YEAR 1992

ANNUAL REPORT

RECEIVED

JUN 1 1993

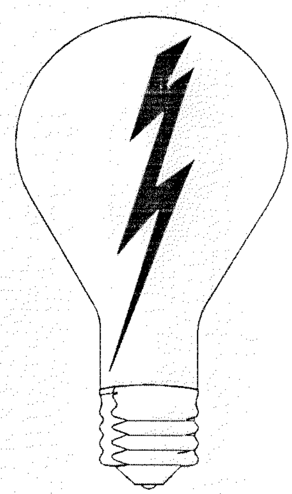
MONT. P. S. COMMISSION

OF

PACIFICORP dba Pacific Power

(COMPANY NAME)

ELECTRIC UTILITY



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

REVISED OCTOBER 20, 1992

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Instructions

General

1. A computer disk, formatted with DOS Version 5.0, is being provided for your convenience. The files were created using the DOS version of Lotus 3.1 and were saved with the wk1 extension. WYSIWYG was used as an addin, these files have the fmt 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.wk1, Schedule 3 is sch3.wk1). 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 7 and 8
Schedule 15
Schedule 18
Schedules 23 through 27
Schedules 34 and 35

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 9, 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 9A, etc.)

Schedule 6

1. Each sale, transfer or retirement of utility plant with a total combined value (higher of original book cost or selling price) of $50,000 or more assigned/allocated to Montana shall be reported on this schedule. Each plant item which requires a mortgage release must be reported regardless of its value.

Schedules 7 and 8

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.

Schedule 13

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 15

1. Companies with defined contribution plans do not need to complete lines 25 through 28.

2. Companies with defined benefit plans must complete the entire form. Lines 10 through 23 shall be filled out using FASB 87 guidelines. Line 25 refers to the minimum required contribution under ERISA. Line 27 refers to the maximum amount deductible for tax purposes.

Schedule 16

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 17

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 and shall be included directly behind the original schedule to which it pertains.

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 only for the months that earnings and dividends are entered. The price/earnings ratio shall be calculated using the average of the high and low market prices for the given month and the quarterly earnings times 4.

3. Enter the actual year end market price in the "TOTAL Year End" row, this amount shall be used to calculate the year end price/earnings ratio. If the computer disk is used, enter the year end market price in the "High" column.

Schedule 28

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 49, if the amount is updated or is from the last rate case. All adjustments shall be calculated using Commission methodology.

Schedule 29

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 32

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 33

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

Schedule 35

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. 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 which occurred during the year. Explain the reason for the outage. If routine maintenance schedules are exceeded, explain the reason.

Schedule 36

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	Don C. Frisbee (Chairman)	Portland, Oregon	$150,000
2	C. M. Bishop, Jr.	Portland, Oregon	52,442
3	C. Todd Conover	Denver, Colorado	38,735
4	Richard C. Edgley	Salt Lake City, Utah	57,968
5	John C. Hampton	Portland, Oregon	52,442
6	Stanley K. Hathaway	Cheyenne, Wyoming	33,793
7	Michael O. Leavitt	Salt Lake City, Utah	42,947
8	Keith R. McKennon	Midland, Michigan	34,571
9	Don M. Wheeler	Salt Lake City, Utah	49,830
10	Nancy Wilgenbusch	Marylhurst, Oregon	34,542
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Sch. 3

OFFICERS

Title	Department Supervised	Name
President and Chief Executive Officer		A. M. Gleason
President - Pacific Power		Paul G. Lorenzini
President - Utah Power		Verl R. Topham
Senior Vice President	Pacific Power Operations	Diana E. Snowden
Senior Vice President	Engineering	Harry A. Haycock
Senior Vice President	Accounting, Taxes and Financial Planning	Daniel L. Spalding
Senior Vice President	Assistant to the President	John A. Bohling
Executive Vice President	Utah Power Operations	John E. Mooney
Controller		Jacqueline S. Bell
Vice President	Thermal Resources	William C. Brauer
Vice President	Community & Energy Services, Material Procurement and Division Support	Shelly R. Faigle
Vice President	Summit Region	Thomas W. Forsgren
Vice President	Public Affairs, Communications and Environmental Policy	Thomas J. Imeson
Vice President	Wyoming Region	Thomas A. Lockhart
Vice President and Treasurer	Finance	Robert F. Lanz
Vice President	Information Management	Stan M. Marks
Vice President and Corporate Secretary	Shareholder Services	Sally A. Nofziger
Vice President	Human Resources	Michael J. Pittman
Vice President	Fuel Resources	Ernest E. Wessman
Vice President	Strategic Planning, Mergers/ Acquisitions & Bulk Power Planning	Dennis P. Steinberg
Vice President	Rocky Mountain Region	Richard D. Westerberg
Assistant Secretary and Controller		H. Arnold Wagner

Sch. 4

CORPORATE STRUCTURE

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1	PacifiCorp Holdings, Inc.	Holding company	(587,734,206)	99.98%
2				
3	North American Energy Services Co.	Maintenance of Steam Plants	(212,317)	0.04%
[illegible]				
5	Pacific Relocation Service Company	Employee relocations	96,014	-0.02%
6				
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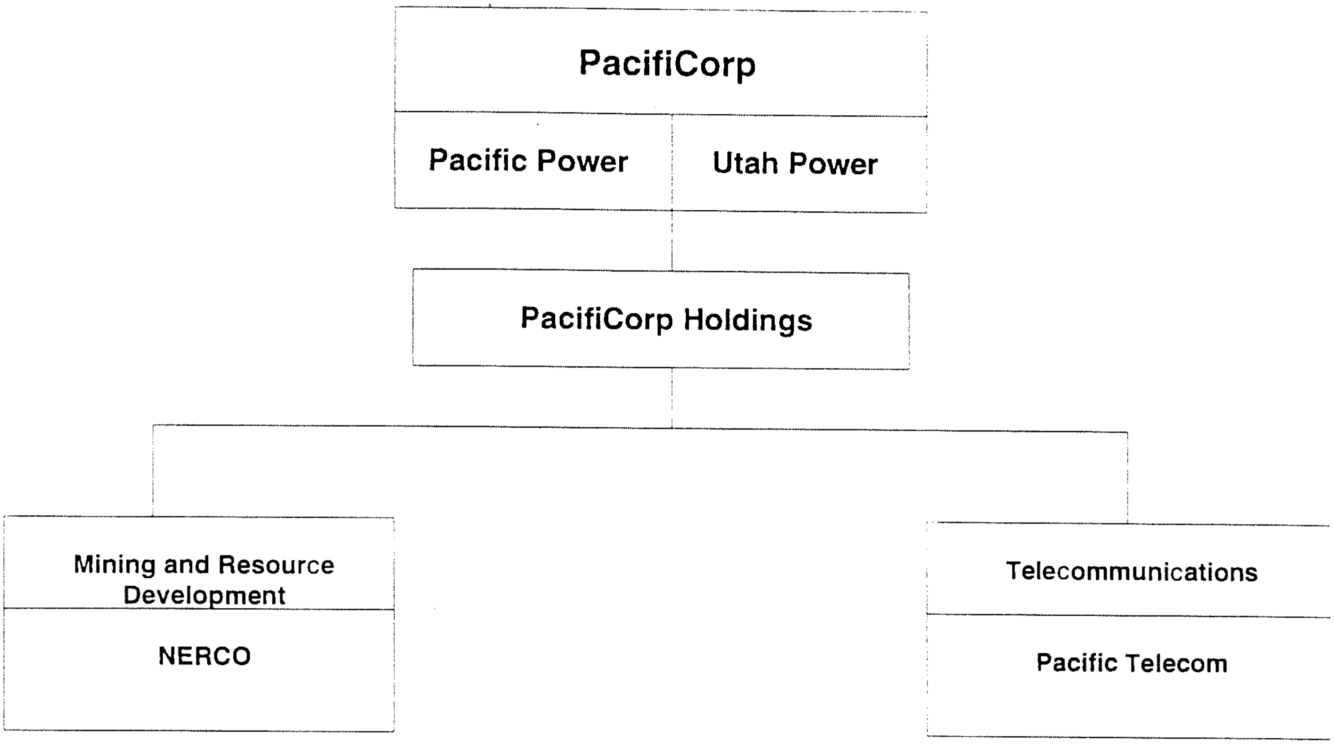
[illegible]				
51				
52				
53	TOTAL		(587,850,509)	100.00%

THE ORGANIZATION

The Company is a diversified electric utility that conducts its retail electric utility business through two divisions, Pacific Power and Utah Power, and engages in power production and sales on a wholesale basis under the name PacifiCorp. The chart below sets forth the corporate structure of the PacifiCorp Group's three principal businesses:



PacifiCorp Holdings was formed to hold the stock of the Company's principal subsidiaries and to facilitate the conduct of business not regulated as electric utilities. Initially named Inner PacifiCorp, this holding company was renamed PacifiCorp Holdings in 1992. Through PacifiCorp Holdings, the Company indirectly owns:

NERCO (82%), a natural resource company that is a significant producer of coal, gold and silver in North America, and of natural gas and oil in the Gulf Coast region of the United States, and is also engaged in the exploration for and development of precious metals, gas and oil. In 1993, PacifiCorp announced the sale of NERCO. That sale is expected to close mid-1993.

Pacific Telecom (87%), a business providing local telephone service and access to the long distance network in Alaska, seven other western states and three midwestern states, providing intrastate and interstate long distance communication services in Alaska, providing cellular mobile telephone services, and engaging in the sale of capacity in a submarine fiber-optic cable between the U.S. and Japan.

In addition, PacifiCorp Holdings holds PacifiCorp Financial Services (100%), a business offering certain specialized financial services, including aviation financing, computer leasing and real estate investments. PacifiCorp Holdings also has wholly-owned subsidiaries that are engaged in other businesses, including independent power production and co-generation.

The following pages provide an organization chart, in columnar form, of PacifiCorp and its subsidiaries. For each subsidiary, the percentage of ownership held by its parent company is listed as well as the state of incorporation. The listing of subsidiaries also contains a numerical reference for each subsidiary in the organization. This reference number is attached to each affiliated interest entity throughout the report to facilitate cross-referencing.

SUBSIDIARIES OF THE COMPANY

PacifiCorp Holdings, Inc., a wholly-owned subsidiary of the Company and a Delaware corporation, has the following subsidiaries:

	Name of Subsidiary	Approximate Percentage of Voting Securities Owned	State or Jurisdiction of Incorporation or Organization
1	NERCO, Inc.	82%	Oregon
	PACE Group, Inc.	100%	Oregon
2	PacifiCorp Financial Services, Inc.	100%	Oregon
	Pacific Development, Inc.	100%	Oregon
	Pacific Harbor Capital, Inc.	100%	Delaware
	PacifiCorp Capital, Inc.	100%	Virginia
	PacifiCorp Credit, Inc.	100%	Oregon
	Paccom Leasing Corporation	100%	Oregon
	Vermont Castings, Inc.	100%	Vermont
3	Pacific Generation Company	100%	Oregon
	Energy National, Inc.	100%	Utah
	ONSITE Energy, Inc.	100%	Oregon
4	Pacific Telecom, Inc.	87%	Washington
5	PacifiCorp Trans, Inc.	100%	Oregon

Pacific Telecom, Inc., an 87% owned subsidiary of PacifiCorp Holdings, Inc., and a Washington corporation, has the following subsidiaries:

Name of Subsidiary	Approximate Percentage of Voting Securities Owned	State or Jurisdiction of Incorporation or Organization
Alascom, Inc.	100%	Alaska
Cascade Autovon Company	100%	Washington
Eagle Telecommunications, Inc./Colorado	100%	Colorado
Eagle Valley Communications Corporation	100%	Colorado
Gem State Utilities Corporation	92%	Idaho
Inter Island Telephone Company, Inc.	100%	Washington
International Communications Holdings, Inc.	85%	Delaware
TRT Communications, Inc.	100%	Delaware
TRT/FTC Communications, Inc.	100%	Delaware
TRT/FTC International, Inc.	100%	Delaware
North-West Telecommunications, Inc.	100%	Nevada
Cencom of Wisconsin, Inc.	100%	Wisconsin
Northland Telephone Company	100%	Minnesota
North-West Telephone Company	100%	Wisconsin
Postville Telephone Company	100%	Wisconsin
The Footville Telephone Company	100%	Wisconsin
Sullivan Telephone Company	100%	Wisconsin
Platteville Telephone Company	100%	Wisconsin
North-West Cellular, Inc.	100%	Nevada
Thorp Telephone Company	100%	Wisconsin
Turtle Lake Telephone Company, Inc.	100%	Wisconsin

Sch. 5

CORPORATE ALLOCATIONS

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Corporate Management Fee		Three Factor Method			
2	6,429,878.58		61.0% to Electric Operations			
3	Electric Portion					
4	3,922,226.58			64,548	1.6457%	3,857,678
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35	TOTAL			64,548	1.6457%	3,857,678

Sch. 6

ASSET SALES, TRANSFERS & RETIREMENTS AFFECTING MT UTILITY

	Plant Description	Plant Account Number	Work Order Number	Item Ever Rate Based (Y or N)	Trans. Date	Trans. Type (S,T,R)	Affiliate Trans. (Y or N)	Mortgage Release (Y or N)	Trans. Amount (000)	Gain Loss (000)
1	Rebuild 12.5 KV Underbuild	364	40903	Y	Jun-92	T	N	N	45	
2	Rebuild 12.5 KV Underbuild	365	40903	Y	Jun-92	T	N	N	25	
3	Rebuild 12.5 KV Underbuild	368	40903	Y	Jun-92	T	N	N	9	
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Sch. 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

	Affiliate Name	Products & Services	Method to Determine Price	Charges to Utility	% Total Affil. Revs	Charges to MT Utility
1	Pacific Telecom	Shareholder Service Records	Cost	159,017	0.02%	2,617
2		Telephone Equipment	Cost	58,571	0.01%	58,571
3		Telephone Svc & Pole Attachments	Cost	83,725	0.01%	3,514
4						
5	NERCO	Fuel Stock	Cost	2,881,802	0.50%	47,198
6						
7	PacifiCorp Financial Services	Leased Office Space	Cost	321,425	0.18%	5,259
8						
9	PacifiCorp Trans, Inc.	Corporate Air Transportation	Cost	4,955,847	67.57%	86,602
10						
11	Pacific Relocation	Moving, Mngmnt & Admin Fees	Cost	163,850	18.35%	2,536
12						
13	Centralia Mining Company	Mine Mngmnt & Mining Svcs	Cost	48,911,133	N/A (1)	801,067
14						
15	Energy West Mining Company	Mine Mngmnt & Mining Svcs	Cost	124,957,860	N/A (1)	2,046,560
16						
17	Glenrock Coal	Fuel Stock	Cost	28,046,619	N/A (1)	459,348
18						
19	Williams Fork Company	Mine Mngmnt & Mining Svcs	Cost	5,387,560	N/A (1)	88,237
20						
21	NESCO	Advanced Engineering Mngmnt &				
22		Construction Mngmnt Techniques	Cost	5,063,698	10.39%	139,235
23						
24	Microrim	Software	Cost	618	N/A (2)	10
25						
26						
27						
28						
29	(1) This company is not evaluated on a stand-alone basis. Therefore, no balance sheet or income statement is available.					
30						
31	(2) PacifiCorp owns less than 20% of Microrim and holds its interest as a cost-based investment. Microrim did not provide an annual report.					
32						
33						
34						

Sch. 8

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% Total Affil. Exp.	Revenues to MT Utility
Pacific Telecom	Printing Services	Cost	9,009	0.0016%	0
	Pole Contact Rental	Cost	120,873	0.0214%	0
NERCO	Printing Services	Cost	7,424	0.0008%	0
	Consulting Services	Cost	8,282	0.0009%	0
PacifiCorp Financial Services	Printing Services	Cost	1,002	0.0003%	0
Pacific Generation	Printing Services	Cost	938	0.0054%	0
	Consulting Services	Cost	3,559	0.0206%	0
PacifiCorp Trans, Inc.	Printing Services	Cost	1,344	0.0200%	0
	Accounting & Accts Payable Svcs	Cost	18,000	0.2674%	0
	Office Rent	Cost	2,846	0.0423%	0
Pacific Relocation	Printing Services	Cost	915	0.1231%	0
	Payroll Processing	Cost	450	0.0606%	0
	Furniture Rental	Cost	263	0.0354%	0

NOTE: Transactions involving services provided by PacifiCorp to affiliated companies are charged to work orders using account 186, Miscellaneous Deferred Debits - Other Work in Progress. On a monthly basis, the balances in each work order are analyzed and cleared to receivable account 146. The affiliate is then billed for the amount due. When payment is received from the affiliate, the receivable is extinguished. Thus, billings to affiliates do not result in charges to accounts affecting ratepayers.

Sch. 9	MONTANA UTILITY INCOME STATEMENT			
	Account Number & Title	Last Year	This Year	% Change
1	400 Operating Revenues	37,690,802	38,472,022	2.07%
2				
3	Operating Expenses			
4	401 Operation Expenses	17,230,564	19,911,551	15.56%
5	402 Maintenance Expenses	2,445,769	2,471,711	1.06%
6	403 Depreciation Expenses	3,666,839	3,994,694	8.94%
7	404-405 Amortization of Electric Plant	148,148	161,730	9.17%
8	406 Amort. of Plant Acquisition Adjustments	9,049	72,765	704.12%
9	407 Amort. of Property Losses, Unrecovered Plant	1,878	0	-100.00%
10	& Regulatory Study Costs			
11	408.1 Taxes Other Than Income Taxes	1,234,572	1,386,989	12.35%
12	409.1 Income Taxes - Federal	2,396,425	1,649,811	-31.16%
13	- Other	565,050	359,033	-36.46%
14	410.1 Provision for Deferred Income Taxes	351,335	1,494,970	325.51%
15	411.1 (Less) Provision for Def. Inc. Taxes - Cr.	(267,538)	(605,403)	126.29%
16	411.4 Investment Tax Credit Adjustment	0	0	
17	411.6 (Less) Gains from Disposition of Utility Plant	0		
18	411.7 Losses from Disposition of Utility Plant	0		
19				
20	TOTAL Utility Operating Expenses	27,782,091	30,897,852	11.21%
21				
22	NET UTILITY OPERATING INCOME	9,908,711	7,574,170	-23.56%

Sch. 10	MONTANA REVENUES			
	Account Number & Title	Last Year	This Year	% Change
1	Sales of Electricity			
2	440 Residential	13,926,844	14,041,531	0.82%
3	442 Commercial & Industrial - Small	9,821,250	10,179,308	3.65%
4	Commercial & Industrial - Large	8,027,993	7,148,965	-10.95%
5	444 Public Street & Highway Lighting	136,118	138,225	1.55%
6	445 Other Sales to Public Authorities	0	0	
7	446 Sales to Railroads & Railways			
8	448 Interdepartmental Sales	28,328	(10)	-100.04%
9				
10	TOTAL Sales to Ultimate Consumers	31,940,533	31,508,019	-1.35%
11	447 Sales for Resale	5,314,706	6,754,597	27.09%
12				
13	TOTAL Sales of Electricity	37,255,239	38,262,616	2.70%
14	449.1 (Less) Provision for Rate Refunds	0	(45,662)	
15				
16	TOTAL Revenue Net of Provision for Refunds	37,255,239	38,216,953	2.58%
17	Other Operating Revenues			
18	450 Forfeited Discounts & Late Payment Revenues	16,467	15,663	-4.88%
19	451 Miscellaneous Service Revenues	9,281	3,530	-61.96%
20	453 Sales of Water & Water Power	2,231	2,277	2.05%
21	454 Rent From Electric Property	137,197	184,369	34.38%
22	455 Interdepartmental Rents		0	
23	456 Other Electric Revenues	270,387	49,230	-81.79%
24				
25	TOTAL Other Operating Revenues	435,563	255,069	-41.44%
26				
27	Total Electric Operating Revenues	37,690,802	38,472,022	2.07%

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, 1992

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 attached hereto.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PacifiCorp (the "Company") is a diversified utility that conducts its retail electric utility business through two divisions, Pacific Power & Light Company ("Pacific Power") and Utah Power & Light Company ("Utah Power"), and engages in power production and sales on a wholesale basis under the name PacifiCorp. The Company holds investments through its wholly-owned subsidiary PacifiCorp Holdings, Inc. ("Holdings," formerly Inner PacifiCorp, Inc."), in subsidiaries including a telecommunications company (Pacific Telecom, Inc.) and a financial services company (PacifiCorp Financial Services, Inc.)

The Company also holds investments in a mining and resources development business (NERCO, Inc.) and an international communications business (International Communications Holdings, Inc.) through Holdings. The Company has agreed to the disposal of these operations. See Note 12.

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

The Company and Holdings guarantee certain debt of the Leveraged ESOP Trust established under the K Plus Plan ("the Trust"). The amounts guaranteed at December 31, 1992 were $27,286,000 and $30,098,000 for the Company and Holdings, respectively. In addition, the Company and Holdings guarantee the Trust's performance under certain interest rate swaps having a total notional principal amount of $48,000,000 that were entered into by the Trust and a commercial bank. These arrangements change the interest rate exposure on the variable rate debt guaranteed by the Company to effective rates of 6.9 percent and 7 percent, respectively, at December 31, 1992. The debt was used to acquire the Company's common stock. Remaining unallocated common shares total 2,614,252.

If generally accepted accounting principles were followed, current assets (in thousands of dollars) would have been increased by $299,883 and $304,210; property, plant and equipment would have been increased by $1,078,899 and $1,168,469; current liabilities would have been increased by $508,966 and $371,634; long-term debt would have been increased by $818,002 and $1,107,551; deferred credits would have been increased by $667,533 and $823,627; Financial Services' investments would have been $1,114,308 and $1,461,552 and Financial Services' debt would have been $715,640 and $1,014,013 as of December 31, 1992 and 1991, respectively. Furthermore, operating revenues would have been increased by $879,589 and $916,563; operating expenses would have been increased by $753,255 and $577,522 for the years ended December 31, 1992 and 1991, respectively. Net cash provided by operating activities would have been increased by $342,280 and net cash used by investing activities would have been decreased by $144,976, for the year ended December 31, 1992. The accounting for investments in subsidiaries on the equity method rather than in accordance with generally accepted accounting principles has no effect on net income; however, on a consolidated basis, common shareholder capital would have been decreased by $21,156 and $28,122 and retained earnings would have been increased by $9,643 and $8,953 as of December 31, 1992 and 1991, respectively, due to Holding's purchase of common stock of the Company and subsequent dividend declarations (see Note 4).

Regulatory Authorities

Accounting for the Company conforms with generally accepted accounting principles as applied to regulated public utilities and as prescribed by the FERC and the regulatory commissions of the various states in which the Company operates.

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.

Electric Property, Plant and Equipment

Electric property, plant and equipment are 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. Maintenance and repairs of property and replacement and renewals of items that are not units of property are charged to operating expense.

Depreciation and Amortization

Depreciation and amortization is computed generally by the straight-line method over the estimated useful lives of the related assets. Provision for depreciation of electric plant (excluding amortization of capital leases) was 3.2 percent of average depreciable assets in 1992 and 1991.

Inventory Valuation

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

Interest Capitalized

Costs of debt and equity funds applicable to utility properties are capitalized during construction. Generally, the composite capitalization rate allowed was 7.1 percent in 1992 and 9.3 percent in 1991.

Income Taxes

The Company provides deferred taxes for differences due to book versus tax depreciation lives and methods and certain other timing differences. Pursuant to regulatory orders, deferred income taxes are not provided for certain other differences. It is expected that regulatory practices affecting the utility business will permit recovery through revenues of income taxes, not provided for currently, when such taxes become payable.

Investment tax credits are deferred and amortized to income over the average estimated lives of the properties in accordance with the accounting practices prescribed by regulatory authorities.

Revenue Recognition

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

NOTE 2. ACQUISITIONS

On April 15, 1992, the Company purchased 243 megawatts of generating assets and fuel resources from Colorado-Ute Electric Association, Inc. for $279,264,000. The purchase was financed with $250,338,000 of First Mortgage and Collateral Trust Bonds ("FMB"), including $47,540,000 of FMB issued as collateral for obligations assumed relating to pollution control revenue bonds.

On April 8, 1991, the Company purchased equity interests in the Wyodak Plant. On June 8, 1991, the Company retired its share of the Wyodak debt, which had been recorded as a capital lease obligation, with issuances of medium-term notes and cash.

Noncash investing and financing activities associated with these acquisitions were as follows:

	MILLIONS OF DOLLARS	
	1992	1991
Net assets acquired	$(279,264)	$(169,916)
Disposition of net property under capital lease	-	132,471
Long-term debt assumed	250,338	105,646
Accrued liabilities and deferred credits assumed	4,845	7,968
Retirement of obligations under capital lease	-	(132,471)

On July 15, 1991, the Company paid $234 million to Arizona Public Service Company ("APS") for Unit No. 4 of the Cholla coal-fired generating plant and related common facilities and commenced providing power to APS under a related power supply agreement.

NOTE 3. SHORT-TERM BORROWING ARRANGEMENTS

At December 31, 1992, the Company had outstanding $232,422,634 in commercial paper and $130,200,000 of borrowings under available bank lines backed by a $500 million revolving credit agreement. The Company has the intent and ability to support short-term borrowings through various revolving credit agreements on a long-term basis. Commitment fees were $619,177 and $443,576 in 1992 and 1991, respectively. Covenants in certain reimbursement agreements relating to letters of credit limit short-term borrowings to 12% of defined capitalization (limiting such borrowings to approximately $360,500,000 at December 31, 1992).

NOTE 4. COMMON AND PREFERRED STOCK

At December 31, 1992 and 1991, the Company had authorized common stock of 750,000,000 shares. The Company had 270,579,042 and 262,411,351 outstanding common shares at December 31, 1992 and 1991, respectively.

Changes in shares of capital stock and common shareholder capital are listed below:

THOUSANDS OF SHARES/DOLLARS	SHARES COMMON STOCK	SHARES PREFERRED STOCK	COMMON SHAREHOLDER CAPITAL
BALANCE, JANUARY 1, 1991	253,204	3,843	$2,405,871
1991 Sales through Dividend Reinvestment and Stock Purchase Plan	2,933	-	65,157
Sales through Employees' Stock Plans	224	-	5,191
Sales to the public	6,050	1,000	130,513
Stock expense, redemptions and repurchases			(4,812)
BALANCE, DECEMBER 31, 1991	262,411	4,843	2,601,920
1992 Sales through Dividend Reinvestment and Stock Purchase Plan	3,790	-	81,551
Sales through Employees' Stock Plans	1,070	-	23,395
Sales to the public	3,308	5,750	74,661
Stock expense, redemptions and repurchases		(60)	(5,433)
BALANCE, DECEMBER 31, 1992	270,579	10,533	$2,776,094

Holdings held 314,982 of the outstanding shares included in the table above at December 31, 1991. Holdings sold all of its PacifiCorp shares in 1992 to the Leveraged ESOP Trust established under the K Plus Plan and to the Company for use as awards in the PacifiCorp Long-Term Incentive Plan.

At December 31, 1992, there were 14,478,255 authorized but unissued shares of common stock reserved for issuance under the Dividend Reinvestment and Stock Purchase Plan, the K Plus Plan and for sales to the public. Eligible employees under the K Plus Plan 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 also invested in the Company's common stock. Employee contributions eligible for matching contributions are limited to 6% 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.

THOUSANDS OF SHARES/DOLLARS

SERIES	PREFERRED STOCK OUTSTANDING AT DECEMBER 31			
	1992 SHARES	1992 AMOUNT	1991 SHARES	1991 AMOUNT
SUBJECT TO MANDATORY REDEMPTION:				
NO PAR SERIAL PREFERRED, 16,000 SHARES AUTHORIZED				
$7.12 ($100 stated value)	440	$ 44,000	500	$ 50,000
7.48	750	75,000	-	-
7.70	1,000	100,000	1,000	100,000
TOTAL SUBJECT TO MANDATORY REDEMPTION		$219,000		$150,000
NOT SUBJECT TO MANDATORY REDEMPTION:				
SERIAL PREFERRED $100 STATED VALUE PER SHARE, 3,500 SHARES AUTHORIZED				
4.52%	2	$ 207	2	$ 207
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	135	13,518
8.92%	69	6,937	69	6,937
9.08%	165	16,489	165	16,489
NO PAR SERIAL PREFERRED, 16,000 SHARES AUTHORIZED				
$1.16 ($25 stated value)	193	4,828	193	4,828
$1.18	420	10,503	420	10,503
$1.28	381	9,530	381	9,530
$1.76	394	9,847	394	9,847
$1.98	502	12,550	502	12,550
$1.98, Series 1992	5,000	125,000	-	-
$2.13	666	16,655	666	16,655
Auction Rate ($100,000 stated value) (a)	2	150,000	2	200,000
5% PREFERRED, $100 STATED VALUE, 127 SHARES AUTHORIZED AND OUTSTANDING	127	12,653	127	12,653
TOTAL NOT SUBJECT TO MANDATORY REDEMPTION		$417,360		$342,360

(a) Dividend rates at December 31, 1992 on 500 shares of Series A, Series B and Series C were 4.1%, 4.3%, and 4.5%, respectively.

The estimated fair value, based upon bid prices from an investment bank, of the redeemable preferred stock would be approximately 1 percent less than its carrying value of $219,000,000 at December 31, 1992.

Mandatory redemption requirements at stated value plus accrued dividends on No Par Serial Preferred Stock are as follows: beginning in 1997, 15,000 shares 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 shares outstanding on June 15, 2007 redeemable on that date. Mandatory redemption requirements for 1993 through 1996 on the $7.12 series were satisfied by the purchase of 60,000 shares at a discount in December 1992. 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.

