SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

/X/ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [FEE REQUIRED] FOR THE FISCAL YEAR ENDED DECEMBER 31, 1995 OR

/ / TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED] FOR THE TRANSITION PERIOD FROM ------------ TO ----------

COMMISSION FILE NUMBER 1-3701

THE WASHINGTON WATER POWER COMPANY
(Exact name of Registrant as specified in its charter)

Washington	91-0462470
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1411 East Mission Avenue, Spokane, Washington	99202-2600
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 509-489-0500

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of Class	Name of Each Exchange on Which Registered
Common Stock, no par value, together with Preferred Share Purchase Rights appurtenant thereto	New York Stock Exchange Pacific Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

Title of Class

Preferred Stock, Cumulative, Without Par Value

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days:

Yes [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 229.405 of this chapter) is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

The aggregate market value of the Registrant's outstanding Common Stock, no par value (the only class of voting stock), held by non-affiliates is $1,035,266,660.00, based on the last reported sale price thereof on the consolidated tape on February 29, 1996.

At February 29, 1996, 55,960,360 shares of Registrant's Common Stock, no par value (the only class of common stock), were outstanding.

Documents Incorporated By Reference

Document	Part of Form 10-K into Which Document is Incorporated
Proxy Statement to be filed in connection with the annual meeting of shareholders to be held May 13, 1996	Part III, Items 10, 11, 12 and 13

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* = not an applicable item in the 1995 calendar year for the Company

ACRONYMS AND TERMS

(The following acronyms and terms are found in multiple locations within the document)

Acronym/Term	Meaning
aMW	- Average Megawatt - a measure of electrical energy over time
BPA	- Bonneville Power Administration
Capacity	- a measure of the rate at which a particular generating source produces electricity
Centralia	- the coal fired Centralia Power Plant in western Washington State
Colstrip	- the coal fired Colstrip Generating Project in southeastern Montana
CPUC	- California Public Utilities Commission
CT	- combustion turbine; a natural gas fired unit used primarily for peaking needs
DSM	- Demand Side Management - the process of helping customers manage their use of energy resources
Energy	- a measure of the amount of electricity produced from a particular generating source over time
FERC	- Federal Energy Regulatory Commission
IPUC	- Idaho Public Utilities Commission
IRP	- Integrated Resource Planning
KW, KWH	- Kilowatt, kilowatthour, 1000 watts or 1000 watt hours
MW, MWH	- Megawatt, megawatthour, 1000 KW or 1000 KWH
MPSC	- Montana Public Service Commission
OPUC	- Public Utility Commission of Oregon
Pentzer	- Pentzer Corporation, a wholly-owned subsidiary of the Company which is the parent company to the majority of the Company's non-utility businesses
Therm	- Unit of measurement for natural gas; a therm is equal to one hundred cubic feet (volume) or 100,000 BTUs (energy)
Watt	- Unit of measurement for electricity; a watt is equal to the rate of work represented by a current of one ampere under a pressure of one volt
WIDCo	- Washington Irrigation & Development Company, a wholly-owned non-utility subsidiary of the Company
WUTC	- Washington Utilities and Transportation Commission
WWP	- The Washington Water Power Company, the Company

PART I

Item 1. Business

Company Overview

The Washington Water Power Company (Company), which was incorporated in the State of Washington in 1889, primarily operates in the electric and natural gas utility businesses. As of December 31, 1995, the Company provides electricity and natural gas in a 26,000 square mile area in eastern Washington and northern Idaho with a population of approximately 765,000. The Company also provides natural gas service in a 4,000 square mile area in northeast and southwest Oregon and in the South Lake Tahoe region of California with a population of approximately 460,000.

The Company's retail and wholesale utility businesses include the generation, purchase, transmission, distribution and sale of electric energy plus the purchase, transportation, distribution and sale of natural gas. In addition to its utility businesses, the Company owns Pentzer Corporation (Pentzer), parent company to the majority of the Company's non-utility businesses.

At December 31, 1995, the Company's employees included 1,390 people in its utility operations and 1,240 people in its majority-owned non-utility businesses. The Company's corporate headquarters are in Spokane, Washington (Spokane), which serves as the Inland Northwest's center for manufacturing, transportation, health care, education, communication, agricultural and service businesses.

For the twelve months ended December 31, 1995, 1994 and 1993, respectively, the Company derived operating revenues and income from operations in the following proportions:

	Operating Revenues			Income from Operations		
	1995	1994	1993	1995	1994	1993
Electricity	65%	67%	73%	80%	81%	80%
Natural Gas	23%	24%	21%	13%	15%	15%
Non-Utility	12%	9%	6%	7%	4%	5%

Merger Agreement Overview

In June, 1994, the Company entered into a merger agreement with Sierra Pacific Resources (SPR), Sierra Pacific Power Company (SPPC) and Altus Corporation (Altus, formerly named Resources West Energy Corporation). 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. Issues raised by the FERC primarily revolve around single-system versus zonal transmission rates, pricing for inter-divisional energy transfers, justification of cost savings and the effects on competition, including access by third-party users to the merged company's transmission system, the resolution of which could have an impact on the level of anticipated savings. 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.

Most of the final orders issued by state commissions include a "reopener" clause that allows the state proceedings to be reopened if any party believes that the FERC or any other state commission has taken some action which makes the Stipulation in such state undesirable.

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations: Future Outlook and Note 16 to Financial Statements for additional information.

Utility Operations Overview

The Company owns and operates nine hydroelectric projects, a wood-waste fueled generating station and three natural gas combustion turbine (CT) peaking units. The Company also owns a 15% share in two coal-fired generating facilities. The

Company contracts with five natural gas pipeline companies for access to domestic and Canadian natural gas supplies.

With this diverse energy resource portfolio, the Company remains one of the nation's lowest-cost producers and sellers of energy services.

At the end of 1995, retail electric service was supplied to approximately 290,000 customers in eastern Washington and northern Idaho. The Company's average hourly load for 1995 was 924 aMW. The Company's annual peak load, including firm contractual obligations, was 2,545 MW. This peak occurred on December 8, 1995, at which time the maximum capacity available from the Company's generating facilities, in addition to firm and non-firm purchases, was 2,855 MW.

At the end of 1995, the Company's natural gas operations served approximately 224,000 customers in parts of Washington, Idaho, Oregon and California. The peak load in 1995 occurred on February 13, 1995 when 2.8 million therms were required. During that peak, 3.5 million therms were available under firm transportation and storage contracts.

In early 1996, the Company experienced record peak loads. The electric peak occurred on February 1, 1996, when the load, including firm and non-firm contractual obligations, totaled 2,936 MW, at which time the maximum capacity available from the Company's generating facilities, in addition to firm and non-firm purchases, was 3,216 MW. The natural gas peak load occurred on January 31, 1996 when approximately 3.5 million therms were required. During that peak, 3.5 million therms were available under firm transportation and storage contracts.

Non-Utility Overview

The Company's principal subsidiary is Pentzer, a wholly owned private investment company whose current portfolio of investments includes companies involved in consumer product promotion, specialty tool manufacturing, metal fabrication, financial services, electronic technology and industrial real estate development.

As of December 31, 1995, Pentzer had approximately $220 million in total assets, or about 10% of the Company's consolidated assets, and about $123 million in shareholder equity.

See Item 1. Business - Non-Utility Business and Note 15 to Financial Statements for additional information.

ELECTRIC SERVICE

GENERAL BUSINESS CONDITIONS

Regulatory, economic and technological changes have brought about the accelerating transformation of the electric utility industry from a vertically integrated monopoly to a business all segments of which are more market driven. The Company believes that it is well positioned to meet the challenges of increased competition due to its low production costs, close proximity to major transmission lines, active participation in wholesale power markets and its dedication to exceptional customer service and business improvement.

Challenges facing the retail electric business include evolving technologies which provide alternate energy supplies, reduced energy consumption and the cost of the energy supplied, self-generation and fuel switching by commercial and industrial customers, as well as the potential for retail wheeling, the costs of increasingly stringent environmental laws and the potential for stranded or nonrecoverable utility assets. The Company continues to compete in the wholesale electric market with other western utilities, federal marketing agencies and power marketers. Business challenges affecting the wholesale electric business include new entrants in the wholesale market, such as power brokers and marketers, competition from low-cost generation being developed by independent power producers and declining margins.

The National Energy Policy Act (NEPA) enacted in 1992 addresses a wide range of issues affecting the wholesale electric business. NEPA gives the FERC expanded authority to order electric utilities to transmit electric power for wholesale purchasers and sellers and increase transmission capacity to provide access at prices that permit the recovery of all costs incurred in connection with the transmission services. NEPA also created a new exception from the provisions of the Public Utility Holding Company Act of 1935 for Exempt Wholesale Generators (EWG). Subject to satisfying various regulatory requirements, EWGs may own generating facilities and make wholesale sales.

On March 29, 1995, the FERC issued a Notice of Proposed Rulemaking (NOPR) relating to transmission services and a supplemental NOPR on Recovery of Stranded Costs. If adopted, the NOPR on open access transmission would require public utilities operating under the Federal Power Act to provide third-party access to their transmission systems. Each utility would also be required to establish separate rates for its transmission and generation services for new wholesale service. Further, utilities would be required to take transmission service under the same tariffs applicable to third-party users. The FERC requested comments on the desirability of unified standards for both wholesale and retail transmission services. The FERC suggested, as a possible approach, the establishment by each vertically integrated electric utility of a distribution function which would be treated as a wholesale customer taking transmission services under the utility's filed wholesale transmission tariff. The FERC recognized, and numerous comments confirmed, that such an approach would change the traditional approach of state-federal allocation of transmission costs. The supplemental NOPR on stranded costs provides a basis for recovery by regulated public utilities of legitimate and verifiable stranded costs associated with existing wholesale requirements customers and retail customers who become unbundled wholesale transmission customers of the utility. The FERC will consider allowing recovery of stranded investment costs associated with retail wheeling only if a state regulatory commission lacks the authority to consider that issue. It is anticipated that the final rules could take effect in the first half of 1996.

The Company does not believe that the Open Access NOPR will have a material effect on the Company's results of operations, assuming that the final rule is adopted substantially as proposed. However, if, in the pending or a subsequent rule-making proceeding, the FERC adopted a rule which had the effect of requiring the wholesale transmission rate to be recognized as the transmission component of retail rates, and if the FERC imposed single-system transmission rates on Altus in the Merger proceeding, this could lead to a reduction of Altus' retail rates in Nevada but would not necessarily result in a corresponding increase in Washington and Idaho. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations: Future Outlook.

Open access tariffs were submitted to the FERC for Altus as a part of the Company/SPR merger application. The Company filed separate open access tariffs on February 29, 1996 in order to provide for open transmission access prior to the merger.

On January 31, 1996, the FERC issued a Notice of Inquiry Concerning Commission's Merger Policy (Merger NOI). The Merger NOI will give the FERC the benefit of public input on how proposed mergers should be evaluated in an open access environment. Comments on the Merger NOI are due by the end of March 1996.

The Washington Utilities and Transportation Commission (WUTC) has issued guiding principles related to its December 1994 Notice of Inquiry (NOI) entitled

"Examining Regulation of Electric Utilities in the Face of Change in the Electric Industry." In January 1996, the Idaho Public Utilities Commission (IPUC) initiated a similar NOI and will hold technical workshops later in 1996. (See Electric Regulatory Issues below.)

If electric utility companies are eventually required to provide retail wheeling service, which is the transmission of electric power from another supplier to a customer located within such utility's service area, the Company believes it will be in a position to benefit since it is committed to remaining one of the country's lowest-cost providers of electric energy. Consequently, the Company believes it faces minimal risk for stranded generation, transmission or distribution assets due to its low cost structure.

ELECTRIC LOAD REQUIREMENTS

The Company provides electric services to retail and wholesale customers. Retail service is provided to 290,000 electric customers. Firm sales to residential, commercial and industrial customers constituted 97% of the retail sales in 1995. Sales to the retail customers are affected by temperature variations, economic conditions and growth in the number of customers. The 1995 annual peak for the retail customer group was 2,545 MW. On February 1, 1996, a new peak of 2,936 MW was recorded due to record cold weather.

The Company's wholesale electric business remains an important part of the Company's overall business strategy. Since 1987, the Company has entered into a number of long-term firm power sales contracts that have increased its wholesale electric business and the Company is continuing to actively pursue electric wholesale business opportunities. In 1995, the Company entered into five new firm wholesale contracts which brought the total non-coincident peak requirements to 972 MW of capacity. Wholesale sales are affected by weather and streamflow conditions and may be affected over time by the restructuring of the electric utility industry.

ELECTRIC RESOURCES

The Company's diverse resource mix of hydroelectric projects, thermal generating facilities and power purchases and exchanges, combined with strategic access to regional electric transmission systems, enables the Company to remain one of the nation's lowest-cost producers and sellers of electric energy services.

Hydroelectric Resources Hydroelectric generation is the Company's lowest cost source of electricity and the availability of hydroelectric generation has a significant effect on the Company's total energy costs. The Company expects to meet about 49% of its total energy requirements with its own hydroelectric generation and long-term hydroelectric contracts in normal water years. The streamflows to Company-owned hydroelectric projects were 120%, 65% and 86% of normal in 1995, 1994 and 1993, respectively. For the years 1995, 1994 and 1993, respectively, 43%, 38% and 43% of the Company's total energy requirements were met by these hydroelectric resources.

