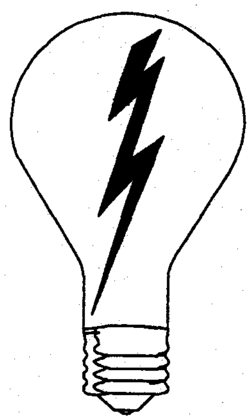
YEAR 1995

ANNUAL REPORT

OF

The Washington Water Power Company

ELECTRIC UTILITY



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

Revised November 9, 1994

Sch. 1 IDENTIFICATION

Legal Name of Respondent:	The Washington Water Power Company
Name Under Which Respondent Does Business:	The Washington Water Power Company
Date Utility Service First Offered in Montana:	July, 1960
Person Responsible for Report:	J.E. Eliassen, Vice President-Finance & CFO
Telephone Number for Report Inquiries:	(509) 482-4171
Address for Correspondence Concerning Report:	East 1411 Mission Avenue Spokane, Washington 99202

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	Paul A. Redmond (1)	1411 E. Mission Avenue, Spokane, WA 99202	511942
2	David A. Clack	325 E. Sprague Avenue, Spokane WA 99202	34788
3	Duane B. Hagadone	P. O. Box 6200, Coeur d' Alene, ID 83816	34600
4	Robert S. Jepson, Jr.	1 Skidway Village Walk, Suite 201, Savanna, GA 31411	31600
5	Eugene W. Meyer	3 Plumbridge Lane, Hilton Head Island, SC 29928	37581
6	General H. Norman Schwarzkopf	400 N. Ashley Street, Suite 3050, Tampa, FL 33602	31600
7	B. Jean Silver	7102 N. Audubon Drive, Spokane, WA 99208	33600
8	Larry A. Stanley	311 W. 32nd Avenue, Spokane, WA 99203	40740
9	R. John Taylor	P. O. Box 538, Lewiston, ID 83501	34600
10	Eugene Thompson (2)	3307 Pine Crest Road, Moscow, ID 83843	16108
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12			
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16			
17	(1) Mr. Redmond is Chairman of the Board, President and Chief Executive Officer		
18	(2) Mr. Thompson retired May 1995.		
19			
20			
21			
22			

Sch. 3

OFFICERS

Title	Department Supervised	Name
Chairman of the Board, President and CEO		Paul A. Redmond
Vice President-Finance and Chief Financial Officer	Finance Department	J.E. Eliassen
Senior Vice President	Rates and Resources	W.L. Bryan
Vice President	Marketing, Public Relations	J.G. Matthiesen
Vice President	Corporate Services, Human Resources	R.D. Fukai
Vice President	Operations	N.J. Racicot
Vice President	Gas Supply	G.G. Ely
Vice President	Business Analysis	L.J. Pierce
Controller	Corporate Accounting, Plant Accounting, Rates	J.W. Buergel
Treasurer	Funds Management, Tax and Payroll, Corporate Finance and Investor Relations	R. R. Peterson
Corporate Secretary	Shareholder Services	T. L. Syms

Sch. 4

CORPORATE STRUCTURE

Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
Pentzer Corporation	Parent Company of all the Company's Subsidiaries, except Washington Irrigation and Development Company, WP Finance, Altus Laboratories, and Altus Energy Solutions.	14,632,201	98.79%
Washington Irrigation and Development Company	Non-Operating	179,232	1.21%
WP Finance Company	Non-Operating	0	
Limestone Company (1)	Non-Operating	580	0.00%
Altus Corporation	Non-Operating	0	
Altus Laboratories	Developing alternative energy products and related R & D.	0	
Altus Energy Solutions	Performs various energy advisory services.	0	
Note (1): Limestone Company was dissolved in 1995.			
TOTAL		14,812,013	

Sch. 5	CORPORATE ALLOCATIONS					
	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1					0.00%	
2			Not Applicable		0.00%	
3					0.00%	
4					0.00%	
5					0.00%	
6					0.00%	
7					0.00%	
8					0.00%	
9					0.00%	
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11					0.00%	
12					0.00%	
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25					0.00%	
26					0.00%	
27					0.00%	
28					0.00%	
29					0.00%	
30					0.00%	
31					0.00%	
32					0.00%	
33					0.00%	
34	TOTAL			0	0.00%	0

Sch. 6	**AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY**					
	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1						
2	Not Applicable					
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32	TOTAL			0		0

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

	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1						
2	Not Applicable					
3						
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31						
32	TOTAL			0		0

Sch. 8	MONTANA UTILITY INCOME STATEMENT			
	Account Number & Title	Last Year	This Year	% Change
1	400 Operating Revenues	5,294,164	2,165,471	-59.10%
2				
3	Operating Expenses			
4	401 Operation Expenses	39,282,247	22,662,284	-42.31%
5	402 Maintenance Expenses	5,268,949	4,742,466	-9.99%
6	403 Depreciation Expenses	8,503,523	8,599,078	1.12%
7	404-405 Amortization of Electric Plant	None or not allocated		
8	406 Amort. of Plant Acquisition Adjustments	None or not allocated		
9	407 Amort. of Property Losses, Unrecovered Plant			
10	& Regulatory Study Costs			
11	408.1 Taxes Other Than Income Taxes	8,884,963	8,722,601	-1.83%
12	409.1 Income Taxes - Federal	None or not allocated		
13	- Other	802,078	1,514,145	88.78%
14	410.1 Provision for Deferred Income Taxes	None or not allocated		
15	411.1 (Less) Provision for Def. Inc. Taxes - Cr.	None or not allocated		
16	411.4 Investment Tax Credit Adjustment	None or not allocated		
17	411.6 (Less) Gains from Disposition of Utility Pla	None or not allocated		
18	411.7 Losses from Disposition of Utility Plant	None or not allocated		
19				
20	TOTAL Utility Operating Expenses	62,741,760	46,240,574	-26.30%
21	NET UTILITY OPERATING INCOME	(57,447,596)	(44,075,103)	23.28%

Sch. 9	MONTANA REVENUES			
	Account Number & Title	Last Year	This Year	% Change
22	Sales of Electricity			
23	440 Residential	7,696	9,233	19.97%
24	442 Commercial & Industrial - Small	1,424	1,592	11.80%
25	Commercial & Industrial - Large			
26	444 Public Street & Highway Lighting			
27	445 Other Sales to Public Authorities			
28	446 Sales to Railroads & Railways			
29	448 Interdepartmental Sales	4,222	5,788	37.09%
30				
31	TOTAL Sales to Ultimate Consumers	13,342	16,613	24.52%
32	447 Sales for Resale	1,410,623	747,035	-47.04%
33				
34	TOTAL Sales of Electricity	1,423,965	763,648	-46.37%
35	449.1 (Less) Provision for Rate Refunds			
36				
37	TOTAL Revenue Net of Provision for Refunds	1,423,965	763,648	-46.37%
38	Other Operating Revenues			
39	450 Forfeited Discounts & Late Payment Revenues			
40	451 Miscellaneous Service Revenues			
41	453 Sales of Water & Water Power	4,629	13,651	194.90%
42	454 Rent From Electric Property	60,865	138,626	127.76%
43	455 Interdepartmental Rents			
44	456 Other Electric Revenues	3,804,705	1,249,546	-67.16%
45				
46	TOTAL Other Operating Revenues	3,870,199	1,401,823	-63.78%
47	Total Electric Operating Revenues	5,294,164	2,165,471	-59.10%

MONTANA OPERATION & MAINTENANCE EXPENSES

	Account Number & Title	Last Year	This Year	% Change
1				
2	Power Production Expenses			
3				
4	**Steam Power Generation**			
5				
6	Operation			
7	(500) Operation Supervision and Engineering	394,167	405,733	2.93
8	(501) Fuel	13,297,936	10,443,964	(21.46)
9	(502) Steam Expenses	1,332,230	1,275,245	(4.28)
10	(503) Steam from Other Sources	4,687	-2,790	(159.53)
11	(Less) Steam Transferred-Cr.	0	0	
12	(505) Electric Expenses	503,210	495,752	(1.48)
13	(506) Miscellaneous Steam Power Expenses	1,186,977	1,458,419	22.87
14	(507) Rents	1,605	2,475	54.21
15				
16	TOTAL Operation - Steam	16,720,812	14,078,798	(15.80)
17				
18	Maintenance			
19	(510) Maintenance Supervision and Engineering	479,475	444,205	(7.36)
20	(511) Maintenance of Structures	354,734	393,769	11.00
21	(512) Maintenance of Boiler Plant	2,603,804	1,870,256	(28.17)
22	(513) Maintenance of Electric Plant	598,462	107,720	(82.00)
23	(514) Maintenance of Miscellaneous Steam Plant	517,900	333,408	(35.62)
24				
25	TOTAL Maintenance - Steam	4,554,375	3,149,358	(30.85)
26				
27	TOTAL Power Production Expenses-Steam Plant	21,275,187	17,228,156	(19.02)
28				
29	Nuclear Power Generation			
30				
31	Operation			
32	(517) Operation Supervision and Engineering			
33	(518) Fuel			
34	(519) Coolants and Water			
35	(520) Steam Expenses			
36	(521) Steam from Other Sources			
37	(Less) (522) Steam Transferred-Cr.			
38	(523) Electric Expenses			
39	(524) Miscellaneous Nuclear Power Expenses			
40	(525) Rents			
41				
42	TOTAL Operation Nuclear	0	0	
43				
44	Maintenance			
45	(528) Maintenance Supervision and Engineering			
46	(529) Maintenance of Structures			
47	(530) Maintenance of Reactor Plant Equipment			
48	(531) Maintenance of Electric Plant			
49	(532) Maintenance of Miscellaneous Nuclear Plant			
50				
51	TOTAL Maintenance Nuclear	0	0	
52				
53	TOTAL Power Production Expenses-Nuclear Power	0	0	

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES			
	Account Number & Title	**Last Year**	**This Year**	**% Change**
1	Power Production Expenses - continued			
2	**Hydraulic Power Generation**			
3				
4	Operation			
5	(535) Operation Supervision and Engineering	28,660	36,252	26.49
6	(536) Water for Power			
7	(537) Hydraulic Expenses	103,936	111,903	7.67
8	(538) Electric Expenses	470,107	508,920	8.26
9	(539) Miscellaneous Hydraulic Power Generation Expenses	73,654	102,654	39.37
10	(540) Rents	110	51	(100.00)
11				
12	TOTAL Operation - Hydraulic	676,467	759,780	12.32
13				
14	Maintenance			
15	(541) Maintenance Supervision and Engineering	1,843	1,953	5.97
16	(542) Maintenance of Structures	66,058	59,157	(10.45)
17	(543) Maintenance of Reservoirs, Dams, and Waterways	155,201	28,543	(81.61)
18	(544) Maintenance of Electric Plant	359,735	360,214	0.13
19	(545) Maintenance of Miscellaneous Hydraulic Plant	9,256	9,112	(1.56)
20				
21	TOTAL Maintenance - Hydraulic	592,093	458,979	(22.48)
22				
23	TOTAL Hydraulic Power Production Expenses	1,268,560	1,218,759	(3.93)
24				
25	**Other Power Generation**			
26				
27	Operation			
28	(546) Operation Supervision and Engineering			
29	(547) Fuel			
30	(548) Generation Expenses			
31	(549) Miscellaneous Other Power Generation Expenses			
32	(550) Rents			
33				
34	TOTAL Operation - Other	0	0	
35				
36	Maintenance			
37	(551) Maintenance Supervision and Engineering	0	0	
38	(552) Maintenance of Structures			
39	(553) Maintenance of Generating and Electric Plant		44	
40	(554) Maintenance of Miscellaneous Other Power Generation Plant			
41				
42	TOTAL Maintenance - Other	0	44	
43				
44	TOTAL Power Production Expenses-Other Power	0	44	
45				
46	**Other Power Supply Expenses**			
47	(555) Purchased Power	21,232,300	5,793,801	(72.71)
48	(556) System Control and Load Dispatching			
49	(557) Other Expenses			
50				
51	TOTAL Other Power Supply Expenses	21,232,300	5,793,801	(72.71)
52				
53	TOTAL Power Production Expenses	43,776,047	24,240,760	(44.63)

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES			
	Account Number & Title	**Last Year**	**This Year**	**% Change**
1	**TRANSMISSION EXPENSES**			
2	Operation			
3	(560) Operation Supervision and Engineering	24,461	23,621	(3.43)
4	(561) Load Dispatching	27,197	27,959	2.80
5	(562) Station Expenses	89,218	96,764	8.46
6	(563) Overhead Line Expenses	24,881	55,805	124.29
7	(564) Underground Line Expenses	0		
8	(565) Transmission of Electricity by Others	119,241	(200,018)	(267.74)
9	(566) Miscellaneous Transmission Expenses	141		
10	(567) Rents	79,059	95,029	20.20
11				
12	TOTAL Operation - Transmission	364,198	99,160	(72.77)
13	Maintenance			
14	(568) Maintenance Supervision and Engineering	6,015	8,703	44.69
15	(569) Maintenance of Structures	(16)		(100.00)
16	(570) Maintenance of Station Equipment	35,071	58,225	66.02
17	(571) Maintenance of Overhead Lines	22,133	57,764	160.99
18	(572) Maintenance of Underground Lines			
19	(573) Maintenance of Miscellaneous Transmission Plant			
20				
21	TOTAL Maintenance - Transmission	63,203	124,692	97.29
22				
23	TOTAL Transmission Expenses	427,401	223,852	(47.62)
24				
25	**DISTRIBUTION EXPENSES**			
26	Operation			
27	(580) Operation Supervision and Engineering			
28	(581) Load Dispatching			
29	(582) Station Expenses	0	2,688	100.00
30	(583) Overhead Line Expenses			
31	(584) Underground Line Expenses	160	0	(100.00)
32	(585) Street Lighting and Signal System Expenses			
33	(586) Meter Expenses			
34	(587) Customer Installations Expenses	113	253	123.89
35	(588) Miscellaneous Distribution Expenses			
36	(589) Rents	12	40	233.33
37				
38	TOTAL Operation - Distribution	285	2,981	945.96
39	Maintenance			
40	(590) Maintenance Supervision and Engineering			
41	(591) Maintenance of Structures			
42	(592) Maintenance of Station Equipment	6	0	(100.00)
43	(593) Maintenance of Overhead Lines	1,021	2,508	145.64
44	(594) Maintenance of Underground Lines	731	425	(41.86)
45	(595) Maintenance of Line Transformers			
46	(596) Maintenance of Street Lighting and Signal Systems			
47	(597) Maintenance of Meters			
48	(598) Maintenance of Miscellaneous Distribution Plant			
49				
50	TOTAL Maintenance - Distribution	1,758	2,933	66.84
51				
52	TOTAL Distribution Expenses	2,043	5,914	189.48
53				