On January 25, 1993, the Company redeemed its $50 million of Series B Auction Rate Preferred Stock.

NOTE 5. LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS

The Company's long-term debt and capital lease obligations were as follows:

THOUSANDS OF DOLLARS/DECEMBER 31,	1992	1991
FIRST MORTGAGE AND COLLATERAL TRUST BONDS		
Maturing 1993 through 1997 / 4.5% - 9.4% (a)	$ 370,287	$ 490,415
Maturing 1998 through 2002 / 6.5% - 10%	879,451	599,251
Maturing 2003 through 2007 / 7% - 9%	520,788	441,516
Maturing 2008 through 2012 / 8% - 9.2%	152,783	76,000
Maturing 2013 through 2017 / 8.3% - 8.8%	218,519	357,000
Maturing 2018 through 2022 / 8.1% - 8.5%	175,000	20,000
Redeemed in February 1992	-	201,306
GUARANTY OF POLLUTION CONTROL REVENUE BONDS		
6% due 2003	21,260	36,900
5.9% - 10.7% due 1993 through 2017 (b)	272,880	249,640
Variable rate due 2005 through 2019 (c)	407,425	369,300
Funds held by trustees	(885)	(852)
OTHER		
Unamortized premium and (discount)	10,984	11,014
Capital lease obligations (Note 6)	18,247	20,033
TOTAL	3,046,739	2,871,523
Less current maturities	52,294	68,049
LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS	$2,994,445	$2,803,474

(a) Includes $50,000 in 9 3/8% 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 0.02% (interest rate 3.6% at December 31, 1992).

(b) Secured by pledged first mortgage bonds and collateral trust 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 or prime rates.

In accordance with Statement of Financial Accounting Standards ("FAS") 107, "Disclosures about Fair Value of Financial Instruments," the fair value of the Company's long-term debt at December 31, 1992, has been estimated by discounting the 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. The fair value of the Company's total long-term debt at December 31, 1992 would be approximately 3% more than its carrying value of $2,994,445.

The Company has entered into interest rate swap and exchange agreements to reduce the impact of changes in interest rates on its variable rate long-term debt. At December 31, 1992, the Company had five outstanding interest rate contracts with commercial banks and Fortune 500 service companies, having a total notional principal amount of $187,000,000. These agreements change the Company's interest rate exposure on the underlying variable rate debt to fixed rates of 6.9% to 8.9%. These contracts mature at various times up to the year 2000. The Company is exposed to credit loss in the event of nonperformance by the other parties to the interest rate swap agreements. However, the Company does not anticipate nonperformance by the counterparties.

The fair value of interest rate swaps is the estimated amount that the Company would pay to terminate the swap agreements, taking into account current interest rates and the credit worthiness of the swap counterparties. The estimated termination cost would have been (in thousands) $55,895 at December 31, 1992.

Approximately $4.3 billion of the assets of the Company secure long-term debt and capital lease obligations. 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.

Maturity and sinking fund requirements on all long-term debt, long-term capital lease obligations and redeemable preferred stock outstanding are as follows:

THOUSANDS OF DOLLARS/FOR THE YEAR	1993	1994	1995	1996	1997
Total requirements	$54,069	$70,598	$48,619	$151,741	$212,974
Portion of total payable in cash	52,294	69,036	47,469	150,591	210,374
Property additions certifiable in lieu of cash (a)	3,063	2,375	1,438	750	750

(a) Certain cash sinking fund requirements may be satisfied on the basis generally of 60% of property additions.

The Company's Mortgage and Deeds of Trust, as supplemented, relating to its long-term debt, restrict the payment of cash dividends and other distributions on common stock. At December 31, 1992, the Company's retained earnings available for these purposes were $125 million.

The Company made interest payments, net of capitalized interest, of $256.7 million and $250.8 million in 1992 and 1991, respectively.

NOTE 6. LEASES

The Company leases certain properties under leases expiring during the next 29 years. 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. Capital leases currently in effect are not significant.

Net rent expense, including amounts attributable to capitalized leases, for the years ending December 31, 1992 and 1991 was (in thousands) $14,890 and $18,563, respectively.

Future minimum lease payments under noncancelable operating leases are (in thousands) $4,979, $4,020, $2,803, $721 and $721 for 1993 through 1997, respectively.

NOTE 7. COMMITMENTS AND CONTINGENCIES

Construction and Other

Construction programs are estimated at $793 million for 1993. As part of these programs, substantial commitments have been made.

Several Superfund sites have been identified where the Company has been or may be designated as potentially a responsible party. Future costs associated with the disposition of these matters are not expected to be material to the Company's financial position and results of operations.

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 presently believes that disposition of these matters will not have a materially adverse effect on the Company's financial position and results of operations.

Jointly Owned and Leased Plant

At December 31, 1992, the Company's participation in plants jointly owned and jointly leased was as follows:

THOUSANDS OF DOLLARS	The Company's Share	Plant in Service	Accumulated Depreciation	Work in Progress
JOINTLY OWNED PLANTS				
Centralia	47.5%	$173,516	$ 94,906	$ 265
Jim Bridger Units 1, 2, 3 and 4	66.7%	773,521	261,948	6,473
Trojan (a)	2.5%	-	-	-
Colstrip Units 3 and 4	10.0%	198,888	42,465	554
Hunter Unit 1	93.8%	252,237	81,159	129
Hunter Unit 2	60.3%	179,327	53,404	218
Wyodak	80.0%	287,798	80,366	5,849
Craig Station, Units 1 and 2	19.3%	143,993 (b)	43,804	1,478
Hayden Station, Unit 1	24.5%	15,134 (b)	10,789	290
Hayden Station, Unit 2	12.6%	16,426 (b)	7,576	175

(a) Plant in service, accumulated depreciation, and construction work in progress balances of $20,580, $8,675, and $1,779, respectively, relating to the Trojan Plant, along with estimated plant closure and decommissioning costs of $15,237 and fuel inventory costs of $1,976 were included in Unrecovered Plant and Regulatory Study Costs. Recovery of these costs is pending approval of certain regulatory commissions.

(b) Excludes unallocated acquisition adjustments of $142,000.

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.

Substantial amounts of power are purchased 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 expense 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 most of them also provide for additional power, withdrawable by the districts upon one to five years notice. For 1992, such purchases approximated 3.3 percent of energy requirements; an additional 9.9 percent was obtained through other purchase and net interchange arrangements.

A summary of the Company's share of long-term arrangements with public utility districts at December 31, 1992, was as follows:

Generating Facility	Year Contract Expires	Capacity (kw)	Percentage of Output	Annual Costs (a) (in thousands)
Wanapum	2009	155,444	18.7%	$ 4,430
Priest Rapids	2005	109,602	13.9	3,141
Rocky Reach	2011	64,297	5.3	1,740
Wells	2018	54,198	7.0	1,642
TOTAL		383,541		$10,953

(a) Annual costs include debt service of $6,151.

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 8. INCOME TAXES

Excluding the equity in earnings of subsidiaries companies, the Company's effective combined Federal and state income tax rate was 39 percent and 32 percent in 1992 and 1991. The difference between taxes calculated as if the statutory Federal tax rate of 34 percent was applied to income before income taxes, and the recorded tax expense is reconciled as follows:

THOUSANDS OF DOLLARS/FOR THE YEAR	1992	1991
COMPUTED FEDERAL INCOME TAXES	$137,566	$185,575
REDUCTION IN TAX RESULTING FROM		
Excess of tax over book depreciation (flow-through basis)	(20,329)	1,849
Investment tax credit	9,440	9,952
Depletion	4,944	5,177
Other items capitalized and miscellaneous differences	(2,218)	5,148
Federal tax reductions	(8,163)	22,126
FEDERAL INCOME TAX	145,729	163,449
STATE INCOME TAX, NET OF FEDERAL INCOME TAX BENEFIT	11,953	10,823
TOTAL INCOME TAX EXPENSE	$157,682	$174,272
INCOME TAX EXPENSE CONSISTS OF THE FOLLOWING		
TAXES CURRENTLY PROVIDED		
Federal	$101,179	$178,771
State	12,370	24,120
DEFERRED INCOME TAXES		
Depreciation differences	48,984	27,214
Sale of contract entitlements	-	(42,862)
Loss on post-merger reacquired debt	12,170	-
Other	(7,552)	(2,993)
INVESTMENT TAX CREDITS/NET	(9,469)	(9,978)
TOTAL INCOME TAX EXPENSE	$157,682	$174,272

Income taxes are not provided on the Company's share of income or losses relating to those investments for which it uses the equity method of accounting.

During 1990, the Internal Revenue Service ("IRS") completed its examination of the Company's federal income tax returns for the years 1983 through 1986, and has proposed certain adjustments that could substantially increase the tax for these years. The Company and the IRS have agreed to a partial settlement on many of the issues. Among the remaining unagreed issues, the IRS is challenging the Company's abandonment of its 10 percent interest in Washington Public Power Supply System Unit 3. The remaining unagreed issues represent the IRS's initial audit position on specific issues and the IRS has not issued a formal notice of tax deficiency. The Company and the IRS continue to discuss the remaining unagreed issues, which await two technical advice memoranda from the national office of the IRS. In the opinion of management, based in part on discussions with counsel, the outcome will not have a material effect on the Company's consolidated financial position or results of operations.

Deferred income taxes have not been provided on certain book and tax timing differences as the method of rate-making is based on taxes currently payable, and it is expected that there will be recovery of future taxes through revenues. At December 31, 1992, accumulated timing differences for which deferred taxes have not been provided amounted to approximately (in thousands) $1,246,000.

The Company adopted the Statement of FAS 109, "Accounting for Income Taxes," effective January 1, 1993. The statement requires that deferred income taxes be recorded for all temporary differences and carryforwards, and that deferred tax balances be based on enacted tax laws at rates that are expected to be in effect when the temporary differences reverse. As a result of the adoption of FAS 109, 1993 net income will be increased by approximately (in thousands) $2,100, assets will be increased by approximately $780,000 and liabilities will be increased by approximately $780,000. This adjustment includes deferred income tax liabilities and related regulatory assets recorded for cumulative income tax temporary differences which will be recovered through rates when the temporary differences reverse.

The Company made income tax payments, net of refunds of (in thousands) $167,457 and $183,641 in 1992 and 1991, respectively.

NOTE 9. RETIREMENT PLANS

The Company has pension plans covering substantially all of its employees. Benefits under these plans 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, 1992, plan assets were primarily invested in common stocks, bonds and U.S. government obligations.

Net pension costs are summarized as follows for the years ended December 31, 1992 and 1991:

THOUSANDS OF DOLLARS	1992	1991
Service cost - benefits earned	$ 12,466	$ 11,673
Interest cost on projected benefit obligation	57,141	55,284
Actual gain on plan assets	(16,824)	(81,363)
Net amortization and deferral	(18,689)	48,561
Regulatory deferral (a)	(6,486)	(33,128)
NET PENSION COST	$ 27,608	$ 1,027

(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 FAS 87 and 88 and that determined for funding purposes.

The funded status, net pension liability and significant assumptions are as follows at December 31, 1992 and 1991:

THOUSANDS OF DOLLARS	PLAN WITH ACCUMULATED BENEFITS IN EXCESS OF ASSETS		PLAN WITH ASSETS IN EXCESS OF ACCUMULATED BENEFITS
	1992	1991	1991
Actuarial present value of benefit obligations:			
Vested benefit obligation	$ 550,362	$ 537,822	$ 20,367
Accumulated benefit obligation	612,264	576,296	21,853
Projected benefit obligation	689,863	631,428	25,745
Plan assets at fair value	461,069	444,992	33,244
Assets in excess of (or less than) projected benefit obligation	(228,794)	(186,436)	7,499
Unrecognized prior service costs	9,911	10,833	-
Unrecognized net (gain) loss	(77,288)	(107,098)	(2,474)
Unrecognized net obligation at January 1, being amortized over 7 to 22 years	115,044	122,107	-
Minimum liability adjustment	(26,778)	(57,519)	-
NET PENSION ASSET (LIABILITY)	$(207,905)	$(218,113)	$ 5,025
Discount rate	9%	9%	8.5%
Expected long-term rate of return on assets on assets	9%	9%	9%
Rate of increase in compensation levels levels	6%	6%	5%

During 1990, as part of its overall cost reduction program, the Company offered an early retirement incentive program. Included in the table above is the present value of all future termination benefits provided of $47,188,000. The Company has received regulatory accounting orders to defer these costs as a regulatory asset to be amortized over thirty years.

The Company provides health care and life insurance benefits for its retirees on a basis substantially similar to those who are active employees. The cost of these benefits, which is charged to expense as incurred, was (in thousands) $9,959 in 1992 and $8,733 in 1991.

The Company adopted FAS 106, "Employer's Accounting for Postretirement Benefits Other Than Pensions," effective January 1, 1993. This statement requires accrual of postretirement benefits, such as health care benefits, during the years an employee provides services. Based upon the most recent actuarial studies, it is estimated the Company has a transition obligation liability of (in thousands) $247,400. The 1993 expense will increase by approximately $20,300, including interest cost, service cost and amortization of the transition obligation. These expenses are not currently included in electric rates. During 1992, action was undertaken in a majority of the Company's regulatory jurisdictions to determine treatment of FAS 106 costs for rate recovery. All but one jurisdiction allowed total FAS 106 costs in principle. Of these jurisdictions, one allowed deferral of the incremental costs until the next general rate case in that jurisdiction and provided assurance of future recovery of deferred amounts. Only one jurisdiction, Utah, which regulates approximately 30 percent of the Company's retail sales, adopted a level of allowed costs less than total FAS 106 costs. A rehearing of that commission's order has been held and the ultimate outcome of the proceeding is still pending. Final decisions as to recovery of these costs will be made during a general rate case. The Company does not plan to file a general rate case in 1993.

NOTE 10. 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 notes receivable/payable-affiliates. These notes are due upon demand and bear interest at a short-term rate as defined under intercompany loan agreements between the Company and its subsidiaries. Net interest expense (income) on these advances was (in thousands) $195 and $(1,957) in 1992 and 1991, respectively.

The Company provides certain management services, such as corporate and financial advice and consultation, to subsidiaries at cost. The amounts charged to the subsidiaries were (in thousands) $2,508 and $5,071 in 1992 and 1991, respectively.

During 1990 and 1989, Holdings purchased shares of the Company's common stock which were used in acquisitions of companies providing communications services in the Midwest by Pacific Telecom, Inc. ("PTI"). PTI provided the funding for the purchase of these shares. The shares not used in the acquisitions were sold to Holdings in 1992, to the K Plus Plan Trust and to the Company for use as awards in the PacifiCorp Long-Term Incentive Plan. Dividends paid to Holdings on these shares were (in thousands) $150 and $488 in 1992 and 1991, respectively.

All of the coal production of the Bridger mine is sold to a steam electric generating plant owned by the Company and Idaho Power Company ("Idaho"). Sales to the plant were (in thousands) $124,700 in 1992 and $118,500 in 1991. In addition, Bridger paid overriding royalties of $639 and $604 to the Company and Idaho in 1992 and 1991, respectively, pursuant to coal lease agreements.

NOTE 11. SUBSIDIARY SPECIAL CHARGES

As a result of credit rating downgrades, Financial Services and Holdings have been experiencing restricted access to debt markets. In order to improve this situation, these subsidiaries have attempted to reduce debt with cash generated by accelerating disinvestment of underperforming and nonstrategic assets. In addition, the Company announced, as a part of its strategic direction, its intent to reduce Financial Services' assets to less than 10 percent of the Company's consolidated assets, which were (in thousands) $11,256,500 at December 31, 1992. The disposition process was being accelerated into an unsettled market for certain of these investments. Related to these actions, Financial Services and Holdings recorded various pretax adjustments of (in thousands) $141,755 and $43,940, respectively, to the carrying value of certain of their assets in the first quarter of 1992.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1992

NOTES TO FINANCIAL STATEMENTS (Continued)

A summary of the special charges included in equity in subsidiary (earnings) losses is as follows:

Holdings	$ 29,000
Financial Services	102,583
TOTAL	$131,583

NOTE 12. DISCONTINUED OPERATIONS OF SUBSIDIARIES

On February 18, 1993, Holdings announced an agreement to sell, by means of a merger, its 82 percent-owned mining and resource development business, NERCO, Inc. ("NERCO"), to Kennecott Corporation ("Kennecott") for cash consideration of $12 per NERCO share, or $384 million, subject to adjustment in certain events. In connection with the proposed merger transaction, a subsidiary of Holdings will, if requested, lend $225 million to a subsidiary of Kennecott. The loan is to be repaid as, and only to the extent that, the borrower receives certain future contract revenues. The merger, which is subject to NERCO shareholder approval, is expected to be completed in the second quarter of 1993 and would result in a pretax gain to Holdings of approximately $154 million. The gain will be recognized over the life of the loan, which could extend through 2009. Holdings has agreed to vote its NERCO shares in favor of the merger.

The net assets attributable to NERCO included in the carrying value of Holdings are summarized as follows:

	MILLIONS OF DOLLARS/DECEMBER 31 1992	1991
Current assets	$ 151,100	$ 198,500
Noncurrent assets	1,075,047	1,822,025
Notes payable	(381,700)	(13,900)
Current portion of long-term debt and capital lease obligations	(309,900)	(52,800)
Other current liabilities	(161,500)	(182,300)
Long-term debt	-	(660,100)
Noncurrent liabilities	(96,300)	(248,700)
Minority interest	(50,399)	(154,494)
NET ASSETS OF DISCONTINUED OPERATIONS	$ 226,348	$ 708,231

The discontinued operations of NERCO are summarized as follows:

	MILLIONS OF DOLLARS/DECEMBER 31 1992	1991
Revenues	$ 671,998	$ 919,582
Costs and expenses	668,071	803,688
Losses on asset dispositions and write-downs	710,800	-
Income (loss) from operations before income taxes	(706,873)	115,894
Income tax (benefit) expense	(155,648)	32,761
Minority interest and other	100,318	(15,414)
INCOME (LOSS) FROM DISCONTINUED OPERATIONS	$ (450,907)	$ 67,719

A subsidiary of Pacific Telecom, Inc. ("Pacific Telecom") has been shown as a discontinued operation pending completion of an agreement of sale, expected to close in the third quarter of 1993.

Holdings incurred after-tax losses attributable to Pacific Telecom's discontinued operations totaling (in thousands) $39,703 in 1992, $9,052 of operating losses and $30,651 of valuation adjustments, and $7,318 in 1991. The net assets of these discontinued operations included in the carrying value of Holdings were $86,102 and $133,059 at December 31, 1992 and 1991, respectively.

NERCO would have been in default of certain loan covenants as a result of losses incurred in 1992 if it had not obtained waivers for the period ended December 31, 1992. NERCO has also obtained waivers of these covenants until June 30, 1993.

The net assets attributable to NERCO included in the carrying value of Holdings are summarized as follows:

	MILLIONS OF DOLLARS/DECEMBER 31 1992	1991
Current assets	$ 151,100	$ 198,500
Noncurrent assets	1,075,047	1,822,025
Notes payable	(381,700)	(13,900)
Current portion of long-term debt and capital lease obligations	(309,900)	(52,800)
Other current liabilities	(161,500)	(182,300)
Long-term debt	-	(660,100)
Noncurrent liabilities	(96,300)	(248,700)
Minority interest	(50,399)	(154,494)
NET ASSETS OF DISCONTINUED OPERATIONS	$ 226,348	$ 708,231

MONTANA OPERATION & MAINTENANCE EXPENSES

Account Number & Title		Last Year	This Year	% Change
Power Production Expenses				
Steam Power Generation				
Operation				
500	Operation Supervision & Engineering	177,075	185,412	4.71%
501	Fuel	7,461,129	8,156,562	9.32%
502	Steam Expenses	326,738	361,656	10.69%
503	Steam from Other Sources	66,496	62,670	-5.75%
504	(Less) Steam Transferred - Cr.	0	0	
505	Electric Expenses	137,868	163,626	18.68%
506	Miscellaneous Steam Power Expenses	295,811	412,500	39.45%
507	Rents	(23,553)	1,585	-106.73%
	TOTAL Operation - Steam	8,441,564	9,344,011	10.69%
Maintenance				
510	Maintenance Supervision & Engineering	224,872	223,379	-0.66%
511	Maintenance of Structures	116,007	104,074	-10.29%
512	Maintenance of Boiler Plant	701,763	688,174	-1.94%
513	Maintenance of Electric Plant	172,119	170,631	-0.86%
514	Maintenance of Miscellaneous Steam Plant	136,343	271,564	99.18%
	TOTAL Maintenance - Steam	1,351,104	1,457,821	7.90%
	TOTAL Steam Power Production Expenses	9,792,668	10,801,833	10.31%
Nuclear Power Generation				
Operation				
517	Operation Supervision & Engineering	31,105	25,085	-19.35%
518	Nuclear Fuel Expense	4,170	6,457	54.84%
519	Coolants & Water	929	869	-6.43%
520	Steam Expenses	8,623	5,860	-32.05%
521	Steam from Other Sources	0	0	
522	(Less) Steam Transferred - Cr.	0	0	
523	Electric Expenses	796	970	21.79%
524	Miscellaneous Nuclear Power Expenses	41,645	39,073	-6.18%
525	Rents	0	0	
	TOTAL Operation - Nuclear	87,269	78,313	-10.26%
Maintenance				
528	Maintenance Supervision & Engineering	8,057	10,295	27.78%
529	Maintenance of Structures	4,663	2,356	-49.48%
530	Maintenance of Reactor Plant Equipment	20,431	(8,475)	-141.48%
531	Maintenance of Electric Plant	3,428	640	-81.32%
532	Maintenance of Miscellaneous Nuclear Plant	8,062	4,382	-45.65%
	TOTAL Maintenance - Nuclear	44,642	9,198	-79.40%
	TOTAL Nuclear Power Production Expenses	131,911	87,511	-33.66%

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses -continued			
2	Hydraulic Power Generation			
3				
4	Operation			
5	535 Operation Supervision & Engineering	9,708	12,068	24.31%
6	536 Water for Power	1,341	833	-37.91%
7	537 Hydraulic Expenses	62,102	52,084	-16.13%
8	538 Electric Expenses	59,073	54,521	-7.71%
9	539 Miscellaneous Hydraulic Power Gen. Expense	26,176	58,822	124.72%
10	540 Rents	169	442	161.65%
11				
12	TOTAL Operation - Hydraulic	158,569	178,770	12.74%
13				
14	Maintenance			
15	541 Maintenance Supervision & Engineering	4,317	3,559	-17.57%
16	542 Maintenance of Structures	14,359	7,568	-47.29%
17	543 Maint. of Reservoirs, Dams & Waterways	29,898	12,895	-56.87%
18	544 Maintenance of Electric Plant	29,504	46,028	56.00%
19	545 Maintenance of Miscellaneous Hydro Plant	19,642	21,263	8.25%
20				
21	TOTAL Maintenance - Hydraulic	97,719	91,313	-6.56%
22				
23	TOTAL Hydraulic Power Production Expenses	256,288	270,083	5.38%
24				
25	Other Power Generation			
26				
27	Operation			
28	546 Operation Supervision & Engineering	58	0	-100.00%
29	547 Fuel	37,151	36,477	-1.81%
30	548 Generation Expenses	339	0	-100.00%
31	549 Miscellaneous Other Power Gen. Expenses	9	0	-100.00%
32	550 Rents	0	0	
33				
34	TOTAL Operation - Other	37,557	36,477	-2.87%
35				
36	Maintenance			
37	551 Maintenance Supervision & Engineering	56	0	-100.00%
38	552 Maintenance of Structures	0	0	
39	553 Maintenance of Generating & Electric Plant	257	0	-100.00%
40	554 Maintenance of Misc. Other Power Gen. Plant	130	0	-100.00%
41				
42	TOTAL Maintenance - Other	443	0	-100.00%
43				
44	TOTAL Other Power Production Expenses	38,000	36,477	-4.01%
45				
46	Other Power Supply Expenses			
47	555 Purchased Power	2,972,001	3,828,960	28.83%
48	556 System Control & Load Dispatching	99,995	87,375	-12.62%
49	557 Other Expenses	227,617	398,574	75.11%
50				
51	TOTAL Other Power Supply Expenses	3,299,613	4,314,909	30.77%
52				
53	TOTAL Power Production Expenses	13,518,480	15,510,813	14.74%

	Account Number & Title	Last Year	This Year	% Change
1	Transmission Expenses			
2	Operation			
3	560 Operation Supervision & Engineering	11,706	9,029	-22.86%
4	561 Load Dispatching	66,409	77,222	16.28%
5	562 Station Expenses	48,159	47,128	-2.14%
6	563 Overhead Line Expenses	21,678	23,590	8.82%
7	564 Underground Line Expenses	17	280	1571.35%
8	565 Transmission of Electricity by Others	847,316	1,044,802	23.31%
9	566 Miscellaneous Transmission Expenses	17,521	14,823	-15.39%
10	567 Rents	16,733	10,062	-39.87%
11				
12	TOTAL Operation - Transmission	1,029,538	1,226,937	19.17%
13	Maintenance			
14	568 Maintenance Supervision & Engineering	13,361	12,956	-3.03%
15	569 Maintenance of Structures	3,529	4,025	14.05%
16	570 Maintenance of Station Equipment	38,363	44,142	15.06%
17	571 Maintenance of Overhead Lines	61,172	60,349	-1.34%
18	572 Maintenance of Underground Lines	12	21	78.15%
19	573 Maintenance of Misc. Transmission Plant	11,419	20,291	77.70%
20				
21	TOTAL Maintenance - Transmission	127,856	141,783	10.89%
22				
23	TOTAL Transmission Expenses	1,157,394	1,368,720	18.26%
24				
25	Distribution Expenses			
26	Operation			
27	580 Operation Supervision & Engineering	37,154	33,309	-10.35%
28	581 Load Dispatching	51,124	45,072	-11.84%
29	582 Station Expenses	25,664	64,336	150.69%
30	583 Overhead Line Expenses	115,568	160,664	39.02%
31	584 Underground Line Expenses	61,764	108,135	75.08%
32	585 Street Lighting & Signal System Expenses	15,353	11,332	-26.19%
33	586 Meter Expenses	91,712	87,123	-5.00%
34	587 Customer Installations Expenses	12,187	9,210	-24.43%
35	588 Miscellaneous Distribution Expenses	152,706	149,626	-2.02%
36	589 Rents	29,748	15,845	-46.74%
37				
38	TOTAL Operation - Distribution	592,981	684,654	15.46%
39	Maintenance			
40	590 Maintenance Supervision & Engineering	46,411	41,361	-10.88%
41	591 Maintenance of Structures	326	1,387	324.99%
42	592 Maintenance of Station Equipment	41,647	24,559	-41.03%
43	593 Maintenance of Overhead Lines	472,403	462,673	-2.06%
44	594 Maintenance of Underground Lines	68,916	83,063	20.53%
45	595 Maintenance of Line Transformers	66,604	39,488	-40.71%
46	596 Maintenance of Street Lighting, Signal Systen	9,315	12,962	39.15%
47	597 Maintenance of Meters	25,859	27,403	5.97%
48	598 Maintenance of Miscellaneous Dist. Plant	19,070	13,906	-27.08%
49				
50	TOTAL Maintenance - Distribution	750,551	706,802	-5.83%
51				
52	TOTAL Distribution Expenses	1,343,532	1,391,456	3.57%
53				

Account Number & Title		Last Year	This Year	% Change
	Customer Accounts Expenses			
Operation				
901	Supervision	62,321	64,167	2.96%
902	Meter Reading Expenses	228,414	241,259	5.62%
903	Customer Records & Collection Expenses	639,741	625,991	-2.15%
904	Uncollectible Accounts Expenses	58,960	139,439	136.50%
905	Miscellaneous Customer Accounts Expenses	24,033	18,387	-23.49%
	TOTAL Customer Accounts Expenses	1,013,469	1,089,243	7.48%
	Customer Service & Information Expenses			
Operation				
907	Supervision	5,425	5,315	-2.04%
908	Customer Assistance Expenses	88,379	105,008	18.82%
909	Informational & Instructional Adv. Expenses	13,576	11,464	-15.56%
910	Miscellaneous Customer Service & Info. Exp.	10,014	9,911	-1.03%
	TOTAL Customer Service & Info Expenses	117,394	131,697	12.18%
	Sales Expenses			
Operation				
911	Supervision	18,154	9,683	-46.66%
912	Demonstrating & Selling Expenses	49,176	102,083	107.59%
913	Advertising Expenses	59,720	24,494	-58.99%
916	Miscellaneous Sales Expenses	8,989	22,371	148.88%
	TOTAL Sales Expenses	136,039	158,631	16.61%
	Administrative & General Expenses			
Operation				
920	Administrative & General Salaries	1,291,371	1,269,133	-1.72%
921	Office Supplies & Expenses	561,932	469,110	-16.52%
922	(Less) Administrative Expenses Transferred - Cr.	0	0	
923	Outside Services Employed	150,385	174,069	15.75%
924	Property Insurance	52,757	157,042	197.67%
925	Injuries & Damages	25,061	148,383	492.10%
926	Employee Pensions & Benefits	953,284	1,550,280	62.63%
927	Franchise Requirements	212	227	6.80%
928	Regulatory Commission Expenses	63,321	135,324	113.71%
929	(Less) Duplicate Charges - Cr.	(1,166,037)	(1,653,712)	41.82%
930.1	General Advertising Expenses		3,181	
930.2	Miscellaneous General Expenses	246,368	291,162	18.18%
931	Rents	137,918	123,708	-10.30%
	TOTAL Operation - Admin. & General	2,316,571	2,667,907	15.17%
Maintenance				
935	Maintenance of General Plant	73,454	64,794	-11.79%
	TOTAL Administrative & General Expenses	2,390,025	2,732,701	14.34%
	TOTAL Operation & Maintenance Expenses	19,676,333	22,383,262	13.76%

