line for overhaul					
9.	07/01/96 00:00	-	07/14/96 02:01	Planned	314.02	119,326.33
	Descr: Overhaul					
10.	07/24/96 14:43	-	07/24/96 17:31	Unplanned	2.80	1,064.00
	Descr: Volts/hertz trip					
11.	07/26/96 23:19	-	07/28/96 12:29	Unplanned	37.17	14,123.33
	Descr: Repair waterwall tube leak					
12.	08/03/96 12:29	-	08/03/96 13:53	Unplanned	1.40	532.00
	Descr: Boiler upset due to burner control malfunction					
13.	08/04/96 02:48	-	08/04/96 03:54	Unplanned	1.10	418.00
	Descr: Main flame loss caused feedwater flow upset					

1996 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						
14.	08/06/96 09:58	-	08/08/96 20:52	Unplanned	58.90	22,382.00
	Descr: Repair boiler tube leak					
15.	08/08/96 21:40	-	08/08/96 23:08	Unplanned	1.47	557.33
	Descr: Feedwater flow upset, high drum level					
16.	08/23/96 07:49	-	08/23/96 10:25	Unplanned	2.60	988.00
	Descr: Furnace pressure upset while blowing furnace taps					
17.	08/23/96 14:43	-	08/23/96 15:44	Unplanned	1.02	386.33
	Descr: Feedwater flow upset					
18.	08/28/96 11:05	-	08/28/96 19:07	Unplanned	8.03	3,052.67
	Descr: Station service transformer 4b2 failure					
19.	08/31/96 01:48	-	08/31/96 03:22	Unplanned	1.57	595.33
	Descr: Ehc pressure failure, b pump discharge line leak					
20.	09/06/96 22:24	-	09/08/96 13:34	Unplanned	39.17	14,883.33
	Descr: Off line to repair tube leak					
21.	09/08/96 14:09	-	09/08/96 15:43	Unplanned	1.57	595.33
	Descr: 'a' boiler feed pump fill valve blocked at 30% open causing low drum					
22.	10/28/96 11:58	-	10/28/96 13:48	Unplanned	1.83	696.67
	Descr: Water backed up into instrument air system					
23.	12/23/96 13:06	-	12/23/96 17:06	Unplanned	4.00	1,520.00
	Descr: Loss of sealing water to vacuum pumps					
	*** * * Unit Summary for Cholla No. 4 for the year 1996 =**				3,274.52	1,244,316.33
Dave Johnston No. 1						
1.	01/06/96 13:42	-	01/06/96 18:12	Unplanned	4.50	477.00
	Descr: All feeders shut off					
2.	03/10/96 23:25	-	03/18/96 07:17	Unplanned	175.87	18,641.87
	Descr: Waterwall tube leak					
3.	03/26/96 23:10	-	03/28/96 00:11	Unplanned	25.02	2,651.77
	Descr: Tube leak					
4.	07/25/96 02:25	-	07/30/96 17:35	Unplanned	135.17	14,327.67
	Descr: Massive water wall tube rupture					
5.	09/27/96 09:11	-	09/27/96 10:21	Unplanned	1.17	123.67
	Descr: Off line lost 1a id - 2400 volt ground					
	*** * * Unit Summary for Dave Johnston No. 1 for the year 1996**				341.73	36,221.98
Dave Johnston No. 2						
1.	01/31/96 13:30	-	02/01/96 13:06	Unplanned	23.60	2,501.60
	Descr: Psh tube leak - taking unit off					
2.	02/05/96 23:00	-	02/08/96 11:43	Unplanned	60.72	6,435.97
	Descr: Psh tube leak					
3.	02/13/96 03:00	-	02/13/96 21:21	Unplanned	18.35	1,945.10
	Descr: Tube leak repair					
4.	04/11/96 00:06	-	04/12/96 21:22	Unplanned	45.27	4,798.27
	Descr: Tube leak economizer					
5.	04/12/96 21:28	-	04/12/96 22:48	Unplanned	1.33	141.33
	Descr: Vacuum trip - differential expansion					
6.	06/17/96 09:47	-	06/17/96 21:36	Unplanned	11.82	1,252.57
	Descr: Tripped 2a mcc					