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES			
	Account Number & Title	**Last Year**	**This Year**	**% Change**
1				
2	**CUSTOMER ACCOUNTS EXPENSES**			
3	Operation			
4	(901) Supervision			
5	(902) Meter Reading Expenses			
6	(903) Customer Records and Collection Expenses	28	0	(100.00)
7	(904) Uncollectible Accounts			
8	(905) Miscellaneous Customer Accounts Expenses			
9				
10	TOTAL Customer Accounts Expenses	28	0	(100.00)
11				
12	**CUSTOMER SERVICE AND INFORMATIONAL EXPENSES**			
13	Operation			
14	(907) Supervision			
15	(908) Customer Assistance Expenses			
16	(909) Informational and Instructional Expenses			
17	(910) Miscellaneous Customer Service and Informational Expenses			
18				
19	TOTAL Cust. Service and Informational Expenses	0	0	
20				
21	**SALES EXPENSES**			
22	Operation			
23	(911) Supervision			
24	(912) Demonstrating and Selling Expenses			
25	(913) Advertising Expenses			
26	(916) Miscellaneous Sales Expenses			
27				
28	TOTAL Sales Expenses	0	0	
29				
30	**ADMINISTRATIVE AND GENERAL EXPENSES**			
31	Operation			
32	(920) Administrative and General Salaries		300	100.00
33	(921) Office Supplies and Expenses	1,946	731	(62.44)
34	(Less) (922) Administrative expenses Transferred-Credit			
35	(923) Outside Services Employed		119,798	100.00
36	(924) Property Insurance	99,718	21,070	(78.87)
37	(925) Injuries and Damages	23,054	3,561	(84.55)
38	(926) Employee Pensions and Benefits	5,697	0	(100.00)
39	(927) Franchise Requirements			
40	(928) Regulatory Commission Expenses	457,742	818,082	78.72
41	(Less) (929) Duplicate Charges-Cr.			
42	(930.1) General Advertising Expenses			
43	(930.2) Miscellaneous General Expenses		963,882	(100.00)
44	(931) Rents			
45				
46	TOTAL Operation	588,157	1,927,424	227.71
47	Maintenance			
48	(935) Maintenance of General Plant	57,520	1,006,460	1,649.76
49				
50	TOTAL Administrative and General Expenses	645,677	2,933,884	354.39
51				
52	TOTAL Electric Operation and Maintenance Expenses	44,851,196	27,404,410	(38.90)
53				

Sch. 11	MONTANA TAXES OTHER THAN INCOME			
	Description of Tax	Last Year	This Year	% Change
2	Real and Personal Property Tax	8,349,506	8,109,378	-2.88%
4	Benficial Use Tax	0	0	
6	Kilowatt Hour Tax	531,594	606,208	14.04%
8	Unemployment Tax	4,095	6,157	50.35%
10	Consumer Council Tax	(264)	833	415.53%
12	Public Commission Tax	32	25	-21.88%
50	**TOTAL MT Taxes other than Income**	8,884,963	8,722,601	-1.83%

Sch. 12:ES TO PERSONS OTHER THAN EMPLOYEES

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
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2					
3	See Schedule Pages 13A - 13H Following				
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50	**TOTAL Payments for Services**		0	0	

Name of Respondent	This Report Is:	Date of Report (Mo,Da, Yr)	Year of Report
The Washington Water Power Company	[X] An Original [ ] A Resubmission	April 30, 1995	Dec. 31, 1994

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES

1. Report the information specified below for all charges made during the year included in any account (including plant accounts) for outside consultative and other professional services. (These services include rate, management, construction, engineering, research, financial, valuation, legal, accounting, purchasing, advertising, labor relations, and public relations, rendered the respondent under written or oral arrangement, for which aggregate payments were made during the year to any corporation, partnership, organization of any kind, or individual [other than for services as an employee or for payments made for medical and related services] amounting to more than $25,000, including payments for legislative services, except those which should be reported in Account 426.4 Expenditures for Certain Civic, Political and Related Activities.

(a) Name and address of person or organization rendering serives.

(b) description of services reveived during year and project of case to which services relate,

(c) basis of charges,

(d) total charges for the year, detailing utility department and account charged.

2. For any services which are of a continuing nature, give the date and term of contract and date of Commission authorization, if contract received Commission approval.

3. Designate with an asterisk associated companies.

(a)	Acres International Corporation			
	10201 Southport Road SW	(c)	Operating	$19,937
	5th Floor		Capital	$25,568
	Calgary, AB CANADA T2W4X9		Other	
(b)	Consulting Engineers		Total	$45,505
(a)	ADP Proxy Solicitation			
		(c)	Operating	$32,283
	PO Box 12298		Capital	
	Newark, NJ 07101-5298		Other	$3,150
(b)	Proxy Solicitation		Total	$35,433
(a)	Bartlit, Beck, Herman, Palenchar & Scott			
	Courthouse PL	(c)	Operating	$39,052
	54 W. Hubbard Street		Capital	
	Chicago, IL 60610		Other	
(b)	Legal		Total	$39,052
(a)	Baumgarten			
		(c)	Operating	$28,959
	444 West 23rd Avenue		Capital	
	Spokane, WA 99203		Other	
(b)	Leadership Consulting		Total	$28,959
(a)	Beacon Hill Partners			
		(c)	Operating	$52,724
	90 Broad Street		Capital	
	New York, NY 10004		Other	$18,460
(b)	Proxy Solicitation		Total	$71,184
(a)	Bison Environmental			
	Great Western Building	(c)	Operating	$33,253
	W. 905 Riverside, Suite 316		Capital	$2,240
	Spokane, WA 99201		Other	$7,800
(b)	Environmental & Engineering Consulting		Total	$43,293
(a)	Black & Veatch			
		(c)	Operating	$7,808
	P.O. Box 27-258		Capital	$15,063
	Kansas City, MO 64180		Other	$138,820
(b)	Consulting Engineers		Total	$161,691

Name of Respondent	This Report Is:	Date of Report (Mo,Da, Yr)	Year of Report
The Washington Water Power Company	[X] An Original [ ] A Resubmission	April 30, 1995	Dec. 31, 1994

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a) C J Design		
Cindy J. Rother	(c) Operating	$58,404
1020 Nez Perce St.	Capital	$1,600
Moscow, ID 83843	Other	
(b) Computer Services & Consulting	Total	$60,004
(a) CH2M Hill		
	(c) Operating	$15,952
P.O. Box 91500	Capital	$103,767
Bellevue, WA 98009-2050	Other	
(b) Environmental & Engineering Consulting	Total	$119,719
(a) Charles River Assoc., Inc.		
John Hancock Tower	(c) Operating	$9,367
200 Clarendon Street	Capital	
Boston, MA 02116-5092	Other	$74,490
(b) Economic Consulting	Total	$83,857
(a) Chemical Bank		
Securities & Trust Services	(c) Operating	$30,635
Box 5747 GPO	Capital	
New York, NY 10087-5747	Other	
(b) Trustee fees	Total	$30,635
(a) Citibank		
111 Wall Street	(c) Operating	$52,773
Sort 4889	Capital	
New York, NY 10043	Other	
(b) Trustee fees	Total	$52,773
(a) D. F. King & Co.		
	(c) Operating	
77 Water Street	Capital	
New York, NY 10005-4495	Other	$154,460
(b) Proxy Solicitation	Total	$154,460
(a) David Evans & Associates		
	(c) Operating	
North 920 Washington, Suite 17	Capital	$74,987
Spokane, WA 99201-2235	Other	
(b) Consulting Engineers	Total	$74,987
(a) Deloitte & Touche		
	(c) Operating	$4,667
111 Third Avenue	Capital	
Seattle, WA 98101	Other	$330,180
(b) Independent Accountants	Total	$334,847

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a)	Donelan, Cleary, Wood & Maser PC			
		(c)	Operating	$37,835
	1275 K St. NW, Ste 850		Capital	
	Washington, DC 20005-4006		Other	
(b)	Legal		Total	$37,835
(a)	Dowell & Associates			
		(c)	Operating	$86,103
	P.O. Box 1400		Capital	
	Mercer Island, WA 98040-1400		Other	
(b)	Tax Consultants		Total	$86,103
(a)	Dunau Associates			
		(c)	Operating	$99,785
	624 E. 24th Avenue		Capital	$14,683
	Spokane, WA 99203		Other	
(b)	Environmental & Engineering Consulting		Total	$114,468
(a)	Ebasco Services, Inc.			
		(c)	Operating	$50,663
	210 Clay Avenue		Capital	$125,435
	Lyndhurst, NJ 07071		Other	
(b)	Consulting Engineers		Total	$176,098
(a)	Electronic Data Systems Corp-Energy Management Associates			
		(c)	Operating	$30,010
	P.O. Box 10552		Capital	$138,856
	Newark, NJ 07193-0552		Other	
(b)	Computer Services & Consulting		Total	$168,866
(a)	Financial Data Systems, Inc.			
	Ed Butler	(c)	Operating	$8,176
	2451 152nd Ave. NE		Capital	$91,626
	Redmond, WA 98052		Other	$22,220
(b)	Consulting Engineers		Total	$122,022
(a)	Hanna & Associates, Inc.			
		(c)	Operating	$27,392
	PO Box 2025		Capital	
	Coeur d' Alene, ID 83814		Other	
(b)	Advertising Consultants		Total	$27,392
(a)	HDR Engineering, Inc.			
		(c)	Operating	
	500-108th Ave. NE, Ste 1200		Capital	$25,175
	Bellevue, WA 98004		Other	
(b)	Consulting Engineers		Total	$25,175

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CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a) Hill & Knowlton, Inc.			
	(c)	Operating	$2,445
420 Lexington Avenue		Capital	
New York, NY 10017		Other	$85,680
(b) Public Relations Consulting		Total	$88,125
(a) Howard Johnson & Company			
	(c)	Operating	$65,277
1111 Third Avenue, Suite 1700		Capital	
Seattle, Wa 98101		Other	
(b) Actuarial & Investment Consulting		Total	$65,277
(a) Inland Empire Employee Assistance Programs Inc.			
	(c)	Operating	$56,821
1403 Grand Blvd., Ste 206N		Capital	
Spokane, WA 99203		Other	
(b) Human Resources Consulting		Total	$56,821
(a) J. K., Inc.			
5750 Hiway 95 North	(c)	Operating	
PO Box 573		Capital	
Sandpoint, ID 83864		Other	$43,760
(b) Consulting Engineers		Total	$43,760
(a) Jerry Jackson & Associates			
	(c)	Operating	$16,536
P.O. Box 2466		Capital	
Chapel Hill, NC 27515		Other	$71,800
(b) Forecast Consulting		Total	$88,336
(a) Joe McKibben			
	(c)	Operating	
2510 Solari Drive		Capital	
Reno, NV 89509		Other	$50,000
(b) Management Consulting		Total	$50,000
(a) John Hilsen			
	(c)	Operating	
PO Box 2127		Capital	
Spokane, WA 99210-2127		Other	$25,000
(b) Environmental & Engineering Consulting		Total	$25,000
(a) Landau Assoc.			
N. 908 Howard	(c)	Operating	$173,033
Suite 206		Capital	
Spokane, WA 99201		Other	$591,510
(b) Environmental & Engineering Consulting		Total	$764,543

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CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a) Litchfield Consulting Group			
One Main Place, Suite 900	(c)	Operating	
101 SW Main Street		Capital	
Portland, OR 97204		Other	$153,370
(b) Electric Utility Consulting		Total	$153,370
(a) M Group Environmental Services			
	(c)	Operating	$203,612
PO Box 3646		Capital	
Spokane, WA 99220		Other	$26,620
(b) Environmental & Engineering Consulting		Total	$230,232
(a) Market Decisions Inc			
	(c)	Operating	$81,566
8959 SW Barbur Blvd, Suite 204		Capital	
Portland, OR 97219		Other	
(b) Marketing Consultants		Total	$81,566
(a) Merrill Schultz & Associates			
	(c)	Operating	$35,299
16400 Southcenter Parkway 300		Capital	
Seattle, WA 98188		Other	
(b) Electric Utility Consulting		Total	$35,299
(a) Moody's Investor Service			
	(c)	Operating	$15,919
P.O. Box 12086		Capital	
Newark, NJ 07101		Other	$40,010
(b) Investment Consultants		Total	$55,929
(a) MSC Life Ins. Co.			
	(c)	Operating	
P.O. Box 3048		Capital	
Spokane, WA 99220-3048		Other	$45,810
(b) 3rd Party Medical Administrator		Total	$45,810
(a) MW Consulting Engineers			
	(c)	Operating	$4,461
W. 222 Wall Street, Suite 200		Capital	$110,804
Spokane, WA 99201		Other	$5,690
(b) Consulting Engineers		Total	$120,955
(a) Nies Mapping			
	(c)	Operating	$320
1950 112th Avenue NE		Capital	$189,619
Bellevue, WA 98004		Other	
(b) Consulting Engineers		Total	$189,939

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CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a) North by Northwest			
	(c)	Operating	$2,567
E 520 North Foothills Dr, Suite 400		Capital	
Spokane, WA 99201		Other	$31,940
(b) Media Production Services		Total	$34,507
(a) Northrop Devine & Tarbell, Inc.			
	(c)	Operating	$18,025
500 Washington Avenue		Capital	$172,501
Portland, ME 04103		Other	
(b) Environmental & Engineering Consulting		Total	$190,526
(a) O'Neill & Co.			
1202 3rd Avenue	(c)	Operating	$30,839
Suite 2700		Capital	
Seattle, WA 98101		Other	$28,310
(b) DSM Measurement & Evaluation Consulting		Total	$59,149
(a) Object Systems International			
	(c)	Operating	
934 N. Catalina Ave.		Capital	$348,254
Burbank, CA 91505		Other	
(b) Computer Consulting		Total	$348,254
(a) Pacific Construction Consultants			
	(c)	Operating	$32,594
4156 148th Avenue NE		Capital	
Redmond, WA 98052		Other	
(b) Auditing services		Total	$32,594
(a) Pacific Hydro			
2150 Mariner Square Drive	(c)	Operating	$35,001
Suite 101		Capital	$6,738
Alameda, CA 94501		Other	
(b) FERC related consulting		Total	$41,739
(a) Paine, Hamblen, Coffin, Brooke & Miller			
	(c)	Operating	$1,328,438
717 W. Sprague, Suite 1200		Capital	$269,818
Spokane, WA 99204		Other	$475,610
(b) Legal		Total	$2,073,866
(a) Patricia A. Newman			
	(c)	Operating	$46,783
75 Skyline Terrace		Capital	
Mill Valley, CA 94941		Other	$7,250
(b) Leadership Consulting		Total	$54,033