Sch. 12 MONTANA TAXES OTHER THAN INCOME

	Description of Tax	Last Year	This Year	% Change
1	California - Property	39,067	38,452	-1.57%
3	Oregon - Property	520,095	505,103	-2.88%
5	Washington - Property	131,658	135,735	3.10%
7	- Pollution Control Credit	(19,885)	(20,022)	0.69%
9	Idaho - Property	45,664	32,879	-28.00%
11	- KWH	165	324	96.36%
13	Montana - Property	124,747	122,797	-1.56%
15	- Franchise and Occupation	(884)	1,925	-317.76%
17	- Regulatory Commision	48,070	72,969	51.80%
19	- Energy Proceeds	4,044	3,891	-3.78%
21	- Consumer Counsel	27,132	21,655	-20.19%
23	Wyoming - Property	189,895	221,396	16.59%
25	Utah - Property	74,283	107,303	44.45%
27	Arizona - Property	39,056	86,181	120.66%
29	Colorado - Property	0	46,498	
31	Federal - Excise Superfund	11,490	9,275	-19.28%
33	Other - Miscellaneous Taxes & License	(25)	628	
53	**TOTAL MT Taxes other than Income**	1,234,572	1,386,989	12.35%

Sch. 13 PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	J BRIDGER FUEL EXP	MINING SERVICES	97,607,316.22	1,606,323.60	1.6457%
2	CENTRALIA COAL MINE	MINING SERVICES	48,754,279.06	802,349.17	1.6457%
3	D JOHNSTON COAL MINE	MINING SERVICES	33,649,567.03	553,770.92	1.6457%
4	ENERGY WEST MINING	CONST./MAINT. CONTRACTS	17,904,248.73	294,650.22	1.6457%
5	WYODAK FUEL EXPENSE	MINING SERVICES	16,544,294.90	272,269.46	1.6457%
6	HAWKEYE CONSTRUCTION	CONST./MAINT. CONTRACTS	12,652,823.67	208,227.52	1.6457%
7	INTERNATIONAL LINE B	CONST./MAINT. CONTRACTS	12,492,559.11	205,590.05	1.6457%
8	UNION POWER CONSTRUC	CONST./MAINT. CONTRACTS	11,067,982.07	182,145.78	1.6457%
9	JOB LINE CONSTRUCTIO	CONST./MAINT. CONTRACTS	9,262,238.91	152,428.67	1.6457%
10	WESTINGHOUSE ELECTRI	CONST./MAINT. CONTRACTS	6,973,261.81	114,758.97	1.6457%
11	STOEL RIVES BOLEY JO	LEGAL	6,461,007.26	106,328.80	1.6457%
12	GENERAL ELECTRIC CO.	CONST./MAINT. CONTRACTS	6,129,703.60	100,876.53	1.6457%
13	TREES INC.	TREE TRIMMING	5,189,503.12	85,403.65	1.6457%
14	GEA POWER COOLING SY	CONST./MAINT. CONTRACTS	5,109,310.72	84,083.93	1.6457%
15	ABB COMBUSTION ENGIN	CONST./MAINT. CONTRACTS	4,466,592.43	73,506.71	1.6457%
16	INDUSTRIAL POWER CON	CONST./MAINT. CONTRACTS	3,871,341.52	63,710.67	1.6457%
17	TRI COR ASSOCIATES	CONST./MAINT. CONTRACTS	3,811,640.98	62,728.18	1.6457%
18	THOMPSON-MCDOUGALL	CONST./MAINT. CONTRACTS	3,298,268.15	54,279.60	1.6457%
19	ORACLE CORPORATION	OTHER CONSULTANTS	3,108,869.70	51,162.67	1.6457%
20	SENIOR BOILER TUBE C	OTHER	2,890,000.00	47,560.73	1.6457%
21	KIDDER PEABODY & CO	OTHER CONSULTANTS	2,677,491.01	44,063.47	1.6457%
22	NORTH AMERICAN ENERG	NESCO	2,656,094.35	43,711.34	1.6457%
23	WILSON CONSTRUCTION	CONST./MAINT. CONTRACTS	2,600,844.00	42,802.09	1.6457%
24	HENKELS & MCCOY, INC	CONST./MAINT. CONTRACTS	2,592,075.88	42,657.79	1.6457%
25	B L MONTAGUE CO, INC	CONST./MAINT. CONTRACTS	2,387,407.00	39,289.56	1.6457%
26	ENERGY WEST MINING	MINING SERVICES	2,255,634.99	37,120.99	1.6457%
27	L E MYERS CO.	CONST./MAINT. CONTRACTS	2,190,643.67	36,051.42	1.6457%
28	PACIFIC ENGINEERING	ENGINEERING	2,068,306.46	34,038.12	1.6457%
29	DEER CREEK COAL MINE	OTHER	2,043,602.11	33,631.56	1.6457%
30	UNIVERSAL TRANSPORT,	FREIGHT & CONTRACT HAULING	1,980,773.06	32,597.58	1.6457%
31	BLACK & VEATCH	ENGINEERING	1,935,317.26	31,849.52	1.6457%
32	CHRISTENSON ELECTRIC	CONST./MAINT. CONTRACTS	1,861,504.07	30,634.77	1.6457%
33	PYNCH-TURNER INCORP	CONST./MAINT. CONTRACTS	1,857,465.33	30,568.31	1.6457%
34	OSMOSE WOOD PRESERVI	CONST./MAINT. CONTRACTS	1,739,073.11	28,619.93	1.6457%
35	BONNEVILLE POWER ADM	CONST./MAINT. CONTRACTS	1,738,439.00	28,609.49	1.6457%
36	MINERICH INC	CONST./MAINT. CONTRACTS	1,671,466.30	27,507.32	1.6457%
37	FURST CONSTRUCTION O	CONST./MAINT. CONTRACTS	1,662,599.07	27,361.39	1.6457%
38	ASPLUNDH TREE EXPERT	TREE TRIMMING	1,644,136.12	27,057.55	1.6457%
39	ASHWORTH TRANSFER CO	FREIGHT & CONTRACT HAULING	1,505,188.32	24,770.88	1.6457%
40	BERMAN & O'RORKE LAW	LEGAL	1,497,365.69	24,642.15	1.6457%
41	ENGINEERING & DESIGN	OTHER	1,494,879.20	24,601.23	1.6457%
42	SARGENT & LUNDY	ENGINEERING	1,482,953.03	24,404.96	1.6457%
43	POWER CITY ELECTRIC,	CONST./MAINT. CONTRACTS	1,450,730.62	23,874.67	1.6457%
44	NEC AMERICA	CONST./MAINT. CONTRACTS	1,348,728.60	22,196.03	1.6457%
45	YOUNG & RUBICAM SAN	OTHER	1,198,153.41	19,718.01	1.6457%
46	INDUSTRIAL CONTRACTO	OTHER	1,173,790.18	19,317.06	1.6457%
47	RALPH D MCDOWELL COR	CONST./MAINT. CONTRACTS	1,130,424.98	18,603.40	1.6457%
48	INTERMOUNTAIN CONSTR	CONST./MAINT. CONTRACTS	1,126,762.50	18,543.13	1.6457%
49	DIGITAL EQUIPMENT CO	COMPUTER EQUIP. MAINTENANCE	1,117,167.06	18,385.22	1.6457%
50	I B M	COMPUTER EQUIP. MAINTENANCE	1,115,693.42	18,360.97	1.6457%
51	POWER SUBSTATIONS, I	OTHER CONSULTANTS	1,111,300.00	18,288.66	1.6457%
52	OTHERS		(26,738,491.35)	(440,035.35)	1.6457%
53	TOTAL Payments for Services		338,822,327.44	5,575,999.05	

Directly Assigned to Montana

Sch. 13	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES				
	Name of Recipient	**Nature of Service**	**Total Company**	**Montana**	**% Montana**
1	MONTANA VENDOR PAYMENTS	($75, 000 or more in expenditures)			
2					
3	NORTH AMERICAN ENERGY	CONST./MAINT. CONTRACTS	107,153.80	107,153.80	100.0000%
4					
5	TREES INC.	CONST./MAINT. CONTRACTS	109,004.89	109,004.89	100.0000%
6					
7	VANALT CO., INC.	CONST./MAINT. CONTRACTS	133,635.15	133,635.15	100.0000%
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52					
53	TOTAL Payments for Services		349,793.84	349,793.84	

Sch. 14 POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS

	Description	Total Company	Montana	% Montana
1	CITIZENS FOR FAIR CAMPAIGN FINANCING	150.00		0.00%
2	COMMITTEE TO ELECT (VARIOUS CANDIDATES)	36,350.00		0.00%
3	CONSUMERS AGAINST REGESIVE TAXATION	2,000.00		0.00%
4	FRIENDS OF PCC	2,500.00		0.00%
5	GREENSPACE MEDIA FUND	1,000.00		0.00%
6	HOUSE DEMOCRATIC CAUCUS	300.00		0.00%
7	HOUSE REPUBLICAN ORGANIZATIONAL COMM.	300.00		0.00%
8	LEADERSHIP FOR WASHIINGTON FUND	50.00		0.00%
9	OREGON CAMPAIGN INSTITUTE	500.00		0.00%
10	OREGONIANS FOR A SOUND ECONOMY	25,000.00		0.00%
11	PAC MATCHING FUND	15,000.00		0.00%
12	ROCKY MOUNTAIN PROGRAM	1,000.00		0.00%
13	RSVP FOUNDATION	100.00		0.00%
14	SENATE DEMOCRAT CAMPAIGN COMMITTEE	300.00		0.00%
15	SENATE REPUBLICAN CAMPAIGN COMMITTEE	500.00		0.00%
16	THE CAMPAIGN FOR A HATE-FREE OREGON	5,000.00		0.00%
17	THE CITIZEN'S CONVENTION	300.00		0.00%
18				
19				
20				
21				
22				
23				
24				
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27				
28				
29				
30				
31				
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37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48	(1) PAC contributions are charged to account 426.4 and are not			
49	allocated to Montana for rate making purposes.			
50				
51				
52				
53	TOTAL (1)	90,350.00		0.00%

Sch. 15 **PENSION COSTS**

	Description	Last Year	This Year	% Change
1				
2	Defined Benefit Plan?	yes	yes	
3				
4	Defined Contribution Plan?	yes	yes	
5				
6	Actuarial Cost Method	Projected Unit	Projected Unit	
7		Credit Method	Credit Method	
8	Is the Plan overfunded?	no	no	
9				
10	Accumulated Benefit Obligation	468,882,573	555,673,703	18.51%
11	Projected Benefit Obligation	522,508,757	626,822,646	19.96%
12	Fair Value of Plan Assets	444,991,945	473,284,874	6.36%
13				
14	Discount Rate for Benefit Obligations	9.00%	9.00%	0.00%
15	Expected Long-Term Return on Assets	9.00%	9.00%	0.00%
16				
17	Net Periodic Pension Cost:			
18	Service Cost	11,076,418	13,063,687	17.94%
19	Interest Cost	44,094,281	52,641,877	19.38%
20	Return on Plan Assets	(35,262,641)	(40,974,592)	16.20%
21	Amortization of Transition Amount	786,954	4,193,431	432.87%
22	Amortization of Gains or Losses	0	(2,157,071)	
23	Total Net Periodic Pension Cost	20,695,012	26,767,332	29.34%
24				
25	Minimum Required Contribution	0	9,197,298	
26	Actual Contribution	0	26,767,000	
27	Maximum Amount Deductible	14,322,214	60,692,363	323.76%
28	Benefit Payments	43,523,472	45,950,376	5.58%
29				
30	Montana Intrastate Costs:			
31	Pension Costs	253,451	310,868	
32	Pension Costs Capitalized	94,266	129,642	
33	Accumulated Pension Asset (Liability) at Year End	(1,909,231)	(2,605,228)	
34				
35	Number of Company Employees:			
36	Covered by the Plan	11,802	12,498	5.90%
37	Not Covered by the Plan	N/A	N/A	
38	Active	7,529	8,048	6.89%
39	Retired	3,412	3,539	3.72%

	Description	Last Year	This Year	% Change
1	General Information			
2				
3	Assumptions:			
4	Discount Rate for Benefit Obligations	N/A	9.00%	
5	Expected Long-Term Return on Assets	N/A	0.00%	
6	Medical Cost Inflation Rate		12% to 6%	
7	Actuarial Cost Method		Projected Unit	
8			Credit Method	
9	List each method used to fund OPEBs (ie: VEBA, 401(h)):			
10	Method - Tax Advantaged (Yes or No)			
11	None			
12				
13				
14				
15				
16	Describe Changes to the Benefit Plan:			
17				
18				
19				
20	Total Company			
21				
22	Accumulated Post Retirement Benefit Obligation (APBO)	N/A	234,281,000	
23	Fair Value of Plan Assets	N/A	0	
24	List the amount funded through each funding method:			
25	VEBA			
26	401(h)			
27	Other ____________			
28	Total amount funded	0	0	
29				
30	List amount that was tax deductible for each type of funding:			
31	VEBA			
32	401(h)			
33	Other ____________			
34	Total amount that was tax deductible	0	0	
35				
36	Net Periodic Post Retirement Benefit Cost:			
37	Service Cost	N/A	4,759,000	
38	Interest Cost	N/A	20,947,000	
39	Return on Plan Assets	N/A	0	
40	Amortization of Transition Obligation	N/A	11,714,000	
41	Amortization of Gains or Losses	N/A	0	
42	Total Net Periodic Post Retirement Benefit Cost	0	37,420,000	
43				
44	Benefit Cost Expensed	N/A	26,407,294	
45	Benefit Cost Capitalized	N/A	11,012,706	
46	Benefit Payments		12,600,000	
47				
48	Number of Company Employees:			
49	Covered by the Plan		11,704	
50	Not Covered by the Plan		N/A	
51	Active		8,604	
52	Retired		3,100	
53	Spouse/Dependants covered by the Plan		N/A	

Sch 16 OTHER POST EMPLOYMENT BENEFITS (OPEBS) (cont.)

	Description	Last Year	This Year	% Change
1				
2	Montana			
3				
4	Accumulated Post Retirement Benefit Obligation (APBO)	N/A	3,855,562	
5	Fair Value of Plan Assets	N/A	0	
6	List the amount funded through each funding method:			
7	VEBA			
8	401(h)			
9	Other ____________			
10	Total amount funded	0	0	
11				
12	List amount that was tax deductible for each type of funding:			
13	VEBA			
14	401(h)			
15	Other ____________			
16	Total amount that was tax deductible	0	0	
17				
18	Net Periodic Post Retirement Benefit Cost:			
19	Service Cost	N/A	78,319	
20	Interest Cost	N/A	344,725	
21	Return on Plan Assets	N/A	0	
22	Amortization of Transition Obligation	N/A	192,777	
23	Amortization of Gains or Losses	N/A	0	
24	Total Net Periodic Post Retirement Benefit Cost	0	615,821	
25				
26	Benefit Cost Expensed	N/A	434,585	
27	Benefit Cost Capitalized	N/A	181,236	
28	Benefit Payments	N/A	207,358	
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:			
41	Order number:			
42				
43	Amount recovered through rates	N/A	0	

Sch. 17 **TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED**

	Name/Title	Base Salary	Bonuses	Other	Total
1	Area Manager C	70,377	6,150	11,925	88,452
	Detail of "Other"				
	- Excess Life Insurance			761	
	- Vehicle Allowance			486	
	- Personal Time Sold			10,553	
	- Safety Award			125	
2	District Manager B	65,178	2,139	9,935	77,252
	Detail of "Other"				
	- Excess Life Insurance			620	
	- Vehicle Allowance			486	
	- Personal Time Sold			8,704	
	- Safety Award			125	
3	Area Operations Manager C	55,495	1,397	17,253	74,145
	Detail of "Other"				
	- Excess Life Insurance			695	
	- Relocation			10,174	
	- Personal Time Sold			6,309	
	- Safety Award			75	
4	Area Customer Service Manager C	62,226	2,055	5,180	69,461
	Detail of "Other"				
	- Excess Life Insurance			800	
	- Personal Time Sold			4,255	
	- Safety Award			125	
5	Power Superintendent B	49,710	1,620	17,825	69,154
	Detail of "Other"				
	- Excess Life Insurance			507	
	- Relocation			13,198	
	- Personal Time Sold			3,995	
	- Safety Award			125	
6	District Operations Manager	52,320	1,676	12,091	66,087
	Detail of "Other"				
	- Excess Life Insurance			165	
	- Personal Time Sold			11,851	
	- Safety Award			75	
7	District Manager B	59,805	1,880	1,309	62,993
	Detail of "Other"				
	- Personal Time Sold			1,279	
	- Safety Award			30	
8	Line Foreman	55,019	1,908	2,183	59,110
	Detail of "Other"				
	- Excess Life Insurance			2,036	
	- Premium Time Pay			10	
	- Overtime Retroactive Pay			12	
	- Safety Award			125	
9	Estimator A	55,330	1,718	1	57,049
	Detail of "Other"				
	- Overtime Retroactive Pay			1	
10	Lineman	53,944	1,601	1,461	57,006
	Detail of "Other"				
	- Excess Life Insurance			287	
	- Premium Time Pay			1,108	
	- Overtime Retroactive Pay			16	
	- Safety Award			50	

Sch. 17 TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

	Name/Title	Base Salary	Bonuses	Other	Total
1	Joel B. Rogers Area Manager C	70,377	6,150	11,925	88,452
2	James M. Redman District Manager B	65,178	2,139	9,935	77,252
3	Donald M. Jordan Area Operations Manager C	55,495	1,397	17,253	74,145
4	Lawrence C. Delibero Area Customer Service Manager C	62,226	2,055	5,180	69,461
5	Coyd A. Fouts, Jr. Power Superintendent B	49,710	1,620	17,825	69,154
6	Dan L. Olmstead District Operations Manager	52,320	1,676	12,091	66,087
7	Lucy S. Tyler District Manager B	59,805	1,880	1,309	62,993
8	Willeam H. Arthur Line Foreman	55,019	1,908	2,183	59,110
9	Eugene R. Drager Estimator A	55,330	1,718	1	57,049
10	Dennis L. Gosney Lineman	53,944	1,601	1,461	57,006

Line	Acct.	Account Title	Last Year	This Year	% Change
1		Assets and Other Debits			
2	Utility Plant				
3	101	Electric Plant in Service	8,007,328,299	8,399,047,917	5 %
4	101.1	Property Under Capital Leases	20,505,744	18,958,044	(8) %
5	102	Electric Plant Purchased or Sold	450,227,778	710,328,780	58 %
6	103	Experimental Electric Plant Unclassified	1,286,190	1,286,190	
7	104	Electric Plant Leased to Others			
8	105	Electric Plant Held for Future Use	9,720,761	6,709,964	(31) %
9	106	Completed Constr. Not Classified – Electric	36,323,956	43,032,492	18 %
10	107	Construction Work in Progress – Electric	243,109,328	268,277,915	10 %
11	108	(Less) Accumulated Depreciation	2,477,396,364	2,630,596,417	6 %
12	111	(Less) Accumulated Amortization	44,190,275	53,971,709	22 %
13	114	Electric Plant Acquisition Adjustments	18,935,142	14,399,618	(24) %
14	115	(Less) Accum. Amort. Elec. Acq. Adj.			
15	118–119	Other Utility Plant – Net	1,236,485	1,206,344	(2) %
16	120	Nuclear Fuel (Net)	2,382,611	80,360	(97) %
17		TOTAL Utility Plant	6,269,469,655	6,778,759,498	8 %
18					
19	Other Property & Investments				
20	121	Nonutility Property	15,718,248	7,693,205	(51) %
21	122	(Less) Accum. Depr. & Amort. for Nonutil. Prop.	932,482	1,003,415	8 %
22	123	Investments in Associated Companies		6,107,928	
23	123.1	Investments in Subsidiary Companies	1,373,185,798	784,660,938	(43) %
24	124	Other Investments	14,945,551	18,632,235	25 %
25	125	Sinking Funds			
26	128	Other Special Funds	26,861	77,550,142	288,609 %
27		TOTAL Other Property & Investments	1,402,943,976	893,641,033	(36) %
28					
29	Current & Accrued Assets				
30	131	Cash	(24,368,216)	(40,297,075)	65 %
31	132–134	Special Deposits	2,017,314	867,664	(57) %
32	135	Working Funds	1,775,147	1,405,679	(21) %
33	136	Temporary Cash Investments	20,755,000	25,600,000	23 %
34	141	Notes Receivable	1,343,027	1,256,047	(6) %
35	142	Customer Accounts Receivable	176,491,277	181,449,297	3 %
36	143	Other Accounts Receivable	42,197,054	70,203,331	66 %
37	144	(Less) Accum. Provision for Uncollectible Accts.	7,848,846	9,495,204	21 %
38	145	Notes Receivable – Associated Companies	1,967,792	490,262	(75) %
39	146	Accounts Receivable – Associated Companies	1,172,464	2,058,124	76 %
40	151	Fuel Stock	71,098,556	70,018,817	(2) %
41	152	Fuel Stock Expenses Undistributed			
42	153	Residuals			
43	154	Plant Materials and Operating Supplies	132,215,645	120,064,866	(9) %
44	155	Merchandise	660,897	104,493	(84) %
45	156	Other Material & Supplies	20,750		(100) %
46	157	Nuclear Materials Held for Sale			
47	163	Stores Expense Undistributed	8,315,338	5,289,480	(36) %
48	165	Prepayments	48,108,799	41,884,241	(13) %
49	171	Interest & Dividends Receivable	3,385,909	1,546,037	(54) %
50	172	Rents Receivable		37,150	
51	173	Accrued Utility Revenues	109,658,750	107,454,859	(2) %
52	174	Miscellaneous Current & Accrued Assets	58,127,747	26,777,559	(54) %
53		TOTAL Current & Accrued Assets	647,094,404	606,715,627	(6) %

Line		Account Title	Last Year	This Year	% Change
1		Assets and Other Debits (cont.)			
2					
3		Deferred Debits			
4					
5	181	Unamortized Debt Expense	11,696,828	15,216,218	30 %
6	182.1	Extraordinary Property Losses	4,964,165	3,899,777	(21) %
7	182.2	Unrecovered Plant & Regulatory Study Costs	374,591	29,936,179	7,892 %
8	182.3	Regulatory Assets			
9	183	Prelim. Survey & Investigation Charges	7,845,134	4,517,077	(42) %
10	184	Clearing Accounts			
11	185	Temporary Facilities	246,036	233,543	(5) %
12	186	Miscellaneous Deferred Debits	383,229,460	262,070,721	(32) %
13	187	Deferred Losses from Disposition of Util. Plant			
14	188	Research, Devel. & Demonstration Expend.			
15	189	Unamortized Loss on Reacquired Debt	42,246,427	70,376,742	67 %
16	190	Accumulated Deferred Income Taxes	29,318,985	42,522,941	45 %
17		TOTAL Deferred Debits	479,921,626	428,773,198	(11) %
18					
19		TOTAL Assets & Other Debits	8,799,429,661	8,707,889,356	(1) %

Line		Account Title	Last Year	This Year	% Change
20					
21		Liabilities and Other Credits			
22					
23		Proprietary Capital			
24	201	Common Stock Issued	2,637,528,658	2,817,115,745	7 %
25	202	Common Stock Subscribed			
26	204	Preferred Stock Issued	492,360,450	636,360,450	29 %
27	205	Preferred Stock Subscribed			
28	207	Premium on Capital Stock			
29	211	Miscellaneous Paid-In Capital			
30	212	Installments Received on Capital Stock	(13,728)	201,951	(1,571) %
31	213	(Less) Discount on Capital Stock			
32	214	(Less) Capital Stock Expense	35,224,759	40,943,989	16 %
33	215	Appropriated Retained Earnings	3,182,660	3,182,660	
34	216	Unappropriated Retained Earnings	987,512,370	197,549,488	(80) %
35	217	(Less) Reacquired Capital Stock	370,000	280,000	(24) %
36		TOTAL Proprietary Capital	4,084,975,651	3,695,634,283	(10) %
37					
38		Long Term Debt			
39					
40	221	Bonds	2,840,476,108	3,017,508,509	6 %
41	222	(Less) Reacquired Bonds			
42	223	Advances from Associated Companies			
43	224	Other Long Term Debt			
44	225	Unamortized Premium on Long Term Debt	16,453,291	14,392,297	(13) %
45	226	(Less) Unamort. Discount on L-Term Debt-Dr.	5,439,279	3,408,263	(37) %
46		TOTAL Long Term Debt	2,851,490,120	3,028,492,543	6 %

Line	Account	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	19,713,154	17,971,653	(9) %
7	228.1	Accumulated Provision for Property Insurance	3,421,540	3,980,294	16 %
8	228.2	Accumulated Provision for Injuries & Damages	4,108,278	3,680,440	(10) %
9	228.3	Accum. Provision for Pensions & Benefits			
10	228.4	Accumulated Misc. Operating Provisions	171,318,212	151,506,464	(12) %
11	229	Accumulated Provision for Rate Refunds	1,512,000	1,700,000	12 %
12		TOTAL Other Noncurrent Liabilities	200,073,184	178,838,851	(11) %
13					
14		Current & Accrued Liabilities			
15					
16	231	Notes Payable	196,940,862	362,622,634	84 %
17	232	Accounts Payable	136,846,161	201,375,063	47 %
18	233	Notes Payable to Associated Companies	10,504,679	19,176,263	83 %
19	234	Accounts Payable to Associated Companies	10,103,541	10,437,670	3 %
20	235	Customer Deposits	7,785,793	8,612,086	11 %
21	236	Taxes Accrued	111,878,764	61,047,317	(45) %
22	237	Interest Accrued	79,097,354	78,597,727	(1) %
23	238	Dividends Declared	104,055,629	114,201,141	10 %
24	239	Matured Long Term Debt	1,792,200	15,450	(99) %
25	240	Matured Interest	126,114	72,214	(43) %
26	241	Tax Collections Payable	9,850,137	7,075,057	(28) %
27	242	Miscellaneous Current & Accrued Liabilities	100,913,329	80,605,066	(20) %
28	243	Obligations Under Capital Leases – Current	320,145	275,339	(14) %
29		TOTAL Current & Accrued Liabilities	770,214,708	944,113,027	23 %
30					
31		Deferred Credits			
32					
33	252	Customer Advances for Construction	13,841,919	13,917,753	1 %
34	253	Other Deferred Credits	95,089,743	89,293,912	(6) %
35	254	Regulatory Liabilities			
36	255	Accumulated Deferred Investment Tax Credit	201,067,410	191,597,943	(5) %
37	256	Deferred Gains from Disposition Of Util. Plant			
38	257	Unamortized Gain on Reacquired Debt	5,858,606	4,824,417	(18) %
39	281–283	Accumulated Deferred Income Taxes	576,818,320	643,624,605	12 %
40		TOTAL Deferred Credits	892,675,998	943,258,630	6 %
41					
42		TOTAL Liabilities & Other Credits	8,799,429,661	8,790,337,334	

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Account Number	Title	Last Year	This Year	% Change
	Intangible Plant			
301	Organization	462,256	460,690	-0.34%
302	Franchises & Consents	78,233	75,719	-3.21%
303	Miscellaneous Intangible Plant	848,476	891,138	5.03%
	TOTAL Intangible Plant	1,388,965	1,427,548	2.78%
	Production Plant			
Steam Production				
310	Land & Land Rights	494,137	526,342	6.52%
311	Structures & Improvements	7,797,453	7,629,278	-2.16%
312	Boiler Plant Equipment	28,447,114	27,844,978	-2.12%
313	Engines & Engine Driven Generators	0	0	
314	Turbogenerator Units	6,691,931	6,771,399	1.19%
315	Accessory Electric Equipment	3,070,145	3,004,541	-2.14%
316	Miscellaneous Power Plant Equipment	595,686	620,416	4.15%
	TOTAL Steam Production Plant	47,096,466	46,396,954	-1.49%
Nuclear Production				
320	Land & Land Rights	867	0	-100.00%
321	Structures & Improvements	143,810	0	-100.00%
322	Reactor Plant Equipment	170,152	0	-100.00%
323	Turbogenerator Units	127,066	0	-100.00%
324	Accessory Electric Equipment	56,141	0	-100.00%
325	Miscellaneous Power Plant Equipment	32,805	0	-100.00%
	TOTAL Nuclear Production Plant	530,841	0	-100.00%
Hydraulic Production				
330	Land & Land Rights	327,088	319,260	-2.39%
331	Structures & Improvements	752,313	773,943	2.88%
332	Reservoirs, Dams & Waterways	4,944,474	4,988,148	0.88%
333	Water Wheels, Turbines & Generators	1,115,528	1,120,894	0.48%
334	Accessory Electric Equipment	371,294	380,223	2.40%
335	Miscellaneous Power Plant Equipment	75,693	89,633	18.42%
336	Roads, Railroads & Bridges	150,042	152,929	1.92%
	TOTAL Hydraulic Production Plant	7,736,432	7,825,031	1.15%