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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
Dave Johnston No. 2						
7.	06/18/96 02:52	-	06/18/96 15:05	Unplanned	12.22	1,294.97
	Descr: Main steam feed to steam seal reg. - packing blew					
8.	07/30/96 23:15	-	08/02/96 06:30	Unplanned	55.25	5,856.50
	Descr: Tube leak - econo					
9.	08/02/96 07:00	-	08/02/96 13:23	Unplanned	6.38	676.63
	Descr: Right side stop valve after seat drain line split					
10.	08/14/96 22:02	-	08/16/96 18:20	Unplanned	44.30	4,695.80
	Descr: Tube leak - cooling turbine out					
11.	08/16/96 18:20	-	08/17/96 07:09	Unplanned	12.82	1,358.57
	Descr: No condensate for start-up					
12.	09/12/96 06:00	-	09/12/96 07:30	Unplanned	1.50	159.00
	Descr: Condenser work					
13.	09/23/96 04:19	-	09/25/96 10:42	Unplanned	54.38	5,764.63
	Descr: Psh tube leak					
14.	09/25/96 11:00	-	09/25/96 12:13	Unplanned	1.22	128.97
	Descr: Mft low vacuum					
15.	11/03/96 03:10	-	11/04/96 05:41	Unplanned	26.52	2,810.77
	Descr: 480 volt bus blew up					
	*** * * Unit Summary for Dave Johnston No. 2 for the year 1996**				375.68	39,820.68
Dave Johnston No. 3						
1.	01/01/96 00:00	-	02/23/96 16:37	Unplanned	1,288.62	296,381.83
	Descr: 3b paf mechanical failure.					
2.	02/23/96 18:00	-	02/23/96 20:48	Unplanned	2.80	644.00
	Descr: Operator trip - ac/dc circuits					
3.	02/24/96 07:05	-	02/24/96 14:00	Unplanned	6.92	1,590.83
	Descr: 4160 "a" buss arcing					
4.	03/25/96 15:08	-	03/27/96 16:11	Unplanned	49.05	11,281.50
	Descr: Off line					
5.	04/09/96 21:44	-	04/10/96 07:45	Unplanned	10.02	2,303.83
	Descr: 'a' mill tripped - unit tripped draft mft ckt being checked.					
6.	04/21/96 13:02	-	04/22/96 03:59	Unplanned	14.95	3,438.50
	Descr: Tube leak					
7.	05/29/96 15:02	-	05/29/96 20:39	Unplanned	5.62	1,291.83
	Descr: Mft - draft - x-mitter accidentally hit by piece of pipe.					
8.	06/08/96 00:55	-	06/08/96 07:55	Unplanned	7.00	1,610.00
	Descr: Repair x-over leak					
9.	06/22/96 23:40	-	06/23/96 08:35	Unplanned	8.92	2,050.83
	Descr: 3a feeder coupling failedmft draft					
10.	07/11/96 19:20	-	07/12/96 00:51	Unplanned	5.52	1,268.83
	Descr: Trip due to loss of ac					
11.	09/27/96 21:40	-	09/29/96 20:44	Unplanned	47.07	10,825.33
	Descr: Unit oos 3b pa fan 3b pa fan replacement					
12.	10/07/96 14:03	-	10/07/96 17:37	Unplanned	3.57	820.33
	Descr: Mft - boiler trip onfurnace pressure					
13.	10/14/96 09:30	-	10/14/96 11:50	Unplanned	2.33	536.67
	Descr: Low vacuum - pond flushing					

1996 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						
14.	10/23/96 22:32	-	10/24/96 23:23	Unplanned	24.85	5,715.50
	Descr: Nw drum safety will not seat					
15.	12/08/96 20:01	-	12/08/96 22:23	Unplanned	2.37	544.33
	Descr: Vac trip on bw					
	*** * * Unit Summary for Dave Johnston No. 3 for the year 1996**				1,479.61	340,304.14
Dave Johnston No. 4						
1.	02/10/96 21:22	-	02/12/96 18:40	Unplanned	45.30	14,949.00
	Descr: Tube leak - east waterwall					
2.	02/12/96 21:07	-	02/13/96 00:21	Unplanned	3.23	1,067.00
	Descr: Hi drum level					
3.	02/14/96 18:54	-	02/15/96 11:12	Unplanned	16.30	5,379.00
	Descr: Flange leak on turbine hp/ip balance port					
4.	03/02/96 21:02	-	03/03/96 22:34	Unplanned	25.53	8,426.00
	Descr: Lower ww tube leak					
5.	05/18/96 23:33	-	05/20/96 00:35	Unplanned	25.03	8,261.00
	Descr: Unit off - 4bah coupling replace					
6.	08/11/96 00:40	-	08/12/96 02:30	Unplanned	25.83	8,525.00
	Descr: Tube leak repair					
7.	08/12/96 02:30	-	08/13/96 00:05	Unplanned	21.58	7,122.50
	Descr: Feedwater block valve leaks					
8.	08/15/96 07:50	-	08/16/96 05:29	Unplanned	21.65	7,144.50
	Descr: Id fan tripped - 4b scrubber plumbob shaft broke					
9.	08/16/96 06:34	-	08/16/96 07:45	Unplanned	1.18	390.50
	Descr: Turbine vacuum trip					
10.	08/21/96 10:20	-	08/21/96 12:13	Unplanned	1.88	621.50
	Descr: Lost power to controls, operator trip					
11.	10/04/96 22:34	-	10/07/96 11:13	Unplanned	60.65	20,014.50
	Descr: Outage					
12.	10/27/96 00:45	-	10/28/96 06:01	Unplanned	30.27	9,988.00
	Descr: Water wall tube leak					
13.	10/28/96 06:26	-	10/29/96 08:59	Unplanned	26.55	8,761.50
	Descr: Water wall tube leak					
	*** * * Unit Summary for Dave Johnston No. 4 for the year 1996**				304.98	100,650.00
Carbon No. 1						
1.	01/10/96 21:15	-	01/10/96 22:52	Unplanned	1.62	113.17
	Descr: 1-1 boiler feed pump was out of service to replace the barrel. 1-2					
2.	01/17/96 19:21	-	01/18/96 16:00	Unplanned	20.65	1,445.50
	Descr: Unit was scheduled off line to repair an economizer tube leak. howev					
3.	01/18/96 16:00	-	01/19/96 18:48	Unplanned	26.80	1,876.00
	Descr: The unit was off line to repair an economizer tube leak. the econo					
4.	01/26/96 11:51	-	01/26/96 13:46	Unplanned	1.92	134.17
	Descr: A drum level transmitter was being calibrated from the max 1000 contr					
5.	06/08/96 10:57	-	06/08/96 19:04	Unplanned	8.12	568.17
	Descr: Unit trip - 1-5 feedwater heater tube leak - unable to maintain drum					
6.	07/07/96 03:02	-	07/07/96 14:00	Unplanned	10.97	767.67
	Descr: Economizer tube leak - the unit had been plugging for a couple of week					