Thermal Resources The Company has a 15% interest in each of two twin-unit coal-fired facilities - the Centralia Power Plant in western Washington and Units 3 and 4 of the Colstrip Generating Project in southeastern Montana. In addition, the Company owns a wood-waste-fired facility known as the Kettle Falls Generating Station in northeastern Washington and three natural gas-fired CTs, one located in Spokane and two in northern Idaho, used for peaking needs. Company-owned thermal facilities provided 21%, 32% and 25% of the Company's total energy requirements for the years 1995, 1994 and 1993, respectively.

Centralia, which is operated by PacifiCorp, is supplied with coal under both a fuel supply agreement in effect through December 2020 and various spot market purchases. In 1995, 1994 and 1993, Centralia provided approximately 30%, 42% and 46%, respectively, of the Company's thermal generation.

Colstrip is supplied with fuel under coal supply and transportation agreements in effect through December 2019 from adjacent coal reserves. The Montana Power Company is the operator of Colstrip. In 1995, 1994 and 1993 Colstrip provided approximately 47%, 48%, and 43% of the Company's thermal generation, respectively.

Kettle Falls' primary fuel is wood-waste generated as a by-product from forest industry operations within one hundred miles of the plant. Natural gas may be used as an alternate fuel. A combination of long-term contracts plus spot purchases provides the Company the flexibility to meet expected future fuel requirements for the plant. In 1995, 1994 and 1993, Kettle Falls provided approximately 8%, 10% and 11% of the Company's thermal generation, respectively.

The CTs are natural gas-fired units, primarily used for peaking needs. The two units in northern Idaho were completed and went into service in early January 1995. The CTs have access to domestic and Canadian natural gas supplied through Pacific Gas Transmission (PGT). In 1995, these units provided approximately 15% of the Company's thermal generation primarily due to the low cost of natural gas during the year. Thermal generation provided by the Spokane CT in prior years was immaterial.

Purchases, Exchanges and Sales In 1995, the Company had various purchase contracts equating to a non-coincident peak of 418 MW, with an average remaining life of 6.7 years. Additionally, long-term hydro purchase contracts of 255 MW were available with an average remaining contract life of 10.5 years. The Company also enters into a significant amount of short-term sales and purchases with durations of up to one-year from surplus Company resources and short-term contracts. Other energy purchases and exchanges for the years 1995, 1994 and 1993 provided approximately 36%, 30% and 32%, respectively, of the Company's total electric energy requirements, including wholesale obligations.

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), the Company is required to purchase generation from qualifying facilities, including small hydroelectric and cogeneration projects, at avoided cost rates adopted by the WUTC and the IPUC. The Company purchased approximately 632,000 MW, or about 5% of the Company's total energy requirements, from these sources at a cost of approximately $27 million in 1995. Current avoided costs range from 2.5 cents per KWH in 1996 to 5.4 cents in 2005 in Washington for projects under one MW. In Idaho, the interim avoided cost rates range from 2.1 cents in 1996 to 4.5 cents in 2005 for projects under one MW. For larger projects, the rates are negotiated and reflect current market conditions.

ELECTRIC REGULATORY ISSUES

The Company, as a public utility, is currently subject to regulation by state utility commissions with respect to rates, accounting, the issuance of securities and other matters. The electric retail operations are subject to the jurisdiction of the WUTC and IPUC. The Company is also subject to the jurisdiction of the FERC for its accounting procedures and its wholesale transmission rates.

In each regulatory jurisdiction, the price the Company may charge for utility services (other than certain wholesale sales and specially negotiated retail rates for industrial or large commercial customers) is currently determined on a "cost of service" basis and is designed to provide, after recovery of allowable operating expenses, an opportunity to earn a reasonable return on "rate base." "Rate base" is generally determined by reference to the original cost (net of accumulated depreciation) of utility plant in service, subject to various adjustments for deferred taxes and other items. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation and retirements of utility plant from service.

The Company is a licensee under the Federal Power Act and its licensed projects are subject to the provisions of Part I of that Act. These provisions include payment for headwater benefits, condemnation of licensed projects upon payment of just compensation and take-over of such projects after the expiration of the license upon payment of the lesser of "net investment" or "fair value" of the project, in either case plus severance damages. See Item 2. Properties - Electric Properties for additional information.

General Rate Cases The Company does not currently plan to file for any general electric rate increases in 1996. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations: Future Outlook for additional information regarding rate freezes related to the proposed merger between the Company, SPPC and SPR. The Company's most recent general electric rate case in Washington was effective in March 1987 and allowed a return on equity of 12.90%. The effective change was a $15.5 million, or 8.9%, increase in anticipated annual revenues. The Company's most recent general electric rate case in Idaho was effective in September 1986 and allowed a return on equity of 12.90%. The effective change was an increase of $3.7 million, or 4.3%, in anticipated annual revenues. The Company anticipates that future rate filings will move away from rate of return regulation toward a performance-based regulatory system.

Integrated Resource Planning (IRP) IRP is a process required by both the WUTC and IPUC and represents the Company's responsibility to meet customer demand for reliable electric energy services at the lowest total cost to both the Company and its customers. The process entails (1) the forecasting of future electric energy needs, (2) the assessment of energy supplies, conservation options, customer costs, and social and environmental impacts and (3) the development of action plans which support a least cost resource strategy. Both the WUTC and IPUC acknowledge the plans as part of a public hearing process but do not approve the resource plans due to concerns about pre-approval outside of actual rate cases. The state commissions place an emphasis on the IRP as an informational tool for long-term planning. The Company is required to file an updated IRP every two years, and filed with both the WUTC and IPUC in April 1995.

Notice of Inquiry (NOI) In December 1994, the WUTC initiated an NOI entitled, "Examining Regulation of Electric Utilities in the Face of Change in the Electric Industry." The WUTC sought comments on the potential structural change in the electric industry, the implications of industry changes for utility regulation and recommendations concerning specific rules and regulations currently used by the WUTC. The NOI process concluded in December 1995 with the issuance by the WUTC of eight guiding principles stating basically that future WUTC regulatory oversight will balance issues such as reliability, pricing responsive to customer needs and selected public policy concerns. In January 1996, the IPUC initiated a similar NOI entitled, "Investigation into Changes Occurring in the Electric Industry." The NOI outlines seven issues which the IPUC believes will need regulatory oversight into the future. After two technical workshops, the IPUC intends to issue a proposed order adopting these issues as guiding principles later in 1996.

Demand Side Management (DSM) The WUTC and IPUC approved as filed, effective January 1, 1995, the Company's proposed electric and natural gas DSM programs for a two-year period ending December 31, 1996. The Company's DSM programs focus on both the continuation of selected existing programs available to broad customer classes and the development of specifically structured programs to influence market demand. The Company's programs, while maintaining a residential electric weatherization program and fuel efficiency awareness programs, now place a greater emphasis on commercial and industrial programs. In a two-year experimental program, the WUTC approved the Company's requested DSM Tariff Rider as filed, effective January 1, 1995. The tariff rider is a separate revenue source and represents a 1.55% electric revenue increase and a 0.52% natural gas increase. The revenues will be used to fund the Company's 1995 and 1996 DSM program expenditures. Under previous accounting treatment, DSM investments, including the applicable interest charge known as Allowance for Funds Used to Conserve Energy (AFUCE), were recorded as deferred assets until an application was made in a future general rate case. The new treatment will treat 1995 and 1996 DSM expenditures as operating expenses during the two-year experimental period. The IPUC approved a similar proposal effective March 10, 1995.

Power Cost Adjustment (PCA) In 1989, the IPUC approved the Company's filing for a PCA whereby the Company is allowed to modify electric rates to recover or rebate a portion of the difference between actual and allowed net power supply costs. In July of 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 costs associated with other wheeling or power contracts. Rate changes are triggered when the deferred balance reaches $2.2 million. On January 1, 1995, a $2.2 million, or 2.5%, surcharge was implemented which expired on December 31, 1995. On September 1, 1995, a $2.3 million, or 2.4%, surcharge was implemented which will expire on August 31, 1996. See Note 1 to Financial Statements for additional details.

ELECTRIC OPERATING STATISTICS

	Years Ended December 31, 1995	1994	1993
ENERGY RESOURCES (thousand MWh):			
Hydro generation (from Company facilities)........	4,038	2,904	3,548
Thermal generation (from Company facilities)......	2,537	3,427	2,791
Purchased power - long-term hydro.................	1,159	1,177	1,117
Purchased power - other...........................	4,113	3,146	3,492
Power exchanges...................................	156	(24)	81
Total power resources...........................	12,003	10,630	11,029
Energy losses and Company use.....................	(525)	(504)	(598)
Total energy resources (net of losses)..........	11,478	10,126	10,431
ENERGY REQUIREMENTS (thousand MWh):			
Residential.......................................	3,150	3,035	3,134
Commercial..	2,592	2,477	2,373
Industrial..	1,803	1,705	1,644
Public street and highway lighting................	23	22	22
Total retail requirements.......................	7,568	7,239	7,173
Firm wholesale....................................	1,953	1,523	1,798
Non-firm wholesale................................	1,957	1,364	1,460
Total energy requirements.......................	11,478	10,126	10,431
RESOURCE AVAILABILITY at time of system peak (MW):			
Total requirements (winter) (1)...................	2,545	2,233	2,126
Total resource availability (winter)..............	2,855	2,468	2,335
Total requirements (summer) (2)...................	2,037	1,793	1,682
Total resource availability (summer)..............	2,660	2,392	2,206
ELECTRIC OPERATING REVENUES (Thousands of Dollars):			
Residential.......................................	$156,755	$146,894	$153,929
Commercial..	140,221	131,254	126,256
Industrial..	60,979	57,438	57,133
Public street and highway lighting................	3,345	3,108	3,022
Total retail revenue............................	361,300	338,694	340,340
Firm wholesale....................................	84,220	64,890	65,420
Non-firm wholesale................................	25,013	26,496	43,214
Total energy revenues...........................	470,533	430,080	448,974
Other revenues....................................	16,456	21,211	15,201
Total electric revenues............................	$486,989	$451,291	$464,175
Income from electric operations - After income tax...	$110,075	$92,918	$92,850
NUMBER OF ELECTRIC CUSTOMERS (Average for Period):			
Residential.......................................	253,364	239,733	233,795
Commercial..	32,236	29,402	28,678
Industrial..	1,107	999	963
Public street and highway lighting................	349	325	308
Total retail customers..........................	287,056	270,459	263,744
Wholesale customers...............................	33	27	28
Total electric customers........................	287,089	270,486	263,772
ELECTRIC RESIDENTIAL SERVICE AVERAGES:			
Annual use per customer (KWh)......................	12,434	12,661	13,406
Revenue per KWh (in cents).........................	4.98	4.84	4.91
Annual revenue per customer........................	$618.69	$612.74	$658.39

(1) Includes firm contract obligations of 733 MW, 539 MW and 485 MW and 327 MW, 242 MW and 120 MW of non-firm sales in 1995, 1994 and 1993, respectively.

(2) Includes firm contract obligations of 691 MW, 509 MW and 610 MW in 1995, 1994 and 1993, respectively, and non-firm sales of 125 MW and 1 MW in 1995 and 1994, respectively. There were no non-firm sales in 1993 during the

summer system peak period.

NATURAL GAS SERVICE

GENERAL BUSINESS CONDITIONS

Natural gas remains competitively priced compared to alternative fuel sources for residential, commercial and industrial customers and is projected to remain so well into the future due to increasing supplies and competition. The Company continues to advise electricity customers as to the cost advantages of converting space and water heating needs to natural gas. Significant growth has occurred in the Company's natural gas business in recent years due to increased demand for natural gas in new construction. The Company also makes sales or provides transportation service directly to large natural gas customers.

Challenges facing the Company's natural gas business include the continuing potential for customers to by-pass the Company's natural gas system. Since 1988, two of the Company's large industrial customers have built their own pipeline interconnections. However, these customers continue to purchase natural gas services from the Company. To reduce the potential for such by-pass, the Company prices its natural gas services, including transportation contracts, competitively, and has varying degrees of flexibility to price its transportation and delivery rates by means of special contracts. The Company has also signed long-term transportation contracts with two of its largest industrial customers which minimizes the chances of these customers by-passing the Company's system in the foreseeable future.

While rate design changes have increased the costs of firm transportation to low load-factor pipeline customers such as the Company, flexible receipt and delivery points and capacity releases allow temporarily under-utilized transportation to be released to others when not needed to serve the Company's customers. The Company is also able to optimize its natural gas portfolio by engaging in non-retail sales. Non-retail sales are made to marketers and producers where points of delivery are outside the Company's retail distribution area.

NATURAL GAS RESOURCES

Natural Gas Supply   A diverse portfolio of resources allows the Company to capture market opportunities that benefit the Company's natural gas customers. Natural gas supplies are available from both domestic and Canadian sources through both firm and short-term, or spot market, purchases. In addition, the Company has access to five pipelines and a natural gas storage facility which allows the Company to optimize its available resources.