Account Number & Title		Last Year	This Year	% Change
	Production Plant (cont.)			
Other Production				
340	Land & Land Rights	0	0	
341	Structures & Improvements	0	0	
342	Fuel Holders, Producers & Accessorie	0	0	
343	Prime Movers	1445	0	-100.00%
344	Generators	28	0	-100.00%
345	Accessory Electric Equipment	953	0	-100.00%
346	Miscellaneous Power Plant Equipmen	0	0	
	TOTAL Other Production Plant	2,426	0	-100.00%
	TOTAL Production Plant	55,366,165	54,221,985	-2.07%
	Transmission Plant			
350	Land & Land Rights	719176	691,796	-3.81%
352	Structures & Improvements	357,859	345,570	-3.43%
353	Station Equipment	6,783,363	7,539,360	11.14%
354	Towers & Fixtures	5,145,108	5,342,391	3.83%
355	Poles & Fixtures	3,037,883	3,123,138	2.81%
356	Overhead Conductors & Devices	7,432,545	7,455,473	0.31%
357	Underground Conduit	192	210	9.64%
358	Underground Conductors & Devices	354	304	-14.19%
359	Roads & Trails	65,926	55,757	-15.43%
	TOTAL Transmission Plant	23,542,406	24,554,000	4.30%
	Distribution Plant			
360	Land & Land Rights	219,549	217,526	-0.92%
361	Structures & Improvements	412,467	415,636	0.77%
362	Station Equipment	7,943,647	7,313,876	-7.93%
363	Storage Battery Equipment	0	0	
364	Poles, Towers & Fixtures	7,832,091	7,923,870	1.17%
365	Overhead Conductors & Devices	8,193,821	8,273,699	0.97%
366	Underground Conduit	1,155,465	1,368,393	18.43%
367	Underground Conductors & Devices	2,015,228	2,190,422	8.69%
368	Line Transformers	11,376,688	12,181,076	7.07%
369	Services	4,369,688	4,439,634	1.60%
370	Meters	1,599,266	1,677,597	4.90%
371	Installations on Customers' Premises	184,484	170,135	-7.78%
372	Leased Property on Customers' Prem	0	0	
373	Street Lighting & Signal Systems	496,512	486,777	-1.96%
	TOTAL Distribution Plant	45,798,906	46,658,641	1.88%

	Account Number & Title		Last Year	This Year	% Change
1					
2		General Plant			
3					
4	389	Land & Land Rights	17,795	20,032	12.57%
5	390	Structures & Improvements	1,653,268	1,421,966	-13.99%
6	391	Office Furniture & Equipment	1,375,683	1,802,653	31.04%
7	392	Transportation Equipment	276,186	320,368	16.00%
8	393	Stores Equipment	80,258	82,390	2.66%
9	394	Tools, Shop & Garage Equipment	358,774	431,248	20.20%
10	395	Laboratory Equipment	530,271	580,533	9.48%
11	396	Power Operated Equipment	367,490	394,970	7.48%
12	397	Communication Equipment	798,497	857,438	7.38%
13	398	Miscellaneous Equipment	30,519	32,322	5.91%
14	399	Other Tangible Property	5,958,294	5,736,346	-3.73%
15					
16		TOTAL General Plant	11,447,035	11,680,265	2.04%
17					
18		TOTAL (Account 101)	137,543,477	138,542,438	0.73%
19					
20	102	Communication Equipment	0	0	
21	103	Miscellaneous Equipment	37,077	35,771	-3.52%
22	106	Other Tangible Property	5,584,282	10,944,030	95.98%
23					
24		TOTAL Electric Plant in Service	143,164,836	149,522,239	4.44%

Sch. 20	MONTANA DEPRECIATION SUMMARY		Accumulated Depreciation		Current
	Functional Plant Classification	Plant Cost	Last Year Bal.	This Year Bal.	Avg. Rate
1					
2	Steam Production		16,147,000	16,815,708	3.08%
3	Nuclear Production		228,000	0	3.98%
4	Hydraulic Production		2,780,000	2,773,099	1.54%
5	Other Production		6,000	8,297	3.08%
6	Transmission		6,683,000	6,774,311	2.36%
7	Distribution		13,165,000	13,589,887	3.32%
8	General		3,884,000	3,996,616	5.89%
9	TOTAL	0	42,893,000	43,957,917	

Sch. 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)			
	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock	1,203,123	1,081,654	-10.10%
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)	1,153,008	1,134,519	-1.60%
9	Transmission Plant (Estimated)	243,298	247,241	1.62%
10	Distribution Plant (Estimated)	496,524	388,888	-21.68%
11	Assigned to Other	13,576	9,793	-27.87%
12	155 Merchandise			
13	156 Other Materials & Supplies			
14	157 Nuclear Materials Held for Sale			
15	163 Stores Expense Undistributed	119,898	87,050	-27.40%
16				
17	TOTAL Materials & Supplies	3,229,427	2,949,145	-8.68%

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		51.79%	12.10%	6.27%
13	Preferred Stock		7.10%	6.40%	0.45%
14	Long Term Debt		41.11%	8.44%	3.47%
15	Other		0.00%	0.00%	0.00%
16	TOTAL		100.00%		10.19%

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	(340,925,328)	506,696,910	(249) %
6	Depreciation	269,976,120	244,096,126	(10) %
7	Amortization	16,656,468	11,917,163	(28) %
8	Deferred Income Taxes – Net	53,602,328	(18,640,806)	(135) %
9	Investment Tax Credit Adjustments – Net	(9,469,467)	(9,115,328)	(4) %
10	Change in Operating Receivables – Net	(22,125,449)	(9,130,733)	(59) %
11	Change in Materials, Supplies & Inventories – Net	4,370,335	271,106	(94) %
12	Change in Operating Payables & Accrued Liabilities – Net	17,083,086	30,678,759	80 %
13	Allowance for Funds Used During Construction (AFUDC)	(7,327,515)	(7,925,747)	8 %
14	Change in Other Assets & Liabilities – Net	43,858,622	100,066,450	128 %
15	Other Operating Activities (explained on attached page)	587,850,509	(135,159,703)	(123) %
16	Net Cash Provided by/(Used in) Operating Activities	613,549,709	713,754,197	16 %
17				
18	Cash Inflows/Outflows From Investment Activities:			
19	Construction/Acquisition of Property, Plant and Equipment	(581,608,580)	(770,028,776)	32 %
20	(net of AFUDC & Capital Lease Related Acquisitions)			
21	Acquisition of Other Noncurrent Assets			
22	Proceeds from Disposal of Noncurrent Assets	2,974,015	4,628,366	56 %
23	Investments In and Advances to Affiliates	674,351	(80,052,000)	(11,971) %
24	Contributions and Advances from Affiliates			
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)	7,935,478	8,076,069	2 %
27	Net Cash Provided by/(Used in) Investing Activities	(570,024,736)	(837,376,341)	47 %
28				
29	Cash Flows from Financing Activities:			
30	Proceeds from Issuance of:			
31	Long–Term Debt	710,308,943	663,215,135	(7) %
32	Preferred Stock	195,189,483	98,428,301	(50) %
33	Common Stock	178,226,151	197,689,704	11 %
34	Other: Intercompany Borrowings	10,149,114	52,498,927	417 %
35	Net Increase in Short–Term Debt			
36	Other:			
37	Payment for Retirement of:			
38	Long–Term Debt	(820,059,354)	(451,651,023)	(45) %
39	Preferred Stock	(56,000,000)		(100) %
40	Common Stock			
41	Other:			
42	Net Decrease in Short–Term Debt	165,681,772	(41,412,079)	(125) %
43	Dividends on Preferred Stock	(35,167,657)	(26,106,307)	(26) %
44	Dividends on Common Stock	(404,456,402)	(382,965,517)	(5) %
45	Other Financing Activities (explained on attached page)			
46	Net Cash Provided by (Used in) Financing Activities	(56,127,950)	109,697,141	(295) %
47				
48				
49	Net Increase/(Decrease) in Cash and Cash Equivalents	(12,602,977)	(13,925,003)	10 %
50	Cash and Cash Equivalents at Beginning of Year	179,245	14,104,248	7,769 %
51	Cash and Cash Equivalents at End of Year	(12,423,732)	179,245	(101) %

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	4-1/2% Series due 4/1/93 30 year	4/63	4/93	15,000,000	11,461,782	11,442,000	N.A.	513,631	4.48%
3	4-5/8% Series due 8/1/93	8/63	8/93	30,000,000	19,610,845	19,666,000	N.A.	912,896	4.66%
4	4-5/8% Series due 8/1/94	8/64	8/94	15,000,000	13,537,798	13,400,000	N.A.	611,308	4.52%
5	4-5/8% Series due 10/1/94	10/64	10/94	30,000,000	19,936,067	20,261,000	N.A.	957,535	4.80%
6	5% Series due 10/1/95	10/65	10/95	30,000,000	14,026,006	14,168,000	N.A.	717,609	5.12%
7	9-3/8% Yen Fin due 7/22/97	7/87	7/97	50,000,000	49,668,437	50,000,000	N.A.	1,840,700	3.71%
8	7% Series due 3/1/98	3/68	3/98	20,000,000	15,982,729	16,000,000	N.A.	1,121,440	7.02%
9	8% Series due 5/1/99	5/69	5/99	25,000,000	20,985,540	21,057,000	N.A.	1,690,877	8.06%
10	7-7/8% Series due 2/1/01	2/71	2/01	40,000,000	27,522,635	28,024,000	N.A.	2,251,448	8.18%
11	8% Series due 10/1/01	10/71	10/01	35,000,000	25,428,951	25,882,000	N.A.	2,111,195	8.30%
12	7-1/2% Series due 5/1/02	5/72	5/02	25,000,000	20,079,174	20,310,000	N.A.	1,542,951	7.68%
13	7-3/4% Series due 10/1/02	10/72	10/02	30,000,000	19,434,644	19,744,000	N.A.	1,557,209	8.01%
14	Adjust. Rate Series due 11/1/02	9/82	11/02	50,000,000	13,116,905	13,234,000	N.A.	1,337,163	10.19%
15	8-3/8% Series due 1/1/04	1/74	1/04	60,000,000	52,154,175	52,695,000	N.A.	4,463,267	8.56%
16	8-3/4% Series due 4/1/06	4/76	4/06	32,000,000	31,628,674	32,000,000	N.A.	2,835,520	8.97%
17	8-3/8% Series due 9/1/06	9/76	9/06	40,000,000	39,689,106	40,000,000	N.A.	3,378,800	8.51%
18	8-5/8% Series due 12/1/06	12/76	12/06	50,000,000	44,781,673	45,075,000	N.A.	3,915,215	8.74%
19	8-1/2% Series due 3/1/07	3/77	3/07	55,000,000	54,884,275	55,000,000	N.A.	4,686,000	8.54%
20	8-1/4% Series due 9/1/07	9/77	9/07	50,000,000	33,055,899	33,175,000	N.A.	2,747,885	8.31%
21	8-7/8% Series due 11/1/07	11/77	11/07	100,000,000	91,978,513	93,345,000	N.A.	8,416,919	9.15%
22	8.271% Series due 10/1/10	4/92	10/10	48,972,000	47,285,288	47,342,000	N.A.	3,921,811	8.29%
23	7.978% Series due 10/1/11	4/92	10/11	4,422,000	4,252,899	4,258,000	N.A.	340,214	8.00%
24	8.493% Series due 10/1/12	4/92	10/12	19,772,000	19,160,020	19,183,000	N.A.	1,631,706	8.52%
25	8.797% Series due 10/1/13	4/92	10/13	16,203,000	15,733,130	15,752,000	N.A.	1,387,751	8.82%
26	8.734% Series due 10/1/14	4/92	10/14	28,218,000	27,455,071	27,488,000	N.A.	2,404,100	8.76%
27	8.294% Series due 10/1/15	4/92	10/15	46,946,000	45,727,156	45,782,000	N.A.	3,802,653	8.32%
28	8.635% Series due 10/1/16	4/92	10/16	18,750,000	18,296,056	18,318,000	N.A.	1,583,957	8.66%
29	8-3/4% Series due 12/1/16	12/86	12/16	92,000,000	92,000,000	92,000,000	N.A.	8,050,000	8.75%
30	8.470% Series due 10/1/17	4/92	10/17	19,609,000	19,156,025	19,179,000	N.A.	1,626,763	8.49%
31									
32	Total First Mortgage Bonds			1,076,892,000	908,029,473	913,780,000		72,358,523	7.97%
33									
34									

Long Term Debt

LONG TERM DEBT (Continued)

	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 %
35	SECURED MEDIUM-TERM NOTES:								
36	7.79% Ser. B due 1/29/93	1/91	1/93	10,000,000	9,955,352	10,000,000	N.A.	803,600	8.07%
37	8.15% Ser. B due 12/30/93	12/90	12/93	1,000,000	1,048,051	1,000,000	N.A.	63,650	6.07%
38	8.11% Ser. B due 1/18/94	1/91	1/94	4,000,000	3,976,141	4,000,000	N.A.	333,560	8.39%
39	8.07% Ser. B due 2/1/94	1/91	2/94	10,000,000	9,945,352	10,000,000	N.A.	827,900	8.32%
40	8-7/8% Ser. A due 6/15/94	6/89	6/94	10,000,000	10,465,515	10,000,000	N.A.	773,500	7.39%
41	8.47% Ser. B due 1/17/95	1/91	1/95	5,000,000	4,965,176	5,000,000	N.A.	434,000	8.74%
42	8.41% Ser. B due 2/1/95	1/91	2/95	10,000,000	9,930,352	10,000,000	N.A.	862,000	8.68%
43	8.59% Ser. B due 12/26/95	12/90	12/95	3,000,000	3,139,655	3,000,000	N.A.	223,740	7.13%
44	8.60% Ser. B due 12/28/95	12/90	12/95	2,500,000	2,616,379	2,500,000	N.A.	186,675	7.13%
45	8.60% Ser. B due 1/25/96	1/91	1/96	1,000,000	993,535	1,000,000	N.A.	87,620	8.82%
46	8.57% Ser. B due 2/1/96	1/91	2/96	11,000,000	10,928,887	11,000,000	N.A.	960,520	8.79%
47	8.55% Ser. B due 2/1/96	1/91	2/96	3,000,000	2,977,605	3,000,000	N.A.	262,110	8.80%
48	8.69% Ser. C due 7/16/96	7/91	7/96	8,500,000	8,442,477	8,500,000	N.A.	753,100	8.92%
49	8.65% Ser. B due 7/17/96	7/91	7/96	1,000,000	994,982	1,000,000	N.A.	87,760	8.82%
50	8.49% Ser. C due 8/15/96	8/91	8/96	14,050,000	13,954,918	14,050,000	N.A.	1,216,730	8.72%
51	8.43% Ser. A due 9/2/96	8/89	9/96	5,000,000	5,228,591	5,000,000	N.A.	378,800	7.24%
52	6.96% Ser. D due 1/22/97	2/92	1/97	1,000,000	912,241	1,000,000	N.A.	91,880	10.07%
53	7.00% Ser. D due 1/27/97	1/92	1/97	15,000,000	14,001,525	15,000,000	N.A.	1,300,350	9.29%
54	7.00% Ser. D due 1/27/97	1/92	1/97	20,000,000	18,668,701	20,000,000	N.A.	1,733,800	9.29%
55	6.99% Ser. D due 2/3/97	1/92	2/97	1,500,000	1,400,152	1,500,000	N.A.	129,870	9.28%
56	6.09% Ser. E due 4/15/97	10/92	4/97	2,000,000	1,791,000	2,000,000	N.A.	179,260	10.01%
57	8.87% Ser. A due 6/20/97	6/91	6/97	20,000,000	19,909,544	20,000,000	N.A.	1,793,800	9.01%
58	8.85% Ser. A due 6/20/97	6/91	6/97	15,000,000	14,917,158	15,000,000	N.A.	1,345,650	9.02%
59	8.78% Ser. B due 6/30/97	6/91	6/97	7,000,000	6,961,340	7,000,000	N.A.	623,070	8.95%
60	8.84% Ser. B due 7/2/97	7/91	7/97	2,000,000	1,988,965	2,000,000	N.A.	179,220	9.01%
61	6.12% Ser. E due 9/29/97	9/92	9/97	10,000,000	9,924,500	10,000,000	N.A.	629,800	6.35%
62	6.12% Ser. E due 9/29/97	9/92	9/97	3,500,000	3,457,000	3,500,000	N.A.	224,385	6.49%
63	6.12% Ser. E due 9/29/97	9/92	9/97	10,000,000	9,924,500	10,000,000	N.A.	629,800	6.35%
64	6.12% Ser. E due 9/29/97	9/92	9/97	10,000,000	9,924,500	10,000,000	N.A.	629,800	6.35%
65	6.14% Ser. E due 9/29/97	9/92	9/97	10,000,000	9,924,500	10,000,000	N.A.	631,800	6.37%
66	5.88% Ser. E due 10/15/97	10/92	10/97	1,000,000	907,888	1,000,000	N.A.	76,010	8.37%
67	6.00% Ser. E due 10/15/97	10/92	10/97	2,300,000	2,058,143	2,300,000	N.A.	183,770	8.93%
68	5.88% Ser. E due 10/15/97	10/92	10/97	12,000,000	10,620,435	12,000,000	N.A.	967,320	9.11%

LONG TERM DEBT (Continued)

	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 %
69	SECURED MEDIUM-TERM NOTES (Cont.):								
70	8.75% Ser. A due 2/12/98	2/91	2/98	5,000,000	4,957,676	5,000,000	N.A.	445,750	8.99%
71	8.75% Ser. B due 2/12/98	2/91	2/98	15,000,000	14,673,027	15,000,000	N.A.	1,337,250	9.11%
72	8.75% Ser. B due 2/12/98	2/91	2/98	15,000,000	14,873,027	15,000,000	N.A.	1,355,550	9.11%
73	8.75% Ser. B due 2/12/98	2/91	2/98	15,000,000	14,780,527	15,000,000	N.A.	1,376,850	9.32%
74	8.75% Ser. A due 2/12/98	2/91	2/98	10,000,000	9,915,352	10,000,000	N.A.	891,500	8.99%
75	8.81% Ser. C due 3/5/98	8/91	3/98	7,000,000	6,949,128	7,000,000	N.A.	626,640	9.02%
76	8.94% Ser. A due 6/25/98	6/91	6/98	15,000,000	14,909,658	15,000,000	N.A.	1,358,700	9.11%
77	8.90% Ser. C due 6/30/98	6/91	6/98	25,000,000	24,805,815	25,000,000	N.A.	2,263,000	9.12%
78	8.95% Ser. A due 6/30/98	6/91	6/98	5,000,000	4,972,386	5,000,000	N.A.	452,900	9.11%
79	8.95% Ser. A due 6/30/98	6/91	6/98	20,000,000	19,879,544	20,000,000	N.A.	1,813,600	9.12%
80	8.96% Ser. A due 7/3/98	7/91	7/98	8,000,000	7,951,860	8,000,000	N.A.	726,240	9.13%
81	8.94% Ser. C due 7/6/98	7/91	7/98	5,000,000	4,961,163	5,000,000	N.A.	454,600	9.16%
82	8.89% Ser. C due 7/20/98	7/91	7/98	5,000,000	4,961,163	5,000,000	N.A.	452,100	9.11%
83	8.82% Ser. C due 8/3/98	8/91	8/98	5,000,000	4,961,163	5,000,000	N.A.	448,600	9.04%
84	8.83% Ser. C due 9/1/98	8/91	9/98	4,000,000	3,970,930	4,000,000	N.A.	359,280	9.05%
85	8.83% Ser. C due 9/1/98	8/91	9/98	4,000,000	3,968,930	4,000,000	N.A.	358,880	9.04%
86	8.83% Ser. C due 9/1/98	8/91	9/98	4,000,000	3,968,330	4,000,000	N.A.	359,280	9.05%
87	8.83% Ser. C due 9/1/98	8/91	9/98	18,000,000	17,860,187	18,000,000	N.A.	1,616,760	9.05%
88	7.45% Ser. D due 1/22/99	1/92	1/99	10,000,000	9,324,350	10,000,000	N.A.	876,200	9.40%
89	7.45% Ser. D due 1/22/99	1/92	1/99	5,000,000	4,662,175	5,000,000	N.A.	458,250	9.83%
90	7.35% Ser. D due 2/1/99	1/92	2/99	4,000,000	3,729,740	4,000,000	N.A.	346,280	9.28%
91	7.45% Ser. D due 2/4/99	2/92	2/99	20,000,000	18,224,829	20,000,000	N.A.	1,839,600	10.09%
92	7.54% Ser. D due 2/15/99	2/92	2/99	15,000,000	13,668,621	15,000,000	N.A.	1,393,950	10.20%
93	7.50% Ser. D due 2/15/99	2/92	2/99	5,000,000	4,556,207	5,000,000	N.A.	462,550	10.15%
94	7.49% Ser. D due 2/15/99	2/92	2/99	30,000,000	27,337,242	30,000,000	N.A.	2,772,000	10.14%
95	7.46% Ser. D due 2/15/99	2/92	2/99	10,000,000	9,112,414	10,000,000	N.A.	920,800	10.10%
96	7.45% Ser. D due 2/15/99	2/92	2/99	20,000,000	18,224,829	20,000,000	N.A.	1,839,600	10.09%
97	7.40% Ser. D due 2/15/99	2/92	2/99	5,000,000	4,556,207	5,000,000	N.A.	457,250	10.04%
98	7.40% Ser. D due 2/15/99	2/92	2/99	5,000,000	4,556,207	5,000,000	N.A.	457,250	10.04%
99	9-1/2% Ser. A due 5/20/99	5/89	5/99	60,000,000	62,718,089	60,000,000	N.A.	5,285,400	8.43%
100	9.48% Ser. A due 5/25/99	5/89	5/99	15,000,000	15,680,772	15,000,000	N.A.	1,318,350	8.41%
101	9-1/2% Ser. A due 6/1/99	5/89	6/99	15,000,000	15,680,772	15,000,000	N.A.	1,321,200	8.43%
102	9-1/2% Ser. A due 6/1/99	5/89	6/99	15,000,000	15,680,772	15,000,000	N.A.	1,321,200	8.43%

LONG TERM DEBT (Continued)

	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 %
103	SECURED MEDIUM-TERM NOTES (Cont.):								
104	9.40% Ser. A due 6/1/99	5/89	6/99	15,000,000	15,740,422	15,000,000	N.A.	1,297,800	8.25%
105	8.55% Ser. A due 8/10/99	8/89	8/99	2,000,000	2,090,603	2,000,000	N.A.	157,740	7.55%
106	8.59% Ser. A due 9/1/99	8/89	9/99	10,000,000	10,457,182	10,000,000	N.A.	792,000	7.57%
107	6.51% Ser. E due 9/23/99	9/92	9/99	15,000,000	14,884,500	15,000,000	N.A.	997,350	6.70%
108	6.53% Ser. E due 9/27/99	9/92	9/99	5,000,000	4,944,500	5,000,000	N.A.	336,550	6.81%
109	6.54% Ser. E due 9/27/99	9/92	9/99	5,000,000	4,944,500	5,000,000	N.A.	337,100	6.82%
110	6.55% Ser. E due 9/28/99	9/92	9/99	1,200,000	1,167,300	1,200,000	N.A.	84,600	7.25%
111	6.86% Ser. E due 9/11/00	9/92	9/00	10,000,000	9,914,500	10,000,000	N.A.	700,100	7.06%
112	6.55% Ser. E due 9/15/00	9/92	9/00	5,000,000	4,944,500	5,000,000	N.A.	336,600	6.81%
113	8.90% Ser. B due 2/15/01	2/91	2/01	20,000,000	19,825,703	20,000,000	N.A.	1,806,000	9.11%
114	8.90% Ser. B due 2/15/01	2/91	2/01	20,000,000	19,825,703	20,000,000	N.A.	1,806,800	9.11%
115	8.88% Ser. B due 2/15/01	2/91	2/01	20,000,000	19,830,703	20,000,000	N.A.	1,802,800	9.09%
116	8.90% Ser. B due 2/15/01	2/91	2/01	20,000,000	19,830,703	20,000,000	N.A.	1,806,800	9.11%
117	9.10% Ser. A due 3/1/01	6/91	3/01	5,000,000	4,969,886	5,000,000	N.A.	459,650	9.25%
118	9.12% Ser. C due 7/5/01	7/91	7/01	5,000,000	4,959,913	5,000,000	N.A.	462,250	9.32%
119	9.12% Ser. C due 7/5/01	7/91	7/01	10,000,000	9,919,826	10,000,000	N.A.	924,500	9.32%
120	9.06% Ser. B due 7/9/01	7/91	7/01	1,000,000	993,982	1,000,000	N.A.	91,530	9.21%
121	9.15% Ser. C due 7/16/01	7/91	7/01	3,000,000	2,975,948	3,000,000	N.A.	278,250	9.35%
122	9.17% Ser. B due 7/17/01	7/91	7/01	1,000,000	993,732	1,000,000	N.A.	92,670	9.33%
123	9.06% Ser. C due 7/23/01	7/91	7/01	1,000,000	991,983	1,000,000	N.A.	91,840	9.26%
124	9.09% Ser. C due 7/24/01	7/91	7/01	1,000,000	991,983	1,000,000	N.A.	92,140	9.29%
125	9.10% Ser. C due 7/30/01	7/91	7/01	5,000,000	4,959,162	5,000,000	N.A.	461,200	9.30%
126	7.50% Ser. E due 8/1/01	11/92	8/01	2,000,000	1,894,328	2,000,000	N.A.	166,940	8.81%
127	8.99% Ser. C due 8/7/01	8/91	8/01	3,000,000	2,975,948	3,000,000	N.A.	273,420	9.19%
128	9.00% Ser. B due 8/8/01	8/91	8/01	2,500,000	2,484,331	2,500,000	N.A.	227,425	9.15%
129	9.00% Ser. C due 8/8/01	8/91	8/01	500,000	495,991	500,000	N.A.	45,620	9.20%
130	7.18% Ser. D due 8/15/02	8/92	8/02	3,500,000	3,478,125	3,500,000	N.A.	254,415	7.31%
131	7.20% Ser. D due 8/15/02	8/92	8/02	6,000,000	5,962,500	6,000,000	N.A.	437,340	7.33%
132	7.12% Ser. D due 8/15/02	8/92	8/02	4,000,000	3,975,000	4,000,000	N.A.	288,360	7.25%
133	7.20% Ser. D due 8/15/02	8/92	8/02	12,000,000	11,925,000	12,000,000	N.A.	874,680	7.33%
134	7.20% Ser. D due 8/15/02	8/92	8/02	6,500,000	6,459,375	6,500,000	N.A.	473,785	7.33%
135	7.20% Ser. D due 8/15/02	8/92	8/02	10,000,000	9,937,500	10,000,000	N.A.	728,900	7.33%
136	7.18% Ser. D due 8/15/02	8/92	8/02	10,000,000	9,937,500	10,000,000	N.A.	726,900	7.31%

LONG TERM DEBT (Continued)

	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 %
137	SECURED MEDIUM-TERM NOTES (Cont.):								
138	7.25% Ser. E due 9/9/02	9/92	9/02	20,000,000	19,849,500	20,000,000	N.A.	1,471,600	7.41%
139	7.21% Ser. E due 9/9/02	9/92	9/02	10,000,000	9,912,000	10,000,000	N.A.	733,600	7.40%
140	7.25% Ser. E due 9/9/02	9/92	9/02	20,000,000	19,849,500	20,000,000	N.A.	1,471,600	7.41%
141	7.14% Ser. E due 9/10/02	9/92	9/02	1,500,000	1,465,125	1,500,000	N.A.	112,110	7.65%
142	6.98% Ser. E due 9/16/02	9/92	9/02	10,000,000	9,912,000	10,000,000	N.A.	710,400	7.17%
143	6.97% Ser. E due 9/16/02	9/92	9/02	2,000,000	1,962,000	2,000,000	N.A.	144,800	7.38%
144	6.95% Ser. E due 9/16/02	9/92	9/02	10,000,000	9,912,000	10,000,000	N.A.	707,400	7.14%
145	7.00% Ser. E due 9/17/02	9/92	9/02	1,000,000	968,250	1,000,000	N.A.	74,560	7.70%
146	6.97% Ser. E due 9/23/02	9/92	9/02	1,500,000	1,465,125	1,500,000	N.A.	109,530	7.48%
147	9.00% Ser. C due 9/1/03	6/91	9/03	55,226,000	51,176,778	51,274,384	N.A.	4,628,026	9.04%
148	7.03% Ser. E due 10/15/03	10/92	10/03	5,000,000	4,033,191	5,000,000	N.A.	498,150	12.35%
149	7.39% Ser. E due 10/21/03	10/92	10/03	5,000,000	4,033,191	5,000,000	N.A.	518,950	12.87%
150	7.27% Ser. E due 10/21/03	10/92	10/03	2,000,000	1,613,276	2,000,000	N.A.	204,800	12.69%
151	7.30% Ser. E due 10/22/03	10/92	10/03	2,000,000	1,613,276	2,000,000	N.A.	205,500	12.74%
152	7.86% Ser. D due 2/16/04	2/92	2/04	2,500,000	2,330,463	2,500,000	N.A.	219,650	9.43%
153	7.79% Ser. D due 2/16/04	2/92	2/04	6,000,000	5,465,948	6,000,000	N.A.	541,140	9.90%
154	7.75% Ser. D due 2/16/04	2/92	2/04	3,000,000	2,732,975	3,000,000	N.A.	269,310	9.85%
155	7.81% Ser. D due 2/16/04	2/92	2/04	20,000,000	18,606,209	20,000,000	N.A.	1,752,000	9.42%
156	7.32% Ser. E due 9/3/04	9/92	9/04	7,500,000	7,427,625	7,500,000	N.A.	558,225	7.52%
157	7.11% Ser. E due 9/24/04	9/92	9/04	6,500,000	6,433,875	6,500,000	N.A.	470,470	7.31%
158	7.66% Ser. E due 10/22/04	11/92	10/04	5,000,000	4,734,570	5,000,000	N.A.	418,500	8.84%
159	7.30% Ser. E due 10/22/04	10/92	10/04	10,000,000	8,066,382	10,000,000	N.A.	1,011,900	12.54%
160	7.30% Ser. E due 10/22/04	10/92	10/04	10,000,000	8,066,382	10,000,000	N.A.	1,011,900	12.54%
161	7.53% Ser. E due 10/26/04	10/92	10/04	750,000	604,979	750,000	N.A.	77,888	12.87%
162	7.71% Ser. E due 10/27/04	10/92	10/04	3,250,000	2,621,575	3,250,000	N.A.	344,305	13.13%
163	7.71% Ser. E due 10/27/04	10/92	10/04	3,000,000	2,419,915	3,000,000	N.A.	317,820	13.13%
164	7.60% Ser. E due 11/1/04	11/92	11/04	1,000,000	946,914	1,000,000	N.A.	83,070	8.77%
165	7.72% Ser. E due 11/2/04	11/92	11/04	1,500,000	1,420,371	1,500,000	N.A.	126,480	8.90%
166	7.36% Ser. E due 10/17/05	10/92	10/05	5,000,000	4,033,191	5,000,000	N.A.	502,900	12.47%
167	7.34% Ser. E due 10/17/05	10/92	10/05	5,000,000	4,033,191	5,000,000	N.A.	501,750	12.44%
168	7.67% Ser. C due 1/10/07	1/92	1/07	5,724,000	5,341,355	5,724,000	N.A.	484,537	9.07%
169	7.43% Ser. E due 9/11/07	9/92	9/07	2,000,000	1,961,500	2,000,000	N.A.	152,960	7.80%
170	7.22% Ser. E due 9/18/07	9/92	9/07	2,500,000	2,458,250	2,500,000	N.A.	185,150	7.53%