1996 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						
7.	07/07/96 14:00	-	07/08/96 14:00	Unplanned	24.00	1,680.00
	Descr: The unit was taken off line for an economizer tube leak. the leak was					
8.	07/08/96 14:00	-	07/09/96 14:42	Unplanned	24.70	1,729.00
	Descr: The unit was taken off line for an economizer tube leak. the leak was					
9.	08/30/96 07:27	-	08/31/96 12:18	Unplanned	28.85	2,019.50
	Descr: The unit was taken off line to repair three tube leaks in the lowtempe					
10.	09/13/96 00:03	-	09/14/96 06:32	Unplanned	30.48	2,133.83
	Descr: Lightning hit the main transformer					
11.	10/15/96 22:25	-	10/19/96 05:33	Unplanned	79.13	5,539.33
	Descr: Unit was taken off line for high id fan vibration. the fan blades					
12.	10/27/96 17:04	-	10/28/96 20:39	Unplanned	27.58	1,930.83
	Descr: Unit off line for high te,perature superheat tube leak. an alignment					
13.	12/04/96 15:39	-	12/05/96 03:06	Unplanned	11.45	801.50
	Descr: 1-1 air preheater circumferential seals broke loose and bound the air					
14.	12/05/96 04:51	-	12/05/96 12:50	Unplanned	7.98	558.83
	Descr: Unit trip (low drum level). the unit had been off line to repair1-1 a					
15.	12/17/96 22:13	-	12/18/96 00:07	Unplanned	1.90	133.00
	Descr: Unit trip - boiler trip. operations and maintenance are unsure if the					
16.	12/18/96 00:29	-	12/18/96 05:24	Unplanned	4.92	344.17
	Descr: The unit had tripped off line and was put back on line. the turbine					
	*** **Unit Summary for Carbon No. 1 for the year 1996 =**				311.07	21,774.67
Carbon No. 2						
1.	01/29/96 22:20	-	01/31/96 18:00	Unplanned	43.67	4,585.00
	Descr: Unit was taken off line to clean the economizer					
2.	01/31/96 18:00	-	01/31/96 22:00	Unplanned	4.00	420.00
	Descr: Unit had been off line to clean the economizer. after completingthe h					
3.	01/31/96 22:00	-	02/02/96 05:19	Unplanned	31.32	3,288.25
	Descr: Unit had been off line to clean the economizer after completingthe h					
4.	02/03/96 08:15	-	02/05/96 02:22	Unplanned	42.12	4,422.25
	Descr: Main condenser tube leak					
5.	03/07/96 16:16	-	03/07/96 20:43	Unplanned	4.45	467.25
	Descr: Turbine thrust bearing pressure switch leaked oil and started a fire					
6.	03/07/96 20:55	-	03/09/96 07:36	Unplanned	34.68	3,641.75
	Descr: Turbine thrust bearing pressure switch was reading 80 psi. the unit					
7.	05/05/96 20:18	-	05/05/96 21:31	Unplanned	1.22	127.75
	Descr: The unit was at full load. rocks in the coal passed thru the grizzly					
8.	05/24/96 10:54	-	05/24/96 23:30	Unplanned	12.60	1,323.00
	Descr: Unit trip due to an economizer tube leak - cro was unable to maintain					
9.	05/24/96 23:30	-	05/26/96 12:30	Unplanned	37.00	3,885.00
	Descr: Unit was off line for an economizer tube leak. the unit remained off					
10.	05/26/96 12:30	-	05/26/96 16:49	Unplanned	4.32	453.25
	Descr: Unit was off line for an economizer tube leak and to clean the econo					
11.	05/27/96 12:19	-	05/27/96 16:30	Unplanned	4.18	439.25
	Descr: The unit was removed from service to repair an oil leak in the station					
12.	05/27/96 16:30	-	05/28/96 01:35	Unplanned	9.08	953.75
	Descr: The unit had been off line to repair a leak in the station service					