Firm natural gas supplies are purchased by the Company through negotiated agreements having terms ranging between one month and ten years with a variety of natural gas suppliers. During 1995, approximately one-third of the Company's purchases were in the short-term market, with contracts on a month-to-month basis. Approximately 30% of the natural gas supply was obtained from domestic sources, with the remaining 70% from Canadian sources.

The Company has access to five natural gas pipelines, Northwest Pipeline Company (NWP), Pacific Gas Transmission (PGT), Paiute Pipeline (Paiute), NOVA Pipeline, Ltd. (NOVA) and Alberta Natural Gas Co. Ltd. (ANG), which provide the Company access to both domestic and Canadian natural gas supplies. In August 1995, the Company obtained increased capacity on the PGT pipeline, which increases the Company's reliance on Canadian sources of natural gas. With this resource portfolio, the Company remains one of the nation's lowest-cost local natural gas distribution companies.

The Company contracts with NWP for three types of firm service (transportation, liquefied natural gas storage and underground storage) and with PGT, NOVA and ANG for firm transportation only. The Company contracts with NOVA, ANG and PGT for additional transportation capacity which became available in November 1995 for service in its Washington, Idaho and Oregon natural gas properties. The Company contracts with Paiute for firm transportation and liquefied natural gas storage to deliver natural gas to its California customers.

Jackson Prairie Natural Gas Storage Project (Storage Project) The Company owns a one-third interest in the Storage Project, which is an underground natural gas storage field located near Chehalis, Washington. The role of the Storage Project in providing flexible natural gas supplies is increasingly important to the Company's natural gas operations as it enables the Company to place natural gas into storage when prices are low or to meet minimum natural gas purchasing requirements, as well as to withdraw natural gas from storage when spot prices are high or as needed to meet high demand periods. The Company, together with the other owners, is pursuing alternatives to increase the potential for both capacity and deliverability at the Storage Project.

The Company has contracted to release some of its Storage Project capacity to two other utilities until 1998 and 2000, respectively, with a provision under one of the releases to partially recall the released capacity if the Company determines additional natural gas is required for its own system supply.

Natural Gas Transportation Services The Company provides transportation service to customers who obtain their own natural gas supplies. Transportation service continued to be a significant component of the Company's total system deliveries in 1995. The competitive nature of the spot natural gas market results in savings in the cost of purchased natural gas, which encourages large customers with fuel-switching capabilities to continue to utilize natural gas for their energy needs. The total volume transported on behalf of transportation customers was approximately 221.3 million therms in 1995. This volume represented approximately 40% of the Company's total system deliveries in 1995.

NATURAL GAS REGULATORY ISSUES

The Company, as a public utility, is currently subject to regulation by four state utility commissions with respect to rates, accounting, the issuance of securities and other matters. The natural gas operations are subject to the jurisdiction of the WUTC, the IPUC, the Public Utility Commission of Oregon (OPUC) and the California Public Utilities Commission (CPUC) in addition to the jurisdiction of the FERC with respect to natural gas rates charged for the release of capacity from the Storage Project. In each jurisdiction, rates are determined substantially as described in Electric Service - Electric Regulatory Issues.

General Rate Cases The Company has no current plans to file for any natural gas general rate cases in 1996. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations: Future Outlook for additional information regarding rate freezes related to the proposed merger with SPPC and SPR. The Company's most recent general natural gas rate case in Washington was effective in August 1990 and allowed a return on equity of 12.90%. The effective change was a $1.1 million, or 2.58%, increase in anticipated annual revenues. The Company's most recent general natural gas rate case in Idaho was effective in October 1989 and allowed a return on equity of 12.75%. The effective change was a decrease of $0.6 million, or 3.66%, in anticipated annual revenues. A reconsideration, effective in February of 1990, granted a $0.1 million, or 0.86%, increase in annual revenues. In addition, the Company from time to time, upon request, receives regulatory approval from the WUTC, the IPUC, the OPUC and the CPUC to adjust rates to reflect changes in the cost of purchased natural gas between general rate cases. The Company anticipates that future rate filings will move away from rate of return regulation toward a performance-based regulatory system.

Integrated Resource Planning (IRP) See Electric Service - Electric Regulatory Issues for a detailed description of the IRP process. The natural gas IRP is a process required by the WUTC, the IPUC and the OPUC. The 1995 natural gas IRP reports were submitted to these commissions in January 1995 with acknowledgments received at the end of 1995. The natural gas IRP is provided to the CPUC for informational purposes only.

Notice of Inquiry (NOI) In August 1995, the WUTC initiated an NOI entitled, "Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry." The WUTC is seeking comments on the potential structural change in the natural gas industry, the implications of industry changes for utility regulation and recommendations concerning specific rules and regulations currently used by the WUTC. The WUTC will use responses from this inquiry to review and, if necessary, revise regulatory procedures and rules concerning such matters as least-cost planning, purchased gas adjustment (PGA) mechanisms and demand side management incentives. The Company provided initial comments in September 1995 and reply comments in early February 1996, and will participate in meetings in March of 1996 pertaining to natural gas procurement incentives.

Demand Side Management (DSM) See Electric Service - Electric Regulatory Issues regarding the WUTC and IPUC DSM applications. In 1993, the OPUC authorized the Company to defer revenue requirements associated with its Oregon DSM investments and established an annual rate adjustment mechanism to reflect the deferred costs on a timely basis. Under this authorization, the Company files annually, concurrent with the Company's annual natural gas tracker filing, a rate adjustment to recover DSM program costs and margin losses. On December 1, 1995, the OPUC approved the Company's annual tracker increase which included such a rate adjustment.

Natural Gas Trackers Natural gas trackers are designed to pass through changes in purchased natural gas costs and do not normally result in any changes in net income to the Company. In October 1995, the Company filed natural gas trackers with the WUTC, the IPUC and the OPUC. The trackers in Washington and Idaho were both approved, effective December 22, 1995, and authorized a $10.6 million, or 13.58%, decrease and a $4.85 million, or 16.68%, decrease, respectively, in the two jurisdictions. The Oregon natural gas tracker, which became effective on December 1, 1995, authorized a $2.6 million, or 5.82%, decrease. A PGA, or natural gas tracker, filing was approved by the CPUC effective January 5, 1995 which authorized a $0.8 million, or 7.71%, increase in California.

NATURAL GAS OPERATING STATISTICS

	Years Ended December 31, 1995	1994	1993
SOURCES OF SUPPLY (Thousands of Therms):			
Purchases	429,903	335,780	300,572
Storage - injections	(31,248)	(20,518)	(26,398)
Storage - withdrawals	32,332	19,053	20,153
Natural gas for transportation	221,261	195,543	197,499
Distribution system gains (losses)	4,923	1,471	7,416
Total supply	657,171	531,329	499,242
THERMS DELIVERED (Thousands of Therms):			
Residential	159,919	150,106	151,261
Commercial	120,838	120,901	114,793
Industrial - firm	14,658	15,614	19,035
Industrial - interruptible	10,621	12,801	15,747
Total retail sales	306,036	299,422	300,836
Non-retail sales	104,831	36,107	--
Transportation	221,261	195,543	197,499
Interdepartmental sales and Company use	25,043	257	907
Total therms - sales and transportation	657,171	531,329	499,242
NET SYSTEM MAXIMUM CAPABILITY (Thousands of Therms):			
Net system maximum demand (winter)	2,758	2,686	2,651
Net system maximum firm contractual capacity (winter)	3,523	3,523	3,523
NATURAL GAS OPERATING REVENUES (Thousands of Dollars):			
Residential	$84,358	$76,597	$68,137
Commercial	52,671	50,981	43,542
Industrial - firm	5,470	5,642	6,089
Industrial - interruptible	1,967	3,570	4,784
Total retail revenues	144,466	136,790	122,552
Non-retail sales	10,530	5,098	--
Transportation	12,340	11,140	10,923
Other revenues	6,891	3,748	4,072
Total natural gas revenues	$174,227	$156,776	$137,547
Income from natural gas operations - After income tax	$18,686	$18,495	$19,406
NUMBER OF NATURAL GAS CUSTOMERS (Average for Period):			
Residential	192,252	179,176	162,400
Commercial	24,606	23,466	22,526
Industrial - firm	281	264	268
Industrial - interruptible	31	33	39
Total retail customers	217,170	202,939	185,233
Non-retail sales	5	1	--
Transportation	75	60	56
Total natural gas customers	217,250	203,000	185,289
NATURAL GAS RESIDENTIAL SERVICE AVERAGES:			
Washington and Idaho			
Annual use per customer (therms)	919	899	1,025
Revenue per therm (in cents)	48.98	47.46	41.55
Annual revenue per customer	$450.07	$426.83	$425.82
Oregon and California			
Annual use per customer (therms)	678	731	775
Revenue per therm (in cents)	61.78	58.62	52.78
Annual revenue per customer	$418.88	$428.64	$409.11
HEATING DEGREE DAYS:			
Spokane, WA			
Actual	6,363	6,225	7,224
30 year average	6,842	6,842	6,882
% of average	93.0	91.0	105.0
Medford, OR			
Actual	3,751	4,348	4,396
30 year average	4.611	4,611	4,798
% of average	81.3	94.3	91.6

ENVIRONMENTAL ISSUES

The Company is subject to environmental regulation by federal, state and local authorities. The generation, transmission, distribution, service and storage facilities in which the Company has an ownership interest have been designed to comply with all environmental laws presently applicable. Furthermore, the Company conducts vigilant and periodic reviews of all its facilities and operations to anticipate emerging environmental issues.

Air Quality. The Company continues to assess both the potential and actual impact of the 1990 Clean Air Act Amendments (CAAA) on the thermal generating plants in which it maintains an ownership interest. Centralia, which is operated by PacifiCorp, is classified as a "Phase II" coal-fired plant under the CAAA and, as such, will be required to reduce sulfur dioxide (SO2) emissions by approximately 40% by the year 2000. The Owners are continuing to assess alternatives for compliance to the CAAA. Results of current studies are expected by the end of 1996. The alternatives most likely to be used in meeting the compliance standards will be some combination of lower sulfur coal, SO2 reduction through clean coal technology and SO2 allowances either purchased or pooled, if available, among the Centralia owners. The anticipated share of costs for SO2 compliance are not expected to have a major economic impact on the Company.

Colstrip, which is also a "Phase II" coal-fired plant and is operated by Montana Power, is not expected to be required to implement any additional SO2 mitigation in the foreseeable future in order to continue operations. Reduction in nitrogen oxides (NOX) will be required at both Centralia and Colstrip prior to the year 2000. The anticipated share of costs for NOX compliance are not expected to have a major economic impact on the Company.

The Company's other thermal projects also are subject to various CAAA standards. Every five years each project requires an updated operating permit (known as a Title V permit) which addresses, among other things, the compliance of the plant with the CAAA. The permit for the Spokane CT was received in 1995. The permit for the Company's Kettle Falls plant is still pending. The operating permit application for the CTs in northern Idaho is currently under consideration. The Company expects to be able to obtain these permits under the CAAA. See Electric Service - Electric System for additional information.

Superfund Sites. The Company was named a potentially responsible party under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 ("CERCLA" or "Superfund") at the Coal Creek site in Chehalis, Washington. The clean-up is now complete, with the exception of some long-term maintenance efforts, at a cost of approximately $14 million. The cost was shared by approximately 90 utilities. The Company's portion, which has already been paid, was about $1.1 million. Insurance recovery of $750,000 was received in May 1995.

The Company has been named as a potentially responsible party under CERCLA at the Chemical Handling site near Denver, Colorado. The Company is one of approximately 1,100 named by the EPA at this site. The site was used by the Company for the disposal of generators. The Company expects that its share of the cost of clean-up will be minimal.

In 1993, the EPA referred a matter to the U.S. Justice Department requesting the Company and other potentially responsible parties to enter into negotiations for the recovery of costs incurred by EPA and for initiation of action in connection with the clean-up at the Spokane Junkyard Site located in Spokane, Washington. Currently, the Justice Department and the Company have entered into an agreement to stay litigation. If an action is commenced, the claim will be for $2.8 million plus costs, including attorneys' fees. The Company has no records showing that any Company equipment was ever deposited at the Spokane Junkyard Site.

The Company and several other potentially responsible parties entered into an administrative order on consent under CERCLA to conduct an engineering evaluation/cost analysis for the site. As of December 31, 1995, an accrued liability of $2.0 million is reflected in the Company's financial statements which represents the Company's best estimate of its maximum exposure for the site.

Refer to Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations: Future Outlook and Note 14 to Financial Statements for additional information.

NON-UTILITY BUSINESS

The majority of the non-utility operations are controlled by Pentzer, a wholly owned subsidiary of the Company. As of December 31, 1995, the Company had an equity investment of approximately $130 million in non-utility businesses, of which approximately $123 million was invested in Pentzer. The remainder was invested in four other subsidiaries, the largest of which is Washington Irrigation and Development Company (WIDCo), which maintains a small investment portfolio.

As of December 31, 1995, Pentzer had approximately $220 million in total assets, or about 10% of the Company's consolidated assets. Pentzer's portfolio of investments includes companies involved in consumer product promotion, specialty tool manufacturing, metal fabrication, financial services, electronic technology and industrial real estate development.