LONG TERM DEBT (Continued)

	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 %
171	SECURED MEDIUM-TERM NOTES (Cont.):								
172	7.27% Ser. E due 9/24/07	9/92	9/07	4,000,000	3,948,500	4,000,000	N.A.	296,560	7.51%
173	9.15% Ser. C due 8/9/11	8/91	8/11	8,000,000	7,925,861	8,000,000	N.A.	740,240	9.34%
174	8.95% Ser. C due 9/1/11	8/91	9/11	25,000,000	24,828,315	25,000,000	N.A.	2,256,250	9.09%
175	8.95% Ser. C due 9/1/11	8/91	9/11	20,000,000	19,870,852	20,000,000	N.A.	1,804,000	9.08%
176	8.92% Ser. C due 9/1/11	8/91	9/11	20,000,000	19,814,652	20,000,000	N.A.	1,804,200	9.11%
177	8.29% Ser. C due 12/30/11	12/91	12/11	3,000,000	2,795,607	3,000,000	N.A.	270,960	9.69%
178	8.26% Ser. C due 1/10/12	1/92	1/12	1,000,000	931,901	1,000,000	N.A.	90,000	9.66%
179	8.28% Ser. C due 1/10/12	1/92	1/12	2,000,000	1,865,802	2,000,000	N.A.	180,200	9.66%
180	8.25% Ser. C due 2/1/12	1/92	2/12	3,000,000	2,795,702	3,000,000	N.A.	269,700	9.65%
181	8.53% Ser. C due 12/16/21	12/91	12/21	15,000,000	13,978,039	15,000,000	N.A.	1,380,300	9.87%
182	8.375% Ser. C due 12/31/21	12/91	12/21	5,000,000	4,659,346	5,000,000	N.A.	451,850	9.70%
183	8.26% Ser. C due 1/7/22	1/92	1/22	5,000,000	4,664,504	5,000,000	N.A.	445,250	9.55%
184	8.27% Ser. C due 1/10/22	1/92	1/22	4,000,000	3,727,603	4,000,000	N.A.	357,040	9.58%
185	8.05% Ser. E due 9/1/22	9/92	9/22	15,000,000	14,862,000	15,000,000	N.A.	1,219,800	8.21%
186	8.11% Ser. E due 9/9/22	9/92	9/22	12,000,000	11,884,500	12,000,000	N.A.	983,640	8.28%
187	8.07% Ser. E due 9/9/22	9/92	9/22	8,000,000	7,914,500	8,000,000	N.A.	653,280	8.25%
188	8.12% Ser. E due 9/9/22	9/92	9/22	50,000,000	49,599,500	50,000,000	N.A.	4,096,000	8.26%
189	8.05% Ser. E due 9/14/22	9/92	9/22	10,000,000	9,899,500	10,000,000	N.A.	814,000	8.22%
190	8.08% Ser. E due 10/14/22	10/92	10/22	26,000,000	20,390,094	26,000,000	N.A.	2,715,700	13.32%
191	8.08% Ser. E due 10/14/22	10/92	10/22	25,000,000	19,584,706	25,000,000	N.A.	2,614,250	13.35%
192									
193	Total Secured Med-Term Notes			1,407,000,000	1,360,983,350	1,403,048,384		121,150,466	8.90%
194									
195	POLL. CTRL. OBLIGATIONS - SECURED BY PLEDGED FIRST MORTGAGE BONDS:								
196	6-1/8% Series due 2/04 Emery	2/74	2/04	14,000,000	13,283,631	13,540,000	N.A.	848,417	6.39%
197	6-1/8% Series due 2/04 Carbon	2/74	2/04	11,000,000	9,482,001	9,665,000	N.A.	605,609	6.39%
198	6-1/8% Series due 2/04 Linciln	2/74	2/04	16,000,000	15,167,276	15,460,000	N.A.	968,723	6.39%
199	6-3/8% Series due 11/06 Emery	11/76	11/06	50,000,000	48,728,350	50,000,000	N.A.	3,285,000	6.74%
200	5.90% Series due 4/08 Emery	4/78	4/08	42,000,000	41,224,321	42,000,000	N.A.	2,534,280	6.15%
201	10.70% Series due 9/14 Emery	9/84	9/14	16,750,000	15,736,753	16,750,000	N.A.	1,912,180	12.15%
202	8-1/4% Series due 6/17 Emery	6/87	6/17	46,500,000	45,117,498	46,500,000	N.A.	3,964,590	8.79%
203	8-5/8% Series due 6/17 Emery	6/87	6/17	16,400,000	15,875,079	16,400,000	N.A.	1,465,012	9.23%
204	8-5/8% Series due 6/17 Lincln	6/87	6/17	8,300,000	8,034,339	8,300,000	N.A.	741,439	9.23%

LONG TERM DEBT (Continued)

	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 %
205	POLL. CTRL. OBLIGATIONS - SECURED BY PLEDGED FIRST MORTGAGE BONDS (Cont.):								
206	6.550% Series due 5/93 Moffat	5/78	5/93	1,560,000	1,558,131	1,560,000	N.A.	110,776	7.11%
207	6.600% Series due 5/94 Moffat	5/78	5/94	1,660,000	1,658,011	1,660,000	N.A.	117,694	7.10%
208	6.650% Series due 5/95 Moffat	5/78	5/95	1,770,000	1,767,880	1,770,000	N.A.	126,024	7.13%
209	6.700% Series due 5/96 Moffat	5/78	5/96	1,890,000	1,887,736	1,890,000	N.A.	135,324	7.17%
210	6.700% Series due 5/97 Moffat	5/78	5/97	2,015,000	2,012,586	2,015,000	N.A.	144,153	7.16%
211	6.700% Series due 5/98 Moffat	5/78	5/98	2,150,000	2,147,424	2,150,000	N.A.	153,725	7.16%
212	6.875% Series due 5/08 Moffat	5/78	5/08	35,030,000	34,988,037	35,030,000	N.A.	2,561,394	7.32%
213	6-3/8% Series due 1/1/07	1/77	1/07	17,000,000	7,974,431	8,190,000	N.A.	538,656	6.75%
214									
215	Total Poll Ctrl Oblg Sec by FMB			284,025,000	266,643,484	272,880,000		20,212,996	7.58%
216									
217	FIXED RATE POLL CTRL REVENUE BONDS:								
218	6% Series due 10/1/03	10/73	10/03	25,000,000	20,964,726	21,260,000	N.A.	1,297,073	6.19%
219									
220	Total Fixed Rate PCRB's			25,000,000	20,964,726	21,260,000		1,297,073	
221									
222	VARIABLE RATE POLL CTRL REVENUE BONDS:								
223	Var. Rate Emery Co. 1991	5/91	7/15	45,000,000	52,440,000	45,000,000	N.A.	4,011,750	7.65%
224	Var. Rate Lincoln Co. 1991	1/91	1/16	45,000,000	52,440,000	45,000,000	N.A.	4,011,750	7.65%
225	Var. Rate Forsyth 1988	1/88	1/18	45,000,000	44,619,802	45,000,000	N.A.	3,858,750	8.65%
226	Var. Rate Sweetwater A	1/88	1/17	50,000,000	49,577,557	50,000,000	N.A.	2,113,000	4.26%
227	Var. Rate Gillette (Wyodak)	1/88	1/18	41,200,000	40,972,358	41,200,000	N.A.	4,985,200	12.17%
228	Var. Rate Sweetwater 88B/Converse	1/88	1/14	28,500,000	27,429,996	28,500,000	N.A.	2,431,905	8.87%
229	Var. Rate Sweetwater C	12/84	12/14	15,000,000	14,772,113	15,000,000	N.A.	1,252,800	8.48%
230	Var. Rate Forsyth 1986	12/86	12/16	8,500,000	8,195,176	8,500,000	N.A.	370,940	4.53%
231	Var. Rate Sweetwater 1990A	7/90	7/19	21,100,000	20,889,000	21,100,000	N.A.	960,894	4.60%
232	Var. Rate Sweetwater 1990A	7/90	7/15	70,000,000	68,965,857	70,000,000	N.A.	6,652,488	9.65%
233	Var. Rate Sweetwater 1992A	9/92	4/05	9,335,000	9,053,325	9,335,000	N.A.	464,883	5.13%
234	Var. Rate Converse 1992	9/92	7/06	22,485,000	21,968,372	22,485,000	N.A.	1,068,487	4.86%
235	Var. Rate Sweetwater 1992B	9/92	12/05	6,305,000	6,172,572	6,305,000	N.A.	300,181	4.86%
236									
237	Total Variable Rate PCRB's			407,425,000	417,496,128	407,425,000		32,483,028	7.78%
238									

LONG TERM DEBT (Continued)

	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 %
239	CONSTR. FUND ON DEPOSIT W/ TRUSTEE:								
240	Lincoln County Constr. Fund			(8,134,830)		0			
241	Sweetwater County Constr. Fund			(21,100,000)		(884,875)			
242									
243	Total Construction Funds (Acct 221.5)			(29,234,830)	0	(884,875)		0	
244									
245									
246	TOTAL BONDS (Acct. 221)			3,171,107,170	2,974,117,161	3,017,508,509		247,502,086	8.32%
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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	5.00%	12,653,300	632,665	5.04%
2	Serial preferred, cumulative:									
3	4.52% Series	11/55	2,065	100.00	103.50	196,824	4.52%	206,500	9,334	4.74%
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	4.72%	6,989,000	329,881	4.74%
9	4.56% Series	2/65	84,592	100.00	102.34	8,410,129	4.56%	8,459,200	385,740	4.59%
10	8.92% Series	11/69	69,375	100.00	102.37	6,923,997	8.92%	6,937,500	618,825	8.94%
11	9.08% Series	6/71	164,893	100.00	104.02	16,440,752	9.08%	16,489,300	1,497,228	9.11%
12	7.96% Series	10/72	135,176	100.00	103.39	13,492,533	7.96%	13,517,600	1,076,001	7.97%
13										
14	No par serial preferred cumulative:									
15	$2.13 Series	5/77	666,210	25.00	26.07	15,992,249	8.52%	16,655,250	1,419,027	8.87%
16	$7.12 Series	3/87	440,000	100.00	107.12	43,510,042	7.12%	44,000,000	3,132,800	7.20%
17	$1.28 Series	9/60	381,220	25.00	26.35	9,530,500	5.12%	9,530,500	487,962	5.12%
18	$1.18 Series	5/62	420,116	25.00	26.15	10,502,900	4.72%	10,502,900	495,737	4.72%
19	$1.16 Series	8/64	193,102	25.00	26.11	4,827,550	4.64%	4,827,550	223,998	4.64%
20	$1.76 Series	3/68	393,868	25.00	25.96	9,846,700	7.04%	9,846,700	693,208	7.04%
21	$1.98 Series – 1971	3/71	501,998	25.00	26.21	12,549,950	7.92%	12,549,950	993,956	7.92%
22	$7.70 Series	8/91	1,000,000	100.00	100.00	99,088,457	7.70%	100,000,000	7,700,000	7.77%
23	$1.98 Series – 1992	5/92	5,000,000	25.00	N. A.	120,787,500	7.92%	125,000,000	9,900,000	8.20%
24	$7.48 Series	6/92	750,000	100.00	N. A.	73,684,265	7.48%	75,000,000	5,610,000	7.61%
25	DARTS Series A	3/87	500	100,000.00	100,000.00	49,167,311	Variable	50,000,000	2,175,000	4.42%
26	DARTS Series B	3/87	500	100,000.00	100,000.00	49,167,311	Variable	50,000,000	2,275,000	4.63%
27	MAPS Series C	10/90	500	No Par	100,000.00	49,241,397	Variable	50,000,000	2,375,000	4.82%
28										
29										
30										
31										
32										
33	TOTAL		10,532,490			626,069,239		636,360,450	42,759,557	6.83%

(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.

Preferred stock

COMMON STOCK

	Avg. Number of Shares Outstanding	Book Value Per Share	Earnings Per Share	Dividends Per Share	Retention Ratio	Market Price High	Low	Price/ Earnings Ratio
January	262,453,910	13.87	0.15			25.250	22.250	
February	263,010,164	13.59	0.09			23.000	21.250	
March	263,593,895	12.66	(0.96)	0.375	-52.08%	22.000	21.000	(7.5)
April	263,893,355	12.73	0.06			23.375	21.250	
May	264,388,024	12.43	0.08			22.750	21.375	
June	266,206,660	12.60	0.08	0.385	-75.00%	23.000	22.000	25.6
July	267,642,670	12.76	0.13			23.625	22.250	
August	268,318,392	12.49	0.12			23.125	22.250	
September	268,846,835	12.52	(0.02)	0.385	-67.39%	23.000	22.125	24.5
October	269,399,257	12.57	0.06			23.125	21.875	
November	269,907,315	12.29	0.11			22.250	18.125	
December	270,469,899	11.00	(1.32)	0.385	-33.48%	20.875	19.250	(4.4)
TOTAL Year End	266,526,853	11.00	(1.42)	1.530	-107.75%	19.750		(13.9)

Common Stock

Sch. 28 **MONTANA EARNED RATE OF RETURN**

		Description	Last Year	This Year	% Change
		Rate Base (Year-end Average)			
1					
2	101	Plant in Service		144,430,578	N / A
3	108	(Less) Accumulated Depreciation		(43,676,896)	N / A
4		**NET Plant in Service**	0	100,753,682	N / A
5					
6		Additions			
7	154, 156	Materials & Supplies		3,031,886	N / A
8	165	Prepayments		641,648	N / A
9		Other Additions		4,206,719	N / A
10		**TOTAL Additions**	0	7,880,253	N / A
11					
12		Deductions			
13	190	Accumulated Deferred Income Taxes		(4,869,626)	N / A
14	252	Customer Advances for Construction		(50,417)	N / A
15	255	Accumulated Def. Investment Tax Credits		(732,605)	N / A
16		Other Deductions		(172,124)	N / A
17		**TOTAL Deductions**	0	(5,824,772)	N / A
18		**TOTAL Rate Base**	0	102,809,163	N / A
19					
20		**Net Earnings**		7,574,170	N / A
21					
22		**Rate of Return on Average Rate Base**		7.37%	N / A
23					
24		**Rate of Return on Average Equity**		6.24%	N / A
25					
26		Major Normalizing Adjustments & Commission			
27		Ratemaking adjustments to Utility Operations			
28		Commission Ordered / Allowed Ratemaking Adjustments			
29		- Malin Midpoint Adj.		31,000	N / A
30		- Unbilled Revenue Adj.		100,138	N / A
31		- Advertising Expense Adj.		(2,095)	N / A
32		- Present Rates Adj.		22,583	N / A
33		- Weather Normalization Adj.		536,125	N / A
34		- Bridger Coal Adj.		13,167	N / A
35		- Production Cost Study Adj.		705,090	N / A
36		- Interest Expense Adj.		287,394	N / A
37					
38					
39		Other Company Ratemaking Adjustments			
40		- Other Adjustments		333,702	N / A
41					
42					
43					
44					
45		**Adjusted Net Earnings**		9,601,274	N / A
46					
47		- Associated Rate Base Adjustments for the above		4,431,242	N / A
48		Reference Ratemaking Adjustments			
49		**Adjusted Rate Base**		107,240,405	N / A
50		**Adjusted Rate of Return on Average Rate Base**		8.95%	N / A
51					
52		**Adjusted Rate of Return on Average Equity**		10.75%	N / A

PACIFICORP
State of Montana - Electric Utility
Schedule 28 Detail for Other Rate Base Additions / Deductions
Twelve Months Ended December 31, 1992

1	Rate Base:	
2	Plant Held for Future Use	94,183
3	Misc Deferred Debits	1,909,370
4	Electric Plant Acquisition Adj	352,644
5	Nuclear Fuel	15,738
6	Working Capital (1)	1,358,042
7	Weatherization Loans	125,344
8	Deferred Trojan Decommissioning	351,398
9	Total Other Additions	4,206,719
10		
11	Deductions:	
12	Accum Prov Trojan Decommissioning	(172,124)
13	Total Other Deductions	(172,124)

(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).

MISCELLANEOUS DEFERRED DEBITS
ALLOCATED - IN THOUSANDS
PERIOD ENDING 12/92

DESCRIPTION			TOTAL COMPANY	ALLOC BASIS	CALIF	OREGON	WASH	ID-PPL	MONTANA	WY-PPL	UTAH	ID-UFL	WY-UFL	FERC
1861	000005032	JB OIL SEEPAGE	21	SG		7	2			3	6	1	1	
1861	000005757	WDK ASH DISPOSAL	87	SG	2	29	8	1	2	13	27	4	4	
1861	000006473	#2 TURBINE OUTAGE	160	INFFSP	5	77	22	1	4	35	13	2	2	
1861	000006707	SWIFT-SPEELYAI	16	DGP	1	8	2			4				
1861	000006934	COMPETITIVE BID		WA										
1861	000007190	REMOVAL OF UST	127	SO	3	38	10	1	2	15	45	7	5	
1861	000007192	COLORADO UTE M&A	11	SG		4	1			2	3			
1861	000007391	HUNTER #2 STM LN		INFFSU										
1861	000007651	FUEL RESOURCES		SE										
1861	000007860	HP ENERGY EFFIC		VARIOUS										
1861	000009260	COMPETITIVE BID		OR										
1861	000009398	XFORMER FAILURE	3	INFTP		1				1				
1861	000009690	ESD ASH MGT ANAL	230	SG	5	75	21	1	4	34	70	10	10	
1861	000009735	ESD ASSESSMENT	6	SO		2				1	2			
1861	000009736	ESD ASSESSMENT	8	SO		2	1			1	3			
1861	000010138	DJ#2 PULV SHAFT	-73	SE	-1	-22	-6		-1	-12	-23	-3	-4	
1861	000010232	MFCS WHITE PAPER	2	SO		1					1			
1861	000010373	DJ#0 RFR 2A CRUSHE	18	INFFSP	1	9	3			4	2			
1861	000010559	GLENN CANYON-NAVAH	25	SG	1	8	2			4	7	1	1	
1861	000010789	CARBON 2-3 MILL FI	8	INFFSU							5			
1861	000011014	NAUGHTON FAN REBLD		INFFSU										
1861	000011473	CARBON DIESEL LINE	10	SG		3	1			1	3			
1861	000011524	HUNTER 303 TURBINE		SG										
1861	000011869	HUNTER 301 COAL MI	3	SG		1					1			
1861	000012245	HUNTER BAGHOUSE RE		INFFSU										
1861	000012306	DJ#2-REPAIR CR MOT	-18	INFFSP	-1	-9	-3			-4	-2			
1861	000022182	DJ INSURANCE LOSS	76	INFFSP	2	36	10	1	2	16	6	1	1	
1861	000031543	ALTURAS LEGAL	103	CA	103									
1861	000045778	WDK ASH DISPOSAL	-2	SG		-1					-1			
1861	000046899	AMBIENT AIR MONITO	675	SG	14	221	63	4	11	99	204	29	28	1
1861	000055118	HIGHLAND BOY CLEAN	133	SO	4	39	11	1	2	16	48	7	6	
1861	000055119	ENVIRON REG FEES	5	SO		2				1	2			
1861	000055121	UG STORAGE TANK	383	SO	10	113	31	2	6	46	137	21	16	1
1861	000055313	HAZARDOUS WASTE	2,878	SO	77	852	230	18	47	344	1,029	155	123	5
1861	000055537	COAL CREEK PCB	176	SO	5	52	14	1	3	21	63	9	7	
1861	000055538	PORT EQUIP PCB	390	SO	10	115	31	2	6	47	139	21	17	1
1861	000057119	UST TIGHTNESS TEST	97	SO	3	29	8	1	2	12	35	5	4	
1861	000057122	BARBER TAR	701	SO	19	207	56	4	12	84	251	38	30	1
1861	000057123	UTAH METAL WORKS	11	SO		3	1			1	4	1		
1861	000057124	PROJECT PENTA	8	SO		2	1			1	3			
1861	000057125	BORS		SO										
1861	000057130	EKOTEK SETTLEMENT	147	SO	4	43	12	1	2	18	52	8	6	
1861	000057141	VISIBILITY STUDIES	752	SG	16	246	70	4	13	111	228	32	32	1
1861	000100445	HIGHLAND BOY SHELT	1	SO										
1861	000102172	HUNTER #3 BOILER		INFFSU										
1861	000102876	NTO CONST COST	3	SO		1					1			
18611	000005032	JB OIL SEEPAGE	-21	SG		-7	-2			-3	-6	-1	-1	
18611	000046899	AMBIENT AIR MONITO	-675	SG	-14	-221	-63	-4	-11	-99	-204	-29	-28	-1
18611	000055118	HIGHLAND BOY CLEAN	-1	SO										
18611	000055119	ENVIRON REG FEES	-5	SO		-2				-1	-2			

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IFTD RPT2
04/21/93
92 NOTES

MISCELLANEOUS DEFERRED DEBITS
ALLOCATED - IN THOUSANDS
PERIOD ENDING 12/92

DESCRIPTION	TOTAL COMPANY	ALLOC BASIS	CALIF	OREGON	WASH	ID-PPL	MONTANA	WY-PPL	UTAH	ID-UPL	WY-UPL	FERC
10671 000057125 BORS		SO										
10671 000057130 EKOTEK SETTLEMENT	122	SO	3	36	10	1	2	15	44	7	5	
10671 000057141 VISIBILITY STUDIES	532	SG	11	174	49	3	9	78	161	23	22	1
10671 000100445 HIGHLAND BOY SHELT	1	SO										
TOTAL MISC DEFERRED	63,311		1,316	18,411	6,488	336	1,316	13,092	16,209	2,386	3,667	89

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ALLOCATED - IN THOUSANDS

DESCRIPTION	TOTAL COMPANY	ALLOC BASIS	CALIF	OREGON	WASH	ID PPL	MONTANA	WY-PPL	UTAH	ID-UPL	WY-UPL	FERC
10672 000010083 WEATHER 0% OR 83	68	OR		68								
10672 000010084 WEATHER 0% OR 84	133	OR		133								
10672 000010085 WEATHER 0% OR 85	175	OR		175								
10672 000010086 WEATHER 0% OR 86	192	OR		192								
10672 000010087 WEATHER 0% OR 87	155	OR		155								
10672 000010088 WEATHER 0% OR 88	193	OR		193								
10672 000010089 WEATHER 0% OR 89	111	OR		111								
10672 000010090 WEATHER 0% OR 90	128	OR		128								
10672 000010091 WEATHER 0% OR 91	190	OR		190								
10672 000010092 WEATHER 0% OR 92	276	OR		278								
10672 000010683 WEATHER 6.5% OR 83	18	OR		18								
10672 000010684 WEATHER 6.5% OR 84	25	OR		25								
10672 000010685 WEATHER 6.5% OR 85	37	OR		37								
10672 000010686 WEATHER 6.5% OR 86	192	OR		192								
10672 000010687 WEATHER 6.5% OR 87	216	OR		216								
10672 000010688 WEATHER 6.5% OR 88	290	OR		290								
10672 000010689 WEATHER 6.5% OR 89	369	OR		369								
10672 000010690 WEATHER 6.5% OR 90	268	OR		268								
10672 000010691 WEATHER 6.5% OR 91	428	OR		428								
10672 000010692 WEATHER 6.5% OR 92	591	OR		591								
10672 000013082 WEATHER WTR HTR 82	5	OR		5								
10672 000016190 ENERGY EXCL OR 90	299	OR		299								
10672 000016290 SCHOOL EFFIC OR 90	15	OR		15								
10672 000016390 IND PARTNERS OR 90	53	OR		53								
10672 000016490 LOW INCOME OR 90	363	OR		363								
10672 000016491 LOW INCOME OR 91	468	OR		468								
10672 000016492 LOW INCOME OR 92	620	OR		620								
10672 000016590 MANF HOMES OR 90	8	OR		8								
10672 000016591 MANF HOMES OR 91	31	OR		31								
10672 000016592 MANF HOMES OR 92		OR										
10672 000016690 RESID APPL OR 90	159	OR		159								
10672 000016790 COMM LOST OR 90	1	OR		1								
10672 000016890 COMM DEMOS OR 90	149	OR		149								
10672 000016990 FAC ENVIRON OR 90	492	OR		492								
10672 000016991 FAC ENVIRON OR 91	965	OR		965								
10672 000016992 FAC ENVIRON OR 92	447	OR		447								
10672 000017090 HOME COMFORT OR 90	126	OR		126								
10672 000017091 HOME COMFORT OR 91	286	OR		286								
10672 000017092 HOME COMFORT OR 92	59	OR		59								
10672 000017191 TECH MONITOR OR 91	14	OR		14								
10672 000017192 TECH MONITOR OR 92	1	OR		1								
10672 000017291 HASSLEFREE EFF 91	333	OR		333								
10672 000017292 HASSLEFREE EFF 92	178	OR		178								
10672 000017391 ENERGY FINANSWER91	2,107	OR		2,107								
10672 000017392 ENERGY FINANSWER92	2	OR		2								
10672 000017491 COMPETITIVE BID 91	8	OR		8								
10672 000017492 COMPETITIVE BID 92	10	OR		10								
10672 000017591 RESID BLDG CODE 91	21	OR		21								
10672 000017592 RESID BLDG CODE 92	30	OR		30								
10672 000017691 ENERGY PARTNERS 91	198	OR		198								

DEFD RPT3
04/21/93
92 NOTES

DEFERRED WEATHERIZATION
ALLOCATED - IN THOUSANDS
PERIOD ENDING 12/92

DESCRIPTION	TOTAL COMPANY	ALLOC BASIS	CALIF	OREGON	WASH	ID-PPL	MONTANA	WY-PPL	UTAH	ID-UPL	WY-UPL	FERC
18692 000035288 SUPER GOOD CENT 88	57	OR		57								
18692 000035789 SUPER GOOD CENT 89	843	OR		843								
18692 000035990 SUPER GOOD CENT 90	3,307	OR		3,307								
18692 000035791 SUPER GOOD CENT 91	3,732	OR		3,732								
18692 000035992 SUPER GOOD CENT 92	5,190	OR		5,190								
18692 000036089 SUPER GOOD CENT 89		WA										
18692 000036288 SUPER GOOD CENT 88	9	MT					9					
18692 000036289 SUPER GOOD CENT 89	24	MT					24					
18692 000036290 SUPER GOOD CENT 90	58	MT					58					
18692 000036291 SUPER GOOD CENT 91	113	MT					113					
18692 000036292 SUPER GOOD CENT 92	146	MT					146					
18692 000036491 SUPER GOOD CENT 91	60	UT							60			
18692 000036492 SUPER GOOD CENT 92	109	UT							109			
18692 000036592 SGC MOBILE HOME 92	89	CA	89									
18692 000036692 SUPER GOOD CENT 92	18	WYP						18				
18692 000040083 WEATHER 0X MT 83	1	MT					1					
18692 000040084 WEATHER 0X MT 84	4	MT					4					
18692 000040085 WEATHER 0X MT 85	3	MT					3					
18692 000040086 WEATHER 0X MT 86	3	MT					3					
18692 000040087 WEATHER 0X MT 87	6	MT					6					
18692 000040088 WEATHER 0X MT 88	36	MT					36					
18692 000040089 WEATHER 0X MT 89	29	MT					29					
18692 000040090 WEATHER 0X MT 90	6	MT					6					
18692 000040091 WEATHER 0X MT 91	4	MT					4					
18692 000040092 WEATHER 0X MT 92	6	MT					6					
18692 000040191 LOW INCOME MT 91	46	MT					46					
18692 000040192 LOW INCOME MT 92	49	MT					49					
18692 000041090 ENERGY EXCL MT 90		MT										
18692 000047191 TECH MONITOR MT 91	1	MT					1					
18692 000047192 TECH MONITOR MT 92		MT										
18692 000047291 HASSLEFREE EFF 91	12	MT					12					
18692 000047292 HASSLEFREE EFF 92	10	MT					10					
18692 000047391 ENERGY FINANSWER91	1	MT					1					
18692 000047392 ENERGY FINANSWER92	2	MT					2					
18692 000048092 FINANSWER 12000 92	11	MT					11					
18692 000048192 WHOLESALE PURCH 92	2	MT					2					
18692 000048292 NANT ACQUISITION92	42	MT					42					
18692 000048392 HOME COMFORT 92	2	MT					2					
18692 000048492 ESC LOANS GAWL 92		MT										
18692 000048792 REFRIGERATION 92	1	MT					1					
18692 000057192 TECH MONITOR 92		WYP										
18692 000050092 FINANSWER 12000 92	30	WYP						30				
18692 000050192 WHOLESALE PURCH 92	9	WYP						9				
18692 000050392 HOME COMFORT 92	5	WYP						5				
18692 000058792 REFRIGERATION 92	2	WYP						2				
18692 000060083 WEATHER 0X CA 83	5	CA	5									
18692 000060084 WEATHER 0X CA 84	9	CA	9									
18692 000060092 WEATHER 0X CA 92	14	CA	14									
18692 000060085 WEATHER 8X CA 85	14	CA	14									
18692 000060086 WEATHER 8X CA 86	12	CA	12									