1996 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						
13.	06/01/96 22:50	-	06/02/96 02:10	Unplanned	3.33	350.00
	Descr: The station service transformer developed an oil leak and was repaired					
14.	08/07/96 23:42	-	08/10/96 06:44	Unplanned	55.03	5,778.50
	Descr: The unit was taken off line because the economizer was plugged (ie,p					
15.	11/13/96 23:00	-	11/16/96 02:03	Unplanned	51.05	5,360.25
	Descr: Unit was taken off line to wash the economizer which was plugged with					
16.	12/29/96 13:22	-	01/01/97 00:00	Unplanned	58.63	6,156.50
	Descr: Unit was taken off line due to #8 exciter bearing high temperature.					
	*** * * Unit Summary for Carbon No. 2 for the year 1996 =**				396.68	41,651.75
Gadsby No. 1						
1.	02/03/96 08:45	-	02/03/96 11:02	Unplanned	2.28	137.00
	Descr: Da and drum level indicators were froze up causing an inaccurate high					
2.	07/10/96 15:35	-	07/10/96 16:35	Unplanned	1.00	60.00
	Descr: Flame scanner failed causing the unit to trip. dispatch elected to ke					
3.	09/16/96 15:34	-	09/16/96 22:00	Unplanned	6.43	386.00
	Descr: Hotwell level indicator showed normal level when actually it was empty					
	*** * * Unit Summary for Gadsby No. 1 for the year 1996 =**				9.71	583.00
Gadsby No. 2						
1.	06/13/96 08:21	-	06/13/96 09:30	Unplanned	1.15	86.25
	Descr: Start up trip					
2.	07/10/96 15:03	-	07/10/96 19:12	Unplanned	4.15	311.25
	Descr: A temporary fitting for testing pressure began leaking. the fitting w					
3.	09/09/96 13:17	-	09/09/96 14:29	Unplanned	1.20	90.00
	Descr: Voltage regulator tripped unit					
4.	09/09/96 17:01	-	09/09/96 19:00	Unplanned	1.98	148.75
	Descr: Voltage regulator tripped unit again					
5.	09/10/96 09:04	-	09/10/96 12:49	Unplanned	3.75	281.25
	Descr: Arcing in exciter.					
6.	09/16/96 07:45	-	09/16/96 22:30	Unplanned	14.75	1,106.25
	Descr: Exciter throwing sparks, found exciter shaft moved about 1/4". coupli					
7.	09/17/96 07:00	-	09/17/96 16:30	Unplanned	9.50	712.50
	Descr: Exciter was throwing sparks, found that the exciter shaft moved 1/4".					
	*** * * Unit Summary for Gadsby No. 2 for the year 1996 =**				36.48	2,736.25
Gadsby No. 3						
1.	06/12/96 16:43	-	06/12/96 21:15	Unplanned	4.53	453.33
	Descr: I&c tech was test drum level "a" norht control when he tripped the uni					
2.	07/12/96 18:16	-	07/12/96 23:25	Unplanned	5.15	515.00
	Descr: Overheating of tube caused departure from nucleate boiling.					
3.	08/10/96 09:10	-	08/10/96 23:27	Unplanned	14.28	1,428.33
	Descr: The unit was not available for operation because of circulating water					
4.	08/11/96 10:20	-	08/12/96 09:01	Unplanned	22.68	2,268.33
	Descr: Ciriculating water piping leak. the outage was set for the time the u					
	*** * * Unit Summary for Gadsby No. 3 for the year 1996 =**				46.64	4,664.99

1996 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. 1						
1.	02/02/96 11:37	-	02/02/96 12:37	Unplanned	1.00	160.00
	Descr: Unit trip ups system failed					
2.	02/24/96 00:00	-	02/25/96 02:51	Unplanned	26.85	4,296.00
	Descr: Unit off line 1-6 & 1-7 fwh problems					
3.	07/10/96 06:27	-	07/10/96 18:17	Unplanned	11.83	1,893.33
	Descr: Condenser tube leak, low drum ph					
4.	09/06/96 02:34	-	09/06/96 07:01	Unplanned	2.23	356.00
	Descr: Boiler furnace draft trip - control problem fd & id					
5.	09/06/96 02:34	-	09/06/96 07:01	Unplanned	2.22	354.67
	Descr: Boiler furnace draft trip - control problem fd & id					
6.	10/26/96 05:00	-	10/26/96 20:23	Unplanned	15.38	2,461.33
	Descr: Unit trip - air flow transmitter failure					
7.	10/26/96 22:01	-	10/26/96 23:26	Unplanned	1.42	226.67
	Descr: Unit trip - electricians, stop valve bypass-ran valves closed on turbi					
8.	11/06/96 23:05	-	11/08/96 05:12	Unplanned	30.12	4,818.67
	Descr: Repair broken circ water lines					
	*** **Unit Summary for Naughton No. 1 for the year 1996 =**				91.05	14,566.67
Naughton No. 2						
1.	02/02/96 11:32	-	02/02/96 13:10	Unplanned	1.63	343.00
	Descr: Unit trip ups system failed					
2.	02/02/96 13:17	-	02/02/96 14:56	Unplanned	1.65	346.50
	Descr: No load timer					
3.	03/13/96 11:43	-	03/15/96 07:05	Unplanned	43.37	9,107.00
	Descr: Unit off, boiler airflow problems, inspect tilts & windbox					
4.	03/24/96 01:15	-	03/24/96 03:19	Unplanned	2.07	434.00
	Descr: Tripped doing sunday valve tests					
5.	03/27/96 14:15	-	03/27/96 16:23	Unplanned	2.13	448.00
	Descr: Voltage regulator problems - sl engineering					
6.	05/17/96 20:30	-	06/26/96 01:00	Planned	940.50	197,505.00
	Descr: Major turbine overhaul					
7.	06/26/96 10:30	-	06/26/96 19:55	Unplanned	9.42	1,977.50
	Descr: Turbine balance shot					
8.	08/03/96 23:25	-	08/05/96 01:16	Unplanned	25.85	5,428.50
	Descr: Cleaned plugged condenser water boxes, plugged w/plastic from cooling					
9.	11/09/96 23:00	-	11/11/96 12:15	Unplanned	37.25	7,822.50
	Descr: Condenser tube leak repair, boiler plugged with ash					
10.	11/30/96 05:15	-	12/01/96 20:59	Unplanned	39.73	8,344.00
	Descr: Unit trip generator ground fault					
11.	12/10/96 23:00	-	12/11/96 02:55	Unplanned	3.92	822.50
	Descr: Electricians repaired 480 circuit brkr on 1-3 raw water pump					
	*** **Unit Summary for Naughton No. 2 for the year 1996 =**				1,107.52	232,578.50
Naughton No. 3						
1.	01/23/96 00:55	-	01/25/96 07:00	Unplanned	54.08	17,847.50
	Descr: Repair waterwall (7) tube leaks					
2.	01/25/96 07:00	-	01/26/96 07:59	Unplanned	12.49	4,122.25
	Descr: Weld repair 3-1 id fan blade					