Pentzer's current investment profile focuses on manufacturers and distributors of industrial and consumer products as well as service businesses. The Company seeks businesses with above average records of earnings growth in industries that are not cyclical or dependent upon high levels of research and development. Emphasis is placed on leading companies with strong market franchises, dominant or proprietary product lines or other significant competitive advantages. Pentzer is particularly interested in companies serving niche markets. Total equity investment in any one company is generally limited to $15 million, and control of the acquired company's board of directors is generally required.

Pentzer's business strategy is to acquire controlling interest in a broad range of middle-market companies, to help these companies grow through internal development and strategic acquisitions, and to sell the portfolio investments either to the public or to strategic buyers when it becomes most advantageous in meeting Pentzer's return on invested capital objectives. Pentzer's goal is to produce financial returns for the Company's shareholders that, over the long-term, should be higher than that of the utility operations. From time to time, a significant portion of Pentzer's earnings contributions may be the result of transactional gains. Accordingly, although the income stream is expected to be positive, it may be uneven from year to year.

Refer to Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations: Results of Operations: Non-Utility Operations and Notes 1 and 15 to Financial Statements for additional information.

ITEM 2. PROPERTIES

ELECTRIC PROPERTIES

The Company's electric properties, located in the States of Washington, Idaho and Montana, include the following:

Generating Plant

	No. of Units	Nameplate Rating (MW)(1)	Present Capability (MW)(2)	Year of FERC License Expiration
Hydroelectric Generating Stations (River)				
Washington:				
Long Lake (Spokane)	4	70.0	72.0	2007
Little Falls (Spokane)	4	32.0	36.0	N/A
Nine Mile (Spokane)	4	26.4	29.0	2007
Upper Falls (Spokane)	1	10.0	10.2	2007
Monroe Street (Spokane)	1	14.8	14.8	2007
Meyers Falls (Colville)	2	1.2	1.3	2023
Idaho:				
Cabinet Gorge (Clark Fork)	4	221.9	236.0	2001 (3)
Post Falls (Spokane)	6	14.8	18.0	2007
Montana:				
Noxon Rapids (Clark Fork)	5	466.7	554.0	2005 (3)
Total Hydroelectric		857.8	971.3	
Thermal Generating Stations				
Washington:				
Centralia (4)	2	199.5	201.0	
Kettle Falls	1	50.7	48.0	
Northeast (Spokane) CT (5)	2	61.2	69.0	
Idaho:				
Rathdrum CT (5), (6)	2	166.5	176.0	
Montana:				
Colstrip (Units 3 and 4) (4)	2	233.4	216.0	
Total Thermal		711.3	710.0	
Total Generation		1,569.1	1,681.3	

N/A Not applicable.

(1) Nameplate Rating, also referred to as "installed capacity", is the manufacturer's assigned power rating under specified conditions.
(2) Capability is the maximum generation of the plant without exceeding approved limits of temperature, stress and environmental conditions.
(3) The formal relicensing process began in September 1995 for Cabinet Gorge and Noxon Rapids.
(4) Jointly-owned; data above refers to Company's respective 15% interests.
(5) Used primarily for peaking needs.
(6) Construction completed in January 1995; see Note 9 to Financial Statements regarding long-term lease financing.

Distribution and Transmission Plant

The Company operates approximately 11,350 miles of primary and secondary distribution lines in its electric system in addition to a transmission system of approximately 550 miles of 230 KV line and 1,545 miles of 115 KV line. The Company also owns a 10% interest in 495 miles of a 500 KV line from Colstrip, Montana and a 15% interest in 3 miles of a 500 KV line from Centralia, Washington to the nearest Bonneville Power Administration (BPA) interconnections.

The 230 KV lines are used primarily to transmit power from the Company's Noxon Rapids and Cabinet Gorge hydroelectric generating stations to major load centers in the Company's service area. The 230 KV lines also transmit to points of interconnection with adjoining electric transmission systems for bulk power transfers. These lines interconnect with BPA at five locations and at one location each with PacifiCorp, Montana Power and Idaho Power Company. The BPA interconnections serve as points of delivery for power from the Colstrip and Centralia generating stations as well as for the interchange of power with the Southwest. The interconnection with PacifiCorp is the point of delivery for power purchased by the Company from Mid-Columbia projects' hydroelectric generating stations.

The 115 KV lines provide for transmission of energy as well as providing for the integration of the Spokane River hydroelectric and Kettle Falls wood-waste generating stations with service area load centers. These lines interconnect with the BPA at nine locations, Grant County Public Utility District (PUD), Seattle City Light and Tacoma City Light at two locations and one interconnect location each with Chelan County PUD, PacifiCorp and Montana Power.

NATURAL GAS PROPERTIES

The Company's natural gas properties have natural gas distribution mains of approximately 3,250 miles in Washington and Idaho and 1,550 miles in Oregon and California, as of December 31, 1995.

The Company, NWP and Washington Natural Gas Company each own a one-third undivided interest in the Storage Project, which has a total peak day deliverability of 4.6 million therms, with a total working natural gas inventory of 155.2 million therms.

ITEM 3. LEGAL PROCEEDINGS

Refer to Note 14 to Financial Statements.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Outstanding shares of Common Stock are listed on the New York and Pacific Stock Exchanges. As of February 29, 1996, there were approximately 33,138 registered shareholders of the Company's no par value Common Stock.

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations: Future Outlook for additional information about common stock dividends.

Refer to Notes 1, 5 and 17 to Financial Statements for additional information.

ITEM 6. SELECTED FINANCIAL DATA

On November 9, 1993, the Company distributed, to shareholders of record on October 25, 1993, shares of its common stock, without par value, under a two-for-one stock split effected in the form of a 100% stock dividend. All references to number of shares and per share information have been adjusted to reflect the common stock split on a retroactive basis.

The Company purchased natural gas distribution properties in Oregon and California from CP National Corporation on September 30, 1991. The 1991 financial information reflects three months of operations of these properties.

On July 31, 1990, WIDCo sold its 50% interest in its coal mining properties. The consolidated financial statements, notes and selected financial data have been reclassified to reflect the continuing operations of the Company. The revenues, expenses, assets and liabilities of the discontinued operations have been reclassified from those categories and netted into single line items in the income statements and balance sheets.

	Years Ended December 31,				
	1995	1994	1993	1992	1991
	(Thousands of Dollars except Per Share Data and Ratios)				
Operating Revenues:					
Utility	$ 661,216	$ 608,067	$ 601,722	$ 524,983	$ 485,075
Non-Utility	93,793	62,698	38,877	32,775	81,732
Total	755,009	670,765	640,599	57,758	566,807
AFUDC/AFUCE	1,631	4,949	4,964	3,751	1,999
Net Income:					
Utility	72,310	63,567	69,510	63,975	69,211
Non-Utility	14,811	13,630	13,266	8,292	1,420
Discontinued Operations	-	-	-	2,403	1,553
Total	87,121	77,197	82,776	74,670	72,184
Preferred Stock Dividend Requirements	9,123	8,656	8,335	6,817	9,292
Income Available for Common Stock	77,998	68,541	74,441	67,853	62,892
Outstanding Common Stock (000s):					
Weighted Average	55,173	53,538	51,616	49,550	46,916
Year-End	55,948	54,421	52,758	50,888	47,902
Book Value per Share	$ 12.82	$ 12.45	$ 12.02	$ 11.54	$ 11.11
Earnings per Share:					
Utility	1.14	1.03	1.19	1.15	1.28
Non-Utility	.27	.25	.25	.17	.03
Discontinued operations	-	-	-	.05	.03
Total	1.41	1.28	1.44	1.37	1.34
Dividends Paid per Common Share	1.24	1.24	1.24	1.24	1.24
Total Assets at Year-End:					
Utility	1,872,391	1,820,671	1,701,652	1,424,812	1,394,800
Non-Utility	226,511	173,582	136,186	109,203	126,713
Total	2,098,902	1,994,253	1,837,838	1,534,015	1,521,513
Long-term Debt at Year-End	738,287	721,146	647,229	596,897	633,434
Preferred Stock Subject to Mandatory Redemption at Year-End	85,000	85,000	85,000	85,000	50,000
Ratio of Earnings to Fixed Charges	3.22	3.24	3.45	3.08	2.96
Ratio of Earnings to Fixed Charges and Preferred Dividend Requirements	2.61	2.59	2.77	2.57	2.35

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The Company 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 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.

RESULTS OF OPERATIONS

OVERALL OPERATIONS

Overall earnings per share for 1995 were $1.41, compared to $1.28 in 1994 and $1.44 in 1993. The 1995 results include improved earnings from the Company's electric operations and $6.1 million in transactional gains from Pentzer Corporation (Pentzer), primarily due to the sale of stock in ITRON, Inc. (ITRON). The 1994 earnings include $8.0 million of gains recorded by Pentzer primarily as a result of the sale of ITRON stock. The 1993 results include gains totaling $12.8 million recorded by Pentzer as a result of the sale of several investments in its portfolio and the sale of stock in the initial public offering by ITRON in November 1993.

Utility income available for common stock increased $8.3 million, or 15%, in 1995 after decreasing $6.3 million, or 10%, in 1994. Utility income contributed $1.14 to earnings per share in 1995, compared to $1.03 in 1994 and $1.19 in 1993. Non-utility income available for common stock increased $1.2 million in 1995 and $0.4 million in 1994 and contributed $0.27 to earnings per share in 1995 and $0.25 in 1994 and 1993.

Income from electric operations increased $17.2 million, or 18%, in 1995 over 1994, primarily due to increased wholesale revenues, resulting from both new power contracts and improved streamflow conditions, and decreased purchased power and fuel expense, both a result of the improved streamflows. Income from natural gas operations increased $0.2 million in 1995 over 1994. During 1995, increased natural gas revenues, which were primarily the result of customer growth, were nearly offset by increased purchased gas costs and other operating expenses. Weather that was 9% warmer than normal during 1994 reduced residential usage for both electric and natural gas customers. Income from electric operations increased $0.1 million in 1994 over 1993 primarily as a result of decreased purchased power expense. Income from natural gas operations decreased $0.9 million in 1994, as compared to 1993, due primarily to increased purchased gas costs that were offset substantially by increased revenues due to customer growth.

Interest expense increased $5.9 million in 1995, as compared to 1994, and $2.9 million in 1994, as compared to 1993, with both increases primarily due to higher levels of outstanding debt and a shift from short-term debt to long-term debt and the resulting higher interest rates. During 1995 and 1994, $78.0 million and $88.0 million, respectively, in long-term debt was issued, while $45.0 million and $7.5 million, respectively, of long-term debt matured or was redeemed. At December 31, 1995, long-term debt outstanding was $17.1 million higher than at December 31, 1994. Long-term debt outstanding at December 31, 1994, was $73.9 million higher than at the end of 1993.

Other Income decreased in 1995 over 1994, primarily due to lower levels of Allowance for Funds Used During Construction (AFUDC) and other capitalized interest, as a result of lower levels of construction and conservation program expenditures. (See Note 1 to Financial Statements for additional information about AFUDC.) Also contributing to the decline in Other Income were the accrual for environmental remediation work (see Note 14 to Financial Statements for additional information) and amortization of the acquisition adjustment from the Company's purchase of PacifiCorp's electric properties in northern Idaho in late December 1994.

UTILITY OPERATIONS

REVENUES

Electric revenues increased in all classes for 1995, as compared to 1994. Wholesale revenues increased $17.8 million, or 20%, in 1995, primarily due to new power contracts for firm service and increased secondary sales, as a result of improved streamflow conditions which led to increased availability of hydroelectric generation in the region, and generation from the Rathdrum combustion turbine which went into service in January 1995. Residential and commercial revenues increased by a combined $18.8 million, primarily as a result of an increase of nearly 16,500 customers, or 6%, during 1995. Approximately 10,000 residential and commercial customers were added through the acquisition of PacifiCorp's electric properties in northern Idaho in late December 1994.

Electric revenues decreased by 3% in 1994, as compared to 1993, due to a combination of decreased residential sales and wholesale sales, partially offset by increased commercial sales and higher wheeling revenues. Wholesale revenues decreased $17.2 million during 1994, compared to 1993, primarily due to a significant short-term sale of wholesale energy in 1993 which increased wholesale revenues in that period, low streamflow conditions during 1994 which led to decreased KWh sales and lower wholesale prices. Residential revenues for 1994 decreased by $7.0 million from 1993, despite a 3% increase in customers, due to warm weather throughout most of the year. Residential usage continues to be affected by new appliance efficiency and other technology which has decreased customers' requirements over time. Commercial revenues increased $5.0 million, or 4%, in 1994, as compared to 1993, due to 3% customer growth and the slightly warmer-than-normal weather which increased air conditioning load. Commercial customers tend to use air conditioning systems at much cooler temperatures than residential customers, with the result that air conditioning load can be up within the commercial sector and not within the residential sector, as during the fall of 1994.

Total natural gas revenues increased $17.5 million, or 11%, in 1995, which was the result of increased therm sales of 24% in 1995. Residential and commercial revenues increased by a combined $9.5 million in 1995 as compared to 1994, primarily as a result of 7% customer growth in those sectors, primarily due to conversions from electric service to natural gas, population growth and new construction. During 1995, the Company sold natural gas on a non-retail sales basis, which accounted for a $5.4 million increase in total revenues. The revenues from these sales were offset by like increases in purchased gas expense. Margins from these transactions are credited back to customers through rate changes for the cost of gas. Transportation sales increased by 13%, leading to a $1.2 million increase in revenues.