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CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

294	(a) Pillsbury Madison & Sutro			
295		(c)	Operating	
296	PO Box 60000		Capital	
297	San Francisco, CA 94160-2391		Other	$49,470
298	(b) Environmental & Engineering Consulting		Total	$49,470
299				
300	(a) Power Engineering, Inc.			
301		(c)	Operating	$58
302	P.O. Box 1066		Capital	
303	Hailey, ID 83333		Other	$37,120
304	(b) Consulting Engineers		Total	$37,178
305				
306	(a) Power International			
307	250 NW Boulevard	(c)	Operating	
308	Suite 206		Capital	
309	Coeur d' Alene, ID 83814		Other	$57,790
310	(b) Consulting Engineers		Total	$57,790
311				
312	(a) PSM International			
313	703 McKinney	(c)	Operating	
314	Suite 430-436		Capital	
315	Dallas, TX 75202-1028		Other	$30,240
316	(b) Environmental & Engineering Consulting		Total	$30,240
317				
318	(a) Quality Resource & Services Inc			
319		(c)	Operating	
320	P.O. Box 14781		Capital	$227,986
321	Spokane, WA 99214		Other	$22,770
322	(b) Payrolling service		Total	$250,756
323				
324	(a) Raytheon Engineers & Constructors			
325	PO Box 8500	(c)	Operating	
326	S 5450		Capital	$28,357
327	Philadelphia, PA 19178		Other	
328	(b) Consulting Engineers		Total	$28,357
329				
330	(a) Reginal F. Wight & Associates			
331		(c)	Operating	$42,983
332	10431 32nd Drive SE		Capital	
333	Everett, WA 98208		Other	
334	(b) Tax Consultants		Total	$42,983
335				
336	(a) Reid & Priest			
337		(c)	Operating	$61,943
338	40 West 57th Street		Capital	
339	New York, NY 10019		Other	$1,437,880
340	(b) Legal		Total	$1,499,823
341				
342				
343				

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CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

344	(a) Remediation Technology			
345		(c)	Operating	
346	9 Pond Lane		Capital	
347	Concord, MA 01742		Other	$86,020
348	(b) Environmental & Engineering Consulting		Total	$86,020
349				
350	(a) RLW Analytics Inc			
351		(c)	Operating	
352	17389 Gehricke Road		Capital	
353	Sonoma, CA 95476		Other	$110,470
354	(b) DSM Measurement & Evaluation Consulting		Total	$110,470
355				
356	(a) S B W Consulting Inc			
357		(c)	Operating	
358	2820 Northup Way, Ste 230		Capital	
359	Bellevue, WA 98004		Other	$49,440
360	(b) DSM Measurement & Evaluation Consulting		Total	$49,440
361				
362	(a) SSR Inc. Engineers			
363		(c)	Operating	$14,751
364	E. 1817 Springfield, Suite G		Capital	$90,772
365	Spokane, WA 99202		Other	
366	(b) Consulting Engineers		Total	$105,523
367				
368	(a) Standard & Poor Corp.			
369		(c)	Operating	$1,850
370	25 Broadway		Capital	
371	New York, NY 10004		Other	$34,250
372	(b) Investment Consultants		Total	$36,100
373				
374	(a) Sullivan & Cromwell			
375		(c)	Operating	
376	125 Broad Street		Capital	
377	New York, NY 10004		Other	$39,100
378	(b) Legal		Total	$39,100
379				
380	(a) Synergetic Resources Corporation			
381		(c)	Operating	$888
382	111 Presidential Blvd, Suite 127		Capital	
383	Bala Cynwyd, PA 19004		Other	$45,110
384	(b) DSM Measurement & Evaluation Consulting		Total	$45,998
385				
386	(a) Technical Resource Solution			
387	3900 W. Alameda Avenue	(c)	Operating	$19,925
388	Suite 1700		Capital	$220,992
389	Burbank, CA 91505		Other	
390	(b) Computer Consulting		Total	$240,917
391				
392				
393				

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CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

394	(a)	The OSD Alliance			
395			(c)	Operating	$405,074
396		1365 Westgate Cntr Dr, Suite L-1		Capital	
397		Winston-Salem, NC 27103-2934		Other	
398	(b)	Redesign Consulting		Total	$405,074
399					
400	(a)	The Wyatt Company			
401			(c)	Operating	$9,472
402		1211 SW Fifth Avenue, Suite 2120		Capital	
403		Portland, OR 97204		Other	$71,670
404	(b)	Actuarial Consultants		Total	$81,142
405					
406	(a)	Thomas R. Hughes & Assoc.			
407			(c)	Operating	$25,422
408		9 Buxton Lane		Capital	
409		Riverside, CT 06876		Other	
410	(b)	FERC related consulting		Total	$25,422
411					
412	(a)	Tucson Economic Consulting			
413			(c)	Operating	$85,237
414		7630 North Sultan Place		Capital	
415		Tucson, AZ 85704		Other	
416	(b)	Consulting Engineers		Total	$85,237
417					
418	(a)	Vestra Resources			
419		54 N. Last Chance Gulch	(c)	Operating	
420		Suite 13		Capital	$28,796
421		Helena, MT 59601		Other	
422	(b)	Computer Consulting		Total	$28,796
423					
424	(a)	White Runkle Zack			
425			(c)	Operating	$742,254
426		P.O. Box 3868		Capital	
427		Spokane, WA 99220		Other	$2,940
428	(b)	Advertising Consultants		Total	$745,194
429					
430	(a)	WSU			
431		240 French	(c)	Operating	
432		Administration Building		Capital	$63,525
433		Pullman, WA 99164-1025		Other	
434	(b)	Consulting Engineers		Total	$63,525
435					
436	(a)				
437			(c)	Operating	
438				Capital	
439				Other	
440	(b)			Total	
441					
442					
443					

Sch. 13	POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS			
	Description	Total Company	Montana	% Montana
1				
2				
3	ENERGY ASSOCIATES - PAC			
4				
5	Friends of Racicot - Martz	400	400	100.00%
6				
7				
8				
9				
10				
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14				
15				
16				
17				
18				
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48				
49				
50	**TOTAL**	400	400	100.00%

Sch. 14 PENSION COSTS

	Description	Last Year	This Year	% Change
1				
2	Plan Name: The Retirement Plan for			
3	The Washington Water Power Company			
4	Defined Benefit Plan: _____X______			
5				
6	Defined Contribution Plan __Yes_____			
7				
8	Is the Plan overfunded? __________			
9				
10	Actuarial Cost Method ________Yes_____________			
11				
12	IRS Code: 001			
13				
14	Annual Contribution by Employer $0			
15				
16				
17	Accumulated Benefit Obligation	90,341,000	116,877,000	29.37%
18	Projected Benefit Obligation	107,540,000	133,233,000	23.89%
19	Fair Value of Plan Assets	119,706,000	140,528,000	17.39%
20				
21	Discount Rate for Benefit Obligations	8.50%	7.50%	-11.76%
22	Expected Long-Term Return on Assets	9.00%	9.00%	0.00%
23				
24	Net Periodic Pension Cost:			
25	Service Cost	4,323,000	3,464,000	-19.87%
26	Interest Cost	8,523,000	9,142,000	7.26%
27	Return on Plan Assets	(248,000)	(27,910,000)	
28	Amortization of Transition Amount	(11,553,000)	17,272,000	249.50%
29	Amortization of Gains or Losses			
30	Total Net Periodic Pension Cost	1,045,000	1,968,000	88.33%
31				
32	Minimum Required Contribution			
33	Actual Contribution			
34	Maximum Amount Deductible			
35	Benefit Payments	6,359,374	7,087,772	11.45%
36				
37	Montana Intrastate Costs:			
38	Pension Costs	Not Available By State		
39	Pension Costs Capitalized			
40	Accumulated Pension Asset (Liability) at Year End			
41				
42	Number of Company Employees:			
43	Covered by the Plan	2,231	2,296	2.91%
44	Not Covered by the Plan			
45	Active	1,319	1,345	1.97%
46	Retired	642	703	9.50%
47	Deferred Vested Terminated	199	248	24.62%

Sch. 15 OTHER POST EMPLOYMENT BENEFITS (OPEBS)

	Description	Last Year	This Year	% Change
1	General Information			
2				
3	Assumptions:			
4	Discount Rate for Benefit Obligations	8.50%	7.50%	-11.76%
5	Expected Long-Term Return on Assets	0.00%	0.00%	
6	Medical Cost Inflation Rate	10.00%	8.00%	-20.00%
7	Actuarial Cost Method	Projected	Projected	
8		Unit Credit	Unit Credit	
9	List each method used to fund OPEBs (ie: VEBA, 401(h)):			
10	Method - Tax Advantaged (Yes or No)			
11				
12	VEBA Yes			
13				
14				
15				
16	Describe Changes to the Benefit Plan:			
17				
18				
19				
20	Total Company			
21		31,072,000	28,718,000	
22	Accumulated Post Retirement Benefit Obligation (APBO)			
23	Fair Value of Plan Assets	32,000	4,772,184	14813.08%
24	List the amount funded through each funding method:			
25	VEBA	32,000	4,772,184	14813.08%
26	401(h)			
27	Other ____________			
28	Total amount funded	32,000	4,772,184	14813.08%
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	802,000	573,000	-28.55%
38	Interest Cost	2,596,000	2,452,000	-5.55%
39	Return on Plan Assets		(226,000)	
40	Amortization of Transition Obligation	1,606,000	1,414,000	-11.96%
41	Amortization of Gains or Losses			
42	Total Net Periodic Post Retirement Benefit C	5,004,000	4,213,000	-15.81%
43				
44	Benefit Cost Expensed			
45	Benefit Cost Capitalized			
46	Benefit Payments			
47				
48	Number of Company Employees:			
49	Covered by the Plan	2,231	2,296	2.91%
50	Not Covered by the Plan			
51	Active	1,319	1,328	0.68%
52	Retired	616	703	14.12%
53	Spouse/Dependants covered by the Plan			

	Description	Last Year	This Year	% Change
1				
2	Montana	Not Available By State		
3				
4	Accumulated Post Retirement Benefit Obligation (APBO)			
5	Fair Value of Plan Assets			
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			
20	Interest Cost			
21	Return on Plan Assets			
22	Amortization of Transition Obligation			
23	Amortization of Gains or Losses			
24	Total Net Periodic Post Retirement Benefit C	0	0	
25				
26	Benefit Cost Expensed			
27	Benefit Cost Capitalized			
28	Benefit Payments			
29				
30	Number of Company Employees:			
31	Covered by the Plan			
32	Not Covered by the Plan			
33	Active			
34	Retired			
35	Spouse/Dependants covered by the Plan			
36				
37	Regulatory Treatment			
38				
39	Commission authorized - most recent			
40	Docket number:			
41	Order number:			
42				
43	Amount recovered through rates			

Sch. 16	TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)						
	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	P.A. Kelly Journey Operator - Noxon	52,057	0	3,361	55,418	53,853	3%
2	J.G. Hanna Station Electrician - Noxon	45,795	0	6,040	51,835	56,215	-8%
3	T.J. Swant License Environ-mental Coordinator	51,829	0	0	51,829	47,569	9%
4	P.J. Aketpy Station Mechanic - Noxon	47,756	0	3,972	51,728	53,703	-4%
5	W.A. Maxvill, Jr. Journeyman Operator Noxon	48,933	0	2,415	51,348	47,328	8%
6	M. Bonney Journeyman Operator Noxon	49,548	0	1,447	50,995	46,276	10%
7	J.L. Garner Journeyman Operator Noxon	47,294	0	2,131	49,425	48,957	1%
8	R. Robbins Journeyman Operator Noxon	47,421	0	1,951	49,372	47,125	5%
9	C.F. Webly Journeyman Operator Noxon	47,978	0	1,365	49,343	48,428	2%
10	D.W. Thomason Journeyman Operator Noxon	47,649	0	1,501	49,150	49,579	-1%

NOTES TO FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations
The Company was incorporated in the State of Washington in 1889, and is primarily engaged as a utility in the generation, purchase, transmission, distribution and sale of electric energy and the purchase, transportation, distribution and sale of natural gas. Natural gas operations are affected to a significant degree by weather conditions and customer growth. The Company's electric operations are highly dependent upon hydroelectric generation for its power supply. As a result, the electric operations of the Company are significantly affected by weather and streamflow conditions and, to a lesser degree, by customer growth. Revenues from new wholesale contracts and the sale of surplus energy to other utilities and the cost of power purchases vary from year to year depending on streamflow conditions and the wholesale power market. The wholesale power market in the Northwest region is affected by several factors, including the availability of water for hydroelectric generation, the availability of base load plants in the region and the demand for power in the Southwest region. Other factors affecting the wholesale power market include new entrants in the wholesale market, such as power brokers and marketers, and competition from low cost generation being developed by independent power producers. Usage by retail customers varies from year to year primarily as a result of weather conditions, the economy in the Company's service area, customer growth, conservation, appliance efficiency and other technology.

Basis of Reporting
The accounting requirements of FERC as set forth in theses financial statements differ from generally accepted accounting prinicples in that the Company accounts for its investment in majority owned subsisiaries on the equity method rather than consolidating the assets, liabilities, revenues and expenses of those subsidiaries. The Company is not presenting comparative statements of retained earnings and cash flows as would be required under generally accepted accounting principles. The accompanying financial statements include the Company's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants (See Note 3). The financial activity of each of the Company's segments is reported in the "Schedule of Information by Business Segments." Such information is an integral part of these financial statements.

The preparation of the Company's consolidated financial statements in conformity with generally accepted accounting principles necessarily requires management to make estimates and assumptions that directly affect the reported amounts of assets, liabilities, revenues and expenses.

System of Accounts
The accounting records of the Company's utility operations are maintained in accordance with the uniform system of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and adopted by the appropriate state regulatory commissions.

Regulation
The Company is subject to state regulation in Washington, Idaho and Montana for its electric operations. Natural gas operations are regulated in Washington, Idaho, Oregon and California. The Company is subject to regulation by the FERC with respect to its wholesale electric transmission rates and the natural gas rates charged for the release of capacity from the Jackson Prairie Storage Project.