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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
Naughton No. 3						
3.	01/25/96 07:00	-	01/26/96 07:59	Unplanned	12.48	4,119.50
	Descr: 3-1 & 3-2 bfp cleaned & flushed oil, 3-1 gov-servo mtr replcd bushings					
4.	01/26/96 08:37	-	01/26/96 13:36	Unplanned	4.98	1,644.50
	Descr: High drum level trip, transfer pwr startup to aux caused trip, south s					
5.	04/03/96 17:49	-	04/05/96 11:26	Unplanned	41.62	13,733.50
	Descr: Low drum ph, cleaned a&b absorbers, chem clean					
6.	05/16/96 07:25	-	05/18/96 01:32	Unplanned	42.12	13,898.50
	Descr: Economizer tube leak, cleaned scrubber absorbers					
7.	07/02/96 08:54	-	07/02/96 20:41	Unplanned	11.78	3,888.50
	Descr: Boiler trip, 3-2bfpt oil probs ran bfpt out, then turbine valve kept u					
8.	07/02/96 21:01	-	07/03/96 11:24	Unplanned	14.38	4,746.50
	Descr: Unit off to repair governor valve problems, dirt in hydraulics					
9.	09/12/96 10:58	-	09/13/96 14:00	Unplanned	27.03	8,921.00
	Descr: Economizer tube leak forced unit offline-ipc on site					
10.	09/13/96 00:00	-	09/18/96 05:15	Unplanned	55.62	18,353.50
	Descr: Install valves on cooling tower					
11.	09/13/96 00:00	-	09/18/96 05:15	Unplanned	55.63	18,356.25
	Descr: Scrubber absorbers cleaned					
12.	09/22/96 00:21	-	09/22/96 02:08	Unplanned	1.78	588.50
	Descr: Boiler trip operator error					
13.	09/22/96 05:25	-	09/25/96 10:48	Unplanned	77.38	25,536.50
	Descr: Repair economizer tube leak, air preheater wash					
14.	11/20/96 09:59	-	11/21/96 06:30	Unplanned	20.52	6,770.50
	Descr: Unit off line to repair front coutant slope waterwall tube leak					
15.	11/20/96 14:00	-	11/22/96 12:09	Unplanned	29.65	9,784.50
	Descr: A&b scrubber absorbers cleaned, guillotine damper b side wouldn't clos					
16.	12/12/96 03:00	-	12/12/96 05:09	Unplanned	2.15	709.50
	Descr: 3-2 bfp trip tri-send filters plugged					
17.	12/12/96 05:25	-	12/12/96 06:44	Unplanned	1.32	434.50
	Descr: 3-2 bfpt trip tri-send filters plugged					
	*** **Unit Summary for Naughton No. 3 for the year 1996 =**				465.01	153,455.50
Huntington No. 1						
1.	04/03/96 19:00	-	04/04/96 23:40	Unplanned	28.67	12,040.00
	Descr: Tube leak					
2.	04/11/96 11:15	-	04/14/96 19:00	Unplanned	79.75	33,495.00
	Descr:					
3.	04/14/96 19:00	-	04/15/96 20:20	Unplanned	25.33	10,640.00
	Descr: Leak					
4.	04/23/96 23:49	-	04/29/96 13:43	Unplanned	133.90	56,238.00
	Descr: Clean					
5.	05/02/96 07:34	-	05/02/96 11:41	Unplanned	4.12	1,729.00
	Descr: Trip					
6.	05/03/96 23:01	-	05/04/96 15:16	Unplanned	16.25	6,825.00
	Descr: Trip					
7.	05/27/96 18:35	-	05/28/96 21:56	Unplanned	27.35	11,487.00
	Descr: Explosion					