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DEFD RPT1
04/21/93
92 NOTES

DEFERRED WEATHERIZATION
ALLOCATED - IN THOUSANDS
PERIOD ENDING 12/92

DESCRIPTION	TOTAL COMPANY	ALLOC BASIS	CALIF	OREGON	WASH	ID-PPL	MONTANA	WY-PPL	UTAH	ID-UPL	WY-UPL	FERC
18692 000080041 LOAD MANAGE PROG91	438	UT							438			
18692 000080191 SUPERFUND		SO										
18692 000080192 INDUSTRIAL FINANSW	132	UT							132			
18692 000080291 SUPERFUND	40	SO	1	12	3		1	5	14	2	2	
18692 000080292 COMM BUILDING	54	UT							54			
18692 000080391 SUPERFUND	2	SO		1					1			
18692 000080392 LOW INCOME	70	UT							70			
18692 000080492 RFT ACQUISITION	81	UT							81			
18692 000087192 TECHNOLOGY MONITOR	1	UT							1			
18692 000087391 ENERGY FINANSWER91		UT										
18692 000087392 ENERGY FINANSWER92	471	UT							471			
18692 000087492 EFF SHOWERHEADS 92	11	UT							11			
18692 000088092 FINANSWER 12000 92	159	UT							159			
18692 000088192 WHOLESALE PURCH 92	29	UT							29			
18692 000088392 HOME COMFORT 92	28	UT							28			
18692 000088492 ESC LOANS GAWL 92		UT										
18692 000088792 REFRIGERATION 92	14	UT							14			
18693 000030091 WEATHER 0X ID 91		IDP										
18693 000030092 WEATHER 0X ID 92		IDP										
18693 000031090 ENERGY EXCL ID 90	15	IDP				15						
18693 000031191 LOW INCOME ID 91	11	IDP				11						
18693 000031192 LOW INCOME ID 92	15	IDP				15						
18693 000032089 WEATHER RES ID 89	2	IDP				2						
18693 000032090 WEATHER RES ID 90	46	IDP				46						
18693 000032091 CASH REBATE ID 91	80	IDP				80						
18693 000032092 CASH REBATE ID 92	67	IDP				67						
18693 000036188 SUPER GOOD CENT 88	13	IDP				13						
18693 000036189 SUPER GOOD CENT 89	45	IDP				45						
18693 000036190 SUPER GOOD CENT 90	66	IDP				66						
18693 000036191 SUPER GOOD CENT 91	129	IDP				129						
18693 000036192 SUPER GOOD CENT 92	198	IDP				198						
18693 000036390 SUPER GOOD CENT 90	134	IDU								134		
18693 000036391 SUPER GOOD CENT 91	222	IDU								222		
18693 000036392 SUPER GOOD CENT 92	399	IDU								399		
18693 000036792 SUPER GOOD CENT 92		WYU										
18693 000037191 TECH MONITOR ID 91	1	IDP				1						
18693 000037192 TECH MONITOR ID 92		IDP										
18693 000037291 HASSLEFREE EF ID91	13	IDP				13						
18693 000037292 HASSLEFREE EF ID92	2	IDP				2						
18693 000037391 ENERGY FINANS ID91	49	IDP				49						
18693 000038092 FINANSWER 12000 92	2	IDP				2						
18693 000038192 WHOLESALE PURCH 92	1	IDP				1						
18693 000038292 MANF ACQUISITION92	28	IDP				28						
18693 000038392 HOME COMFORT 92	1	IDP				1						
18693 000038492 ESC LOANS GAWL 92		IDP										
18693 000038792 REFRIGERATION 92		IDP										
18693 000070002 CASH GRANT ID 92	872	IDU								872		
18693 000070090 LOW INCOME ID 90	6	IDU								6		
18693 000070091 LOW INCOME ID 91	20	IDU								20		
18693 000070092 LOW INCOME ID 92	35	IDU								35		

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MISCELLANEOUS DEFERRED DEBITS
ALLOCATED - IN THOUSANDS
PERIOD ENDING 12/91

	DESCRIPTION	TOTAL COMPANY	ALLOC BASIS	CALIF	OREGON	WASH	ID-PPL	MONTANA	WY-PPL	UTAH	ID-UPL	WY-UPL	FERC
1861	000005032 JB OIL SEEPAGE	21	SG		7	2			3	6	1	1	
1861	000005519 TRAIL MTN DRILL		SE										
1861	000005757 WDK ASH DISPOSAL	89	SG	2	29	8	1	2	13	27	4	4	
1861	000006473 #2 TURBINE OUTAGE	666	INFFSP	20	317	91	6	17	143	55	8	8	
1861	000006603 KLAMATH TROUT	36	DGP	1	19	5		1	9				
1861	000006703 UMPQUA LICENSE	97	DGP	3	53	15	1	3	24				
1861	000006707 SWIFT-SPEELYAI	10	DGP		5	1			2				
1861	000006711 YALE PHASE III	106	DGP	4	57	16	1	3	26				
1861	000006712 CONDIT LICENSE	119	DGP	4	64	18	1	3	29				
1861	000006713 BEND LICENSE	47	DGP	2	25	7		1	11				
1861	000006718 BEND REHAB	28	DGP	1	15	4		1	7				
1861	000006770 ASHTON LICENSE	9	DGU							7	1	1	
1861	000006771 CUTLER LICENSE	73	DGU							57	8	8	
1861	000006781 CUTLER LICENSE	43	DGU							34	5	5	
1861	000006834 COMPETITIVE BID		WA										
1861	000007190 REMOVAL OF UST	122	SO	3	36	10	1	2	15	44	7	5	
1861	000007198 COLORADO UTE M&A	1,300	SG	27	425	121	8	22	191	394	55	55	2
1861	000007391 HUNTER #2 STM LN	412	INFFSU	2	24	7		1	11	286	40	40	2
1861	000007651 FUEL RESOURCES		SE										
1861	000007765 HUNTER 302 REMOTE	19	INFFSU		1				1	13	2	2	
1861	000007860 HP ENERGY EFFIC		VARIOUS										
1861	000008054 HUNTER 303 ID FAN	88	INFFSU		5	1			2	61	9	8	
1861	000008056 JB FEED PUMP #21	70	INFFSP	2	34	10	1	2	15	6	1	1	
1861	000009260 COMPETITIVE BID		OR										
1861	000009390 HUNTER #3 XFORMER	201	INFFSU	1	12	3		1	5	140	20	19	1
1861	000009398 XFORMER FAILURE	202	INFTP	6	97	28	2	5	44	16	2	2	
1861	000009815 HUNTINGTON #1	97	INFFSU		6	2			3	67	9	9	
1861	000009957 HUNTINGTON #2	89	INFFSU		5	1			2	62	9	9	
1861	000009724 HUNTINGTON #1 ID	39	INFFSU		2	1			1	27	4	4	
1861	000009994 CARBON #2 GENERAL	171	INFFSU	1	10	3		1	4	119	17	17	1
1861	000010030 CARBON #2 BOILER	27	INFFSU		2				1	19	3	3	
1861	000022182 IJ INSURANCE LOSS	466	INFFSP	14	223	63	4	12	100	38	5	5	
1861	000022183 JB INSURANCE LOSS	104	INFFSP	3	50	14	1	3	22	9	1	1	
1861	000022184 WDK INSURANCE LOSS	-252	INFFSP	-8	-121	-34	-2	-6	-54	-21	-3	-3	
1861	000031541 OR VEGETATION MNGT	187	OR		187								
1861	000031543 ALTURAS LEGAL	103	CA	103									
1861	000045770 WDK ASH DISPOSAL	-2	SG		-1					-1			
1861	000046395 UI SERHR CHANGE OU	47	INFFSP	1	23	6		1	10	4	1	1	
1861	000046899 AMBIENT AIR MONITO	675	SG	14	221	63	4	11	99	204	29	28	1
1861	000055119 ENVIRON REG FEES	5	SO		2				1	2			
1861	000055121 UG STORAGE TANK	327	SO	9	97	26	2	5	39	117	18	14	1
1861	000055313 HAZARDOUS WASTE	1,360	SO	36	402	108	8	22	163	486	73	58	2
1861	000055537 COAL CREEK FCB	162	SO	4	48	13	1	3	19	58	9	7	
1861	000055539 PORT EQUIP FCB	125	SO	3	37	10	1	2	15	45	7	5	
1861	000055656 WATER DAMAGE	2	SO		1					1			
1861	000057119 UST TIGHTNESS TEST	91	SO	2	27	7	1	1	11	33	5	4	
1861	000057121 AMERICAN BARREL	1,994	SO	53	590	159	12	33	238	713	107	85	3
1861	000057122 BARBER TAR	140	SO	4	42	11	1	2	17	50	8	6	
1861	000057123 UTAH METAL WORKS	10	SO		3	1			1	4	1		
1861	000057124 PROJECT PENTA	8	SO		2	1			1	3			

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DEFD RPT2
04/21/93
72 NOTES

MISCELLANEOUS DEFERRED DEBITS
ALLOCATED - IN THOUSANDS
PERIOD ENDING 12/91

PAGE 03

DESCRIPTION	TOTAL COMPANY	ALLOC BASIS	CALIF	OREGON	WASH	ID-PPL	MONTANA	WY-PPL	UTAH	ID-UPL	WY-UPL	FERC
18671 000055537 COAL CREEK PCB	84	SO	2	25	7	1	1	10	30	5	4	
18671 000055539 PORT EQUIP PCB	95	SO	3	28	8	1	2	11	34	5	4	
18671 000057122 BARBER TAR	88	SO	2	26	7	1	1	10	31	5	4	
18671 000057123 UTAH METAL WORKS	6	SO		2				1	2			
18671 000057125 BORG		SO										
18671 000057130 EKOTEK SETTLEMENT	53	SO	1	16	4		1	6	19	3	2	
18671 000057141 VISIBILITY STUDIES	400	SG	8	131	37	2	7	59	121	17	17	1
18671 000100445 HIGHLAND BOY SHELT	1	SO										
TOTAL MISC DEFERRED	72,857		1,446	20,329	7,012	369	1,467	15,731	18,534	2,717	5,144	109

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DEFD RPT1
04/21/93
93 NOTES

DEFERRED WEATHERIZATION
ALLOCATED - IN THOUSANDS
PERIOD ENDING 12/91

	DESCRIPTION	TOTAL COMPANY	ALLOC BASIS	CALIF	OREGON	WASH	ID-PPL	MONTANA	WY-PPL	UTAH	ID-UPL	WY-UPL	FERC
1861	000006036 COMM PRESCRIPT	225	OR		225								
1861	000006038 HOME COMFORT	127	CA		127								
1861	000006039 ENERGY FINANSWER	144	IDP		144								
1861	000006556 WHOLESALE PURCH	211	SG		211								
1861	000009227 ENERGY FINANSWER	8	UT		8								
1861	000009256 LOW INCOME	36	UT		36								
1861	000010384 ZERO INTEREST-OR	38	OR		38								
1861	000010529 6% INTEREST -OR	49	OR		49								
1861	000010593 ZERO INTEREST-WA	240	WA		240								
1861	000010594 ZERO INTEREST-MT	259	MT		259								
1861	000010621 ZERO INTEREST-ID	339	IDP		339								
1861	000021573 LOW INCOME	422	CA		422								
1861	000055388 PROG ADMIN	301	CA		301								
1861	000057022 DESIGN ADVANTAGE	476	OR		476								
1861	000057024 INDUSTRIAL PARTNER	11	OR		11								
1861	000057025 LOW INCOME	1	OR		1								
1861	000057026 MANUFAC HOUSING	337	OR		337								
1861	000057165 LOW INCOME	16	CA		16								
1861	000057221 ENERGY EXCELLENCE	59	IDP		59								
1861	000057223 ENERGY EXCELLENCE	409	MT		409								
1861	000057249 SUPER GOOD CENTS	520	OR		520								
1861	000057250 SUPER GOOD CENTS	10	IDP		10								
1861	000057251 SUPER GOOD CENTS	35	MT		35								
1861	000057252 SUPER GOOD CENTS	179	IDU		179								
1861	000057253 LOW INCOME	1	IDU		1								
1861	000057254 CASH GRANT-UPL	168	IDU		168								
1861	000066210 FAC ENVIRONMENTS	530	OR		530								
1861	000066211 HOME COMFORT	1,034	OR		1,034								
1868	000000002 WEATHERIZATION	135	IDU		135								
1868	000000040 WEATHERIZATION	306	UT		306								
1869	000000040 WEATHERIZATION	16	UT		16								
18692	000010082 WEATHER OX OR 82	370	OR		370								
18692	000010083 WEATHER OX OR 83	2,327	OR		2,327								
18692	000010084 WEATHER OX OR 84	9	OR		9								
18692	000010085 WEATHER OX OR 85	24	OR		24								
18692	000010086 WEATHER OX OR 86	212	OR		212								
18692	000010087 WEATHER OX OR 87	10	OR		10								
18692	000010088 WEATHER OX OR 88	1,438	OR		1,438								
18692	000010089 WEATHER OX OR 89		OR										
18692	000010090 WEATHER OX OR 90	102	OR			102							

DEFD RPT1
04/21/93
92 NOTES

DEFERRED WEATHERIZATION
ALLOCATED - IN THOUSANDS
PERIOD ENDING 12/91

DESCRIPTION	TOTAL COMPANY	ALLOC BASIS	CALIF	OREGON	WASH	ID-PPL	MONTANA	WY-PPL	UTAH	ID-UFL	WY-UFL	FERC
18692 000060086 WEATHER 8X CA 86	15	CA	15									
18692 000060087 WEATHER 8X CA 87	5	CA	5									
18692 000060088 WEATHER 8X CA 88	1	CA	1									
18692 000060089 WEATHER 8X CA 89		CA										
18692 000060090 WEATHER 8X CA 90	1	CA	1									
18692 000060091 WEATHER 8X CA 91	14	CA	14									
18692 000061082 WEATHER CA 82	1	CA	1									
18692 000061083 WEATHER CA 83	114	CA	114									
18692 000061084 WEATHER CA 84	19	CA	19									
18692 000061085 WEATHER CA 85	3	CA	3									
18692 000061086 WEATHER CA 86	6	CA	6									
18692 000061087 WEATHER CA 87	20	CA	20									
18692 000061088 WEATHER CA 88	49	CA	49									
18692 000061089 WEATHER CA 89	16	CA	16									
18692 000062087 WINTER SAVER CA 87	60	CA	60									
18692 000062088 WINTER SAVER CA 88	42	CA	42									
18692 000062089 WINTER SAVER CA 89	169	CA	169									
18692 000062090 WINTER SAVER CA 90	91	CA	91									
18692 000063082 WATER HEATER CA 82	3	CA	3									
18692 000063083 WATER HEATER CA 83	2	CA	2									
18692 000064082 WATER HEATER CA 82		CA										
18692 000064083 WATER HEATER CA 83		CA										
18692 000065083 HEAT PUMP CA 83	2	CA	2									
18692 000065084 HEAT PUMP CA 84	1	CA	1									
18692 000065085 HEAT PUMP CA 85	2	CA	2									
18692 000065086 HEAT PUMP CA 86	1	CA	1									
18692 000067086 LOW INCOME CA 86	93	CA	93									
18692 000067087 LOW INCOME CA 87	9	CA	9									
18692 000067088 LOW INCOME CA 88		CA										
18692 000067089 LOW INCOME CA 89	1	CA	1									
18692 000067091 LOW INCOME CA 91	168	CA	168									
18692 000067191 TECH MONITOR CA 91	1	CA	1									
18692 000067291 HASSLEFREE EFF 91	20	CA	20									
18692 000067391 ENERGY FINANSWER91	44	CA	44									
18692 000068190 WATER HEATER CA 90	11	CA	11									
18692 000068191 WATER HEATER CA 91	4	CA	4									
18692 000068290 HEAT PUMP CA 90	2	CA	2									
18692 000068291 HEAT PUMP CA 91		CA										
18692 000068390 CRESCENT CTY CA 90	29	CA	29									
18692 000068391 CRESCENT CTY CA 91		CA										
18692 000068481 HOME COMFORT CA 91	9	CA	9									
18692 000068491 MANF HOMES CA 91	38	CA	38									
18692 000070090 LOW INCOME ID 90	6	IDU								6		
18692 000070091 LOW INCOME ID 91	20	IDU								20		
18692 000070190 CASH GRANT ID 90	165	IDU								165		
18692 000070191 CASH GRANT ID 91	38	IDU								38		
18692 000077391 ENERGY FINANSWER91	13	IDU								13		
18692 000080040 WEATHERIZATION 91	200	UT							200			
18692 000080041 LOAD MANAGE PROG91	658	UT							658			
18692 000080191 SUPERFUND	114	SO	3	34	9	1	2	14	41	6	5	

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Sch. 29

MONTANA COMPOSITE STATISTICS

	Description	Amount
	Plant (Intrastate Only)	
101	Plant in Service	294,660,402
107	Construction Work in Progress	2,475,290
114	Plant Acquisition Adjustments	0
105	Plant Held for Future Use	0
154, 156	Materials & Supplies	2,069,456
	(Less):	
108, 111	Depreciation & Amortization Reserves	(71,261,085)
252	Contributions in Aid of Construction	(2,801,233)
	NET BOOK COSTS	225,142,830
	Revenues & Expenses	
400	Operating Revenues	38,472,022
403 - 407	Depreciation & Amortization Expenses	4,229,189
409	Federal & State Income Taxes	2,898,412
408	Other Taxes	1,386,989
	Other Operating Expenses	22,383,262
	TOTAL Operating Expenses	30,897,852
	Net Operating Income	7,574,170
415-421.1	Other Income	0
421.2-426.5	Other Deductions	0
	NET INCOME	7,574,170
	Customers (Intrastate Only)	
	Year End Average:	
	Residential	25,518
	Commercial	4,696
	Industrial	211
	Other	41
	TOTAL NUMBER OF CUSTOMERS	30,466
	Other Statistics (Intrastate Only)	
	Average Annual Residential Use (Kwh)	11,522
	Average Annual Residential Cost per (Kwh) (Cents) *	4.78
	* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
	Average Residential Monthly Bill	$45.85
	Gross Plant per Customer	$9,671.78

Sch. 30 MONTANA CUSTOMER INFORMATION

	City/Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Bigfork	N. A.	2,328	657	30	3,015
2	Columbia Falls	2,942	2,673	617	42	3,332
3	Kalispell	11,917	10,165	2,781	267	13,213
4	Kila	N. A.	205	42		247
5	Lakeside	N. A.	940	250	7	1,197
6	Libby	2,532	4,339	1,241	65	5,645
7	Rollins	N. A.	255	54	4	313
8	Sommers	N. A.	586	164	10	760
9	Swan Lake	N. A.	169	37	1	207
10	Whitefish	4,368	4,611	1,160	29	5,800
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	TOTAL Montana Customers	21,759	26,271	7,003	455	33,729

Sch. 31	MONTANA EMPLOYEE COUNTS			
	Department	Year Beginning	Year End	Average
1	Big Fork	2	2	2
2	Facilities Engineering		1	1
3	Kalispell District	33	35	34
4	Kalispell Power	5	5	5
5	Libby District	10	10	10
6	Montana Area	5	6	6
7	Whitefish District	11	10	11
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52				
53	TOTAL Montana Employees	66	69	68

Sch. 32 **MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) --- In (000's)**

	Project Description	Total Company	Total Montana
1	THIRD AC PURCHASE FROM BPA	32,250	548
2	MEAD-PHOENIX 500 KV LINE	19,000	323
3	DIXONVILLE-MERIDIAN 500KV LINE 91 CONST	17,787	302
4	RESOURCE ACQUISITION-JAMES RIVER CAMAS COGE	14,134	240
5	RELOCATE TRANS LINE FOR SLC AIRPORT	12,678	215
6	WYODAK RELOCATE LOWER COAL	11,494	188
7	TRAIL MOUNTAIN	10,061	165
8	COTTONWOOD PREP PLANT - FINE COAL CIRCUIT	10,059	171
9	DAVE JOHNSTON PLANT - PURCHASE WATER RIGHTS	9,125	155
10	MERIDIAN 500KV SUB CONST BUS/D-M LN POS SHARE	8,380	142
11	MERWIN HATCHERY	8,227	229
12	JORDAN 138/46 KV SUBSTATION AND TRANSMISSION	6,159	105
13	WYODAK REPLACE HIGH VOLTAGE FIELDS IN PRECIPI	6,001	102
14	THERMOPOLIS - HILLTOP 115KV LINE	5,753	98
15	TAYLRSVL 138/46 KV XFMR AND 138 KV LINE TO MIDVA	5,546	94
16	SOCC-PURCHASE NEW ENERGY MGT. COMPUTER SYS	5,317	90
17	NAUGHTON 270: ASH POND IMPROVEMENTS/EXPANS	4,857	83
18	AUTOMATED MAPPING PROJECT EXPENSES	4,842	80
19	NAUGHTON 270: S02 COMPLIANCE STUDY	4,458	76
20	COTTONWOOD MINE - MINE EXTENSION 1993	4,393	72
21	BEND-BUILD 69KV LINE TO PELTON RE-REG	3,990	68
22	BPA ALVEY 500KV SUBSTATION-CONSTRUCT BY BPA	3,614	61
23	DJ#0--UNIT #0 COAL UNLOADING FACILITY	3,543	60
24	PARK CITY AREA BACKUP	3,514	60
25	DATA INTEGRATION PROTOTYPE	3,452	57
26	RSC ACQ - WEST SIDE CTS	3,435	58
27	MALIN SUB - INSTL 2ND 500-230KV TRANSF BANK	3,370	57
28	DIXONVILLE 500KV SUB CONSTRUCT STATION SHARE	3,277	56
29	LINE 87 - REBUILD LINE SLIDING INTO OCEAN	3,255	55
30	GLEN CANYON - NAVAJO TIE LINE	2,800	48
31	JB UNIT 1 CONDENSATE POLISHER	2,696	46
32	APS COMBUSTION TURBINES - ENGINEERING	2,672	45
33	CENTRALIA MINE: (4) 190 HAUL TRUCKS	2,616	43
34	DEER CREEK MINE - MINE EXTENSION 1993	2,588	42
35	COVE SUB-CONSTR NEW COVE 230-69KV SUB	2,471	42
36	N UMPQUA RELICENSING	2,441	68
37	RELATIONAL MPCS	2,415	40
38	RIVERDALE 46 KV SUBSTATION - 3 YEAR REBUILD	2,339	40
39	INFO RESOURCES INTEGRATION PROJECT	2,273	37
40	BRIDGER MINE - DRAGLINE TUB (UNIT # 844)	2,184	36
41	1993 BOOM RECONSTRUCTION	2,062	34
42	COTTONWOOD MINE - FAN INSTALLATION	2,043	33
43	HUNTINGTON PLANT #1 COOLING TOWER FILL	2,034	35
44	HUNTINGTON PLANT #2 COOLING TOWER FILL	2,034	35
45	SERVICE TO THIOKOL & MORTON AT 138 KV	1,951	33
46	TIMPIE-SKUNK RIDGE 46 KV LINE & SWITCHRACK	1,819	31
47	DAVE JOHNSTON MINE: PURCHASE (1) SHOVEL	1,778	29
48	COLSTRIP PROJECT BETTERMENTS	1,683	29
49	TOOELE-DUGWAY #2 46 KV LINE	1,670	28
50	TRANS PLNG PRE-SWIP	1,600	27
51	115 LN PILOT BUTTE CHINA HAT	1,594	27
52	ALL OTHER	524,012	N/A
53	TOTAL	803,743	4,838

Sch. 33 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
1	Jan.	09	0800	6,794	5,193,052	962,816
2	Feb.	05	0800	6,682	4,753,931	996,338
3	Mar.	09	0800	6,242	4,766,749	1,041,512
4	Apr.	07	0900	6,137	4,450,507	850,408
5	May	18	1100	6,159	4,797,788	954,987
6	Jun.	23	1400	6,953	4,800,576	891,876
7	Jul.	27	1500	6,767	5,268,993	1,142,260
8	Aug.	13	1600	7,011	5,296,389	1,189,515
9	Sep.	03	1400	6,064	4,757,462	1,098,143
10	Oct.	15	0800	6,277	4,970,217	1,119,371
11	Nov.	24	0800	7,028	5,105,450	1,088,173
12	Dec.	04	0800	7,258	5,477,347	983,213
13	TOTAL				59,638,461	12,318,612

Montana

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale
14	Jan.	20	0900	132	91,737	17,086
15	Feb.	04	1000	125	85,682	17,681
16	Mar.	09	0800	118	84,376	18,483
17	Apr.	08	0900	115	77,331	15,091
18	May	12	0800	102	76,963	16,947
19	Jun.	24	1200	97	76,205	15,827
20	Jul.	17	1100	98	76,348	20,271
21	Aug.	24	0900	103	78,642	21,109
22	Sep.	18	0900	108	79,102	19,488
23	Oct.	16	1000	117	82,696	19,864
24	Nov.	24	0800	133	90,790	19,311
25	Dec.	30	1100	164	106,415	17,448
26	TOTAL				1,006,287	218,606

Sch. 34 TOTAL SYSTEM Sources & Disposition of Energy

	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	48,934,365	Sales to Ultimate Consumers	
3	Nuclear	114,346	(Include Interdepartmental)	41,511,308
4	Hydro - Conventional	2,630,055		
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	79,036	for Resale	1,101,300
7	(Less) Energy for Pumping			
8	**NET Generation**	51,757,802	Non-Requirements Sales	
9	Purchases	8,150,219	for Resale	12,318,612
10	Power Exchanges			
11	Received	22,149,119	Energy Furnished	
12	Delivered	22,058,780	Without Charge	160
13	**NET Exchanges**	90,339		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	1,438,392	Electric Utility	80,608
16	Delivered	1,438,392		
17	**NET Transmission Wheeling**	0	Total Energy Losses	4,626,473
18	Transmission by Others Losses	(359,899)		
19	**TOTAL**	59,638,461	**TOTAL**	59,638,461

Sch. 35

SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak - MW	Annual Energy - MWH
1	Thermal	Cholla Unit No. 4	Joseph City, Arizona	392.0	2,842,970
2	Thermal	Craig Units #1 & #2	Craig, Colorado	177.0	925,543
3	Thermal	Hayden Plant	Hayden, Colorado	84.0	375,737
4	Thermal	Colstrip Unit #3 & #4	Colstrip, Montana	147.0	1,134,348
5	Thermal	Carbon Plant	Castle Gate, Utah	174.0	1,308,130
6	Thermal	Gadsby Plant	Salt Lake City, Utah	101.0	453,758
7	Thermal	Hunter Plant	Castle Dale, Utah	1,029.0	7,445,537
8	Thermal	Huntington Plant	Huntington, Utah	842.0	6,168,469
9	Thermal	Centralia Plant	Centralia, Washington	624.0	4,540,578
10	Thermal	Dave Johnston Plant	Glenrock, Wyoming	787.0	6,050,195
11	Thermal	Jim Bridger Plant	Rock Springs, Wyoming	1,627.0	10,801,447
12	Thermal	Wyodak Plant	Gillette, Wyoming	278.0	2,239,218
13	Thermal	Naughton Plant	Kemmerer, Wyoming	683.0	4,462,066
14	Geothermal	Blundell Plant	Milford, Utah	25.0	186,369
15	Combustion Turbine	Little Moutain Plant	Ogden, Utah	15.0	79,036
16	Nuclear	Trojan Plant	Rainier, Oregon	29.0	114,346
17	Hydro	Copco #1	Copco, California	24.0	35,256
18	Hydro	Copco #2	Copco, California	28.0	46,805
19	Hydro	Fall Creek	Copco, California	2.2	11,248
20	Hydro	Iron Gate	Hornbrook, California	15.0	44,911
21	Hydro	Ashton	Ashton, Idaho	7.2	30,449
22	Hydro	Cove	Grace, Idaho	7.2	19,613
23	Hydro	Grace	Grace, Idaho	33.2	96,310
24	Hydro	Last Chance	Grace, Idaho	1.4	4,300
25	Hydro	Oneida	Preston, Idaho	21.4	32,218
26	Hydro	Paris	Paris, Idaho	0.8	991
27	Hydro	Soda	Soda, Idaho	8.1	16,478
28	Hydro	St. Anthony	St. Anthony, Idaho	0.6	2,279
29	Hydro	Bigfork	Bigfork, Montana	4.0	27,810
30	Hydro	Bend	Bend, Oregon	1.1	3,970
31	Hydro	Clearwater #1	Toketee Falls, Oregon	15.0	38,870
32	Hydro	Clearwater #2	Toketee Falls, Oregon	25.0	35,047
33	Hydro	Cline Falls	Redmond, Oregon	1.0	2,133
34	Hydro	Eagle Point	Eagle Point, Oregon	3.0	10,751
35	Hydro	East Side	Klamath Falls, Oregon	3.0	12,143
36	Hydro	Fish Creek	Toketee Falls, Oregon	13.0	37,488
37	Hydro	John C. Boyle	Keno, Oregon	43.0	68,960
38	Hydro	Lemolo #1	Toketee Falls, Oregon	29.0	83,674
39	Hydro	Lemolo #2	Toketee Falls, Oregon	36.0	118,631
40	Hydro	Powerdale	Hood River, Oregon	6.0	33,996
41	Hydro	Prospect #1	Prospect, Oregon	4.0	18,948
42	Hydro	Prospect #2	Prospect, Oregon	36.0	186,723
43	Hydro	Prospect #3	Prospect, Oregon	7.0	16,274
44	Hydro	Prospect #4	Prospect, Oregon	1.0	3,906
45	Hydro	Slide Creek	Toketee Falls, Oregon	20.0	63,097
46	Hydro	Soda Springs	Toketee Falls, Oregon	13.0	47,057
47	Hydro	Stayton	Stayton, Oregon	0.6	2,763
48	Hydro	Toketee	Toketee Falls, Oregon	31.0	163,176
49	Hydro	Wallowa Falls	Joseph, Oregon	1.1	3,313
50	Hydro	West Side	Klamath Falls, Oregon	0.6	124
51	Hydro	American Fork	Plesant Grove, Utah	0.1	4,580
52	Hydro	Beaver - Upper	Beaver, Utah	2.2	8,115