Total natural gas revenues increased in all customer classes except industrial in 1994 compared to 1993. In 1994, natural gas revenues from residential and commercial customers rose by $8.5 million and $7.4 million, respectively. The increased revenues were due to customer growth and higher average prices than in 1993, which were offset in part by lower usage per customer as a result of warm temperatures. Much of the customer growth during the early part of 1994 was the result of the Company's emphasis on conversions from electric service to natural gas. Revisions in the Company's Demand Side Management programs in 1994 have lessened the pace of conversions. During 1994, the Company began selling natural gas on a non-retail sales basis, which resulted in a $5.1 million increase in revenues and a like increase in purchased gas expense.

OPERATING EXPENSES

Improved streamflow conditions, which resulted in increased hydroelectric generation, caused purchased power expense for 1995 to decline by $8.6 million from 1994. Hydroelectric generation was 105% above normal, due to streamflows which were 120% of normal in 1995. Purchased power costs in 1994 decreased $12.5 million, or 11%, from levels incurred during 1993, primarily due to increased purchases during 1993 to complete a significant short-term sale of wholesale energy and to replace lost thermal generation due to plant outages. Hydroelectric generation in 1994 was 23% below normal, caused by streamflows which were 65% of normal.

Fuel costs decreased $6.9 million in 1995 compared to 1994 as a result of the increased availability of hydroelectric generation. The decreased thermal plant fuel expense was partially offset by fuel expense for generation from the Rathdrum combustion turbines, particularly in the last half of the year. Fuel costs increased $4.9 million in 1994 over 1993 due to increased thermal generation as a result of the low streamflows in 1994 and shutdowns at thermal plants during 1993 which decreased fuel expense for that year.

A large portion of purchased gas expense is variable costs, with the result that increases in revenues are generally offset by like increases in purchased gas expense. Natural gas purchased expense increased $11.1 million, or 12%, in 1995 as compared to 1994, primarily as the result of an increase in therm sales of

125.8 million, or 24%. Increases

in therm sales were primarily due to customer growth in all customer classes and non-retail sales. Natural gas purchased expense increased $19.4 million in 1994 from 1993, which was the result of increased therm sales of 32.1 million therms.

Other electric operating and maintenance expenses increased $19.6 million in 1995 primarily due to lease payments and operating expenses related to the Rathdrum combustion turbine, increased amortization of conservation programs, a higher accrual for uncollectible accounts, environmental remediation reserves (see Note 14 to Financial Statements for additional information) and the Idaho Power Cost Adjustment (PCA), which allows the Company to change rates to recover or rebate a portion of the difference between actual and allowed net power supply costs. Net PCA adjustments, resulting from improved streamflow conditions, accounted for $5.8 million of the increase in other operating and maintenance expenses in 1995 from 1994. Net PCA adjustments, resulting from low hydroelectric conditions, accounted for $4.1 million of the decrease in other operating and maintenance expenses in 1994 from 1993. Transmission and distribution costs decreased by a combined $3.3 million in 1994, as a result of decreased wholesale KWh sales and the associated wheeling costs, which also contributed to the decrease in other operating and maintenance expenses from the 1993 levels.

Administrative and general expenses increased by $5.3 million in 1995, compared to 1994, primarily due to lease payments for computer software systems, labor expenses resulting from merger activities and other labor-related costs. Administrative and general expenses increased by $3.7 million in 1994 over 1993, primarily due to labor-related cost increases.

Depreciation and amortization expense increased $2.7 million in 1995, primarily due to increased plant-in-service, particularly natural gas plant. During 1994, depreciation and amortization expense increased $1.0 million due to increased electric plant.

Other taxes, primarily excise and business and occupational taxes, were up $1.3 million in 1995 over 1994 due to increased revenues in 1995.

Income taxes increased by $9.9 million, or 26%, in 1995, as a result of increased income from electric operations. Electric operations accounted for $8.7 million of the increase. Income tax expense decreased $3.2 million in 1994 as compared to 1993 primarily due to decreased income from electric operations.

NON-UTILITY OPERATIONS

Non-utility operations include the results of Pentzer and four other subsidiary companies. Pentzer's business strategy is to acquire controlling interests in a broad range of middle-market companies, to help these companies grow through internal development and strategic acquisitions and to sell the portfolio investments either to the public or to strategic buyers when it becomes most advantageous in meeting Pentzer's return on invested capital objectives. Pentzer's goal is to produce financial returns for the Company's shareholders that, over the long-term, should be higher than that of the utility operations. From time to time, a significant portion of Pentzer's earnings contributions may be the result of transactional gains. Accordingly, although the income stream is expected to be positive, it may be uneven from year to year.

Non-utility net income for 1995 was $14.8 million, which represents a 9% increase over 1994 earnings of $13.6 million. The increase in 1995 earnings primarily resulted from a $2.2 million increase in non-transactional earnings over 1994 as a result of improved earnings from companies in Pentzer's investment portfolio, including earnings from two companies newly acquired in 1995. Non-utility operating revenues and expenses both increased substantially in 1995 as compared to 1994 as a result of acquisitions over the past two years.

Non-utility net income for 1994 increased 3% over 1993 earnings. The increase in 1994 earnings primarily resulted from improved earnings from companies in Pentzer's investment portfolio, including earnings from newly acquired companies. Non-utility operating revenues and expenses both increased substantially in 1994 as compared to 1993 as a result of acquisitions during both 1994 and 1993.

Transactional gains in 1995 declined by $1.1 million as compared to 1994. Transactional gains of $8.0 million in 1994 declined by $4.8 million as compared to 1993. The 1995 and 1994 transactional gains were primarily the result of gains recorded from the sale of ITRON stock. The 1993 transactional gains included gains of $7.1 million from the sale of companies involved in telecommunications, technology and energy and a transactional gain of $5.7 million from the sale of ITRON stock.

LIQUIDITY AND CAPITAL RESOURCES

UTILITY

The Company funds capital expenditures with a combination of internally-generated cash and external financing. The level of cash generated internally and the amount that is available for capital expenditures fluctuates annually. Cash provided by operating activities remains the Company's primary source of funds for operating needs, dividends and construction expenditures.

Operating Activities Cash from operating activities less cash dividends paid provided 83% of utility capital expenditures in 1995 as compared to 66% in 1994 and 67% in 1993. Cash available from operating activities in 1995 declined from 1994 primarily due to increases in deferred taxes and various working capital components, such as receivables, materials and supplies, fuel stock and natural gas stored and prepayments on power contracts, partially offset by the positive effect of purchased gas deferrals. However, as discussed below, construction expenditures declined by 13% in 1995 from 1994 so that cash from operating activities provided a higher percentage of the funds for construction than in the two previous years. See Note 1 to Financial Statements for additional information.

Investing Activities Cash used in investing activities decreased in 1995 over 1994 primarily due to the acquisition of the northern Idaho properties of PacifiCorp for $33 million in 1994 and a $22 million decrease in other capital requirements, which included conservation-related capital expenditures. Utility capital expenditures, excluding Allowance for Funds Used During Construction (AFUDC) and Allowance for Funds Used to Conserve Energy (AFUCE, a carrying charge similar to AFUDC for conservation-related capital expenditures), were $338 million for the 1993-1995 period.

Financing Activities During the 1993-1995 period, $95.0 million of long-term debt matured and $231.6 million of higher-cost debt and preferred stock was redeemed and refinanced at lower cost. During 1995, $45 million of long-term debt, with an average interest rate of 7.19%, matured and $78 million of First Mortgage Bonds issued in the form of Secured Medium-Term Notes were issued at an average interest rate of 7.1% and an average maturity of 8 years.

Capital expenditures are financed on an interim basis with notes payable (due within one year). The Company has $160 million in committed lines of credit. In addition, the Company may borrow up to $60 million through other borrowing arrangements with banks. As of December 31, 1995, $19.5 million was outstanding under the committed lines of credit and $10.0 million was outstanding under other short-term borrowing arrangements.

From time to time the Company enters into sale/leaseback arrangements for various long-term assets which provide additional sources of funds. See Note 9 to Financial Statements for additional information.

The Company is restricted under various agreements as to the additional securities it can issue. Under the most restrictive test of the Company's Mortgage, an additional $524 million of First Mortgage Bonds could be issued as of December 31, 1995. As of December 31, 1995, under its Restated Articles of Incorporation, approximately $673 million of additional preferred stock could be issued at an assumed dividend rate of 7.25%.

During the 1996-1998 period, utility capital expenditures are expected to be $237 million, and $90 million will be required for long-term debt maturities and preferred stock sinking fund requirements. During this three-year period, the Company estimates that internally-generated funds will average 95% of the funds needed for its capital expenditure program. Minimal amounts of external financing will be required to fund maturing long-term debt, preferred stock sinking fund requirements and the remaining portion of capital expenditures. These estimates of capital expenditures are subject to continuing review and adjustment. Actual capital expenditures may vary from these estimates due to factors such as changes in business conditions, construction schedules and environmental requirements. These projections relate to the Company on a stand-alone basis and do not reflect any adjustment for the effects of the proposed merger of the Company, Sierra Pacific Resources (SPR) and Sierra Pacific Power Company (SPPC) with and into Altus Corporation (Altus). See Future Outlook - Merger below.

See Notes 4, 5, 6, 7, 8 and 9 to Financial Statements for additional details related to financing activities.

NON-UTILITY

Capital expenditures for the non-utility operations were $13 million for the 1993-1995 period. During this period, $9 million of debt was repaid and capital expenditures were partially financed by the $14 million in proceeds from new long-term debt.

The non-utility operations have $48 million in short-term borrowing arrangements ($26.6 million outstanding as of December 31, 1995) to fund corporate requirements on an interim basis. At December 31, 1995, the non-utility operations had $32.2 million in cash and marketable securities with $28.5 million in long-term debt outstanding.

The 1996-1998 non-utility capital expenditures are expected to be $6 million, and $21 million in debt maturities will also occur. During the next three years, internally-generated cash and other debt obligations are expected to provide the majority of the funds for the non-utility capital expenditure requirements.

TOTAL COMPANY CASH REQUIREMENTS

(Millions of Dollars)	Actual (1)			Projected (2)		
	1993	1994	1995	1996	1997	1998
Capital Expenditures (3):						
Utility:						
Electric	$ 60	$ 57	$ 45	$45	$48	$48
Natural gas	26	27	26	23	20	23
All other	49	39	9	9	10	11
Total Utility	135	123	80	77	78	82
Non-Utility	3	9	5	2	2	2
Total Company	$138	$132	$ 85	$79	$80	$84
Debt and Preferred Stock Maturities, Redemptions & Sinking Fund Requirements (Consolidated) (4):	$274	$ 8	$ 45	$47	$43	$21

(1) Excludes $62 million for the combustion turbine project located in Rathdrum, Idaho for which the Company has obtained separate long-term lease financing; see Note 9 to Financial Statements for additional information. Also excludes $33 million in 1994 for the acquisition of the northern Idaho electric properties of PacifiCorp.
(2) These projections relate to the Company on a stand-alone basis and do not reflect any adjustment for the effects of the proposed merger of the Company, SPR and SPPC with and into Altus.
(3) Excludes AFUDC and AFUCE.
(4) Excludes notes payable (due within one year).

The Company's total common equity increased by $40 million to $717 million at the end of 1995. The 1995 increase was primarily due to the issuance of 1.5 million shares of common stock through both the Dividend Reinvestment Plan and the Investment and Employee Stock Ownership Plan for proceeds of $24.0 million and a $10.2 million increase in retained earnings. The Company's consolidated capital structure at December 31, 1995, was 46% debt, 9% preferred stock and 45% common equity as compared to 47% debt, 9% preferred stock and 44% common equity at year-end 1994.

FUTURE OUTLOOK

Merger

In June 1994, the Company, Sierra Pacific Resources (SPR), Sierra Pacific Power Company, a subsidiary of SPR (SPPC), and Altus Corporation (Altus, formerly named Resources West Energy Corporation), a newly formed subsidiary of the Company, entered into an Agreement and Plan of Reorganization and Merger, as subsequently amended (Merger Agreement), which provides for the merger of the Company, SPR and SPPC into Altus. SPR and SPPC are both Nevada corporations with headquarters in Reno. The Merger Agreement provides that after the effective date of the merger, Altus' corporate headquarters office and principal executive offices will be located in Spokane and that the headquarters of the Washington Water Power and Sierra Pacific operating divisions will be in Spokane and Reno, respectively. As a result of the Merger Agreement, holders of WWP Common Stock would receive one share and holders of SPR Common Stock would receive 1.44 shares of Altus Common Stock, respectively. Each outstanding share of Preferred Stock of WWP and SPPC, respectively, will be converted into the right to receive one share of Altus Preferred Stock with equal stated value and dividends and like redemption provisions and rights upon liquidation.

Approval of the proposed merger was obtained from WWP, SPR and SPPC shareholders at meetings held on November 18, 1994. The Merger Agreement is also subject to certain customary closing conditions, including

without limitation, the receipt of all necessary governmental approvals, including approval of the Federal Energy Regulatory Commission (FERC) and the state utility commissions of California (CPUC), Idaho (IPUC), Montana (MPSC), Nevada (PSCN), Oregon (OPUC) and Washington (WUTC). Applications were filed with each of the state commissions and the FERC in the third quarter of 1994.