1996 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						
8.	06/27/96 02:12	-	06/30/96 00:22	Unplanned	70.17	29,470.00
	Descr: Leak					
9.	07/14/96 08:50	-	07/15/96 20:30	Unplanned	35.67	14,980.00
	Descr: Tube leak					
10.	08/16/96 23:03	-	08/18/96 21:30	Unplanned	46.45	19,509.00
	Descr: Tube leak					
11.	11/23/96 00:00	-	11/24/96 05:41	Unplanned	29.68	12,467.00
	Descr: Leak					
12.	12/16/96 08:23	-	12/17/96 00:37	Unplanned	16.23	6,818.00
	Descr: Sprinkler system went off causing unit to trip - 138 kv disconnect					
	*** **Unit Summary for Huntington No. 1 for the year 1996 =**				513.57	215,698.00
Huntington No. 2						
1.	01/18/96 01:10	-	01/18/96 17:10	Unplanned	16.00	6,800.00
	Descr: Leak					
2.	01/18/96 17:10	-	01/22/96 14:05	Unplanned	92.92	39,489.58
	Descr: Leak					
3.	01/22/96 19:56	-	01/23/96 13:30	Unplanned	17.57	7,465.83
	Descr: Leak					
4.	01/23/96 13:30	-	01/24/96 00:00	Unplanned	10.50	4,462.50
	Descr: Will not close					
5.	01/25/96 09:10	-	01/26/96 10:18	Unplanned	25.13	10,681.67
	Descr: Leak					
6.	03/18/96 12:17	-	03/19/96 17:00	Unplanned	28.72	12,204.58
	Descr: Second reheater tube leak					
7.	04/14/96 00:00	-	04/14/96 13:13	Unplanned	13.22	5,617.08
	Descr: Tube leak					
8.	05/27/96 18:34	-	05/28/96 21:56	Unplanned	27.37	11,630.83
	Descr: Unit trip					
9.	05/28/96 21:56	-	06/12/96 16:41	Unplanned	354.75	150,768.75
	Descr: Damaged					
10.	07/13/96 23:00	-	07/16/96 17:00	Unplanned	66.00	28,050.00
	Descr: Deslagging					
11.	07/16/96 19:00	-	07/16/96 20:00	Unplanned	1.00	425.00
	Descr: Deslagging					
12.	09/22/96 07:53	-	09/22/96 13:00	Unplanned	5.12	2,174.58
	Descr: Wash					
13.	09/22/96 13:00	-	09/24/96 00:25	Unplanned	35.42	15,052.08
	Descr: Will not close					
14.	10/02/96 00:22	-	10/02/96 06:00	Unplanned	5.63	2,394.17
	Descr: Failure					
15.	10/02/96 06:00	-	10/03/96 03:48	Unplanned	21.80	9,265.00
	Descr: Leak					
16.	10/03/96 03:48	-	10/03/96 09:41	Unplanned	5.88	2,500.42
	Descr: Startup failure					
17.	10/18/96 16:26	-	10/19/96 09:30	Unplanned	17.07	7,253.33
	Descr: Failure					
	*** **Unit Summary for Huntington No. 2 for the year 1996 =**				744.10	316,235.40

1996 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						
1.	03/02/96 04:02	-	03/02/96 21:18	Unplanned	17.27	5,784.33
	Descr: Waterwall tube leak caused by previous deslagging.					
2.	03/02/96 21:18	-	03/03/96 01:18	Unplanned	4.00	1,340.00
	Descr: Lighter problems delayed startup.					
3.	06/19/96 20:21	-	06/20/96 04:08	Unplanned	7.78	2,607.42
	Descr: Motor leads shorted.					
4.	06/20/96 04:08	-	06/20/96 05:24	Unplanned	1.27	424.33
	Descr: Unit tripped on high vibration.					
5.	06/20/96 05:33	-	06/20/96 07:31	Unplanned	1.97	658.83
	Descr: Unit tripped on high vibration.					
6.	07/22/96 19:52	-	07/24/96 21:06	Unplanned	49.23	16,493.17
	Descr: Tube leak.					
7.	07/25/96 01:12	-	07/25/96 23:12	Unplanned	22.00	7,370.00
	Descr: Tube leak.					
8.	07/26/96 01:50	-	07/27/96 04:30	Unplanned	26.67	8,933.33
	Descr: Tube leak.					
9.	08/18/96 01:55	-	08/19/96 04:13	Unplanned	26.30	8,810.50
	Descr: Tube leak.					
10.	08/19/96 04:23	-	08/19/96 05:52	Unplanned	1.48	496.92
	Descr: Problems with lighter groups caused unit to trip - high drum level.					
11.	12/03/96 17:21	-	12/03/96 20:20	Unplanned	2.98	999.42
	Descr: Tripped breaker, back-up failed to operate					
12.	12/14/96 00:08	-	12/15/96 03:38	Unplanned	27.50	9,212.50
	Descr: Water wall tube leak					
	*** Unit Summary for Wyodak for the year 1996 =				188.45	63,130.75
Little Mountain						
1.	05/01/96 07:15	-	05/31/96 00:00	Planned	712.75	9,978.50
	Descr: Turbine inspection and minor overhaul;some minor boiler workoverhaul c					
2.	09/14/96 06:00	-	09/14/96 23:40	Unplanned	17.67	247.33
	Descr: Minor boiler maintenance while gslm was down for short outage					
3.	09/24/96 13:30	-	09/24/96 18:28	Unplanned	4.97	69.53
	Descr: Unit was taken off line to check high generator stator temp. alarm					
4.	11/14/96 17:15	-	11/14/96 18:45	Unplanned	1.50	21.00
	Descr: Over temperature channel trip 26et1					
	*** Unit Summary for Little Mountain for the year 1996 =				736.89	10,316.36
Blundell						
1.	02/18/96 14:25	-	02/18/96 17:18	Unplanned	2.88	66.32
	Descr: Took unit off line to repair an ehc leak on the control valve					
2.	02/28/96 08:41	-	03/01/96 19:11	Unplanned	58.50	1,345.50
	Descr: Unit off line to repair control valve					
3.	03/01/96 22:22	-	03/02/96 19:29	Unplanned	21.12	485.68
	Descr: Unit off line to repair condenser screens					
4.	04/05/96 16:37	-	04/05/96 22:24	Unplanned	5.78	133.02
	Descr: Brine isolation valve at well 54-3 replaced					
5.	06/13/96 12:30	-	06/13/96 15:39	Unplanned	3.15	72.45
	Descr: Unit tripped. steam supplier lost vent stack control					