Operating Revenues
The Company accrues estimated unbilled revenues for electric and natural gas services provided through month-end.

Earnings Per Share
Earnings per share have been computed based on the weighted average number of common shares outstanding during the period.

Utility Plant
The cost of additions to utility plant, including an allowance for funds used during construction and replacements of units of property and betterments, is capitalized. Costs of depreciable units of property retired plus costs of removal less salvage are charged to accumulated depreciation.

Allowance for Funds Used During Construction
The Allowance for Funds Used During Construction (AFUDC) represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. In accordance with the uniform system of accounts prescribed by regulatory authorities, AFUDC is capitalized as a part of the cost of utility plant and is credited currently as a noncash item to Other Income (see Other Income above). The Company generally is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a fair return thereon, through its inclusion in rate base and the provision for depreciation after the related utility plant has been placed in service. Cash inflow related to AFUDC does not occur until the related utility plant investment is placed in service.

The effective AFUDC rate was 10.67% in 1995, 1994 and 1993. The Company's AFUDC rates do not exceed the maximum allowable rates as determined in accordance with the requirements of regulatory authorities.

Depreciation
For utility operations, depreciation provisions are estimated by a method of depreciation accounting utilizing unit rates for hydroelectric plants and composite rates for other properties. Such rates are designed to provide for retirements of properties at the expiration of their service lives. The rates for hydroelectric plants include annuity and interest components, in which the interest component is 6%. For utility operations, the ratio of depreciation provisions to average depreciable property was 2.57% in 1995, 2.56% in 1994 and 2.68% in 1993.

Cash and Cash Equivalents
For the purposes of the Consolidated Statements of Cash Flows, the Company considers all temporary investments with an initial maturity of three months or less to be cash equivalents.

Derivative Financial Instruments
The Company has used derivative instruments to a limited extent as a means of hedging its costs and preserving margins in the wholesale power business. The extent of derivatives used through the end of 1995 is not significant. The Company may continue to use derivative instruments for hedging and risk mitigation purposes, but has adopted a policy not to trade in derivatives for speculative reasons.

Deferred Charges and Credits
The Company prepares its financial statements in accordance with the provisions of FAS No. 71, "Accounting for the Effects of Certain Types of Regulation." A regulated enterprise can prepare its financial statements in accordance with FAS No. 71 only if (i) the enterprise's rates for regulated services are established by or subject to approval by an independent third-party regulator, (ii) the regulated rates are designed to recover the enterprise's cost of providing the regulated services and (iii) in view of demand for the regulated services and the level of competition, it is reasonable to assume that rates set at levels that will recover the enterprise's costs can be charged to and collected from customers. FAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements. In certain circumstances, FAS No. 71 requires that certain costs and/or obligations (such as incurred costs not currently recovered through rates, but expected to be so recovered in the future) be reflected in a deferral account in the balance sheet and not be reflected in the statement of income or loss until matching revenues are recognized. If at some point in the future the Company determines that it no longer meets the criteria for continued application of FAS No. 71 to all or a portion of the Company's regulated operations, the Company would be required to write off its regulatory assets and would be precluded from the future deferral in the Balance Sheet of costs not recovered through rates at the time such costs were incurred, even if such costs were expected to be recovered in the future.

The Company's primary regulatory assets include Investment in Exchange Power, conservation programs, deferred income taxes, the provision for postretirement benefits, unrecovered purchased gas costs and debt issuance and redemption costs. Included in Deferred Charges, Other are merger transaction and transition costs. Deferred credits include the gain on the general office building sale/leaseback being amortized over the life of the lease.

Power and Natural Gas Cost Adjustment Provisions
In 1989, the Idaho Public Utilities Commission (IPUC) approved the Company's filing for a power cost adjustment mechanism (PCA). The PCA is designed to allow the Company to modify electric rates to recover or rebate a portion of the difference between actual and allowed net power supply costs. On July 18, 1994, the IPUC approved an indefinite extension of the Company's proposed modifications to the PCA. The modified PCA tracks changes in hydroelectric generation, secondary prices, related changes in thermal generation and PURPA contracts, but it no longer tracks changes in revenues or cost associated with other wheeling or power contracts. Rate changes are triggered when the deferred balance reaches $2.2 million. As of December 31, 1995, $0.7 million of credits not yet subject to a rebate had accumulated in the PCA deferral account. The following surcharges were in effect during the past three years:

$2.3 million (2.4%) surcharge effective September 1, 1995, which will expire August 31, 1996
$2.2 million (2.5%) surcharge effective January 1, 1995, which expired December 31, 1995
$2.3 million (2.6%) surcharge effective November 1, 1992, which expired October 31, 1993

Under established regulatory practices, the Company is also allowed to adjust its natural gas rates from time to time to reflect increases or decreases in the cost of natural gas purchased. Differences between actual natural gas costs and the natural gas costs allowed in rates are deferred and charged or credited to expense when regulators approve inclusion of the cost changes in rates.

Income Taxes
The Company and its eligible subsidiaries file consolidated federal income tax returns. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis. The Company's federal income tax returns have been examined with all issues resolved, and all payments made, through the 1992 return.

New Accounting Standards
FAS No. 121, entitled "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," was issued by the Financial Accounting Standards Board (FASB), and is effective for fiscal years beginning after December 15, 1995. FAS No. 121 requires the review of certain assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If an asset is determined to be impaired, a loss is recognized. The Company will adopt the standard on January 1, 1996, but does not expect any material impact on the Company's financial position or results of operations. The Company will continue to periodically review its assets to determine whether any assets meet the requirements for impairment recognition under this standard.

FAS No. 123, entitled "Accounting for Stock-Based Compensation," which is effective for fiscal years beginning after December 15, 1995, addresses the recommended accounting and disclosure for stock-based employee compensation plans. The Company will adopt the standard on January 1, 1996, but will continue to measure stock-based compensation according to Accounting Principles Board Opinion (APB) 25.

NOTE 2. PROPERTY, PLANT AND EQUIPMENT

The year-end balances of the major classifications of property, plant and equipment are detailed in the following table (dollars in thousands):

	At December 31, 1995	1994
Electric:		
Production	$ 691,192	$ 678,356
Transmission	248,587	238,912
Distribution	510,489	458,867
Construction work in progress (CWIP) and other	73,119	101,863
Electric total	1,523,387	1,477,998
Natural Gas:		
Underground storage	16,385	14,946
Transmission	3,060	3,090
Distribution	276,295	253,830
CWIP and other	46,207	45,108
Natural Gas total	341,947	316,974
Common plant (including CWIP)	38,332	34,624
Total utility	1,903,666	1,829,596
Non-utility	60,498	56,466
Total	$1,964,164	$1,886,062

NOTE 3. JOINTLY OWNED ELECTRIC FACILITIES

The Company has invested in several jointly owned generating plants. Financing for the Company's ownership in the projects is provided by the Company. The Company's share of related operating and maintenance expenses for plants in service is included in corresponding accounts in the Consolidated Statements of Income. The following table indicates the Company's percentage ownership and the extent of the Company's investment in such plants at December 31, 1995:

			Company's Current Share of				
Project	KW of Installed Capacity	Fuel Source	Ownership (%)	Plant in Service	Accumulated Depreciation	Net Plant In Service	Construction Work in Progress
					(Thousands of Dollars)		
Centralia	1,330,000	Coal	15%	$ 55,197	$32,683	$ 22,514	$1,337
Colstrip 3 & 4	1,556,000	Coal	15	272,338	88,205	184,133	-

NOTE 4. ACCOUNTS RECEIVABLE SALE

The Company has entered into an agreement whereby it can sell without recourse, on a revolving basis, up to $40,000,000 of interests in certain accounts receivable, both billed and unbilled. The Company is obligated to pay fees which approximate the purchaser's cost of issuing commercial paper equal in value to the interests in receivables sold. The amount of such fees is included in operating expenses. At both December 31, 1995 and 1994, $40,000,000 in receivables had been sold pursuant to the agreement.

NOTE 5. COMMON STOCK

In April 1990, the Company sold 1,000,000 shares of its common stock to the Trustee of the Investment and Employee Stock Ownership Plan for Employees of the Company (Plan) for the benefit of the participants and beneficiaries of the Plan. In payment for the shares of Common Stock, the Trustee issued a promissory note payable to the Company in the amount of $14,125,000. Dividends paid on the stock held by the Trustee, plus Company contributions to the Plan, if any, are used by the Trustee to make interest and principal payments on the promissory note. The balance of the promissory note receivable from the Trustee ($11,690,250 at December 31, 1995) is reflected as a reduction to common equity. The shares of Common Stock are allocated to the accounts of participants in the Plan as the note is repaid. During 1995, the cost recorded for the Plan was $2,857,000. This included the cost for an additional 304,353 shares which were issued for ongoing employee and Company contributions to the Plan. Interest on the note payable to the Company, cash and stock contributions to the Plan and dividends on the shares held by the Trustee were $1,146,000, $2,350,000 and $1,215,000, respectively.

In February 1990, the Company adopted a shareholder rights plan, which was subsequently amended, pursuant to which holders of Common Stock outstanding on March 2, 1990, or issued thereafter, have been granted one preferred share purchase right (Right) on each outstanding share of Common Stock. Each Right, initially evidenced by and traded with the shares of Common Stock, entitles the registered holder to purchase one two-hundredth of a share of Preferred Stock of the Company, without par value, at an exercise price of $40, subject to certain adjustments, regulatory approval and other specified conditions. The Rights will be exercisable only if a person or group acquires 10% or more of the Common Stock or announces a tender offer, the consummation of which would result in the beneficial ownership by a person or group of 10% or more of the Common Stock. The Rights may be redeemed, at a redemption price of $0.005 per Right, by the Board of Directors of the Company at any time until any person or group has acquired 10% or more of the Common Stock. The Rights will expire on the earlier of February 16, 2000 or the effective time of the merger with Sierra Pacific Resources (SPR), Sierra Pacific Power Company (SPPC) and Altus Corporation (Altus). See Note 16 for additional information about the proposed merger.

During 1992, the Company received authorization to issue 1.5 million shares of Common Stock under a second Periodic Offering Program (POP). In 1993, 576,400 shares of the POP were issued for net proceeds of $11.2 million. Through December 31, 1993, 927,600 shares of the POP were issued for net proceeds of $17.3 million. No shares were issued under the POP during 1994 or 1995. At December 31, 1995, 572,400 shares remained authorized but unissued.

The Company has a Dividend Reinvestment and Stock Purchase Plan under which the Company's stockholders may automatically reinvest their dividends and make optional cash payments for the purchase of the Company's Common Stock at current market value.

Sales of Common Stock for 1995, 1994 and 1993 are summarized below (in thousands of dollars):

	1995		1994		1993	
	Shares	Amount	Shares	Amount	Shares	Amount
Balance at January 1	54,420,696	$570,603	52,757,545	$544,609	50,888,130	$508,202
Employee Investment Plan (401-K)	304,353	4,718	272,278	4,302	165,335	3,216
Dividend Reinvestment Plan	1,222,918	19,315	1,390,873	21,692	1,127,680	21,779
Periodic Offering	-	-	-	-	576,400	11,412
Total Issues	1,527,271	24,033	1,663,151	25,994	1,869,415	36,407
Balance at December 31	55,947,967	$594,636	54,420,696	$570,603	52,757,545	$544,609

NOTE 6. PREFERRED STOCK

Cumulative Preferred Stock Not Subject to Mandatory Redemption:
The dividend rate on Flexible Auction Preferred Stock, Series J is reset every 49 days based on an auction. During 1995, the dividend rate varied from 4.410% to 5.150% and at December 31, 1995, was 5.150%. Series J is subject to redemption at the Company's option at a redemption price of 100% per share plus accrued dividends.

Cumulative Preferred Stock Subject to Mandatory Redemption:

Redemption requirements:

$8.625, Series I - On June 15, 1996, 1997, 1998, 1999 and 2000, the Company must redeem 100,000 shares at $100 per share plus accumulated dividends. The Company may, at its option, redeem up to 100,000 shares in addition to the required redemption on any redemption date.

$6.95, Series K - On September 15, 2002, 2003, 2004, 2005 and 2006, the Company must redeem 17,500 shares at $100 per share plus accumulated dividends through a mandatory sinking fund. Remaining shares must be redeemed on September 15, 2007. The Company has the right to redeem an additional 17,500 shares on each September 15 redemption date.

There are $50 million in mandatory redemption requirements during the 1996-2000 period.

The fair value of the Company's preferred stock at December 31, 1995 and 1994 is estimated to be $139.8 million, or 104% of the carrying value and $135.1 million, or 100% of the carrying value, respectively. These estimates are based on available market information.

NOTE 7. LONG-TERM DEBT

The annual sinking fund requirements and maturities for the next five years for First Mortgage Bonds outstanding at December 31, 1995 are as follows:

Year Ended December 31	Maturities	Sinking Fund Requirements	Total
		(Thousands of Dollars)	
1996..................	$35,000	$4,747	$39,747
1997..................	31,000	4,547	35,547
1998..................	10,000	4,437	14,437
1999..................	47,500	4,437	51,937
2000..................	35,000	4,287	39,287

The sinking fund requirements may be met by certification of property additions at the rate of 167% of requirements. All of the utility plant is subject to the lien of the Mortgage and Deed of Trust securing outstanding First Mortgage Bonds.

In 1993, $25,000,000 of Unsecured Medium-Term Notes were issued. At December 31, 1995, the Company had outstanding $207,500,000 of such notes with maturities between 1 and 28 years and with interest rates varying between 5.50% and 9.58%.

In 1995, 1994 and 1993, $78,000,000, $88,000,000 and $225,000,000, respectively, of First Mortgage Bonds in the form of Secured Medium-Term Notes were issued. At December 31, 1995, the Company had outstanding $391,000,000 of such notes with maturities between 1 and 28 years and with interest rates varying between 4.72% and 8.25%. As of December 31, 1995, the Company had remaining authorization to issue up to $109,000,000.

At December 31, 1995, the Company had $29,500,000 outstanding under borrowing arrangements which will be refinanced in 1996. See Note 8 for details of credit agreements.

The fair value of the Company's long-term debt at December 31, 1995 and 1994 is estimated to be $733.2 million, or 107% of the carrying value and $673.0 million, or 93% of the carrying value, respectively. These estimates are based on available market information.