The MPSC issued an order in October 1994 declining to exercise jurisdiction. The Company has received orders approving the merger from the commissions of each state. The major points of each order are as follows:

Washington:
- Order approving the merger was issued on September 28, 1995
- Electric and gas base rate freeze through December 31, 2000
- Purchased gas benefits flowed through annual Purchased Gas Adjustment (PGA)
- Accelerated amortization of Washington electric DSM to provide full amortization by December 31, 2003
- On October 17, 1995, the Commission stayed the effectiveness of the September 28, 1995 order, so as to allow its staff and Public Counsel the opportunity to review and evaluate the order of the Nevada Commission; this stay was subsequently lifted by order of the Commission dated December 5, 1995. The amended WUTC order states that if the use of single-system pricing information by any other jurisdiction or the inter-divisional compensation for use of transmission facilities affects allocation of revenues, expenses, rate base or cost of capital to the detriment of Washington ratepayers, such effects will not be reflected in Washington results of operations for any purpose. The amended WUTC order states that "shareholders are at risk for any differences if there are costs that are made unrecoverable by this prohibition."

Idaho:
- Order approving the merger was issued on September 19, 1995
- Electric and gas base rate freeze through December 31, 2000
- Purchased gas benefits flowed through annual PGA
- Earnings capped at 12.0% ROE, with earnings above 12.0% shared 50/50 with customers through the PGA/PCA (Power Cost Adjustment)

Oregon:
- Order approving the merger was issued on June 23, 1995
- No rate freeze
- Purchased gas benefits flowed through annual PGA, plus a sharing of non-purchased gas benefits to partially offset the expenses associated with additional transmission capacity on Pacific Gas Transmission facilities to Medford

California:
- Order approving the merger was issued on October 18, 1995
- Electric and gas base rate freeze through December 31, 1999
- All electric and gas tracking mechanisms suspended during the rate freeze. Balances in the electric and gas tracking accounts will be set to zero upon merger. Exempt from annual electric and gas cost of capital proceedings
- Electric rate reduction of $3.1 million in 1996 related to the suspension of the electric tracking mechanism and elimination of the balances in the tracking accounts
- On February 12, 1996, SPR and the Company filed a petition for an Order of the Commission modifying its October 18, 1995 Order, so as to extend the date by which both companies would otherwise be obligated to submit additional regulatory filings, including general rate case filings, in the event the merger was not consummated by March 31, 1996

Nevada:
- Order approving the merger was issued on October 18, 1995
- Electric and gas base rate freeze through December 31, 1999. Water rates frozen through December 31, 1996
- Gas tracker suspended through January 1, 1997. Electric power/fuel cost tracker suspended through December 31, 1999
- One-time refunds related to a prior rate stipulation of $9 million electric and $4 million gas. Earnings for 1997-1999 capped at 12.0% ROE, with earnings above 12.0% shared 50/50 with customers. On October 25, 1995, the Company and SPR filed a petition with the PSCN requesting clarification of their order. The companies sought clarification on two key issues within the PSCN's order. The two issues were electric single-system pricing for retail services and the distribution of benefits related to the

Alturas transmission project. On November 20, 1995, the PSCN issued an order denying the petition for clarification.

On November 29, 1995, the FERC ordered evidentiary hearings concerning the proposed merger. Issues raised by the FERC primarily revolve around single-system versus zonal transmission rates, pricing for inter-divisional energy transfers, justification of cost savings and the effects on competition, including access by third-party users to the merged company's transmission system, the resolution of which could have an impact on the level of anticipated savings. (See Competition and Business Risk below for additional information on the issuance of the FERC's policy statement in the forthcoming rulemaking on transmission access and pricing.) 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.

Most of the final orders issued by state commissions include a "reopener" clause that allows the state proceedings to be reopened if any party believes that the FERC or any other state commission has taken some action which makes the Stipulation in such state undesirable.

If closing conditions contained in the Merger Agreement are not satisfied or in the event that the merger is not closed on or before June 27, 1996 and either of the parties exercises its right of termination any time thereafter as provided in the Merger Agreement, the Company would continue to operate as a separate utility and expense the merger costs that were incurred.

See Note 16 to Financial Statements for additional information.

Competition and Business Risk

The electric and natural gas utility businesses continue to undergo numerous transformations and are becoming increasingly competitive as a result of economic, regulatory and technological changes. The Company believes that it is well positioned to meet future challenges due to its low production costs, close proximity to major transmission lines and natural gas pipelines, active participation in the wholesale electric market and its commitment to high levels of customer satisfaction, cost reduction and continuous improvement of work processes. Additionally, the Company continually evaluates merger and acquisition opportunities that will allow it to expand its economies of scale and diversify its risk posed by weather and economic conditions.

The Company continues to compete for new retail electric customers with various rural electric cooperatives and public utility districts in and adjacent to its service territories. Challenges facing the electric business include the potential for retail wheeling, the costs of increasingly stringent environmental laws and the potential for stranded or nonrecoverable utility assets. Challenges facing the electric retail business include evolving technologies which provide alternate energy supplies, reduced energy consumption and the cost of the energy supplied, self-generation and fuel switching by commercial and industrial customers. If electric utility companies are eventually required to provide retail wheeling service, which is the transmission of electric power from another supplier to a customer located within such utility's service area, the Company believes it will be in a position to benefit since it is committed to remaining one of the country's lowest-cost providers of electric energy. Consequently, the Company believes it faces minimal risk for stranded generation, transmission or distribution assets due to its low cost structure.

The National Energy Policy Act (NEPA) enacted in 1992 addresses a wide range of issues affecting the wholesale electric business. The Company believes NEPA provides future transmission, energy production and sales opportunities to the Company and complements the Company's commitment to the wholesale electric business.

On March 29, 1995, the FERC issued a Notice of Proposed Rulemaking (NOPR) relating to transmission services and a supplemental NOPR on Recovery of Stranded Costs. If adopted, the NOPR on open access transmission would require public utilities operating under the Federal Power Act to provide third-party access to their transmission systems. Each utility would also be required to establish separate rates for its transmission and generation services for new wholesale service. Further, utilities would be required to take transmission service under the same tariffs applicable to third-party users. The FERC requested comments on the desirability of unified standards for both wholesale and retail transmission services. The FERC suggested, as a possible approach, the establishment by each vertically integrated electric utility of a distribution function which would be treated as a wholesale customer taking transmission services under the utility's filed wholesale transmission tariff. The FERC recognized, and numerous comments confirmed, that such an approach would change the traditional approach of state-federal allocation of transmission costs. The supplemental NOPR on stranded costs provides a basis for recovery by regulated public

utilities of legitimate and verifiable stranded costs associated with existing wholesale requirements customers and retail customers who become unbundled wholesale transmission customers of the utility. The FERC will consider allowing recovery of stranded investment costs associated with retail wheeling only if a state regulatory commission lacks the authority to consider that issue. It is anticipated that the final rules could take effect in the first half of 1996.

The Company does not believe that the Open Access NOPR will have a material effect on the Company's results of operations, assuming that the final rule is adopted substantially as proposed. However, if, in the pending or a subsequent rule-making proceeding, the FERC adopted a rule which had the effect of requiring the wholesale transmission rate to be recognized as the transmission component of retail rates, and if the FERC imposed single-system transmission rates on Altus in the Merger proceeding, this could lead to a reduction of Altus' retail rates in Nevada but would not necessarily result in a corresponding increase in Washington and Idaho.

The Company continues to compete in the wholesale electric market with other western utilities, federal marketing agencies and power marketers. Business challenges affecting the wholesale electric business include new entrants in the wholesale market, such as power brokers and marketers, competition from low-cost generation being developed by independent power producers and declining margins.

Natural gas remains priced competitively compared to other alternative fuel sources for residential, commercial and industrial customers and is projected to remain so well into the future due to increasing supplies and competition. Challenges facing the Company's natural gas business include the potential for customers to by-pass the Company's natural gas system. Since 1988, two of the Company's large industrial customers have built their own pipeline interconnection. However, these customers continue to purchase natural gas services from the Company. To reduce the potential for such by-pass, the Company prices its natural gas services, including transportation contracts, competitively and has varying degrees of flexibility to price its transportation and delivery rates by means of special contracts. The Company has also signed long-term transportation contracts with two of its largest industrial customers which minimizes the risks of these customers by-passing the Company's system in the foreseeable future.

Resource planning for both the electric and natural gas businesses has been integrated so that the Company's customers are provided the most efficient and cost-effective products possible for all their energy requirements. The Company's need for future electric resources to serve retail loads is expected to remain very minimal. The switching of electric heating customers to natural gas requires increased efforts on the Company's part in negotiating and securing competitively-priced natural gas supplies for the future.

Economic and Load Growth

The Company expects economic growth to increase in its eastern Washington and northern Idaho service area. The Company, along with others in the service area, continues its efforts to expand existing businesses and attract new businesses to the Inland Northwest. In the past, agriculture, mining and lumber have been the primary industries. However, health care, electronic and other manufacturing, tourism and the service sectors have become increasingly important industries that operate in the Company's service area. In addition, the Company also anticipates strong economic growth to continue in its Oregon service area.

The Company anticipates electric retail load growth to average approximately 1.4% annually for the next five years primarily due to increases in both population and the number of businesses in its service territory. Although the number of electric customers is expected to increase, the average annual usage by residential customers is expected to remain stable on a weather-adjusted basis.

The Company anticipates natural gas load growth, including transportation volumes, in its Washington and Idaho service area to average approximately 3.1% annually for the next five years. The Oregon and South Lake Tahoe, California service areas are anticipated to realize 3.2% growth annually during that same period.

The forward-looking projections set forth above regarding retail sales growth are based, in part, upon publicly available population and demographic studies conducted independently. The Company's expectations regarding retail sales growth are also based upon various assumptions including, without limitation, assumptions relating to weather and economic and competitive conditions and an assumption that the Company will incur no material loss of retail customers due to self-generation or retail wheeling. Changes in the underlying assumptions can cause actual experience to vary significantly from forward-looking projections.

Environmental Issues

Since December 1991, a number of species of fish in the Northwest, including the Snake River sockeye salmon and chinook salmon, the Kootenai River white sturgeon and the bull trout have either been added to the endangered species list under the Federal Endangered Species Act (ESA), listed as "threatened" under the ESA or been petitioned for listing under the ESA. Thus far, measures which have been adopted and implemented to save both the Snake River sockeye salmon and chinook salmon have not directly impacted generation levels at any of the Company's hydroelectric dams. The Company does, however, purchase power from four projects on the Columbia River that are being directly impacted by these ongoing mitigation measures. The reduction in generation at these projects is relatively minor, resulting in minimal economic impact on the Company at this time. Future actions to save these, and other as yet unidentified fish or wildlife species, could further impact the Company's operations or the operations of some of its major customers. However, it is currently impossible to predict likely economic costs to the Company resulting from these actions.

See Note 14 to Financial Statements for additional information.

Other

The Board of Directors considers the level of dividends on the Company's common stock on a continuing basis, taking into account numerous factors including, without limitation, the Company's results of operations and financial condition, as well as general economic and competitive conditions. The Company's net income available for dividends are derived from its retail electric and natural gas utility operations and, increasingly, from its growing wholesale electric operations and Pentzer's non-utility investment operations.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The Independent Auditor's Report and Financial Statements begin on the next page.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not applicable.

INDEPENDENT AUDITORS' REPORT

The Washington Water Power Company
Spokane, Washington

We have audited the accompanying consolidated balance sheets and statements of capitalization of The Washington Water Power Company and subsidiaries (the Company) as of December 31, 1995 and 1994, and the related consolidated statements of income and retained earnings, cash flows, and the schedules of information by business segments for each of the three years in the period ended December 31, 1995. These financial statements and schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedules based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements and schedules are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements and schedules. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement and schedule presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements and schedules present fairly, in all material respects, the financial position of the Company and its subsidiaries at December 31, 1995 and 1994, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1995, in conformity with generally accepted accounting principles. In addition, the schedules referred to above present fairly, in all material respects, the segment information of the Company and its subsidiaries in accordance with generally accepted accounting principles.