Sch. 35	SOURCES OF ELECTRIC SUPPLY				
	Type	Plant Name	Location	Annual Peak - MW	Annual Energy - MWH
53	Hydro	Cutler	Collinston, Utah	25.5	26,350
54	Hydro	Fountain Green	Fountain Green, Utah	0.1	477
55	Hydro	Granite	Salt Lake City, Utah	0.5	3,168
56	Hydro	Gunlock	Gunlock, Utah	0.6	1,873
57	Hydro	Olmsted	Orem, Utah	5.3	11,282
58	Hydro	Pioneer	Ogden, Utah	2.6	7,772
59	Hydro	Sand Cove	Sand Cove, Utah	0.5	1,740
60	Hydro	Snake Creek	Midway, Utah	0.2	901
61	Hydro	Stairs	Salt Lake City, Utah	1.2	3,647
62	Hydro	Veyo	Veyo, Utah	0.3	559
63	Hydro	Weber	Uintah, Utah	3.2	11,433
64	Hydro	Condit	Underwood, Washingto	15.0	68,422
65	Hydro	Drop	Naches, Washington	1.0	5,797
66	Hydro	Merwin	Ariel, Washington	149.0	331,108
67	Hydro	Naches	Naches, Washington	6.0	20,628
68	Hydro	Swift #1	Cougar, Washington	237.0	433,519
69	Hydro	Yale	Amboy, Washington	130.0	372,892
70	Hydro	Viva Naughton	Kemmerer, Wyoming	0.7	1,297
71	Pumping	Lifton	Lifton, Idaho		(5,217)
72					
73		Total Net Generation			51,757,802
74					
75		**POWER PURCHASES A/C 555**			
76					
77	Albany, City of		(1)		59
78	Alturas Cemetery District		09-30-1983		2
79	Anaheim, City of		(1)		1,035
80	Arizona Public Service Company		(2)		102,169
81	Arizona Public Service Company		(1)		77,340
82	Ashland, City of		(3)		1,622
83	BC Hydro		(1)		38,807
84	Beaver City		(4)		74
85	Bell Mountain Power		01-02-2020		1,019
86	Biomass One, Limited Partnership		01-31-2010		156,794
87	Birch Creek Hydro		08-21-2019		11,890
88	Black Hills Power & Light Company		06-30-2012		46,222
89	Black Hills Power & Light Company		(1)		2,215
90	Blanding City		(4)		1,069
91	Bogus Creek		12-31-2017		1,177
92	Boise Cascade Corporation		(1)		347
93	Bonneville Power Administration		(5)		
94	Bonneville Power Administration		(6)		
95	Bonneville Power Administration		(1)		336,079
96	Boston Power		12-31-2004		338
97	Boyd, James		12-31-2003		2,003
98	CDM Hydro		12-04-2019		21,877
99	Central Oregon Irrigation District		12-31-2018		14,964
100	Champion International Corp.		06-30-1994		27,821
101	Chelan County Public Utility Dist. No. 1		.08-31-2018		304,884
102	Chelan County Public Utility Dist. No. 1		(1)		17,129
103	Colockum Transmission Company		(1)		160
104	Colorado Public Service Company		(1)		164,468

Sch. 35	SOURCES OF ELECTRIC SUPPLY			
	Type / Plant Name	Location	Annual Peak - MW	Annual Energy - MWH
105	Colorado Ute Electric Associates	(1)		28,220
106	Columbia Storage Power Exchange	(7)		261,286
107	Cook Electric	12-31-2017		6,548
108	Coos Curry Electric Cooperative	(4)		66
109	Cowlitz County Public Utility Dist. No. 1	(1)		554
110	Curtiss Livestock	12-31-1993		72
111	DAW Forest Products Company	(1)		1,570
112	Deer Creek Water Control District	(1)		588
113	Deseret Generation & Trans. Coop.	(1)		451,964
114	Difani, Chris	04-30-2007		45
115	Douglas County Public Utility Dist. No. 1	08-31-2018		258,692
116	Douglas County Public Utility Dist. No. 1	(1)		31,439
117	DR Johnson Lumber Company	12-31-2006		63,299
118	El Paso Electric Company	(1)		3,865
119	Eugene Water & Electric Board	(1)		16,956
120	Falls Creek	12-31-2019		9,753
121	Farmers Irrigation #2	12-31-2010		16,962
122	Fery, Lloyd	12-31-1993		275
123	Fillmore City	(4)		77
124	Fox, Marian	(4)		1
125	FS Industries Limited	(1)		2,095
126	Galesville Dam	12-31-2021		1,410
127	General Chemical Company	(1)		4,683
128	Georgetown Power	07-02-2019		1,761
129	Grand Valley Rural Power Lines	(4)		102
130	Grant County Public Utility Dist. No. 2	(8)		87,600
131	Grant County Public Utility Dist. No. 2	10-31-2005		586,164
132	Grant County Public Utility Dist. No. 2	10-31-2005		828,254
133	Grant County Public Utility Dist. No. 2	(1)		86,948
134	Idaho Falls, City of	11-02-2023		40,282
135	Idaho Power Company	(1)		8,625
136	Ingram Warm Springs Ranch	05-31-2021		4,354
137	Intermountain Power Project	06-15-2027		352,725
138	Lacomb Hydro	12-31-2018		2,401
139	Lagoon Corporation	12-31-1993		100
140	Lake Siskiyou	12-31-2020		15,724
141	Lehi Cogeneration Associates	03-29-1993		15,120
142	Los Angeles, City of	(1)		19,775
143	Luckey, Paul	12-31-2013		306
144	Middlefork Irrigation District	12-31-2004		19,772
145	Mink Creek Hydro	12-31-2021		5,514
146	Montana Power Company	(9)		131,760
147	Montana Power Company	(1)		9,112
148	Morgan City	(4)		21
149	Mountain Energy	12-31-2004		51
150	Murray City	(4)		207
151	Nephi City	(4)		25
152	New Mexico Public Service Company	(1)		329,519
153	Nichols Gap	12-31-2021		1,866
154	Nicholson Sunnybar Ranch	06-27-2020		1,911
155	North Fork Sprague	12-31-2023		1,376
156	Odell Creek	12-31-2010		84

Sch. 35	SOURCES OF ELECTRIC SUPPLY				
	Type	Plant Name	Location	Annual Peak - MW	Annual Energy - MWH
157	Opal Springs		12-31-2020		25,609
158	Ormsby, Leslie		12-31-1993		11
159	O.J. Power Company		03-04-2021		335
160	Pacific Gas & Electric Company		(1)		9,970
161	Pancheri, Inc.		03-01-2013		84
162	Plains Electric		(1)		35,219
163	Platte River Power Authority		(1)		63,656
164	PLM, Inc		12-31-2013		489
165	Porcupine Reservoir Company		01-05-2016		
166	Portland General Electric Company		(10)		24,000
167	Portland General Electric Company		(1)		14,640
168	Preston City Hydro		02-24-2017		2,734
169	Provo City		(4)		183
170	Puget Sound Power & Light Company		(1)		45,142
171	Riverside, City of		(1)		600
172	Rocky Mountain Generation Cooperative		(1)		200,783
173	Rousch, Neil		12-31-1993		251
174	Royal Oak		12-31-1998		
175	Salt River Project		(1)		184,553
176	Salt River Project		(15)		
177	San Diego Gas & Electric Company		(1)		8,252
178	Santiam Water Control District		12-31-2019		1,078
179	Seattle City Light		(1)		2,375
180	Sierra Pacific Power Company		(1)		385
181	Slate Creek		12-31-2018		8,978
182	Solar Research		12-31-2009		527
183	Southern California Edison Company		(1)		86,869
184	Southern California Edison Company		(15)		
185	Southern California Edison Company		(15)		7,389
186	Southwestern Public Service Company		(1)		89,956
187	Spanish Fork City		(4)		44
188	Springville City		(4)		23
189	Strawberry Electric Service District		(1)		114
190	Tacoma City Light		(1)		10,309
191	Teton Generation Station		02-02-2020		1,550
192	Thayne Ranch Hydro		12-31-2015		1,522
193	TKO		01-01-2013		250
194	Tri-State Generation & Transmission		(11)		856,190
195	Tucson Electric Power Company		(1)		117,502
196	United States Bureau of Reclamation		10-06-2000		37,141
197	United States Bureau of Reclamation		(1)		10,953
198	Utah Assoc. Municipal Power Systems		(1)		25,433
199	Walla Walla, City of		12-31-2012		15,290
200	Warm Springs Forest Products Industry		(1)		1,988
201	Warm Springs Power Enterprises		12-31-2001		69,117
202	Washington Public Power Supply System		(12)		584,994
203	Washington Water Power Company		(13)		439,200
204	Washington Water Power Company		(14)		20,100
205	Washington Water Power Company		(1)		64,031
206	West Kootenay Power & Light Company		(1)		11,917
207	Western Area Power Administration		(1)		5,775

SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak - MW	Annual Energy - MWH
208	Westinghouse		12-15-2022		7,432
209	White, J.E.		12-31-2017		936
210	Whitmore Oxygen		(1)		1,822
211	Whitney, A.C.		None		2
212	Wiggins, Duane		12-31-1993		4
213	Yakima Tieton		12-31-2005		8,197
214	System Deviation		(16)		872
216		Total Power Purchases			8,150,219
218		Net Exchanges			90,339
220		Transmission by Others Losses			(359,899)
222		Total Sources			59,638,461

225 **Notes:**

226 (1) Non-firm.
227 (2) Arizona Public Service - Contract Termination Date: Oct. 31, 2020.
228 (3) City of Ashland - Contract Termination Date: Upon 30 days written notice.
229 (4) Under electric service agreement subject to termination upon timely notification.
230 (5) Bonneville Power Administration - Contract Termination Date: August 31, 2011.
231 (6) Bonneville Power Administration - Contract Termination Date: March 31, 2003.
232 (7) Columbia Storage Power Exchange - Contract Termination Date: March 31, 2003.
233 (8) Grant County PUD No. 2 - Contract Termination Date: Later of September 1, 1988
234 or 2 years written notice.
235 (9) Montana Power Company - Contract Termination Date: December 31, 1995.
236 (10) Portland General Electric Co. - Contract Termination Date: December 18, 2001.
237 (11) Tri-State Generation & Trans. - Contract Termination Date: December 31, 2020.
238 (12) Washington Public Power Supply System - Contract Termination Date: June 30, 1996.
239 (13) Washington Water Power Co. - Contract Termination Date: December 31, 1995.
240 (14) Washington Water Power Co. - Contract Termination Date: December 31, 1995.
241 (15) Short-term firm, where duration of commitment for service is one year or less.
242 (16) Not applicable; adjustment for inadvertent interchange.

1992 Hydro Power Plant Outages
Exceeding 24 Hour Duration

Plant	Date of Outage	Cause of Outage	Duration
Large Plants			
Cutler	None		
Grace	21-Feb-92	#4 Unit Tripped - Step-Up transformer trouble	26 hrs 25 min
	28-Dec-92	#5 Unit Tripped - Bearing failure	112 hrs 45 min
Olmstead	8-Jun-92	#4 Unit offline - Central Utah Water Conserv. District shut off water supply after non company truck carrying ammonium nitrate crashed into the river.	27 hrs
Oneida	1-Jan-92	#2 Unit taken offline - excessive unit vibration	1381 hrs 32 min
	27-Feb-92	#2 Unit offline - upper guide bearing damage	430 hrs 55 min
	17-Mar-92	#2 Unit offline - upper guide bearing damage. Note: unit overhauled and cleaned during extended outage. During outage period new butterfly valves installed ahead of Units #1 and #2 to replace old Johnson valves	6943 hrs 40 min
Soda	None		
Merwin	30-Jan-92	#2 Unit - upper slip ring went to ground	123 hrs 27 min
Yale	None		
Swift No. 1	None		
Copco No. 1	15-Jul-92	Relay base shorting out	147 hrs 56 min
Copco No. 2	22-Apr-92	Field breaker went out	165 hrs
	29-Aug-92	BFV limit switch out of adjustment	26 hrs
	20-Nov-92	Relay would not latch	70 hrs 35 min
J. C. Boyle	None		
Iron Gate	None		
Soda Springs	None		
Slide Creek	None		
Fish Creek	None		
Clearwater No. 1	None		

1992 Hydro Power Plant Outages
Exceeding 24 Hour Duration

Plant	Date of Outage	Cause of Outage	Duration
Clearwater No. 2	None		
Lemolo No. 1	4-Sep-92	Turbin bearing over temp	168 hrs
Lemolo No. 2	None		
Toketee	21-Feb-92	Solid state excieter B/O. Bad diode and blown fuse.	310 hrs 55 min
	10-Apr-92	Alarm on S/D, possible turbine bearing out	3431 hrs 5 min
	9-Dec-92	Hot packing. Replaced packing.	45 hrs 5 min
	13-Dec-92	Oil leak at turbin bearing probe	28 hrs 38 min
Prospect No. 2	None		
Small Plants			
American Fork	1-Apr-92	Flowline leak - offline until section of flowline could be replaced.	503 hrs 40 min
Ashton	None		
Beaver - Upper	None		
Bend	None		
Bigfork	None		
Cline Falls	None		
Conduit	None		
Cove	None		
Drop	26-Feb-92	Canal failure	336 hrs 45 min
	24-Jul-92	Canal washout caused by failure of Naches-Selah flume	98 hrs 10 min
Eagle Point	None		
East Side	None		

1992 Hydro Power Plant Outages
Exceeding 24 Hour Duration

Plant	Date of Outage	Cause of Outage	Duration
Fall Creek		Water actuator out	out entire year
Fountain Green	1-Jan-92	Unit tripped - under voltage condition	37 hrs 30 min
	2-May-92	Unit tripped - under voltage condition	37 hrs 45 min
	9-May-92	Unit tripped - under voltage condition	98 hrs 50 min
	4-Jun-92	Unit tripped - under voltage condition	96 hrs
	3-Oct-92	Unit tripped - under voltage condition	25 hrs 35 min
Granite	12-Aug-92	Unit offline - Flowline Failure - excessive leakage . Rebuilt section of flume	2090 hrs 22 min
Gunlock	None		
Last Chance	16-Aug-92	#1, #2, #3 units offline - Control computer trouble	192 hrs 15 min
	24-Aug-92	#1, #2, #3 units offline - Hydraulic gate control failure	201 hrs 35 min
Naches	26-Feb-92	Canal failure	336 hrs 36 min
	30-Apr-92	#2 Unit offline - bearing failure	65 hrs
	24-Jul-92	Canal washout caused by failure of Naches-flume	98 hrs 10 min
Paris	None		
Poineer	18-Apr-92	#6 Unit offline - Flowline failure. Several wood-staves were replaced.	50 hrs 45 min
Powerdale	24-Oct-92	Failure of pnematic control valve on Johnson valve	41 hrs 2 min
Prospect 1	None		
Prospect No. 3	2-Feb-92	D. C. short	24 hrs 20 min
Prospect No. 4	19-Feb-92	Hot bearing	160 hrs 20 min
Sand Cove	26-Jan-92	Unit tripped - flowline damaged. Repaired shrot section of steel pipeline.	142 hrs
Snake Creek	2-Nov-92	#1 Unit tripped - Protective relay trouble	32 hrs 50 min
Stairs	1-Aug-92	Unit offline - Replace exciter rotor	122 hrs 15 min

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Carbon #1								
1.	01/16/92	23:23	-	01/17/92	13:49	Forced	14.43	981.44
	Descr: WATERWALL TUBE LEAK IN THE VICINITY OF A WATERWALL SOOT-BLOWER							
2.	04/10/92	23:20	-	05/18/92	11:42	Planned	900.37	61,224.89
	Descr: UNIT 1 PLANNED OVERHAUL							
3.	05/18/92	12:58	-	05/18/92	15:02	Forced	2.07	140.49
	Descr: FEEDWATER REGULATING VALVE FAILURE							
4.	05/21/92	00:58	-	05/21/92	04:44	Forced	3.77	256.09
	Descr: TRIPPED ON TEST							
5.	05/21/92	04:44	-	05/21/92	05:46	Forced	1.03	70.24
	Descr: ATTEMPT TO RE-SYNCHRONIZE FAILED							
6.	07/27/92	11:48	-	07/27/92	16:10	Forced	4.37	296.89
	Descr: OIL LEAK ON CIRCUIT BREAKER 171							
7.	07/27/92	16:10	-	07/27/92	19:17	Forced	3.12	211.89
	Descr: START-UP FAILURE							
8.	08/07/92	12:43	-	08/08/92	05:12	Forced	16.48	1,120.84
	Descr: BOILER TUBE LEAK IN THE ECONOMIZER SECTION							
9.	08/22/92	21:44	-	08/23/92	00:00	Forced	2.27	154.09
	Descr: UNIT TRIP DUE TO OPERATOR ERROR							
	***** Unit Summary for Carbon #1 for the year 1992 =**						947.91	64,456.86
Carbon #2								
1.	01/15/92	00:05	-	01/15/92	13:42	Forced	13.62	1,429.68
	Descr: WATERWALL TUBE LEAK IN THE VICINITY OF THE WALL SOOT BLOWER							
2.	02/27/92	12:39	-	02/27/92	13:39	Forced	1.00	105.00
	Descr: OPERATOR ERROR - TRIP DUE TO LOSS OF FANS ON BOILER							
3.	02/27/92	13:39	-	02/27/92	18:00	Forced	4.35	456.75
	Descr: RELIEF VALVE BONNET BLEW OFF ON RECIRC LINE ON THE #2-1 BOILER FEED							
4.	02/27/92	18:00	-	02/27/92	21:51	Forced	3.85	404.25
	Descr: CONDENSATE SAMPLE LINE FOR LAB IS IN NEED OF REPAIR							
5.	05/14/92	09:24	-	05/14/92	14:14	Forced	4.83	507.47
	Descr: UNIT TRIP DUE TO HUMAN ERROR AT SWITCHYARD							
6.	09/02/92	21:45	-	09/04/92	21:29	Forced	47.73	5,011.97
	Descr: REPAIR SUPERHEATER TUBE LEAK							

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Centralia #1								
15.	12/12/92	17:12	-	12/12/92	21:49	Forced	4.62	3,023.48
	Descr: EH CONTROL PROBLEMS							
16.	12/12/92	21:49	-	12/12/92	22:44	Forced	0.92	599.98
	Descr: TURBINE TRIP SOLENOID ACTIVATED - CAUSE UNKNOWN							
17.	12/13/92	01:30	-	12/13/92	02:27	Forced	0.95	622.25
	Descr: TURBINE TRIP SOLENOID ACTIVATED - CAUSE UNKNOWN							
18.	12/13/92	02:27	-	12/13/92	08:50	Forced	6.38	4,180.87
	Descr: DATA LOGGER PROBLEMS							
19.	12/13/92	08:50	-	12/13/92	15:12	Forced	6.37	4,169.73
	Descr: TURBINE TRIP SOLENOID ACTIVATED - CAUSE UNKNOWN							
20.	12/25/92	18:04	-	12/25/92	19:32	Forced	1.47	960.23
	Descr: SOE 1ST REPORT - UNDERFREQUENCY. THE UNDERFREQUENCY SIGNAL APPEARS TO							
21.	12/25/92	20:43	-	12/26/92	00:45	Forced	4.03	2,641.62
	Descr: SOE 1ST OUT REPORT - SOLENOID TRIP. SUSPECT PROBLEM WITH UNDERFREQUENC							
	*** **Unit Summary for Centralia #1 for the year 1992 =**						1,047.16	685,878.69
Centralia #2								
1.	02/07/92	00:21	-	02/12/92	14:01	Maint.	133.67	87,551.23
	Descr: WATERWALL TUBE LEAK IN BOILER THROAT AREA							
2.	02/28/92	17:48	-	02/29/92	01:57	Forced	8.15	5,338.25
	Descr: TURBINE E-H SYSTEM LEAK REPAIR							
3.	11/14/92	00:00	-	11/16/92	09:30	Forced	57.50	37,662.50
	Descr: WATERWALL TUBE LEAK							
	*** **Unit Summary for Centralia #2 for the year 1992 =**						199.32	130,551.98
Cholla #4								
1.	02/16/92	19:07	-	02/17/92	23:28	Forced	28.35	9,922.50
	Descr: UNIT OFF LINE TO REPAIR BOILER TUBE LEAK							
2.	02/17/92	23:28	-	02/22/92	04:40	Forced	101.20	35,420.00
	Descr: METAL FAILURE CAUSED LINE RUPTURE FLOODING CIRCULATING WATER PUMPMOTOR							
3.	02/22/92	06:40	-	02/22/92	07:56	Forced	1.27	443.10
	Descr: LOSS OF FEEDWATER CONTROL WHEN TRANSFERRING "B" BOILER FEED PUMP FROM							

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Dave Johnston #1								
4.	07/02/92	10:00	-	07/06/92	04:42	Forced	90.70	9,523.50
	Descr: CONTINUED WITH WATERWALL TUBE LEAK REPAIRS							
5.	07/06/92	06:54	-	07/07/92	16:08	Forced	33.23	3,489.47
	Descr: WATERWALL TUBE LEAK							
6.	07/07/92	16:08	-	07/07/92	17:40	Forced	1.53	160.97
	Descr: IGNITOR PROBLEMS ON STARTUP							
7.	07/07/92	17:40	-	07/07/92	20:31	Forced	2.85	299.25
	Descr: CONTINUED WITH WATERWALL REPAIRS							
8.	07/07/92	22:39	-	07/07/92	23:16	Forced	0.62	64.68
	Descr: HI DRUM LEVEL							
	*** * * Unit Summary for Dave Johnston #1 for the year**						177.40	18,626.80
Dave Johnston #2								
1.	01/22/92	13:12	-	01/22/92	14:33	Forced	1.35	141.75
	Descr: BOILER CONTROLSDUE TO #1 TRIP							
2.	01/30/92	00:20	-	01/30/92	07:42	Forced	7.37	773.43
	Descr: C PHASE OF DISCONNECT LOOSE							
3.	02/28/92	23:11	-	03/01/92	00:00	Forced	24.82	2,605.68
	Descr: AIR HEATER WASH							
4.	03/01/92	00:00	-	03/01/92	09:04	Forced	9.07	951.93
	Descr: AIR HEATER WASH							
5.	03/14/92	10:41	-	03/16/92	04:57	Forced	42.27	4,437.93
	Descr: PRIMARY SUPERHEAT TUBE LEAK							
6.	03/30/92	13:13	-	03/30/92	14:02	Forced	0.82	85.68
	Descr: VAC TRIP							
7.	04/03/92	23:34	-	04/06/92	14:00	Forced	61.43	6,450.47
	Descr: WATER WALL TUBE LEAKS							
8.	04/06/92	16:50	-	04/06/92	18:33	Forced	1.72	180.18
	Descr: HI DRUM LEVEL							
9.	05/15/92	23:24	-	06/10/92	10:49	Planned	611.42	64,198.68
	Descr:							
10.	06/11/92	10:03	-	06/12/92	17:43	Forced	31.67	3,324.93
	Descr: SUPERHEAT TUBE LEAK							

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Dave Johnston #3								
11.	10/18/92	13:01	-	10/19/92	08:40	Forced	19.65	4,323.00
	Descr: CLEAN SLAG SCREEN							
12.	10/20/92	12:35	-	10/20/92	14:28	Forced	1.88	414.26
	Descr: 3B PA DAMPER/DRAFT TRIP							
13.	10/20/92	15:54	-	10/20/92	16:25	Forced	0.52	113.52
	Descr: LOW VACUUM TRIP,DUE TO SJAE							
14.	10/20/92	17:56	-	10/20/92	18:47	Forced	0.85	187.00
	Descr: DRUM LEVEL TRIP,DUE TO MILLS							
15.	10/21/92	03:52	-	10/22/92	16:07	Forced	36.25	7,975.00
	Descr: CLEAN SLAG SCREEN							
16.	10/22/92	16:07	-	10/22/92	20:10	Forced	4.05	891.00
	Descr: 3A ID FAN DAMPER LEAK THRU							
17.	10/24/92	14:00	-	10/24/92	14:55	Forced	0.92	201.52
	Descr: DRAFT TRIP,CONTROL TUNING							
18.	10/28/92	07:20	-	10/28/92	08:14	Forced	0.90	198.00
	Descr: MFT,INVERTER FAILURE							
19.	10/28/92	09:28	-	10/28/92	11:52	Forced	2.40	528.00
	Descr: MFT,INVERTOR FAILURE							
20.	10/31/92	00:25	-	11/01/92	22:28	Maint.	46.05	10,131.00
	Descr: REBUILD SLAG SCREEN							
21.	12/20/92	02:55	-	12/22/92	13:57	Forced	59.03	12,987.26
	Descr: CLINKER IN THROAT							
	*** **Unit Summary for Dave Johnston #3 for the year**						1,260.23	277,246.20
Dave Johnston #4								
1.	01/28/92	02:14	-	01/28/92	10:00	Forced	7.77	2,485.12
	Descr: RELAY PROBLEMS IN SWITCHYARD							
2.	01/28/92	10:00	-	01/30/92	18:33	Forced	56.55	18,096.00
	Descr: TUBELEAK WATERWALL							
3.	01/30/92	18:34	-	01/30/92	19:02	Forced	0.47	149.12
	Descr: UNDER EXCITATION GEN. VOLTAGE CONTROL							
4.	03/20/92	19:14	-	03/24/92	16:54	Forced	93.67	29,973.12
	Descr: WATER WALL TUBE LEAK							

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Dave Johnston #4								
22.	10/17/92	21:51	-	10/17/92	23:01	Forced	1.17	373.12
	Descr: FLAME FAILURE,IGNITORS							
23.	11/20/92	12:25	-	11/20/92	16:50	Forced	4.42	1,413.12
	Descr: ELEC. SHORT IN PULV. CONTROLS							
24.	11/25/92	08:02	-	11/25/92	11:55	Forced	3.88	1,242.56
	Descr: B STARTER COOLER PUMP MOTOR FAILED							
25.	12/04/92	09:43	-	12/04/92	10:41	Forced	0.97	309.12
	Descr: INSTRUMENT ISOLATION ERROR							
26.	12/04/92	10:56	-	12/04/92	11:31	Forced	0.58	186.56
	Descr: COULD NOT GET COAL UP TO SILO							
27.	12/13/92	07:25	-	12/14/92	22:35	Forced	39.17	12,533.12
	Descr: TUBE LEAK C CORNER							
	*** * * Unit Summary for Dave Johnston #4 for the year**						420.35	134,503.36
Gadsby #3								
1.	01/13/92	22:54	-	01/14/92	18:15	Maint.	19.35	1,935.00
	Descr: TUBE LEAK AT TOP ELEVATION OF FLEXIBLE SLIP SPACERS, NORTH SIDE OF FE-							
2.	01/14/92	18:15	-	01/14/92	19:15	Maint.	1.00	100.00
	Descr: INSTRUMENT AIR LINES TO BOTH FD AND ID FAN CONTROLS FROZEN. UNIT HAD B							
3.	01/14/92	19:15	-	01/15/92	04:33	Maint.	9.30	930.00
	Descr: APPARATUS MAINTENANCE HAD TO ADD 200 GALLONS OF OIL TO TRANSFORMER							
4.	05/09/92	00:17	-	05/09/92	20:30	Maint.	20.22	2,021.60
	Descr: TUBE LEAKS AT TOE OF WELDS, BOTH SIDES OF FEMALE SLIP SPACERS, SECOND							
5.	05/09/92	21:00	-	05/10/92	06:10	Forced	9.17	916.60
	Descr: NEED TO PURGE BOILER FOR STARTUP							
6.	10/30/92	23:09	-	12/01/92	11:48	Planned	756.65	75,665.00
	Descr: UNIT OFF LINE FOR SCHEDULED OVERHAUL.							
7.	12/15/92	21:37	-	12/15/92	23:15	Forced	1.63	163.30
	Descr: BAILEY WAS ATTEMPTING TO TUNE FURNACE DRAFT AND CAUSED DRAFT TRIP							
8.	12/16/92	06:53	-	12/16/92	08:49	Forced	1.93	193.30
	Descr: TRIP SEEMED TO BE CAUSED BY UNEXPLAINED LINK BETWEEN NEW BURNER MANAGE							
9.	12/16/92	11:54	-	12/16/92	14:11	Forced	2.28	228.30
	Descr: BOILER TRIP SEEMED TO BE CAUSED BY UNKNOWN LINK BETWEEN THE NEW BURNER							