NOTE 8. BANK BORROWINGS AND COMMERCIAL PAPER

At December 31, 1995, the Company maintained total lines of credit with various banks under two separate credit agreements amounting to $160,000,000. The Company has one revolving line of credit, expiring December 9, 1997, which provides a total credit commitment of $70,000,000. The second revolving credit agreement is composed of two tranches totaling $90,000,000. One tranche provides for up to $50,000,000 of notes to be outstanding at any one time, while the other provides for up to $40,000,000 of notes to be outstanding at any one time. Both tranches of this agreement expire on July 24, 1996. The Company pays commitment fees of up to 0.15% per annum on the average daily unused portion of each credit agreement.

In addition, under various agreements with banks, the Company can have up to $60,000,000 in loans outstanding at any one time, with the loans available at the banks' discretion. These arrangements provide, if funds are made available, for fixed-term loans for up to 180 days at a fixed rate of interest. In December 1994, the Company terminated its commercial paper program.

Balances and interest rates of bank borrowings under these arrangements were as follows:

	Years Ended December 31,	
	1995	1994
	(Dollars in thousands)	
Balance outstanding at end of period:		
Fixed-term loans	$ 10,000	$ 33,000
Revolving credit agreement	19,500	25,000
Maximum balance during period:		
Fixed-term loans	$ 10,000	$ 52,000
Commercial paper	-	20,000
Revolving credit agreement	28,500	32,000
Average daily balance during period:		
Fixed-term loans	$ 5,484	$ 29,373
Revolving credit agreement	13,886	10,941
Average annual interest rate during period:		
Fixed-term loans	6.15%	4.64%
Revolving credit agreement	6.11	4.49
Average annual interest rate at end of period:		
Fixed-term loans	6.06%	6.28%
Revolving credit agreement	6.08	6.28

NOTE 9. LEASES

The Company has entered into several lease arrangements involving various assets, with minimum terms ranging from eleven months to seventeen years and expiration dates from 1995 to 2011. Certain of the lease arrangements require the Company, upon the occurrence of specified events, to purchase the leased assets for varying amounts over the term of the lease. The Company's management believes that the likelihood of the occurrence of the specified events under which the Company could be required to purchase the property is remote. Rent expense for the years ended December 31, 1995, 1994 and 1993 was $10.7 million, $2.3 million and $1.9 million, respectively. Future minimum lease payments (in thousands of dollars) required under operating leases that have initial or remaining noncancelable lease terms in excess of one year as of December 31, 1995 are estimated as follows:

Year ending December 31:	
1996	$ 8,450
1997	7,635
1998	1,847
1999	2,257
2000	2,257
Later years	24,829
Total minimum payments required	$ 47,275

The Company also has various other operating leases, which are charged to operating expense, consisting of a large number of small, relatively short-term, renewable agreements for various items, such as office equipment and office space.

NOTE 10. PENSION PLANS

The Company has a pension plan covering substantially all of its regular full-time employees. Certain of the Company's subsidiaries also participate in this plan. Individual benefits under this plan are based upon years of service and the employee's average compensation as specified in the Plan. The Company's funding policy is to contribute annually an amount equal to the net periodic pension cost, provided that such contributions are not less than the minimum amounts required to be funded under the Employee Retirement Income Security Act, nor more than the maximum amounts which are currently deductible for tax purposes. Pension fund assets are invested primarily in marketable debt and equity securities. The Company also has another plan which covers the executive officers.

Net pension cost (income) for 1995, 1994 and 1993 is summarized as follows:

	1995	1994	1993
	(Thousands of Dollars)		
Service cost-benefits earned during the period	$ 3,464	$ 4,323	$ 3,150
Interest cost on projected benefit obligation	9,142	8,523	7,771
Actual return on plan assets	(27,910)	(248)	(15,108)
Net amortization and deferral	17,272	(11,553)	3,717
Net periodic pension cost (income)	$ 1,968	$ 1,045	$ (470)

The funded status of the Plans and the pension liability at December 31, 1995, 1994 and 1993, are as follows:

	1995	1994	1993
	(Thousands of dollars)		
Actuarial present value of benefit obligation:			
Accumulated benefit obligation (including vested benefits of $(114,964,000), $(88,596,000) and $(84,531,000), respectively)	$(116,877)	$ (90,341)	$ (85,368)
Projected benefit obligation for service rendered to date	$(133,233)	$(107,540)	$(104,025)
Plan assets at fair value	140,528	119,706	126,879
Plan assets in excess of projected benefit obligation	7,295	12,166	22,854
Unrecognized net gain from returns different than assumed	(19,704)	(17,939)	(21,503)
Prior service costs not yet recognized	18,385	14,803	7,983
Unrecognized net transition asset at year-end (being amortized over 11 to 19 years)	(10,273)	(11,359)	(12,445)
Regulatory deferrals	-	(1,841)	(3,256)
Pension liability	$ (4,297)	$ (4,170)	$ (6,367)

Assumptions used in calculations were:

Discount rate at year-end	7.5%	8.5%	7.5%
Rate of increase in future compensation level	4.0%	4.0%	4.0%
Expected long-term rate of return on assets	9.0%	9.0%	9.0%

NOTE 11. OTHER POSTRETIREMENT BENEFITS

FAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," requires the Company to accrue the estimated cost of postretirement benefit payments during the years that employees provide services and allows recognition of the unrecognized transition obligation in the year of adoption or the amortization of such obligation over a period of up to twenty years. The Company elected to amortize this obligation of approximately $34,500,000 over a period of twenty years, beginning in 1993.

The Company has received accounting orders from the Washington Utilities and Transportation Commission (WUTC) and the IPUC allowing the current deferral of expense accruals under this Statement as a regulatory asset for future recovery. At such time that rate recovery is requested and allowed, cumulative deferrals will be amortized over the remainder of the twenty-year amortization period. The Company expects to be able to recover the amortized amounts. Therefore, the Company's cash flows and income from operations were not affected by implementation of this Statement through 1995. The Company will begin recognition of the expense accruals in 1996.

The Company provides certain health care and life insurance benefits for substantially all of its retired employees. In 1995, 1994 and 1993, the Company recognized $1,800,000, $1,270,000 and $1,250,000, respectively, as an expense for postretirement health care and life insurance benefits. The following table sets forth the health care plan's funded status at December 31, 1995, 1994 and 1993.

Accumulated postretirement benefit obligation (thousands of dollars):

	1995	1994	1993
Retirees	617	642	620
Active plan participants	1,328	1,319	1,341
Total participants	1,945	1,961	1,961
Unfunded accumulated postretirement benefit obligation	$(28,718)	$(31,072)	$(39,595)
Unrecognized (gain)/loss	(3,396)	(4,897)	1,886
Unrecognized transition obligation	27,288	28,894	33,600
Accrued postretirement benefit cost	$ (4,826)	$ (7,075)	$ (4,109)

Net postretirement benefit cost for 1995, 1994 and 1993 (thousands of dollars):

	1995	1994	1993
Service cost - benefits earned during the period	$ 573	$ 802	$1,156
Return on the plan assets (if any)	(226)	-	-
Interest cost on accumulated postretirement benefit obligation	2,452	2,596	3,006
Amortization of transition obligation	1,414	1,606	1,769
Total net periodic cost	$4,213	$5,004	$5,931

The currently assumed health care cost trend rate used in measuring the accumulated postretirement benefit obligation is 8.0% for 1995, decreasing linearly each successive year until it reaches 5.0% in 1999. The assumed rate of future medical cost increases has been gradually decreased since the adoption of FAS 106 in response to the actual leveling off of cost increases in the plan. A one-percentage-point increase in the assumed health care cost trend rate for each year would increase the accumulated postretirement benefit obligation as of December 31, 1995 and net postretirement health care cost by approximately $2,299,000. The assumed discount rate used in determining the accumulated postretirement benefit obligation was 7.5%.

NOTE 12. ACCOUNTING FOR INCOME TAXES

As of December 31, 1995 and 1994, the Company had recorded net regulatory assets of $169,432,000 and $174,349,000, respectively, related to the probable recovery of FAS No. 109, "Accounting for Income Taxes," deferred tax liabilities from customers through future rates. Such net regulatory assets will be adjusted by amounts recovered through rates.

Deferred income taxes reflect the net tax effects of (a) temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes, and (b) tax credit carryforwards. The net deferred federal income tax liability consists of the following (thousands of dollars):

	1995	1994	1993
Deferred tax liabilities:			
Differences between book and tax bases of utility plant	$320,502	$317,991	$297,175
Loss on reacquired debt	7,173	8,216	9,243
Deferred natural gas credits	-	1,095	2,679
Other	10,013	8,957	5,575
Total deferred tax liabilities	337,688	336,259	314,672
Deferred tax assets:			
Reserves not currently deductible	15,742	14,429	14,486
Contributions in aid of construction	4,634	3,710	2,975
Deferred natural gas credits	3,894	-	-
Gain on sale of office building	1,463	1,555	1,647
Other	4,426	6,398	6,659
Total deferred tax assets	30,159	26,092	25,767
Net deferred tax liability	$307,529	$310,167	$288,905

A reconciliation of federal income taxes derived from statutory tax rates applied to income from continuing operations and federal income tax as set forth in the accompanying Consolidated Statements of Income and Retained Earnings is as follows (the current and deferred effective tax rates are approximately the same during all periods):

	For the Years Ended December 31,		
	1995	**1994**	**1993**
		(Thousands of Dollars)	
Computed federal income taxes at statutory rate	$47,875	$41,983	$43,363
Increase (decrease) in tax resulting from:			
Accelerated tax depreciation	(909)	1,725	(2,229)
Equity earnings in affiliates	-	(497)	(560)
Other	1,297	(1,320)	1,684
Total federal income tax expense*	$48,263	$41,891	$42,258
Income Tax Expense Consists of the Following:			
Federal taxes currently provided	$48,318	$32,334	$34,749
Deferred income taxes	(55)	9,557	7,509
Total federal income tax expense	48,263	41,891	42,258
State income tax expense	4,153	2,805	245
Federal and state income taxes	$52,416	$44,696	$42,503

*Federal Income Tax Expense:			
Utility	$41,203	$35,513	$36,385
Non-utility	7,060	6,378	5,873
Total Federal Income Tax Expense	$48,263	$41,891	$42,258
Federal statutory rate	35%	35%	35%

NOTE 13. LONG-TERM PURCHASED POWER CONTRACTS WITH REQUIRED MINIMUM PAYMENTS

Under fixed contracts with Public Utility Districts (PUD), the Company has agreed to purchase portions of the output of certain generating facilities. Although the Company has no investment in such facilities, these contracts provide that the Company pay certain minimum amounts (which are based at least in part on the debt service requirements of the supplier) whether or not the facility is operating. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in operations and maintenance expense in the Statement of Income. Information as of December 31, 1995, pertaining to these contracts is summarized in the following table:

	Company's Current Share of					
	Output	Kilowatt Capability	Annual Costs(2)	Debt Service Costs(3)	Revenue Bonds Outstanding	Contract Expiration Date
			(Thousands of Dollars)			
PUD Contracts:						
Chelan County PUD:						
Lake Chelan Project	100.0% (1)	58,000	$1,933	$ 258	$ -	1995
Rocky Reach Project	2.9	37,000	1,166	556	3,617	2011
Grant County PUD:						
Priest Rapids Project	6.1	55,000	1,766	1,132	7,830	2005
Wanapum Project	8.2	75,000	2,194	1,460	15,009	2009
Douglas County PUD:						
Wells Project	3.9	30,000	1,021	608	7,392	2018
Totals		255,000	$8,080	$4,014	$33,848	

(1) The Company purchased 100% of the Lake Chelan Project output and sold back to the PUD about 40% of the output to supply local service area requirements. The contract expired during 1995.

(2) The annual costs will change in proportion to the percentage of output allocated to the Company in a particular year. Amounts represent the operating costs for the year 1995.

(3) Included in annual costs.

Actual expenses for payments made under the above contracts for the years 1995, 1994 and 1993, were $8,080,000, $8,717,000 and $8,721,000, respectively. The estimated aggregate amounts of required minimum payments (the Company's share of debt service costs) under the above contracts for the next five years are $3,684,000 in 1996, $3,860,000 in 1997, $5,555,000 in 1998, $5,594,000 in 1999 and $6,948,000 in 2000 (minimum payments thereafter are dependent on then market conditions). In addition, the Company will be required to pay its proportionate share of the variable operating expenses of these projects.

NOTE 14. COMMITMENTS AND CONTINGENCIES

Nez Perce Tribe

On December 6, 1991, the Nez Perce Tribe filed an action against the Company in U. S. District Court for the District of Idaho alleging, among other things, that two dams formerly operated by the Company, the Lewiston Dam on the Clearwater River and the Grangeville Dam on the South Fork of the Clearwater River, provided inadequate passage to migrating anadromous fish in violation of rights under treaties between the Tribe and the United States made in 1855 and 1863. The Lewiston and Grangeville Dams, which had been owned and operated by other utilities under hydroelectric licenses from the Federal Power Commission (the "FPC", predecessor of the FERC) prior to acquisition by the Company, were acquired by the Company in 1937 with the approval of the FPC, but were dismantled and removed in 1973 and 1963, respectively. The Tribe initially indicated through expert opinion disclosures that they were seeking actual and punitive damages of $208 million. However, supplemental disclosures reflect allegations of actual loss under different assumptions of between $425 million and $650 million.

Discovery had been stayed pending a decision by the Court on a case involving some similar issues brought by the Tribe against Idaho Power Company. The Court has since decided these issues and has dismissed all claims against Idaho Power. The Idaho Power case has now been appealed by the Nez Perce Tribe to the Ninth Circuit Court of Appeals. On November 21, 1994, the Company filed its Motion and Brief in Support of Summary Judgment of Dismissal. The Nez Perce Tribe has filed a reply brief, and has requested oral argument. A hearing on the Company's Motion for Summary Judgment was held by the Court on July 27, 1995. On September 22, 1995, the federal magistrate issued a written opinion recommending to the District Court that the Company's Motion for Summary Judgment be granted and the Tribe's claims dismissed. The matter is still pending before the District Court. The case has not yet been set for trial. The Company is presently unable to assess the likelihood of an adverse outcome in this litigation, or estimate an amount or range of potential loss in the event of an adverse outcome.