Deloitte & Touche LLP

Seattle, Washington
January 26, 1996 (March 1, 1996 as to Note 15)

CONSOLIDATED STATEMENTS OF INCOME AND RETAINED EARNINGS

The Washington Water Power Company

For the Years Ended December 31
Thousands of Dollars

	1995	1994	1993
OPERATING REVENUES	$755,009	$670,765	$640,599
OPERATING EXPENSES:			
Operations and maintenance	388,119	350,703	322,117
Administrative and general	62,486	59,645	55,083
Depreciation and amortization	67,572	59,479	58,354
Taxes other than income taxes	46,992	45,480	44,195
Total operating expenses	565,169	515,307	479,749
INCOME FROM OPERATIONS	189,840	155,458	160,850
OTHER INCOME (EXPENSE):			
Interest expense	(59,022)	(53,077)	(50,133)
Net gain on subsidiary transactions	9,328	11,519	9,915
Other income (deductions)-net	(609)	7,993	4,647
Total other income (expense)-net	(50,303)	(33,565)	(35,571)
INCOME BEFORE INCOME TAXES	139,537	121,893	125,279
INCOME TAXES	52,416	44,696	42,503
NET INCOME	87,121	77,197	82,776
DEDUCT-Preferred stock dividend requirements	9,123	8,656	8,335
INCOME AVAILABLE FOR COMMON STOCK	$ 77,998	$ 68,541	$ 74,441
Average common shares outstanding (thousands)	55,173	53,538	51,616
EARNINGS PER SHARE OF COMMON STOCK	$ 1.41	$ 1.28	$ 1.44
Dividends paid per common share	$ 1.24	$ 1.24	$ 1.24
RETAINED EARNINGS, JANUARY 1	$114,848	$112,424	$101,644
NET INCOME	87,121	77,197	82,776
DIVIDENDS DECLARED:			
Preferred stock	(8,971)	(8,823)	(8,219)
Common stock	(68,392)	(66,378)	(64,209)
ESOP dividend tax savings	425	428	432
RETAINED EARNINGS, DECEMBER 31	$125,031	$114,848	$112,424

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS
The Washington Water Power Company

At December 31
Thousands of Dollars

	1995	1994
ASSETS:		
UTILITY PLANT-Original Cost:		
Electric-net	$1,523,387	$1,477,998
Natural Gas	341,947	316,974
Common plant	38,332	34,624
Utility plant	1,903,666	1,829,596
Less accumulated depreciation and amortization:		
Electric	429,891	394,559
Natural Gas	106,129	97,217
Common plant	10,228	8,775
Net utility plant	1,357,418	1,329,045
OTHER PROPERTY AND INVESTMENTS:		
Investment in exchange power-net	82,252	88,615
Non-utility properties and investments	135,612	100,174
Other-net	9,593	13,971
Total other property and investments	227,457	202,760
CURRENT ASSETS:		
Cash and cash equivalents	5,164	5,178
Temporary cash investments	27,395	27,928
Accounts and notes receivable-net	102,389	74,524
Materials and supplies, fuel stock and natural gas stored.	38,004	21,384
Prepayments and other	11,020	7,552
Total current assets	183,972	136,566
DEFFERRED CHARGES:		
Regulatory assets for deferred income tax	169,432	174,349
Conservation programs	62,793	66,511
Prepaid power purchases	32,605	13,680
Unamortized debt expense	25,684	28,406
Other-net	39,541	42,936
Total deferred charges	330,055	325,882
TOTAL	$2,098,902	$1,994,253
CAPITALIZATION AND LIABILITIES:		
CAPITALIZATION (See Consolidated Statements of Capitalization)	$1,590,412	$1,533,640
CURRENT LIABILITIES:		
Accounts payable	64,841	46,217
Taxes and interest accrued	39,415	28,931
Other	64,703	58,541
Total current liabilities	168,959	133,689
DEFERRED CREDITS:		
Deferred income taxes	307,529	310,167
Other	32,002	16,757
Total deferred credits	339,531	326,924
COMMITMENTS AND CONTINGENCIES (Notes 9, 13 and 14)		
TOTAL	$2,098,902	$1,994,253

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF CAPITALIZATION
The Washington Water Power Company

At December 31
Thousands of Dollars

	1995	1994
COMMON EQUITY:		
Common stock, no par value; 200,000,000 shares authorized: shares outstanding: 1995-55,947,967; 1994-54,420,696	$ 594,636	$ 570,603
Note receivable from employee stock ownership plan	(11,690)	(12,267)
Capital stock expense and other paid in capital	(10,072)	(10,031)
Unrealized investment gain-net	19,220	14,341
Retained earnings	125,031	114,848
Total common equity	717,125	677,494
PREFERRED STOCK-CUMULATIVE:		
10,000,000 shares authorized:		
Not subject to mandatory redemption:		
Flexible Auction Series J; 500 shares outstanding ($100,000 stated value)	50,000	50,000
Total not subject to mandatory redemption	50,000	50,000
Subject to mandatory redemption:		
$8.625 Series I; 500,000 shares outstanding ($100 stated value)	50,000	50,000
$6.95 Series K; 350,000 shares outstanding ($100 stated value)	35,000	35,000
Total subject to mandatory redemption	85,000	85,000
LONG-TERM DEBT:		
First Mortgage Bonds:		
4 5/8% due March 1, 1995	--	10,000
7 1/8% due December 1, 2013	66,700	66,700
7 2/5% due December 1, 2016	17,000	17,000
Secured Medium-Term Notes:		
Series A - 4.72% to 8.06% due 1996 through 2023	250,000	250,000
Series B - 6.50% to 8.25% due 1997 through 2010	141,000	63,000
Total first mortgage bonds	474,700	406,700
Pollution Control Bonds:		
6% Series due 2023	4,100	4,100
Unsecured Medium-Term Notes:		
Series A - 7.94% to 9.58% due 1997 through 2007	72,500	92,500
Series B - 5.50% to 8.55% due 1996 through 2023	135,000	150,000
Total unsecured medium-term notes	207,500	242,500
Notes payable (due within one year) to be refinanced	29,500	58,000
Other	22,487	9,846
Total long-term debt	738,287	721,146
TOTAL CAPITALIZATION	$1,590,412	$1,533,640

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
Increase (Decrease) in Cash and Cash Equivalents
The Washington Water Power Company

For the Years Ended December 31
Thousands of Dollars

	1995	1994	1993
OPERATING ACTIVITIES:			
Net income	$ 87,121	$ 77,197	$ 82,776
NON-CASH ITEMS INCLUDED IN NET INCOME:			
Depreciation and amortization	67,572	59,479	58,354
Provision for deferred income taxes	(5,487)	15,380	6,962
Allowance for equity funds used during construction	(589)	(1,261)	(1,666)
Power and natural gas cost deferrals and amortizations	16,156	6,365	(7,624)
Deferred revenues and other	9,600	5,971	6,968
(Increase) decrease in working capital components:			
Receivables and prepaid expense	(22,279)	(12,458)	1,116
Materials & supplies, fuel stock and natural gas stored	(11,733)	(1,864)	(2,001)
Payables and other accrued liabilities	21,532	4,343	(1,846)
Other	(29,661)	(8,309)	8,767
NET CASH PROVIDED BY OPERATING ACTIVITIES	132,232	144,843	151,806
INVESTING ACTIVITIES:			
Construction expenditures (excluding AFUDC-equity funds)	(83,494)	(95,815)	(111,118)
Other capital requirements	550	(21,603)	(30,216)
(Increase) decrease in other noncurrent balance sheet items-net	8,893	(21,686)	(1,063)
Assets acquired and investments in subsidiaries	(13,864)	(43,823)	2,725
NET CASH USED IN INVESTING ACTIVITIES	(87,915)	(182,927)	(139,672)
FINANCING ACTIVITIES:			
Increase (decrease) in short-term borrowings	(28,500)	(10,001)	64,001
Proceeds from issuance of long-term debt	78,000	88,000	254,100
Redemption and maturity of long-term debt	(45,000)	(7,500)	(274,100)
Sale of common stock	12,518	14,934	25,899
Redemption premiums	--	--	(9,595)
Other	4,150	10,051	(7,819)
NET FINANCING ACTIVITIES BEFORE CASH DIVIDENDS	21,168	95,484	52,486
Less cash dividends paid	(65,499)	(63,423)	(61,773)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(44,331)	32,061	(9,287)
NET INCREASE (DECREASE) IN CASH & CASH EQUIVALENTS	(14)	(6,023)	2,847
CASH & CASH EQUIVALENTS AT BEGINNING OF PERIOD	5,178	11,201	8,354
CASH & CASH EQUIVALENTS AT END OF PERIOD	$ 5,164	$ 5,178	$ 11,201
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid during the period:			
Interest	$ 53,415	$ 46,861	$ 47,854
Income taxes	$ 50,004	$ 34,094	$ 35,649
Noncash financing and investing activities	$ 87,763	$ 25,891	$ 13,327

The Accompanying Notes are an Integral Part of These Statements.

SCHEDULE OF INFORMATION BY BUSINESS SEGMENTS
The Washington Water Power Company

For the Years Ended December 31
Thousands of Dollars

	1995	1994	1993
OPERATING REVENUES:			
Electric	$ 486,989	$ 451,291	$ 464,175
Natural Gas	174,227	156,776	137,547
Non-utility	93,793	62,698	38,877
Total operating revenues	$ 755,009	$ 670,765	$ 640,599
OPERATIONS AND MAINTENANCE EXPENSES:			
Electric:			
Power purchased	$ 97,669	$ 106,277	$ 118,809
Fuel for generation	32,298	39,176	34,233
Other electric	80,834	61,268	68,567
Natural Gas:			
Natural gas purchased for resale	102,375	91,277	71,867
Other natural gas	15,655	14,297	14,286
Non-utility	59,288	38,408	14,355
Total operations and maintenance expenses	$ 388,119	$ 350,703	$ 322,117
ADMINISTRATIVE AND GENERAL EXPENSES:			
Electric	$ 39,087	$ 35,190	$ 32,376
Natural Gas	12,351	10,944	10,069
Non-utility	11,048	13,511	12,638
Total administrative and general expenses	$ 62,486	$ 59,645	$ 55,083
DEPRECIATION AND AMORTIZATION EXPENSES:			
Electric	$ 49,499	$ 48,233	$ 47,003
Natural Gas	9,670	8,199	8,470
Non-utility	8,403	3,047	2,881
Total depreciation and amortization expenses	$ 67,572	$ 59,479	$ 58,354
INCOME FROM OPERATIONS:			
Electric	$ 150,988	$ 125,125	$ 128,166
Natural Gas	25,356	23,926	24,942
Non-utility	13,496	6,407	7,742
Total income from operations	$ 189,840	$ 155,458	$ 160,850
INCOME AVAILABLE FOR COMMON STOCK:			
Utility operations	$ 63,187	$ 54,911	$ 61,175
Non-utility operations	14,811	13,630	13,266
Total income available for common stock	$ 77,998	$ 68,541	$ 74,441
ASSETS:			
Electric	$1,440,560	$1,441,643	$1,372,128
Natural Gas	274,408	247,060	220,253
Common plant	28,104	25,849	27,572
Other utility assets	129,319	106,118	81,699
Non-utility assets	226,511	173,583	136,186
Total assets	$2,098,902	$1,994,253	$1,837,838
CAPITAL EXPENDITURES (excluding AFUDC/AFUCE):			
Electric	$ 44,656	$ 70,791	$ 84,277
Natural Gas	25,939	32,682	30,774
Common plant	9,349	19,262	19,801
Non-utility	4,934	8,701	3,452
Total capital expenditures	$ 84,878	$ 131,436	$ 138,304

The Accompanying Notes are an Integral Part of These Statements.

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 financial statements are presented on a consolidated basis and, as such, include the assets, liabilities, revenues and expenses of The Washington Water Power Company (Company) and its wholly owned subsidiaries, Pentzer Corporation (Pentzer), Washington Irrigation and Development Company (WIDCo), Altus Laboratories, Altus Energy Solutions and WP Finance Company. All material intercompany transactions have been eliminated in the consolidation. As discussed in Note 15, the 1993 and 1994 operating results for ITRON were accounted for on the equity method; however, as of December 31, 1994, Pentzer's investment in ITRON is classified as available for sale and recorded at fair value on the Consolidated Balance Sheets. 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.

OTHER INCOME-NET

Other income-net is composed of the following items:

	Years Ended December 31, 1995	1994	1993
	(Thousands of Dollars)		
Interest income	$ 3,645	$ 3,535	$ 4,058
Capitalized interest (debt)	1,042	3,687	3,027
Gain (loss) on property dispositions	1,272	738	(1,370)
Equity earnings in subsidiary companies	-	1,774	1,653
Minority interest	(314)	(289)	(1,273)
Capitalized interest (equity)	589	1,261	1,666
Other	(6,843)	(2,713)	(3,114)
Total	$ (609)	$ 7,993	$ 4,647

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.

TEMPORARY INVESTMENTS

Under FAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities," investments in debt and marketable equity securities are classified as "available for sale" and are recorded at fair value. Investments totaling $37.1 million and $27.4 million are included on the Consolidated Balance Sheets at December 31, 1995 as other property and investments and current assets, respectively. Investments totaling $34.1 million and $27.9 million are included on the Consolidated Balance Sheets at December 31, 1994 as other property and investments and current assets, respectively. Unrealized investment gains, as of December 31, 1995 and 1994, of $19.2 million and $14.3 million, respectively, net of taxes, are reflected as a separate component of shareholders' equity on the Consolidated Statements of Capitalization.

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 Consolidated 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.

RECLASSIFICATIONS

Certain prior year amounts have been reclassified to conform to current statement format. These reclassifications were made for comparative purposes and have not affected previously reported total net income or common shareholders' equity.

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	At December 31, 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.

Included in other long-term debt are the following related to non-utility operations (in thousands of dollars):

	Outstanding at December 31	
	1995	1994
Notes payable - variable rates through 1999	$24,372	$12,518
Industrial revenue bonds - variable rate through 2003	-	450
Capital lease obligations	4,715	16
Total non-utility	29,087	12,984
Less: current portion	6,813	2,960
Net non-utility long-term debt	$22,274	$10,024

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

Non-utility operations have $48 million in short-term borrowing arrangements available. At December 31, 1995 and 1994, $26.6 million and $22.3 million, respectively, were outstanding.