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Hunter #1								
12.	09/03/92	22:31	-	09/11/92	22:07	Forced	191.60	75,682.00
	Descr: UNIT TRIP - 3 MILL DUCTS BLOWN UP							
13.	09/16/92	00:09	-	09/18/92	01:51	Maint.	49.70	19,631.50
	Descr: BOILER TUBE LEAK - SUPERHEAT							
14.	10/05/92	12:51	-	10/05/92	21:42	Forced	8.85	3,495.75
	Descr: UNIT TRIP - UPS SYSTEM TESTING							
15.	12/05/92	00:00	-	12/06/92	06:19	Forced	30.32	11,974.82
	Descr: BOILER TUBE LEAK (WATERWALL)							
	*** * * Unit Summary for Hunter #1 for the year 1992 =**						1,358.26	536,506.79
Hunter #2								
1.	01/05/92	08:04	-	01/05/92	10:55	Forced	2.85	1,125.75
	Descr: UNIT TRIP - #2-3 MCC TRIPPED							
2.	01/21/92	07:10	-	01/21/92	12:30	Forced	5.33	2,106.54
	Descr: UNIT TRIPPED - FW TRANSMITTER FROZEN							
3.	01/25/92	04:22	-	01/25/92	22:59	Forced	18.62	7,353.32
	Descr: UNIT OFF - REPAIR 2-5 MILL HOT AIR GATE							
4.	02/02/92	21:32	-	02/04/92	10:42	Forced	37.17	14,680.57
	Descr: OFF LINE FOR PRECIP WORK							
5.	02/22/92	19:30	-	02/22/92	21:30	Forced	2.00	790.00
	Descr: OFF LINE - LUMP COAL							
6.	02/29/92	05:45	-	03/01/92	00:00	Forced	18.25	7,208.75
	Descr: UNOT OFF LINE - CONDENSER TUBE LEAK							
7.	03/10/92	00:00	-	03/10/92	20:35	Forced	20.58	8,130.29
	Descr: UNIT OFF LINE - CONDENSER TUBE LEAK							
8.	06/12/92	00:00	-	06/13/92	14:15	Forced	38.25	15,108.75
	Descr: OFF LINE - PRECIP WORK							
9.	06/19/92	16:25	-	06/19/92	17:57	Forced	1.53	605.54
	Descr: OFF LINE - BCP DIFF TRIP							
10.	06/20/92	00:00	-	06/21/92	12:28	Forced	36.47	14,404.07
	Descr: OFF LINE FOR MILL AND PRECIP WORK							
11.	09/04/92	00:03	-	09/05/92	17:27	Forced	41.40	16,353.00
	Descr: UNIT OFF LINE - WATER IN COAL SILOS							

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Hunter #3								
12.	08/27/92	12:53	-	08/27/92	15:09	Forced	2.27	895.07
	Descr: UNIT TRIP, 3-1 BAGHOUSE TRIP							
13.	10/09/92	07:49	-	10/11/92	17:44	Forced	57.92	22,876.82
	Descr: BOILER TUBE LEAK - PRIMARY SUPERHEAT							
14.	10/24/92	08:58	-	10/26/92	13:07	Forced	53.15	20,994.25
	Descr: BOILER TUBE LEAK (REHEAT SECTION)							
	*** **Unit Summary for Hunter #3 for the year 1992 =**						517.57	204,437.01
Huntington #1								
1.	01/24/92	09:58	-	01/26/92	01:34	Forced	39.60	15,840.00
	Descr: OFF LINE DUE TO BOILER ASH PLUGGAGE (HIGH ASH COAL).							
2.	06/25/92	00:18	-	06/25/92	04:10	Forced	3.87	1,546.40
	Descr: TESTING TURBINE STOP VALVES, TURBINE TRIPPED, REASON UNDETERMINED, POS							
3.	10/24/92	22:30	-	10/25/92	12:00	Forced	14.50	5,800.00
	Descr: FAILED							
4.	10/25/92	12:01	-	10/29/92	01:38	Forced	85.62	34,246.40
	Descr: MOTOR BURNED UP DUE TO PUMP SHAFT LEAKS							
5.	10/29/92	02:11	-	10/29/92	03:42	Forced	1.52	606.40
	Descr: PROBLEMS WITH MOV-12, TRYING TO PUT UNIT ON LINE AFTER TRIP							
6.	10/29/92	04:58	-	10/29/92	19:14	Forced	14.27	5,706.40
	Descr: BOILER TRIP							
7.	10/29/92	19:56	-	10/31/92	20:07	Forced	48.18	19,273.20
	Descr: BOILER TRIP							
	*** **Unit Summary for Huntington #1 for the year 1992 =**						207.56	83,018.80
Huntington #2								
1.	03/28/92	00:08	-	03/28/92	01:11	Forced	1.05	425.25
	Descr: BOILER TRIP CAUSED BY ELECTRICAL CONTROLS.							
2.	03/28/92	02:11	-	05/15/92	09:47	Planned	1,158.60	469,233.00
	Descr: TURBINE OFF LINE FOR GENERAL OVERHAUL							
3.	05/15/92	10:44	-	05/15/92	12:06	Forced	1.37	553.23
	Descr: LOST BOILER DUE TO A FLAME SCANNER PROBLEM							
4.	05/15/92	12:44	-	05/15/92	13:58	Forced	1.23	499.37
	Descr: LOW DRUM LEVEL							

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Time	-	Ending Date	Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger #1								
1.	01/17/92	06:42	-	01/17/92	07:33	Forced	0.85	442.00
	Descr: SWITCHYARD TRIP-LOST BORAH LINE.							
2.	01/24/92	14:18	-	01/25/92	14:25	Forced	24.12	12,540.32
	Descr: BTG TRIPPED BY OPERATOR. SUPERHEAT TUBE LEAK. FOUND TUBE LEAK IN REH							
3.	02/12/92	07:10	-	02/12/92	07:53	Forced	0.72	372.32
	Descr: BORAH LINE TRIP.							
4.	02/12/92	08:11	-	02/13/92	11:11	Forced	27.00	14,040.00
	Descr: LOW FURNACE AIR FLOW WHILE LOWERING LOAD TO REMOVE UNIT FROM SERVICE.							
5.	02/14/92	03:34	-	02/14/92	21:39	Forced	18.08	9,403.16
	Descr: MANUAL OPERATOR TRIP. REHEAT TUBE LEAK AT K-5.							
6.	03/14/92	01:06	-	03/15/92	07:34	Forced	30.47	15,842.32
	Descr: MANUAL OPERATOR TRIP. REHEAT TUBE LEAK PANEL 61 TUBE 5 & 6. FUEL OIL							
7.	03/15/92	21:04	-	03/16/92	15:04	Forced	18.00	9,360.00
	Descr: REHEAT TUBE LEAK.							
8.	03/18/92	08:06	-	03/19/92	05:33	Forced	21.45	11,154.00
	Descr: FLAME FAILURE TRIP-HAD THREE MILLS ON ABOVE 50%. SCANNERS TRIPPED WHI							
9.	03/27/92	23:51	-	04/27/92	00:09	Planned	719.30	374,036.00
	Descr: MANUAL BY OPERATOR. ANNUAL OVERHAUL. NOTE 72 HOURS SHOULD BE CHARGE							
10.	06/17/92	15:02	-	06/19/92	03:27	Forced	36.42	18,936.32
	Descr: CONTROL OPERATOR USED THE TURBINE TRIP BUTTON AT 000MW-SUPERHEAT TUBE							
11.	07/11/92	06:25	-	07/13/92	01:16	Forced	42.85	22,282.00
	Descr: WATERWALL TUBE LEAK.							
12.	07/13/92	04:50	-	07/13/92	05:50	Forced	1.00	520.00
	Descr: TURBINE TRIP, HIGH BACK PRESSURE. TRIPPED ABS LOW.							
13.	07/15/92	06:24	-	07/16/92	03:35	Forced	21.18	11,015.16
	Descr: OPERATOR TRIP. BOILER TUBE LEAK.							
14.	08/06/92	04:22	-	08/06/92	05:19	Forced	0.95	494.00
	Descr: TURBINE THRUST BEARING LOW LUBE OIL PRESSURE. HI. CIRC. WATER AND L/O							
15.	08/09/92	00:53	-	08/10/92	00:00	Forced	23.12	12,020.32
	Descr: BOILER TUBE LEAKS, 2 REHEATER (45-5, 14-6) AND ONE WATERWALL.							
16.	08/10/92	00:00	-	08/10/92	18:06	Forced	18.10	9,412.00
	Descr: INSPECT AND REPAIR CRACKS IN THE ID FANS.							

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger #2								
1.	01/17/92	12:08	-	01/17/92	13:08	Forced	1.00	520.00
	Descr: SWITCHYARD TRIP-LOST KINPORT LINE.							
2.	01/17/92	13:25	-	01/17/92	14:00	Forced	0.58	303.16
	Descr: LOSS OF IGNITION ENERGY-IGNITORS WOULD NOT SEAL IN.							
3.	01/28/92	01:04	-	01/29/92	05:00	Forced	27.93	14,525.16
	Descr: LOSS OF 22 APH MAIN AND AUX. DRIVE.							
4.	04/11/92	22:18	-	04/12/92	03:21	Forced	5.05	2,626.00
	Descr: OPERATOR TRIP. LOW VOLTAGE ON AUX. BUS. PROBLEM STARTED WHEN LIGHTIN							
5.	04/30/92	00:21	-	04/30/92	01:21	Forced	1.00	520.00
	Descr: SWITCHYARD TRIP. KINPORT LINE RELAYED. GENERATOR DC REGULATOR PROBLE							
6.	06/11/92	08:08	-	06/12/92	16:24	Forced	32.27	16,778.32
	Descr: UNIT CONTROL OPERATOR USED TURBINE TRIP BUTTON AT 000MW. #22 APH AND							
7.	06/19/92	00:33	-	06/20/92	23:48	Forced	47.25	24,570.00
	Descr: CONTROL BOARD TURBINE TRIP BUTTON BY CONTROL OPERATOR. SUPERHEAT TUBE							
8.	07/13/92	11:06	-	07/15/92	03:37	Forced	40.52	21,068.32
	Descr: OPERATOR INITIATED TRIP FROM BTG BOARD. DIVISION PANE; #5 TUBE LEAK.							
9.	07/17/92	15:05	-	07/17/92	16:14	Forced	1.15	598.00
	Descr: SWITCHYARD TRIP,KINPORT LINE TRIPPED AND TRIPPED ASSOCIATED UNIT (UNIT							
10.	08/19/92	04:05	-	08/19/92	05:21	Forced	1.27	658.32
	Descr: KINPORT LINE TRIP. KINPORT LINE LOADING. RELAY 552-22/AX GENERATOR B							
11.	09/08/92	23:48	-	09/10/92	22:48	Forced	47.00	24,440.00
	Descr: TUBE LEAK-SH PENDANT PLATEN WATER-COOLED SPACER.							
12.	09/10/92	22:48	-	09/13/92	23:16	Forced	72.47	37,682.32
	Descr: ID FAN INSPECTION AND REPAIR.							
13.	11/21/92	21:32	-	11/22/92	14:00	Forced	16.47	8,562.32
	Descr: OPERATOR TRIP. REPLACE BOILER DRUM SIGHT GLASS WATER-SIDE ISOLATION V							
14.	11/22/92	14:00	-	11/22/92	19:04	Forced	5.07	2,634.32
	Descr: REPAIR #22 PA FAN INLET VANE POSITIONER ON INBOARD SIDE.							
15.	11/23/92	03:52	-	11/23/92	04:48	Forced	0.93	485.16
	Descr: HI BACK PRESS.-LOST 21 CIRC. WTR. PUMP. UNIT RUNNING AT CONSTANT LOAD							
16.	11/26/92	05:32	-	11/26/92	08:16	Forced	2.73	1,421.16
	Descr: UNIT TRIP-LOST KINPORT LINE.							

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger #3								
13.	06/08/92	08:41	-	06/08/92	12:15	Forced	3.57	1,854.32
	Descr: ELECTRICAL TRIP.							
14.	06/30/92	08:40	-	06/30/92	10:03	Forced	1.38	719.16
	Descr: TURBINE MASTER TRIP. EHC FLUID PRESSURE LESS THAN 1200 PSI. BYPASS V							
15.	07/24/92	17:01	-	07/25/92	13:34	Forced	20.55	10,686.00
	Descr: HIGH VIBRATION ON 4 TURBINE BEARING. WATERWALL TUBE LEAK REPAIRED WHI							
16.	08/12/92	06:16	-	08/12/92	07:30	Forced	1.23	641.16
	Descr: GOSHEN LINE RELAYED.							
17.	08/12/92	07:30	-	08/12/92	13:34	Forced	6.07	3,154.32
	Descr: MCC 324 AND MOTOR SUCTION OIL PUMP-#31 EHC PUMP CONTROL POWER TRANSFOR							
18.	08/12/92	13:34	-	08/12/92	14:30	Forced	0.93	485.16
	Descr: SEDC TRIP-INSTANT TRIP-SEDC WAS NOT RESET. CLEAR TRIP AND ROLL TURBIN							
19.	08/29/92	06:10	-	08/29/92	07:13	Forced	1.05	546.00
	Descr: SWITCHYARD TRIP. LOSS OF GOSHEN LINE.							
20.	09/30/92	23:47	-	10/02/92	09:02	Forced	33.25	17,290.00
	Descr: DESLAG REHEATER. OPERATOR INITIATED WITH TURBINE TRIP PUSH BUTTON. D							
21.	10/02/92	09:02	-	10/03/92	02:28	Forced	17.43	9,065.16
	Descr: WATERWALL TUBE LEAK.							
22.	10/03/92	06:19	-	10/03/92	08:37	Forced	2.30	1,196.00
	Descr: TRIPPED BY OPERATOR AT 400 MW'S-HIGH TURBINE VIBRATION. #3 BEARING, 1							
23.	10/15/92	10:31	-	10/15/92	12:17	Forced	1.77	918.32
	Descr: HOT P.A. DUCT PRESSURE-CONTRACTORS WORKING NEAR TRANSMITTER. P.A. DUCT							
24.	10/15/92	13:46	-	10/15/92	14:27	Forced	0.68	355.16
	Descr: PA DUCT PRESSURE LOW. BURNT OUT RELAYS ON PA DUCT PRESSURE TIME DELAY							
25.	10/27/92	06:45	-	10/27/92	07:20	Forced	0.58	303.16
	Descr: UNIT TRIP DUE TO KINPORT LINE TRIP-RAS ARMED.							
26.	10/27/92	07:20	-	10/28/92	01:13	Forced	17.88	9,299.16
	Descr: UNIT OFF TO REPAIR SUPERHEATER PENDANT PLATEN TUBE LEAK.							
27.	11/10/92	03:15	-	11/10/92	15:03	Forced	11.80	6,136.00
	Descr: PUSH BUTTON(OPERATOR). LOW BOILER PH, CONDENSER TUBE LEAK.							

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger #4								
12.	04/17/92	19:31	-	04/18/92	22:37	Forced	27.10	14,092.00
	Descr: FLAME FAILURE. WATERWALL TUBE LEAK.							
13.	04/19/92	00:04	-	04/19/92	02:23	Forced	2.32	1,204.32
	Descr: TOTAL FLAME FAILURE DURING START UP OF UNIT. 52 MINUTES TO HANG JUMPE							
14.	05/07/92	22:49	-	05/09/92	02:18	Forced	27.48	14,291.16
	Descr: OPERATOR INITIATED DUE TO WATERWALL TUBE LEAK. BOILER TUBE LEAK, WATE							
15.	06/16/92	21:19	-	06/18/92	06:49	Forced	33.50	17,420.00
	Descr: PUSH BUTTON BY OPERATOR. REHEAT TUBE LEAK.							
16.	07/09/92	00:47	-	07/11/92	00:23	Forced	47.60	24,752.00
	Descr: OPERATOR INITIATED-BLOWN DIAPHRAM IN TURBINE. EXTRACTION STEAM LINE RE							
17.	07/11/92	00:25	-	07/11/92	03:22	Forced	2.95	1,534.00
	Descr: LOSS OF IGNITION ENERGY-BOILER TRIP-41 MILL IGNITION ENERGY.							
18.	08/14/92	08:26	-	08/14/92	10:08	Forced	1.70	884.00
	Descr: FURNACE PRESSURE HIGH PS708A. C&ET BLOWING FURNACE TAPS. LINE PRESSU							
19.	09/02/92	23:31	-	09/03/92	10:09	Forced	10.63	5,529.16
	Descr: BOILER WATER PH 7.0. CONDENSER TUBE LEAK-DROVE BOILER CHEMISTRY OUT O							
20.	09/03/92	11:07	-	09/03/92	13:45	Forced	2.63	1,369.16
	Descr: BOILER WATER PH 7.0. VERY LOW PHOSPHATE IN BOILER-ASSOCIATED WITH CON							
21.	09/18/92	00:00	-	09/19/92	06:24	Forced	30.40	15,808.00
	Descr: OPERATOR OPENED GEN. BREAKER 10H354 ON REVERSE POWER BYPASS-BOILER SLA							
22.	10/03/92	11:16	-	10/03/92	17:32	Forced	6.27	3,258.32
	Descr: #41 BUS TRIPPED AND STARTUP TRANSFORMER DID NOT WORK TAKING OFF ALL EQ							
23.	10/07/92	18:16	-	10/07/92	19:12	Forced	0.93	485.16
	Descr: UNIT TRIPPED BY SWITCHYARD, RASA-LOST 345KV LINE. SWITCHYARD 500 LINE(							
24.	10/18/92	17:02	-	10/18/92	18:39	Forced	1.62	840.32
	Descr: STATOR OUTLES TEMP. HI DUE TO FAILURE OF TEMP. CONTROL VALVE.							
25.	10/28/92	23:00	-	10/29/92	19:53	Forced	20.88	10,859.16
	Descr: BOILER TUBE LEAK-SUPERHEAT.							
26.	11/02/92	06:35	-	11/02/92	08:09	Forced	1.57	814.32
	Descr: HIGH FURNACE PRESSURE DUE TO FCD MAIN BYPASS NOT OPERNING.							
27.	11/02/92	08:29	-	11/02/92	10:30	Forced	2.02	1,048.32
	Descr: MANUAL TRIP BY OPERATOR. #1 MAIN STOP VALVE WOULD NOT OPEN. SERVO PL							

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Naughton #1								
9.	06/03/92	07:00	-	06/03/92	14:51	Forced	7.85	1,256.00
	Descr: UNIT OFF-PACKING LEAK W1 ECONOMIZER DRAIN							
10.	07/23/92	23:27	-	07/24/92	06:24	Maint.	6.95	1,112.00
	Descr: DEAERATOR DOOR LEAKING							
11.	09/10/92	11:23	-	09/11/92	21:47	Forced	34.40	5,504.00
	Descr: UNIT OFF - WATERWALL TUBE LEAK							
12.	10/16/92	21:42	-	11/16/92	12:57	Planned	736.25	117,800.00
	Descr: MAJOR BOILER OVERHAUL, EXCITER REPLACEMENT, HORIZ SH, ETC.							
13.	12/04/92	22:53	-	12/05/92	14:05	Forced	15.20	2,432.00
	Descr: UNIT OFF-GASKET LEAK ON DEAERATOR DOOR							
14.	12/08/92	17:26	-	12/09/92	00:14	Forced	6.80	1,088.00
	Descr: UNIT TRIP - EXCITER TRIPPED							
	***** Unit Summary for Naughton #1 for the year 1992 =**						1,106.40	177,026.40
Naughton #2								
1.	01/27/92	21:27	-	01/31/92	14:15	Forced	88.80	18,648.00
	Descr: EROSION/WEAR - LEAK							
2.	05/08/92	23:12	-	06/10/92	02:49	Planned	771.62	162,039.36
	Descr: UNIT SCHEDULED OVERHAUL 4 WEEKS BOILER INTERNALS TURBINE VALVES, CIRC							
3.	06/10/92	06:30	-	06/10/92	16:38	Forced	10.13	2,127.93
	Descr: OVERSPEED TESTING - UNIT STARTUP							
4.	06/16/92	16:27	-	06/17/92	12:00	Forced	19.55	4,105.50
	Descr: UNIT OFF-CONDENSATE TUBE LEAK-1 TUBE PLUGGED; DA CONTROL VALVE PROBLEM							
5.	06/17/92	12:00	-	06/19/92	23:20	Forced	59.33	12,459.93
	Descr: UNIT OFF-GENERATOR GROUND RELAY PROBLEM							
	***** Unit Summary for Naughton #2 for the year 1992 =**						949.43	199,380.72
Naughton #3								
1.	01/10/92	00:12	-	01/12/92	03:02	Forced	50.83	16,774.89
	Descr: WATERWALL TUBE LEAK(LEFT FRONT)							
2.	01/13/92	15:57	-	01/13/92	17:54	Forced	1.95	643.50
	Descr: CONDENSOR PROBLEMS							
3.	01/16/92	11:53	-	01/18/92	13:22	Forced	49.48	16,329.39
	Descr: WATER WALL TUBE LEAK							

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Naughton #3								
21.	12/05/92	18:59	-	12/07/92	12:54	Forced	41.92	13,832.28
	Descr: UNIT OFF-WATERWALL TUBE LEAK							
22.	12/18/92	01:24	-	12/19/92	20:38	Forced	43.23	14,266.89
	Descr: UNIT OFF-REHEAT TUBE LEAK							
	*** * * Unit Summary for Naughton #3 for the year 1992 =**						850.25	280,580.19
Wyodak								
1.	02/09/92	10:59	-	02/09/92	19:00	Forced	8.02	2,565.12
	Descr: TRIP FROM BLACK HILLS SPEARFISH LINE, RELAYING DID NOT CLEAR LINE							
2.	02/09/92	19:00	-	02/10/92	09:00	Forced	14.00	4,480.00
	Descr: OPERATOR OPENED WRONG VALVE WHICH FLOODED DA AND SHORTED OUT MCC'S							
3.	02/10/92	09:00	-	02/10/92	15:00	Forced	6.00	1,920.00
	Descr: START-UP DELAYED DUE TO PROBLEMS WITH IGNITORS							
4.	02/10/92	15:00	-	02/10/92	17:00	Forced	2.00	640.00
	Descr: DELAY TO START-UP BECAUSE OF DRUM LEVEL, PROBLEMS WITH DRUM SWELL							
5.	02/10/92	17:00	-	02/10/92	20:44	Forced	3.73	1,194.56
	Descr: DELAY TO START-UP BECAUSE OF REPAIRS TO BURNER							
6.	05/15/92	23:31	-	05/17/92	04:30	Maint.	28.98	9,274.56
	Descr: PLUGGED REHEATER DUE TO POOR QUALITY COAL AND OVERFIRING BOILER							
7.	05/17/92	04:30	-	05/17/92	07:32	Maint. Ext.	3.03	970.56
	Descr: A3, B3, C-GROUP, E-GROUP LIGHTERS HAD PLUGGED TIPS AND AIR PRESSURE							
8.	06/19/92	23:41	-	06/20/92	19:42	Maint.	20.02	6,405.12
	Descr: WATER WALL TUBE LEAK - FRONT VESTIBULE							
9.	06/20/92	19:42	-	06/20/92	22:42	Forced	3.00	960.00
	Descr: PLUGGED IGNITORS AND OTHER PROBLEMS WITH IGNITORS							
10.	06/23/92	00:16	-	06/24/92	01:07	Forced	24.85	7,952.00
	Descr: WATER WALL TUBE LEAK - THROAT							
11.	06/24/92	01:07	-	06/24/92	01:37	Forced	0.50	160.00
	Descr: PROBLEMS WITH BFP RECIRC VALVES							
12.	06/24/92	01:37	-	06/24/92	04:07	Forced	2.50	800.00
	Descr: PLUGGED IGNITERS AND OTHER PROBLEMS WITH IGNITERS							
13.	09/04/92	21:27	-	09/05/92	03:17	Forced	5.83	1,866.56
	Descr: UNIT TRIPPED DURING TURBINE OVERSPEED TEST DUE TO TIMING RESET PROBLEM							

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Beginning Time	-	Ending Date	Ending Time	Outage Type	Hrs. Duration	MWH Lost
Blundell								
5.	04/08/92	06:05	-	04/08/92	18:34	Forced	12.48	262.14
	Descr: CONDENSATE POT REPAIRS/VENT STACK VALVE MAIN STEAM LINE							
6.	04/09/92	01:25	-	04/09/92	04:20	Forced	2.92	61.24
	Descr: UNIT TRIPPED; STEAM SEALS TURBINE EXHAUST LOW VACUUM							
7.	04/22/92	16:05	-	04/22/92	19:10	Forced	3.08	64.74
	Descr: UNIT RUNBACK; #44 BREAKER AT CAMERON TRIPPED							
8.	04/29/92	13:10	-	04/29/92	13:40	Forced	0.50	10.50
	Descr: RUNBACK; #44 BREAKER AT CAMERON SUBSTATION OPENED							
9.	05/22/92	10:08	-	05/22/92	10:26	Forced	0.30	6.30
	Descr: OCB21 TRIPPED; MINERAL MT./COVE FORT 46 KV LINE TRIPPED							
10.	05/24/92	13:52	-	05/24/92	14:10	Forced	0.30	6.30
	Descr: CAMERON SUB OCB44 BREAKER OPENED, CAUSING OCB21 TO TRIP/UNIT RUNBACK							
11.	06/12/92	15:50	-	06/12/92	16:24	Forced	0.57	11.89
	Descr: UNIT RUNBACK; CAMERON LINE TRIP							
12.	08/02/92	13:38	-	08/02/92	14:32	Forced	0.90	18.90
	Descr: CO1B DISCHARGE CLOSED AND UNIT WAS LOST							
13.	08/29/92	15:34	-	08/29/92	17:10	Forced	1.60	33.60
	Descr: LOST PLANT INSTRUMENT AIR							
14.	08/30/92	21:32	-	08/31/92	00:04	Forced	2.53	53.19
	Descr: OCB-21 TRIPPED AND UNIT TRIPPED. LIGHTNING AND VOLTZ/HZ RELAY							
15.	09/06/92	15:29	-	10/05/92	13:50	Planned	694.35	14,581.35
	Descr: PLANT OVERHAUL							
16.	10/07/92	11:50	-	10/07/92	12:27	Forced	0.62	12.94
	Descr: UNIT RUNBACK; LINE TROUBLE AT SIGURD ON 138KV LINE							
17.	11/22/92	07:02	-	11/22/92	07:21	Forced	0.32	6.64
	Descr: UNIT TRIPPED DUE TO FAULTY #1 EHC PUMP WHILE TESTING STOP VALVE							
18.	12/12/92	03:53	-	12/12/92	04:43	Forced	0.83	17.49
	Descr: OCB21 TRIPPED; LINE FAULT IN MINERSVILLE							
19.	12/12/92	21:19	-	12/12/92	21:27	Forced	0.13	2.79
	Descr: OCB21 CIRCUIT BREAKER TRIPPED; LINE FAULT IN SIGURD							
	***** Unit Summary for Blundell for the year 1992 =**						736.37	15,463.57

Sch. 36 **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	Zero Interest Program									
2	Initiated - 1978	$5,000	$4,198	19.10%	0.00	7	0.00	7	0.00	0
3	Projected Life - Indefinite									
4	Low Income Program									
5	Initiated - 1987	$52,500	$47,541	10.43%	0.00	33	0.00	33	0.00	0
6	Projected Life - Indefinite									
7	Efficient Heat Pump									
8	Initiated - 1986	$10,000	$9,400	6.38%	0.01	95	0.02	141	0.01	46
9	Projected Life - Indefinite									
10	Efficient Water Heaters									
11	Initiated - 1987	$7,000	$6,155	13.73%	0.00	40	0.00	41	0.00	1
12	Projected Life - Indefinite									
13	Super Good Cents									
14	Initiated - 1988	$200,400	$142,092	41.04%	0.04	303	0.04	344	0.00	41
15	Projected Life - Indefinite									
16	Manufactured Acquisition Program									
17	Initiated - 1991	$205,743	$62,400	229.72%	0.04	360	0.02	174	(0.02)	(186)
18	Projected Life - Indefinite									
19	Energy FinAnswer									
20	Initiated - 1991	$55,000	$1,560	3425.64%	0.01	119	0.00	0	(0.01)	(119)
21	Projected Life - Indefinite									
22	Energy FinAnswer 12,000									
23	Initiated - 1992	$79,294	$12,704	524.17%	0.02	196	0.00	0	(0.02)	(196)
24	Projected Life - Indefinite									
25										
26										
27										
28										
29										
30										
31										
32										
33	TOTAL	$614,937	$286,050	114.98%	0.12	1,153	0.08	740	(0.04)	(413)

Program	"Participant" Description	Conservation "Unit" Description	1992 Participants	1992 Units Acquired/Processed
Zero Interest Program	Any Single Family home owner with permanently connected electric heat. Must meet minimum credit approval.	Homes Weatherized	8	8
Low Income Program	Any residence w/electric heat as the primary heat source. Must meet income requirement: 125% of Federal poverty level.	Homes Weatherized Water Heater refurbish/replace	38 88	38 88
Efficient Heat Pumps	Small Commercial or Residential customers with 1.5 - 7.5 ton Heat Pump installed by an H-Pro dealer. Must have HSPF standard >= 7.0	Heat Pump: Air to Air or Ground Source	74	74
Efficient Water Heaters	Any Single Family home owner may sign up for Hassle Free program which pays for replac ment of their electric water heater with a more efficient unit if it fails.	Water Heaters Replaced	122	122
Super Good Cents	Any builder or owner of a New residential , electrically heated home in Pacific Power's Montana service territory.	New Homes	57	57
Manufactured Acquisition Program	Manufacturers of New electrically heated manufactured homes.	New Manufactured Homes	14	14
Energy FinAnswer	Owners or developers of new commercial buildings or new additions over 12,000 square feet.	Square footage of treated space	0	0
Energy FinAnswer 12,000	Owners or developers of new commercial buildings or new additions under 12,000 square feet.	Square footage of treated space	0	0

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