Oil Spill

The Company completed an updated investigation of an oil spill from an underground storage tank that occurred several years ago in downtown Spokane at the site of the Company's steam heat plant. The Company purchased the plant in 1916 and operated it as a non-regulated plant until it was deactivated in 1986 in a business decision unrelated to the spill. After the Bunker C fuel oil spill, initial studies suggested that the oil was being adequately contained by both geological features and man-made structures. The Washington State Department of Ecology (DOE) concurred with these findings. However, more recent tests showed that the oil has migrated approximately one city block beyond the steam plant property. On December 6, 1993, the Company asked the DOE to enter into negotiations for a Consent Decree which provided for additional remedial investigation and a feasibility study. The Consent Decree, entered on November 8, 1994, provided for 22 additional soil borings to be made around the site, which have been completed. It is anticipated that a clean-up action plan will be approved by the first quarter of 1996 and that the oil spill clean-up will be conducted in 1996. As of December 31, 1995, an accrual of $3.1 million is reflected on the Company's financial statements, which represents the Company's best estimate of its liability.

The Company has completed a remedial investigation/feasibility study (RI/FS) report, which has been submitted to the DOE. The RI/FS report is subject to public review and comment. The report includes a recommended clean-up action plan (RCAP).

On August 17, 1995, a lawsuit was filed against the Company in Superior Court of the State of Washington for Spokane County by Davenport Sun International Hotels and Properties, Inc., the owner of a hotel property in downtown Spokane, Washington. The Complaint alleges that the oil released from the Company's Central Steamplant trespassed on property owned by the plaintiff. In addition, the plaintiff claims that the Steamplant has caused a diminution of value of plaintiff's land. Generally, the Complaint is based on a claim of negligence, trespass and nuisance. Discovery has been initiated by the Company and is in the initial stages. The matter has not been set for trial. The Company is presently unable to assess the likelihood of an adverse outcome in this litigation, or estimate an amount or range of potential loss in the event of an adverse outcome.

Firestorm

On October 16, 1991, gale-force winds struck a five-county area in eastern Washington and a seven-county area in northern Idaho. These winds were responsible for causing 92 separate wildland fires, resulting in two deaths and the loss of 114 homes and other structures, some of which were located in the Company's service territory. Four separate class action lawsuits were filed against the Company by private individuals in the Superior Court of Spokane County on October 13, 1993. These suits concern fires identified as Midway, Golden Cirrus, Nine Mile and Chattaroy. All of these suits were certified as class actions on September 16, 1994, and bifurcated for trial of liability and damage issues by order of the same date. The Company's Motion for Reconsideration was denied on October 21, 1994, and a Motion for Discretionary Review of the Court's decision on certification of class actions was timely filed with the Washington Court of Appeals (Division III) on November 14, 1994.

The Company was also served with two suits in Spokane County Superior Court filed on April 20, 1994 and on September 15, 1994, both of which sought individual damages from separate fires within the Chattaroy Fire complex. Five additional and separate suits were brought by Grange Insurance Company, and were filed in Spokane County Superior Court on October 10, 1994, for approximately $2.2 million paid to Grange insureds for the same fire areas. Two additional class action suits were also filed - one in Lincoln County Superior Court, filed on October 14, 1994, for a fire known as "Nine Mile West" (previously included in the Spokane County Nine Mile suit certified as a class action), and the second in Spokane County Superior Court, filed on October 14, 1994, for the Ponderosa Fire area (which had not been the subject of previous suit). The Lincoln County suit has been transferred to Spokane County and both suits have now also been certified as class actions.

Complainants in all cases allege various theories of tortious conduct, including negligence, creation of a public nuisance, strict liability and trespass; in most cases, complainants allege that fires were caused by electric distribution and/or transmission lines downed by wind-downed trees. The lawsuits seek recovery for property damage, emotional and mental distress, lost income and punitive damages, but do not specify the amount of damages being sought. Discovery is ongoing and the Company is presently unable to assess the likelihood of an adverse outcome or estimate an amount or range of potential loss in the event of an adverse outcome. Trials are scheduled to commence on various dates between February 3, 1997 and November 2, 1998. The Company was previously presented with a claim from the Washington State Department of Natural Resources (DNR) for fire suppression costs associated with five of these fires in eastern Washington. The total of the DNR claim was $1.0 million. On July 22, 1993, the Company entered into a settlement with the DNR whereby the Company agreed to pay $200,000 to DNR in full settlement of any and all DNR claims; however, there was no admission of liability on the part of the Company.

Williams Lake Lawsuit

On December 21, 1995, a lawsuit was commenced in Vancouver, British Columbia against the Company's subsidiary, Pentzer Corporation (Pentzer), by Tondu Energy Systems, Inc. and T.E.S. Williams Lake Partnership alleging contract violations, conspiracy, misrepresentation and breach of fiduciary duties in regard to the 1993 sale of assets of Pentzer Energy Services, Inc. to B.C. Gas, Inc. and a U.S. subsidiary of B.C. Gas. The claims involve an alleged first right to purchase interests in the Williams Lake, British Columbia wood-fired generating station. The suit seeks damages in excess of $10 million, plus exemplary damages, prejudgment interest, costs and attorneys' fees. Also named as defendants are B.C. Gas, Inc., Inland Pacific Energy (Williams Lake) Corp., Pentzer Energy Services, Inc. and WP Energy Company. This action originally had been filed in Spokane Superior Court against each of the same defendants and Washington Water Power. By order dated June 6, 1995, all claims against Washington Water Power were dismissed by that court with prejudice and the claims against the remaining defendants were dismissed without prejudice on the grounds that the lawsuit should have been brought in British Columbia. The Company is presently unable to assess the likelihood of an adverse outcome or estimate an amount or range of potential loss in the event of an adverse outcome.

Other Contingencies

The Company routinely assesses, based on in-depth studies, expert analyses and legal reviews, its contingencies, obligations and commitments for remediation of contaminated sites, including assessments of ranges and probabilities of recoveries from other responsible parties who have and have not agreed to a settlement and recoveries from insurance carriers. The Company's policy is to immediately accrue and charge to current expense identified exposures related to environmental remediation sites based on estimates of investigation, cleanup and monitoring costs to be incurred.

The Company has long-term contracts related to the purchase of fuel for thermal generation, natural gas and hydroelectric power. Terms of the natural gas purchase contracts range from one month to five years and the majority provide for minimum purchases at the then effective market rate. The Company also has various agreements for the purchase, sale or exchange of electric energy with other utilities, cogenerators, small power producers and government agencies.

As of December 31, 1995, the Company's collective bargaining agreement with the International Brotherhood of Electrical Workers represented approximately 47% of employees. The current agreement with the union local representing the majority of the bargaining unit employees expires on March 25, 1997. A local agreement in the South Lake Tahoe area, which represents approximately 7 employees, expires on June 30, 1996.

NOTE 15. ACQUISITIONS AND DISPOSITIONS

During 1995, Pentzer acquired two companies, one that designs and packages point-of-purchase displays and other marketing materials for national manufacturers of consumer products and the other that manufactures and assembles metal and wood products for the computer, video arcade and point-of-purchase industries. In 1994 and 1993, Pentzer acquired two and three companies, respectively. Sales of Pentzer's interest in companies involved in telecommunications, technology and energy services resulted in transactional gains of $7.1 million in 1993.

In 1992, Pentzer's common stock ownership in ITRON was reduced from approximately 60% to approximately 40% as a result of the issuance of common stock by ITRON in an acquisition. Accordingly, beginning in 1992, Pentzer's share of ITRON's earnings was accounted for by the equity method and was included in Other Income-Net and its investment in ITRON was reflected on the balance sheet under Other Property and Investments. ITRON's initial public offering in November 1993 and Pentzer's sales of ITRON stock during 1993 and 1994 resulted in a reduction in Pentzer's ownership interest to approximately 14%. As a result, Pentzer's investment in ITRON, beginning in December 1994, is classified as available for sale and recorded at fair value on the Consolidated Balance Sheets.

On March 1, 1996, a subsidiary of Pentzer sold certain property that was held for sale. The sale resulted in a pre-tax gain of approximately $19.3 million, which will be recognized in the first quarter of 1996.

NOTE 16. PROPOSED MERGER

In June 1994, the Company, Sierra Pacific Resources (SPR), Sierra Pacific Power Company, a subsidiary of SPR (SPPC), and Altus Corporation, a newly formed subsidiary of the Company (Altus, formerly named Resources West Energy Corporation), entered into an Agreement and Plan of Reorganization and Merger, dated as of June 27, 1994, as amended October 4, 1994 which provides for the merger of the Company, SPR and SPPC with and into Altus. In 1994, applications seeking approval of the merger were filed with the Federal Energy Regulatory Commission (FERC) and with the state utility commissions of California, Idaho, Montana, Nevada, Oregon and Washington. The Montana Public Service Commission issued an order in October 1994 declining to exercise jurisdiction. The Company has received orders approving the merger from the commissions of all the other states. On November 29, 1995, the FERC ordered evidentiary hearings concerning the proposed merger. An administrative law judge has been assigned to the merger proceeding and a pre-hearing conference was held on December 13, 1995 to set a procedural schedule. The companies filed supplemental testimony on February 1, 1996. Hearings are scheduled to begin on June 4, 1996. Based on this schedule, the companies believe an order could be issued by the FERC in 1996 or early 1997.

The merger is designed to qualify as a pooling-of-interests for accounting and financial reporting purposes. Under this method of accounting, the recorded assets and liabilities of the Company, SPR and SPPC will be carried forward to consolidated financial statements of Altus at their recorded amounts; income of Altus will include income of the Company, SPR and SPPC for the entire fiscal year in which the merger occurs; and the reported income of the separate corporations for prior periods will be combined and restated as income of Altus.

As of December 31, 1995, $14.5 million in merger transaction and transition costs have been deferred and are included on the Company's balance sheet as Other Deferred Charges. The cost of severance and early retirement options elected by certain eligible employees affected by the merger is expected to be approximately $8 million. The

Company will determine the treatment of these costs based on regulatory rulings, generally accepted accounting principles and tax regulations. It is anticipated that for accounting purposes these merger transaction and transition costs will be expensed by Altus in the quarter the merger is completed.

The following pro forma condensed financial information combines the historical consolidated balance sheets and statements of income of the Company and SPR after giving effect to the merger. The unaudited pro forma condensed consolidated balance sheet at December 31, 1995 gives effect to the merger as if it had occurred at December 31, 1995. The unaudited pro forma condensed consolidated statements of income for each of the three years in the period ended December 31, 1995 give effect to the merger as if it had occurred at January 1, 1993. These statements are prepared on the basis of accounting for the merger as a pooling-of-interests and are based on the assumptions set forth in the paragraph below. The pro forma condensed financial information has been prepared from, and should be read in conjunction with the Company's historical consolidated audited financial statements and related notes thereto of which this note is a part and SPR's historical consolidated audited financial statements and related notes thereto included in reports filed by SPR pursuant to the Securities Exchange Act, as amended. The information contained herein with respect to SPR and its subsidiaries has been supplied by SPR. The information is not necessarily indicative of the financial position or operating results that would have occurred had the merger been consummated on the date, or at the beginning of the periods, for which the merger is being given effect, nor is it necessarily indicative of future operating results or financial position.

Intercompany transactions (including purchased and exchanged power transactions) between the Company and SPR during the periods presented were not material and, accordingly, no pro forma adjustments were made to eliminate such transactions. For comparative purposes, certain historical amounts have been reclassified to conform to the pro forma condensed financial statement format. The net cost savings estimated to be achieved by the merger are not reflected in the pro forma financial statements. Pro forma per share data and common shares outstanding for Altus give effect to the conversion of each share of WWP Common Stock into one share of Altus Common Stock and the conversion of each share of SPR Common Stock into 1.44 shares of Altus Common Stock.

Pro Forma Condensed Consolidated Balance Sheet (unaudited, in thousands of dollars):

At December 31, 1995	WWP	SPR	ALTUS
Assets			
Utility plant in service-net	$1,880,620	$1,816,444	$3,697,064
Construction work in progress	23,046	153,066	176,112
Total	1,903,666	1,969,510	3,873,176
Accumulated depreciation and amortization	546,248	556,710	1,102,958
Net utility plant	1,357,418	1,412,800	2,770,218
Other property and investments	227,457	45,290	272,747
Current assets	183,972	129,414	313,386
Deferred charges	330,055	169,123	499,178
Total assets	$2,098,902	$1,756,627	$3,855,529
Capitalization and Liabilities			
Common stock and additional paid-in capital	$ 594,636	$ 463,705	$1,058,341
Other shareholders equity	122,489	80,845	203,334
Preferred stock	135,000	86,715	221,715
Long-term debt	738,287	573,933	1,312,220
Total capitalization	1,590,412	1,205,198	2,795,610
Current liabilities	168,959	203,364	372,323
Deferred income taxes	309,790	159,300	469,090
Other deferred credits	29,741	188,765	218,506
Total capitalization and liabilities	$2,098,902	$1,756,627	$3,855,529
Common shares outstanding (thousands)	55,948	30,035	99,198

Pro Forma Condensed Consolidated Statements of Income (unaudited, in thousands of dollars, except per share amounts):

1995	WWP	SPR	ALTUS
Operating revenues	$755,009	$606,122	$1,361,131
Operating expenses	565,169	464,787	1,029,956
Income from operations	189,840	141,335	331,175
Net income	87,121	65,413	152,534
Income available for common stock	77,998	58,039	136,037
Average common shares outstanding	55,173	29,755	98,020
Earnings per share	$1.41	$1.95	$1.39

1994	WWP	SPR	ALTUS
Operating revenues	$670,765	$626,312	$1,297,077
Operating expenses	515,307	498,860	1,014,167
Income from operations	155,458	127,452	282,910
Net income	77,197	60,300	137,497
Income available for common stock	68,541	52,366	120,907
Average common shares outstanding	53,538	29,219	95,613
Earnings per share	$1.28	$1.79	$1.26

1993	WWP	SPR	ALTUS
Operating revenues	$640,599	$528,075	$1,168,674
Operating expenses	479,749	415,286	895,035
Income from operations	160,850	112,789	273,639
Net income	82,776	53,151	135,927
Income available for common stock	74,441	44,890	119,331
Average common shares outstanding	51,616	26,895	90,345
Earnings per share	$1.44	$1.67	$1.32

Sch. 17 COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION							
	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	P. A. Redmond Chairman of the Board, President Chief Executive Officer	511,942			511,942	498,742	1.03%
2	W. L. Bryan Senior Vice President Rates & Resources	181,659			181,659	176,976	1.03%
3	J. E. Eliassen Vice President Finance & Chief Financial Officer	181,659		27,185	208,844	181,083	1.15%
4	R. D. Fukai Vice President Corporate Services and Human Resources	165,142		6,378	171,520	172,552	-0.60%
5	N. J. Racicot Vice President Operations	165,142		6,378	171,520	163,510	1.05%