1996 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
Blundell						
6.	07/01/96 13:40	-	07/01/96 21:16	Unplanned	7.60	174.80
	Descr: Unit runback - transmission line problems					
7.	07/02/96 14:25	-	07/02/96 21:54	Unplanned	7.48	172.12
	Descr: Unit runback - transmission line problems					
8.	07/14/96 11:15	-	07/14/96 13:00	Unplanned	1.75	40.25
	Descr: Unit trip - lost br-4, br-5a and then the unit					
9.	07/15/96 20:06	-	07/15/96 21:13	Unplanned	1.12	25.68
	Descr: A lightening strike cause ocb-21 to open which took the unit off line					
10.	08/10/96 16:57	-	08/10/96 18:30	Unplanned	1.55	35.65
	Descr: Unit run back - ocb21 opened due to system problems					
11.	09/17/96 05:41	-	09/19/96 15:40	Unplanned	57.98	1,333.62
	Descr: Repair turbine control valve					
12.	10/15/96 03:25	-	10/15/96 13:25	Unplanned	10.00	230.00
	Descr: Unit tripped during start up. unit kept off line because of problem					
13.	11/18/96 09:11	-	11/18/96 10:40	Unplanned	1.48	34.12
	Descr: Unit tripped when mcc b12 opened up					
	*** **Unit Summary for Blundell for the year 1996 =**				180.39	4,149.21

HYDRO FORCED OUTAGE REPORT
Outages of 24 hours or longer duration

Plant	Date	Tme Offline	Date	Time Online	Outage Hours	Reason
Bend Plant Unit #1	07/15/96	9:30	07/16/96	12:30	27	Broken grate raker.
Bend Plant Unit #2	07/15/96	10:00	07/16/96	12:30	27	Broken grate raker.
Bend Plant Unit #3	07/15/96	10:00	07/16/96	14:00	28	Broken grate raker.
Big Fork Unit #2	03/01/96	9:39	03/18/96	15:43	438	Leak in bearing cooling coil.
Big Fork Unit #3	01/01/96	0:01	01/10/96	16:03	256	Governor actuator problem.
Cline Falls	10/29/96	13:30	11/06/96	9:30	188	Generator bearing repair.
Condit, Unit #1	02/08/96	17:20	04/12/96	16:45	1,512	Flooded powerhouse.
Condit, Unit #2	02/08/96	17:20	06/05/96	13:32	2,808	Flooded powerhouse.
Condit, Unit #1	12/23/96	8:20	01/03/97	11:20	267	Cleaned bearing water jacket.
Powerdale	11/19/96	16:37	11/21/96	15:19	47	Ice, no transmission line.
Powerdale	12/26/96	11:26	12/27/96	17:03	30	Fish screens iced up.
Powerdale	12/29/96	8:43	12/30/96	15:35	31	Fish screens iced up.
John C Boyle	02/18/96		02/20/96		72	Out of service due to bombing.
John C Boyle	09/14/96		09/15/96		24	Failed lightning arrestor on transformer.
West Side	09/05/96		09/22/96		408	Wiped bearing.
Eagle Point	01/09/96	16:00	01/16/96	10:45	162	Because of slide in canal.
Eagle Point	01/29/96	15:20	03/04/96	9:15	839	Because of slide in canal.
Eagle Point	04/26/96	14:13	05/11/96	9:15	355	Because of slide in canal.
Eagle Point	10/24/96	10:42	10/26/96	21:25	56	Repair leak in canal.
Eagle Point	12/05/96	16:58	12/13/96	21:49	197	Because of slide in canal.
American Fork	01/01/96		12/31/96		8,760	Flowline failure occured May 1993. Waiting on approval of Forest Service and FERC to return plant to service.
Fountain Green	05/26/96		12/31/96		5,256	Generator winding failure.
Grace Unit #4	07/14/96		07/17/96		90	Generator differential damaged slip rings.
Grace Unit #5	10/24/96		10/30/96		121	Step-up transformer differential.
Last Chance Unit #1	01/01/96		01/02/96		29	Lube oil pump failure.
Last Chance Unit #3	08/01/96		08/28/96		655	Unit generator lead burned off.
Last Chance Unit #1	09/21/96		12/31/96		2,448	Turbine shaft failure / new shaft fabricated.
Oneida Unit #1	08/21/96		09/10/96		466	Babbit in oil / repaired Kingsbury & shoes.
Paris Unit #1	12/26/96		12/27/96		46	Canal filled in with snow.
Pioneer Unit #6	01/01/96		02/10/96		961	Excessive vibration / modified head cover.
Snakecreek Unit #2	10/24/96		10/31/96		179	Needle nozzle linkage fairlue / fabricated linkage.
Stairs Unit #1	02/01/96		02/07/96		170	Avalanche - Distribution line outage.
Stairs Unit #1	03/29/96		03/31/96		54	Distribution line outage.
Stairs Unit #1	04/18/96		04/19/96		44	Distribution line outage.
Stairs Unit #1	04/25/96		04/30/96		100	Distribution line outage.