Sch. 18 **BALANCE SHEET**

Line		Account Title	Last Year	This Year	% Change
1		Assets and Other Debits			
2		**Utility Plant**			
3					
4	101	Electric/Gas Plant in Service	1,742,677,015	1,847,159,678	6.00
5	101.1	Property Under Capital Leases			
6	102	Electric Plant Purchased or Sold	32,874,591		(100.00)
7	104	Electric Plant Leased to Others			
8	105	Electric Plant Held for Future Use			
9	106	Completed Plant Not Classified - Electric			
10	107	Construction Work in Progress - Electric/Gas	27,315,515	23,045,612	(15.63)
11	108	(Less) Accumulated Depreciation	(494,088,822)	(532,758,263)	7.83
12	111	(Less) Accumulated Amortization	(2,050,490)	(6,033,574)	194.25
13	114	Electric/Gas Plant Acquisition Adjustment	26,728,593	33,460,579	25.19
14	115	(Less) Accum. Amortization of Acquisition Adjustment	(4,411,819)	(7,456,427)	69.01
15	120	Nuclear Fuel			
16		TOTAL Utility Plant	1,329,044,583	1,357,417,605	2.13
17					
18		**Other Property & Investments**			
19					
20	121	Nonutility Property	2,975,769	3,257,253	9.46
21	122	(Less) Accum. Depr. & Amort. for Nonutility Property	(120,420)	(46,469)	(61.41)
22	123	Investments in Associated Companies			
23	123.1	Investments in Subsidiary Companies	99,743,859	111,133,036	11.42
24	124	Other Investments	102,657,332	96,249,278	(6.24)
25	125	Special Funds	12,202,384	7,291,107	(40.25)
26		TOTAL Other Property and Investments	217,458,924	217,884,205	0.20
27					
28		**Current & Accrued Assets**			
29					
30	131	Cash	(3,377,708)	(6,624,308)	96.12
31	132-134	Special Deposits	10,000	13,423	34.23
32	135	Working Funds	109,830	168,794	53.69
33	136	Temporary Cash Investments	26,948	174,604	547.93
34	141	Notes Receivable	5,238	0	(100.00)
35	142	Customer Accounts Receivable	35,134,239	52,001,169	48.01
36	143	Other Accounts Receivable	2,327,443	1,834,662	(21.17)
37	144	(Less) Accum. Provision for Uncollectible Accounts	(1,071,059)	(809,585)	(24.41)
38	145	Notes Receivable - Associated Companies			
39	146	Accounts Receivable - Associated Companies	39,336	14,860	(62.22)
40	151	Fuel Stock	5,137,719	12,057,886	134.69
41	152	Fuel Stock Expenses Undistributed	0		
42	153	Residuals			
43	154	Plant Materials and Operating Supplies	10,758,535	11,758,880	9.30
44	155	Merchandise			
45	156	Other Material Supplies	64,021	18,998	(70.33)
46	157	Nuclear Materials Held for Sale			
47	163	Stores Expense Undistributed	(41,955)	111,037	(364.66)
48	164-165	Gas Storage Accounts and Prepayments	20,562,553	42,476,120	106.57
49	171	Interest & Dividends Receivable	27,594	47,658	72.71
50	172	Rents Receivable	1,094,110	1,080,965	(1.20)
51	173	Accrued Utility Revenues			
52	174	Miscellaneous Current and Accrued Assets	3,098,122	1,434,665	(53.69)
53		TOTAL Current and Accrued Assets	73,904,966	115,759,828	56.63

Sch. 18 **BALANCE SHEET**

		Account Title	Last Year	This Year	% Change
1					
2		Assets & Other Debits (con't)			
3					
4	**Deferred Debits**				
5					
6	181	Unamortized Debt Expense	5,044,968	4,951,981	(1.84)
7	182.1	Extraordinary Property Loses			
8	182.2	Unrecovered Plant & Regulatory Study Costs	2,113,739	1,643,360	(22.25)
9	182.3	Other Regulatory Assets	182,212,021	179,243,068	(1.63)
10	183	Preliminary Survey & Investigation Charges	8,842,368	5,930,342	(32.93)
11	184	Clearing Accounts	923,471	358,084	(61.22)
12	185	Temporary Facilities			
13	186	Miscellaneous Deferred Debits	84,873,823	86,263,006	1.64
14	187	Deferred Losses from Disposition of Utility Plant			
15	188	Research Development & Demonstration Expenditures	43,993	28,553	(35.10)
16	189	Unamortized Loss on Reacquired Debt	23,360,741	20,731,542	(11.25)
17	190-191	Accumulated Deferred Income Taxes	32,655,148	14,636,618	(55.18)
18		TOTAL Deferred Debits	340,070,272	313,786,554	(7.73)
19					
20		TOTAL Assets & Other Debits	1,960,478,745	2,004,848,192	2.26

		Account Title	Last Year	This Year	% Change
21					
22		Liabilities and Other Credits			
23					
24	**Proprietary Capital**				
25					
26	201	Common Stock Issued	570,603,199	594,636,442	4.21
27	202	Common Stock Subscribed			
28	204	Preferred Stock Issued	135,000,000	135,000,000	
29	205	Preferrd Stock Subscribed			
30	207	Premium on Capital Stock			
31	211	Miscellaneous Pain-In Capital			
32	213	(Less) Discount on Capital Stoak			
33	214	(Less) Capital Stock Expense	(10,030,549)	(10,072,202)	0.42
34	215	Appropriated Rertained Earnings	38,556,587	37,544,065	(2.63)
35	216	Unappropriated Retained Earnings	76,291,101	87,487,469	14.68
36	217	(less) Reacquired Capital Stock			
37		TOTAL Proprietary Capital	810,420,338	844,595,774	4.22
38					
39	**Long Term Debt**				
40					
41	221	Bonds	410,800,000	478,800,000	16.55
42	222	(Less) Reacquired Bonds			
43	223	Advances From Associated Companies			
44	224	Other Long Term Debt	300,616,573	237,072,763	(21.14)
45	225	Unamortized Premium on Long Term Debt			
46	226	(Less) Unamort. Discount on Long Term Debt (Dr.)	(1,435,026)	(1,309,602)	(8.74)
47		TOTAL Long Term Debt	709,981,547	714,563,161	0.65

Sch. 18 **BALANCE SHEET**

Line	Account	Account Title	Last Year	This Year	% Change
1					
2		Total Liabilities and Other Credits (con't)			
3					
4	**Other Noncurrent Liabilities**				
5					
6	227	Obligations Under Capital Leases - Noncurrent			
7	228.1	Accumulated Provision for Property Inurance			
8	228.2	Accumulated Provision for Injuries & Damages	1,598,278	1,614,037	0.99
9	228.3	Accumulated Provision for Pensions & Benefits	7,450,713	552,829	(92.58)
10	228.4	Accmulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds			
12		TOTAL Other Noncurrent Liabilities	9,048,991	2,166,866	(76.05)
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable			
17	232	Accounts Payable	38,118,149	39,381,209	3.31
18	233	Notes Payable to Associated Companies			
19	234	Accounts Payable to Associated Companies			
20	235	Customer Deposits	734,664	665,512	(9.41)
21	236	Taxes Accruded	17,089,360	25,597,248	49.78
22	237	Interest Accrued	10,954,038	13,578,897	23.96
23	238	Dividends Declared	227,764	0	(100.00)
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	831,300	927,602	11.58
27	242	Miscellaneous Current & Accrued Liabilities	16,496,751	16,942,790	2.70
28	243	Obligations Under Capital Leases - Current			
29		TOTAL Current & Accrued Liabilities	84,452,026	97,093,258	14.97
30					
31	**Deferred Credits**				
32					
33	252	Customes Advances for Construction	2,344,697	3,140,435	33.94
34	253	Other Deferred Credits	12,032,595	14,933,616	24.11
35	254	Other Regulatory Liabilities	1,798,228	1,738,206	
36	255	Accumulated Deferred Investment Tax Credit	2,358,416	2,260,569	(4.15)
37	256	Deferred Gains from Disposition of Utility Plant			
38	257	Unamortized Gain on Reacquired Debt			
39	281-283	Accumulated Deferred Income Taxes	328,041,907	324,356,308	(1.12)
40		TOTAL Deferred Credits	346,575,843	346,429,134	(0.04)
41					
42		TOTAL Liabilities & Other Credits	1,960,478,745	2,004,848,192	2.26

Sch. 19 ITANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Account Number & Title		Last Year	This Year	% Change
Intangible Plant				
301	Organization			
302	Franchises & Consents	193,078	193,078	0.00%
303	Miscellaneous Intangible Plant	22,283	23,437	5.18%
TOTAL Intangible Plant		215,361	216,515	0.54%
Production Plant				
Steam Production				
310	Land & Land Rights	1,306,668	1,306,667	0.00%
311	Structures & Improvements	99,067,221	99,085,492	0.02%
312	Boiler Plant Equipment	114,127,518	114,245,432	0.10%
313	Engines & Engine Driven Generators			
314	Turbogenerator Units	25,538,994	28,181,866	10.35%
315	Accessory Electric Equipment	13,418,852	13,423,939	0.04%
316	Miscellaneous Power Plant Equipment	12,146,327	12,233,182	0.72%
TOTAL Steam Production Plant		265,605,580	268,476,578	1.08%
Nuclear Production				
320	Land & Land Rights			
321	Structures & Improvements			
322	Reactor Plant Equipment			
323	Turbogenerator Units			
324	Accessory Electric Equipment			
325	Miscellaneous Power Plant Equipment			
TOTAL Nuclear Production Plant		0	0	
Hydraulic Production				
330	Land & Land Rights	37,917,514	37,917,514	0.00%
331	Structures & Improvements	10,290,197	10,427,235	1.33%
332	Reservoirs, Dams & Waterways	30,765,424	30,816,218	0.17%
333	Water Wheels, Turbines & Generators	30,436,161	30,085,726	-1.15%
334	Accessory Electric Equipment	3,165,127	3,180,787	0.49%
335	Miscellaneous Power Plant Equipment	1,653,387	1,654,246	0.05%
336	Roads, Railroads & Bridges	88,694	88,694	0.00%
TOTAL Hydraulic Production Plant		114,316,504	114,170,420	-0.13%

Account Number & Title		Last Year	This Year	% Change
Production Plant (cont.)				
Other Production				
340	Land & Land Rights			
341	Structures & Improvements			
342	Fuel Holders, Producers & Accessories			
343	Prime Movers			
344	Generators			
345	Accessory Electric Equipment			
346	Miscellaneous Power Plant Equipment			
	TOTAL Other Production Plant	0	0	
	TOTAL Production Plant	379922084	382646998	0.72%
Transmission Plant				
350	Land & Land Rights	883384	338384	-61.69%
352	Structures & Improvements	130527	130527	0.00%
353	Station Equipment	14260552	14113678	-1.03%
354	Towers & Fixtures	15991563	15996667	0.03%
355	Poles & Fixtures	6716711	6740844	0.36%
356	Overhead Conductors & Devices	15699715	15700731	0.01%
357	Underground Conduit			
358	Underground Conductors & Devices			
359	Roads & Trails	367477	367477	0.00%
	TOTAL Transmission Plant	54049929	53388308	-1.22%
Distribution Plant				
360	Land & Land Rights	15881	15881	0.00%
361	Structures & Improvements	133565	133565	0.00%
362	Station Equipment			
363	Storage Battery Equipment	8955	8955	0.00%
364	Poles, Towers & Fixtures	6676	6676	0.00%
365	Overhead Conductors & Devices	46	46	0.00%
366	Underground Conduit	637	637	0.00%
367	Underground Conductors & Devices	897	897	0.00%
368	Line Transformers	128	128	0.00%
369	Services	29	29	0.00%
370	Meters			
371	Installations on Customers' Premises			
372	Leased Property on Customers' Premises			
373	Street Lighting & Signal Systems			
	TOTAL Distribution Plant	**166814**	**166814**	0.00%

Sch. 19 [illegible]NA PLANT IN SERVICE (ASSIGNED & ALLOCATED)				P. 3 of 3
	Account Number & Title	Last Year	This Year	% Change
1				
2	**General Plant**			
3				
4	389 Land & Land Rights			
5	390 Structures & Improvements			
6	391 Office Furniture & Equipment			
7	392 Transportation Equipment			
8	393 Stores Equipment			
9	394 Tools, Shop & Garage Equipment			
10	395 Laboratory Equipment			
11	396 Power Operated Equipment			
12	397 Communication Equipment			
13	398 Miscellaneous Equipment			
14	399 Other Tangible Property			
15				
16	**TOTAL General Plant**	**0**	**0**	
17				
18	**TOTAL Electric Plant in Service**	**434354188**	**436963636**	

Sch. 20	TANA DEPRECIATION SUMMARY				
			Accumulated Depreciation		Current
	Functional Plant Classification	Plant Cost	Last Year Bal.	This Year Bal.	Avg. Rate
1					
2	Steam Production	267,169,910	80,182,560	88,196,231	28.84%
3	Nuclear Production				
4	Hydraulic Production	104,340,558	7,590,776	7,798,073	7.00%
5	Other Production				
6	Transmission				
7	Distribution				
8	General				
9	TOTAL	371510468	87773336	95994304	

Sch. 21	?IALS & SUPPLIES (ASSIGNED & ALLOCATED)			
	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock	329,434	382,975	16.25%
3	152 Fuel Stock Expenses Undistributed	0	0	
4	153 Residuals			
5	154 Plant Materials & Operating Supplies:			
6	Assigned to Construction (Estimated)			
7	Assigned to Operations & Maintenance			
8	Production Plant (Estimated)	2,525,297	2,512,558	-0.50%
9	Transmission Plant (Estimated)			
10	Distribution Plant (Estimated)			
11	Assigned to Other			
12	155 Merchandise			
13	156 Other Materials & Supplies			
14	157 Nuclear Materials Held for Sale			
15	163 Stores Expense Undistributed			
16				
17	TOTAL Materials & Supplies	2,854,731	2,895,533	1.42%

Sch. 22	;ULATORY CAPITAL STRUCTURE & COSTS			
	Commission Accepted - Most Recent	% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number			
2	Order Number	Reference is made to Schedule 27		
3				
4	Common Equity			0.00%
5	Preferred Stock			0.00%
6	Long Term Debt			0.00%
7	Other			0.00%
8	TOTAL	0.00%		0.00%
9				
10	Actual at Year End			
11				
12	Common Equity			0.00%
13	Preferred Stock			0.00%
14	Long Term Debt			0.00%
15	Other			0.00%
16	TOTAL	0.00%		0.00%