HYDRO FORCED OUTAGE REPORT
Outages of 24 hours or longer duration

Plant	Date	Tme Offline	Date	Time Online	Outage Hours	Reason
St. Anthony Unit #1	02/17/96		05/09/96		1,973	Wicket gate assembly separated from draft tube.
St. Anthony Unit #1	07/02/96		07/08/96		141	Exciter failure.
Weber Unit #1	07/15/96		07/18/96		82	Solid state exciter failure C phase wiring.
Soda Springs Unit #1	11/18/96				138	Broken Gate Links, Damage to trash racks.
Slide Creek Unite #1	01/06/96				32	Shear pin fell into main exciter.
Clearwater 1 Unit #1	02/05/96				462	Line 57 down from cw2 - flume 9 landslide.
Clearwater 2 Unit #1	12/02/96				25	Landslide above canal / repair roadbank.
Clearwater 2 Unit #1	12/03/96				59	Install new butterfly bypass valve.
Lemolo 1 Unit #1	01/20/96				28	Line 53 fault, A phase inst.
Toketee Unit #1	01/15/96				413	Wiped lower guide bearing.
Toketee Unit #2	07/18/96				255	Repair governor.

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	$866	$3,924	-77.93%						
4	Projected Life - to be rolled into SGC HIP in 1994									
5	Low Income Program									
6	Initiated - 1987	$40,340	$40,448	-0.27%						
7	Projected Life - Indefinite									
8										
9	Residential Appliance							22		22
10	Efficient Heat Pumps									
11	Initiated - 1986		$2,540	-100.00%						
12	Projected Life - Indefinite									
13	Efficient Water Heaters									
14	Initiated - 1987		$4,346	-100.00%						
15	Projected Life - Indefinite									
16	SERP									
17	Initiated - 1994		$7,561	-100.00%						
18	Projected Life - 1997									
19										
20	New Residential							26		26
21	Super Good Cents Home Improvement Pgm									
22	Initiated - 1993									
23	Projected Life - Indefinite									
24	Super Good Cents									
25	Initiated - 1988	$59,006	$182,901	-67.74%						
26	Projected Life - Indefinite									
27	Manufactured Aquisition Program (MAP)									
28	Initiated - 1991	$378,250	$65,419	478.20%						
29	Projected Life - Indefinite									
30										
31					0.09	796	0.04	330	(0.05)	(466)
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	$24,949	$21,793	14.48%						
4	Projected Life - Indefinite									
5	Energy FinAnswer 12,000									
6	Initiated - 1992	$186								
7	Projected Life - Indefinite									
8										
9	Industrial				0.40	3,504	0.03	297	(0.37)	(3,207)
10	Industrial FinAnwser									
11	Initiated - 1995		$3,297	-100.00%						
12	Projected Life - Indefinite									
13										
14										
15										
16										
17										
18										
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	TOTAL	$503,597	$332,229	51.58%	0.49	4,300	0.07	675	(0.42)	(3,625)

Sch. 36

MONTANA CONSUMPTION AND REVENUES

	Sales of Electricity	Operating Revenues		MegaWatt Hours Sold		Avg. No. of Customers	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	Residential	$18,161,798	$16,852,868	362,264	334,967	28,275	27,825
2	Commercial - Small	12,549,315	11,580,152	269,661	249,616	5,545	5,172
3	Commercial - Large						
4	Industrial - Small	N.A.	N.A.	N.A.	N.A.	N.A.	216
5	Industrial - Large	10,858,213	9,216,688	322,279	272,683	262	10
6	Interruptible Industrial						
7	Public Street & Highway Lighting	157,610	145,920	2,392	2,322	49	43
8	Other Sales to Public Authorities						
9	Sales to Cooperatives						
10	Sales to Other Utilities	13,302,591	8,597,128	552,343	303,999	1	1
11	Interdepartmental						
12							
13	TOTAL	$55,029,527	$46,392,756	1,508,939	1,163,587	34,132	33,267

Excludes Other Electric Revenues.