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	87,121,176	77,196,839	12.86%
6	Depreciation	45,845,759	42,386,694	8.16%
7	Amortization	25,114,734	24,127,608	4.09%
8	Deferred Income Taxes - Net	(3,858,675)	15,688,601	-124.60%
9	Investment Tax Credit Adjustments - Net	(97,847)	(97,836)	-0.01%
10	Change in Operating Receivables - Net	(15,840,748)	(7,746,749)	-104.48%
11	Change in Materials, Supplies & Inventories - Net	(6,274,214)	(797,103)	-687.13%
12	Change in Operating Payables & Accrued Liabilities - Net	12,195,194	2,388,060	410.67%
13	Allowance for Funds Used During Construction (AFUDC)	589,017	(1,261,256)	146.70%
14	Change in Other Assets & Liabilities - Net	14,989,177		
15	Other Operating Activities (explained on attached page)	(13,012,865)	(17,428,422)	25.34%
16	Net Cash Provided by/(Used in) Operating Activities	146,770,708	134,456,436	9.16%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipmen	(77,788,557)	(119,989,151)	35.17%
20	(net of AFUDC & Capital Lease Related Acquisitions)			
21	Acquisition of Other Noncurrent Assets			
22	Proceeds from Disposal of Noncurrent Assets			
23	Investments In and Advances to Affiliates			
24	Contributions and Advances from Affiliates			
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)	3,600,000	(34,637,115)	110.39%
27	Net Cash Provided by/(Used in) Investing Activities	(74,188,557)	(154,626,266)	52.02%
28				
29	**Cash Flows from Financing Activities:**			
30	Proceeds from Issuance of:			
31	Long-Term Debt	78,000,000	88,000,000	-11.36%
32	Preferred Stock	0	0	
33	Common Stock	24,033,243	25,994,690	-7.55%
34	Other:	576,500	0	
35	Net Increase in Short-Term Debt		(10,000,749)	100.00%
36	Other:	(635,453)	488,750	-230.02%
37	Payment for Retirement of:			
38	Long-Term Debt	45,000,000	(7,500,000)	700.00%
39	Preferred Stock	0	0	
40	Common Stock			
41	Other:	(43,809)		
42	Net Decrease in Short-Term Debt	(28,500,000)	(1,169,267)	-2337.42%
43	Dividends on Preferred Stock	(9,307,525)	(8,486,025)	-9.68%
44	Dividends on Common Stock	(68,282,794)	(66,487,171)	-2.70%
45	Other Financing Activities (explained on attached page)			
46	Net Cash Provided by (Used in) Financing Activities	40,840,162	20,840,228	95.97%
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	113,422,313	670,398	16818.65%
49	**Cash and Cash Equivalents at Beginning of Year**	(3,230,930)	(3,901,328)	17.18%
50	**Cash and Cash Equivalents at End of Year**	110,191,383	(3,230,930)	3510.52%

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									
3	4 5/8% Series	3/1/65	3/1/95	10,000,000	991,403	0			
4	7 1/8 % Series	12/1/89	12/1/13	66,700,000	63,614,202	66,700,000	7.54%	5,031,631	7.54%
5	7 2/5% Series	12/1/89	12/1/16	17,000,000	16,418,069	17,000,000	7.70%	1,309,320	7.70%
6									
7									
8	6% Pollution Control	7/1/93	12/1/23	4,100,000	3,913,000	4,100,000	6.34%	259,924	6.34%
9									
10	Secured Medium Term								
11	Series A	Var.	Var.	250,000,000	248,374,625	250,000,000	6.85%	17,121,104	6.85%
12	Series B	Var.	Var.	141,000,000	140,211,500	141,000,000	7.60%	10,718,718	7.60%
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									
32	TOTAL			488,800,000	473,522,799	478,800,000		34,440,697	7.19%

Sch. 25 **PREFERRED STOCK**

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1										
2	Flexible Auction									
3	Non-Redeemable:									
4	Series "J"	var.	500	**	-	47,463,854	var.	50,000,000	var.	var.
5										
6										
7	Redeemable:									
8	Series "I"	4/26/90	500000	*	-	46,505,987	8.63%	50,000,000	4,312,500	9.27%
9	Series "K"	9/15/92	350000	*	-	32,910,815	6.95%	50,000,000	2,432,500	7.39%
10										
11										
12										
13										
14										
15	* $100									
16	** $100,000									
17										
18										
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	**TOTAL**					126,880,656		150,000,000	6,745,000	

Sch. 26 **COMMON STOCK**

Line		Avg. Number of Shares Outstanding	Book Value Per Share	Earnings Per Share	Dividends Per Share	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
4	January	54,515,234					15.00	13.50	
6	February	54,560,857					16.00	14.88	
8	March	54,846,574	12.67	0.48	0.31		15.13	14.63	11.5
10	April	54,924,793					15.75	14.75	
12	May	54,980,153					15.50	14.75	
14	June	55,237,359	12.76	0.23	0.31		16.00	15.13	12.5
16	July	55,299,130					15.88	15.00	
18	August	55,349,839					15.88	15.38	
20	September	55,617,091	12.57	0.16	0.31		16.38	15.38	12.2
22	October	55,696,399					17.75	16.00	
24	November	55,728,197					17.75	16.13	
26	December	55,947,967	12.82	0.54	0.31		18.13	17.25	12.4
32	**TOTAL Year End**			1.41	1.24	12.06%			0.0

Sch. 27	MONTANA EARNED RATE OF RETURN				
		Description Rate Base	Last Year	This Year	% Change
1					
2	101	Plant in Service			
3	108	(Less) Accumulated Depreciation			
4		**NET Plant in Service**	0	0	
5					
6		Additions			
7	154, 15(	Materials & Supplies			
8	165	Prepayments			
9		Other Additions			
10		**TOTAL Additions**	0	0	
11					
12		Deductions			
13	190	Accumulated Deferred Income Taxes			
14	252	Customer Advances for Construction			
15	255	Accumulated Def. Investment Tax Credits			
16		Other Deductions			
17		**TOTAL Deductions**	0	0	
18		**TOTAL Rate Base**	0	0	
19					
20		**Net Earnings**			
21					
22		**Rate of Return on Average Rate Base**			
23					
24		**Rate of Return on Average Equity**			
25					
26	Major Normalizing Adjustments & Commission				
27	Ratemaking adjustments to Utility Operations				
28			The Washington Water Power		
29			Company has 19 customers		
30			with 1995 revenues amounting		
31			to $2,165,471 in the State of		
32			Montana. Rates charged were		
33			based on the Company's last		
34			rate order from the Idaho		
35			Public Utilities Commission		
36			and accepted by the Montana		
37			Commission. The Company		
38			does not calculate separate rate		
39			of return for the Montana		
40			jurisdiction.		
41					
42					
43					
44					
45					
46					
47		**Adjusted Rate of Return on Average Rate Base**			
48					
49		**Adjusted Rate of Return on Average Equity**			

Sch. 28		MONTANA COMPOSITE STATISTICS	
		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	436,964
5	107	Construction Work in Progress	
6	114	Plant Acquisition Adjustments	
7	105	Plant Held for Future Use	
8	154, 156	Materials & Supplies	2,896
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	(95,994)
11	252	Contributions in Aid of Construction	
12			
13		NET BOOK COSTS	343,866
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	2,165
18			
19	403 - 407	Depreciation & Amortization Expenses	8,599
20		Federal & State Income Taxes	1,514
21		Other Taxes	8,723
22		Other Operating Expenses	27,404
23		TOTAL Operating Expenses	46,240
24			
25		Net Operating Income	(44,075)
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	
29			
30		NET INCOME	(44,075)
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	11
36		Commercial	1
37		Industrial	7
38		Other	
39			
40		TOTAL NUMBER OF CUSTOMERS	19
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh)	17,898
45		Average Annual Residential Cost per (Kwh) (Cents) *	4.6896
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	70
48		Gross Plant per Customer	39,724

Sch. 29 **MONTANA CUSTOMER INFORMATION**

	City/Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1						0
2	Noxon, Montana		11	1	6	18
3						0
4	Hot Springs, Montana (Secondary Sales for				1	1
5	Resale to Montana Power Company)					0
6						0
7						0
8						0
9						0
10						0
11						0
12						0
13						0
14						0
15						0
16						0
17						0
18						0
19						0
20						0
21						0
22						0
23						0
24						0
25						0
26						0
27						0
28						0
29						0
30						0
31						0
32	**TOTAL Montana Customers**	0	11	1	7	19

Sch. 30	MONTANA EMPLOYEE COUNTS			
	Department	Year Beginning	Year End	Average
1				0
2	Noxon Generating Station	17	22	20
3				0
4				0
5				0
6				0
7				0
8				0
9				0
10				0
11				0
12				0
13				0
14				0
15				0
16				0
17				0
18				0
19				0
20				0
21				0
22				0
23				0
24				0
25				0
26				0
27				0
28				0
29				0
30				0
31				0
32				0
33				0
34				0
35				0
36				0
37				0
38				0
39				0
40				0
41				0
42				0
43				0
44				0
45				0
46				0
47				0
48				0
49				0
50	**TOTAL Montana Employees**	17	22	20

Sch. 31 NA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)

	Project Description	Total Company	Total Montana
1			
2	Noxon Pine Cr #2 230 KV Transmission Construct	357,793	357,793
3			
4	Noxon - Hydro Relicensing	1,512,034	1,512,034
5			
6	Minor Projects (6) Under $100,000	49,467	49,467
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
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45			
46			
47			
48			
49			
50	TOTAL	1,919,294	1,919,294

Sch. 32 TOTAL SYSTEM & MONTANA PEAK AND ENERGY

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
	System					
1	Jan.	4	800	1,443	991,798	194,516
2	Feb.	13	800	1,477	864,900	211,419
3	Mar.	1	800	1,268	901,888	189,500
4	Apr.	10	800	1,156	781,903	159,815
5	May	30	1500	1,179	811,764	194,107
6	Jun.	1	1700	1,133	953,477	340,223
7	Jul.	20	1400	1,240	902,317	268,193
8	Aug.	4	1600	1,210	992,939	353,604
9	Sep.	14	1500	1,103	988,844	396,328
10	Oct.	31	800	1,297	1,093,168	426,192
11	Nov.	22	800	1,339	1,235,277	523,543
12	Dec.	8	800	1,540	1,484,887	652,168
13	TOTAL				12,003,162	3,909,608
	Montana					
14	Jan.					42,645
15	Feb.	Not	Not			20,572
16	Mar.	Available	Available			67,940
17	Apr.			Not Available	Not Available	1,715
18	May					3,440
19	Jun.					1,280
20	Jul.					7,105
21	Aug.					30,000
22	Sep.					88,875
23	Oct.					82,990
24	Nov.					39,185
25	Dec.					53,965
26	TOTAL				0	439,712

Sch. 33 TOTAL SYSTEM Sources & Disposition of Energy

	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	2,162,392	Sales to Ultimate Consumers (Include Interdepartmental)	7,582,295
3	Nuclear			
4	Hydro - Conventional	4,037,581		
5	Hydro - Pumped Storage		Requirements Sales for Resale	0
6	Other	374,369		
7	(Less) Energy for Pumping			
8	**NET Generation**	6,574,342	Non-Requirements Sales for Resale	3,909,608
9	Purchases	5,265,923		
10	Power Exchanges			
11	Received	1,075,675	Energy Furnished Without Charge	
12	Delivered	912,778		
13	**NET Exchanges**	162,897		
14	Transmission Wheeling for Others		Energy Used Within Electric Utility	
15	Received	2,458,646		
16	Delivered	2,458,646		
17	**NET Transmission Wheeling**	0	Total Energy Losses	511,259
18	Transmission by Others Losses			
19	**TOTAL**	12,003,162	**TOTAL**	12,003,162

Sch. 34	SOURCES OF ELECTRIC SUPPLY				
Line	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Washington:				
2	Thermal	Centralia	Centralia, WA	199.5	770753
3	Thermal	Kettle Falls	Kettle Falls, WA	54	200237
4	Hydro	Little Falls	Ford, WA	41	212327
5	Hydro	Long Lake	Ford, WA	80	499554
6	Hydro	Meyers Falls	Colville, WA	1.3	7239
7	Hydro	Monroe Street	Spokane, WA	17	74890
8	Hydro	Nine Mile	Spokane, WA	29	116203
9	Hydro	Upper Falls	Spokane, WA	12	74254
10	Combustion -				
11	Turbine	Northeast	Spokane, WA	61.2	115
15	Idaho:				
16	Hydro	Cabinet Gorge	Clark Fork, ID	243	1139942
17	Hydro	Post Falls	Post Falls, ID	19	73534
18	Combustion -				
19	Turbine	Rathdrum	Rathdrum, ID	174	374254
23	Montana:				
24	Thermal	Colstrip #3 & #4	Colstrip, MT	219	1191402
25	Hydro	Noxon	Thompson Falls, MT	554	1839638
49	Total			1704	6574342

Sch. 35 **RVATION & DEMAND SIDE MANAGEMENT PROGRAMS**

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings W & MWH)		Achieved Savings (MW & MWH)		Difference (MW & MWH)	
1									0	0
2	Not Applicable								0	0
3									0	0
4									0	0
5									0	0
6									0	0
7									0	0
8									0	0
9									0	0
10									0	0
11									0	0
12									0	0
13									0	0
14									0	0
15									0	0
16									0	0
17									0	0
18									0	0
19									0	0
20									0	0
21									0	0
22									0	0
23									0	0
24									0	0
25									0	0
26									0	0
27									0	0
28									0	0
29									0	0
30									0	0
31									0	0
32	TOTAL	$0	$0		0	0	0	0	0	0

Sch. 36	MONTANA CONSUMPTION AND REVENUES						
		Operating Revenues		MegaWatt Hours Sold		Avg. No. of Customers	
	Sales of Electricity	Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	Residential	$9,233	$7,696		169	11	12
2	Commercial - Small	1,592	1,424		21	1	3
3	Commercial - Large						
4	Industrial - Small						
5	Industrial - Large						
6	Interruptible Industrial						
7	Public Street & Highway Lighting						
8	Other Sales to Public Authorities						
9	Sales to Cooperatives						
10	Sales to Other Utilities	747,035	1,410,623		73,600	1	1
11	Interdepartmental	5,788	4,222		67		
12							
13	TOTAL	$763,648	$1,423,965	0	73857	13	16