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 Consolidated Statements 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 the 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

NOTE 17. SELECTED QUARTERLY INFORMATION (UNAUDITED)

The Company's electric and natural gas operations are significantly affected by weather conditions. Consequently, there can be large variances in revenues, expenses and net income between quarters based on seasonal factors such as temperatures and streamflow conditions.

A summary of quarterly operations (in thousands of dollars except per share amounts) for 1995 and 1994 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
1995				
Operating revenues	$197,928	$158,973	$157,869	$240,239
Operating income	58,474	40,103	31,565	59,698
Net income	28,453	15,163	10,885	32,619
Income available for common stock	26,156	12,865	8,618	30,359
Outstanding common stock (000s):				
Weighted average	54,582	54,986	55,363	55,745
Year-end	54,847	55,237	55,617	55,948
Earnings per share:				
Utility operations	$ 0.43	$ 0.19	$ 0.11	$ 0.41
Non-utility operations	0.05	0.04	0.05	0.13
Total	$ 0.48	$ 0.23	$ 0.16	$ 0.54
Dividends paid per common share	$ 0.31	$ 0.31	$ 0.31	$ 0.31
Trading price range per share:				
High	$ 16	$ 16	$ 16 3/8	$ 18
Low	$ 13 1/2	$ 14 3/4	$ 15	$ 16
1994				
Operating revenues	$190,871	$147,173	$142,334	$190,552
Operating income	51,690	34,015	22,973	46,782
Net income	26,691	15,696	8,104	26,705
Income available for common stock	24,621	13,547	5,918	24,455
Outstanding common stock (000s):				
Weighted average	52,911	53,316	53,751	54,158
Year-end	53,140	53,584	54,017	54,421
Earnings per share:				
Utility operations	$ 0.43	$ 0.21	$ 0.05	$ 0.34
Non-utility operations	0.03	0.04	0.06	0.12
Total	$ 0.46	$ 0.25	$ 0.11	$ 0.46
Dividends paid per common share	$ 0.31	$ 0.31	$ 0.31	$ 0.31
Trading price range per share:				
High	$ 18 7/8	$ 17 7/8	$ 16 1/4	$ 14 7/8
Low	$ 16 5/8	$ 14 1/4	$ 13 7/8	$ 13 5/8

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Information regarding the directors of the Registrant has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Registrant's Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 13, 1996.

Executive Officers of the Registrant

Name	Age	Business Experience During Past 5 Years
Paul A. Redmond	59	Chairman of the Board, President and Chief Executive Officer since February 1994; Chairman of the Board and Chief Executive Officer May 1988 - February 1994.
W. Lester Bryan	55	Senior Vice President - Rates & Resources since May 1992; Vice President - Power Supply August 1983 - May 1992.
Jon E. Eliassen	48	Vice President - Finance and Chief Financial Officer since February 1986.
Gary G. Ely	48	Vice President - Natural Gas since February 1991.
Robert D. Fukai	46	Vice President - Human Resources, Corporate Services & Marketing since January 1993; Vice President - Corporate Services & Human Resources October 1992 - December 1992; Vice President - Operations May 1986 - October 1992.
JoAnn G. Matthiesen	55	Vice President - Organization Effectiveness, Public Relations & Assistant to the Chairman since January 1993; Vice President - Marketing, Public Relations & Assistant to the Chairman February 1991 - January 1993.
Lawrence J. Pierce	43	Vice President - Business Analysis since August 1994; Director - Business Analysis February 1992 - August 1994; Treasurer February 1986 - February 1992.
Nancy J. Racicot	48	Vice President - Operations since October 1992; Vice President - Corporate Services March 1990 - October 1992.
Ronald R. Peterson	43	Treasurer since February 1992; Manager - Customer Information Services March 1991 - February 1992.
John W. Buergel	52	Controller since May 1990.
Terry L. Syms	47	Corporate Secretary & Manager - Shareholder Relations since March 1988.

All of the Company's executive officers, with the exception of Messrs. Bryan, Ely, and Buergel and Ms. Racicot, were officers or directors of one or more of the Company's subsidiaries in 1995.

Executive officers are elected annually by the Board of Directors.

ITEM 11. EXECUTIVE COMPENSATION

Information regarding executive compensation has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Registrant's Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 13, 1996.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

(a) Security ownership of certain beneficial owners (owning 5% or more of Registrant's voting securities):

None.

(b) Security ownership of management:

Information regarding security ownership of management has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Registrant's Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 13, 1996.

(c) Changes in control:

None.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information regarding certain relationships and related transactions has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Registrant's Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 13, 1996.

PART IV

ITEM 14. FINANCIAL STATEMENTS, FINANCIAL STATEMENT SCHEDULES, EXHIBITS AND REPORTS ON FORM 8-K

(a) 1. Financial Statements (Included in Part II of this report):

Independent Auditors' Report

Consolidated Statements of Income and Retained Earnings for the Years Ended December 31, 1995, 1994 and 1993

Consolidated Balance Sheets, December 31, 1995 and 1994

Consolidated Statements of Capitalization, December 31, 1995 and 1994

Consolidated Statements of Cash Flows for the Years Ended December 31, 1995, 1994 and 1993

Schedule of Information by Business Segments for the Years Ended December 31, 1995, 1994 and 1993

Notes to Financial Statements

(a) 2. Financial Statement Schedules:

None

(a) 3. Exhibits:

Reference is made to the Exhibit Index commencing on page 55. The Exhibits include the management contracts and compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601(10)(iii) of Regulation S-K.

(b) Reports on Form 8-K:

Dated November 29, 1995, regarding the FERC hearing process on the proposed Merger between the Company, Sierra Pacific Resources and Sierra Pacific Power Company.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

THE WASHINGTON WATER POWER COMPANY

March 12, 1996 By /s/ PAUL A. REDMOND

Date: March 12, 1996

Paul A. Redmond
Chairman of the Board, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ PAUL A. REDMOND Paul A. Redmond (Chairman of the Board, President and Chief Executive Officer)	Principal Executive Officer and Director	March 12, 1996
/s/ J. E. ELIASSEN J. E. Eliassen (Vice President - Finance and Chief Financial Officer)	Principal Financial and Accounting Officer	March 12, 1996
/s/ DAVID A. CLACK David A. Clack	Director	March 12, 1996
/s/ DUANE B. HAGADONE Duane B. Hagadone	Director	March 12, 1996
/s/ ROBERT S. JEPSON, JR. Robert S. Jepson, Jr.	Director	March 12, 1996
/s/ EUGENE W. MEYER Eugene W. Meyer	Director	March 12, 1996
/s/ H. NORMAN SCHWARZKOPF General H. Norman Schwarzkopf	Director	March 12, 1996
/s/ B. JEAN SILVER B. Jean Silver	Director	March 12, 1996
/s/ LARRY A. STANLEY Larry A. Stanley	Director	March 12, 1996
/s/ R. JOHN TAYLOR R. John Taylor	Director	March 12, 1996

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Registration Statement No. 2-81697 on Form S-8, in Registration Statement No. 2-94816 on Form S-8, in Registration Statement No. 33-49662 on Form S-3, in Registration Statement No. 33-51669 on Form S-3, in Registration Statement No. 33-53655 on Form S-3 and in Registration Statement No. 33-54791 on Form S-8 of our report dated January 26, 1996 (March 1, 1996 as to Note 15) appearing in this Annual Report on Form 10-K of The Washington Water Power Company for the year ended December 31, 1995.

Deloitte & Touche LLP

Seattle, Washington
March 12, 1996

EXHIBIT INDEX

Exhibit	Previously Filed* With Registration Number	As Exhibit	
2	1-3701 (with Form 8-K dated June 27, 1994)	2(a)	Agreement and Plan of Reorganization and Merger, dated as of June 27, 1994, by and among the Company, Sierra Pacific Resources, Sierra Pacific Power Company, and Resources West Energy Corporation.
3(a)	1-3701 (with 1994 2nd Quarter 10-Q)	4(a)	Restated Articles of Incorporation of the Company as filed August 4, 1994.
3(b)	1-3701 (with 1995 2nd Quarter 10-Q)	4(a)	Bylaws of the Company, as amended, May 11, 1995.
4(a)-1	2-4077	B-3	Mortgage and Deed of Trust, dated as of June 1, 1939.
4(a)-2	2-9812	4(c)	First Supplemental Indenture, dated as of October 1, 1952.
4(a)-3	2-60728	2(b)-2	Second Supplemental Indenture, dated as of May 1, 1953.
4(a)-4	2-13421	4(b)-3	Third Supplemental Indenture, dated as of December 1, 1955.
4(a)-5	2-13421	4(b)-4	Fourth Supplemental Indenture, dated as of March 15, 1967.
4(a)-6	2-60728	2(b)-5	Fifth Supplemental Indenture, dated as of July 1, 1957.
4(a)-7	2-60728	2(b)-6	Sixth Supplemental Indenture, dated as of January 1, 1958.
4(a)-8	2-60728	2(b)-7	Seventh Supplemental Indenture, dated as of August 1, 1958.
4(a)-9	2-60728	2(b)-8	Eighth Supplemental Indenture, dated as of January 1, 1959.
4(a)-10	2-60728	2(b)-9	Ninth Supplemental Indenture, dated as of January 1, 1960.
4(a)-11	2-60728	2(b)-10	Tenth Supplemental Indenture, dated as of April 1, 1964.
4(a)-12	2-60728	2(b)-11	Eleventh Supplemental Indenture, dated as of March 1, 1965.
4(a)-13	2-60728	2(b)-12	Twelfth Supplemental Indenture, dated as of May 1, 1966.
4(a)-14	2-60728	2(b)-13	Thirteenth Supplemental Indenture, dated as of August 1, 1966.
4(a)-15	2-60728	2(b)-14	Fourteenth Supplemental Indenture, dated as of April 1, 1970.
4(a)-16	2-60728	2(b)-15	Fifteenth Supplemental Indenture, dated as of May 1, 1973.
4(a)-17	2-60728	2(b)-16	Sixteenth Supplemental Indenture, dated as of February 1, 1975.
4(a)-18	2-60728	2(b)-17	Seventeenth Supplemental Indenture, dated as of November 1, 1976.
4(a)-19	2-69080	2(b)-18	Eighteenth Supplemental Indenture, dated as of June 1, 1980.

*Incorporated herein by reference.
**Filed herewith.

EXHIBIT INDEX (continued)

Exhibit	Previously Filed* With Registration Number	Previously Filed* As Exhibit	
4(a)-20	1-3701 (with 1980 Form 10-K)	4(a)-20	Nineteenth Supplemental Indenture, dated as of January 1, 1981.
4(a)-21	2-79571	4(a)-21	Twentieth Supplemental Indenture, dated as of August 1, 1982.
4(a)-22	1-3701 (with Form 8-K dated September 20, 1983)	4(a)-22	Twenty-First Supplemental Indenture, dated as of September 1, 1983.
4(a)-23	2-94816	4(a)-23	Twenty-Second Supplemental Indenture, dated as of March 1, 1984.
4(a)-24	1-3701 (with 1986 Form 10-K)	4(a)-24	Twenty-Third Supplemental Indenture, dated as of December 1, 1986.
4(a)-25	1-3701 (with 1987 Form 10-K)	4(a)-25	Twenty-Fourth Supplemental Indenture, dated as of January 1, 1988.
4(a)-26	1-3701 (with 1989 Form 10-K)	4(a)-26	Twenty-Fifth Supplemental Indenture, dated as of October 1, 1989.
4(a)-27	33-51669	4(a)-27	Twenty-Sixth Supplemental Indenture, dated as of April 1, 1993.
4(a)-28	1-3701 (with 1993 Form 10-K)	4(a)-28	Twenty-Seventh Supplemental Indenture, dated as of January 1, 1994.
4(b)-1	1-3701 (with 1989 Form 10-K)	4(e)-1	Loan Agreement between City of Forsyth, Rosebud County, and the Company, dated as of November 1, 1989 (Series 1989 A and 1989 B). Replaces Exhibit 4(e)-1 (agreement between the Company and City of Forsyth, Rosebud County, Montana, dated as of October 1, 1986) filed with Form 10-K for 1986 and Exhibit 4(g)-1 (agreement between the Company and City of Forsyth, Rosebud County, Montana, dated as of April 1, 1987) filed with Form 10-K for 1987.
4(b)-2	1-3701 (with 1989 Form 10-K)	4(e)-2	Indenture of Trust, Pollution Control Revenue Refunding Bonds (Series 1989 A and 1989 B) between City of Forsyth, Rosebud County, Montana and Chemical Bank, dated as of November 1, 1989. Replaces Exhibit 4(e)-2 (Indenture of Trust between City of Forsyth, Rosebud County, Montana and Chemical Bank dated as of October 1, 1986) filed with Form 10-K for 1986 and Exhibit 4(g)-2 (Indenture of Trust between City of Forsyth, Rosebud County, Montana and Chemical Bank, dated as of April 1, 1987) filed with Form 10-K for 1987.
4(c)-1	1-3701 (with 1988 Form 10-K)	4(h)-1	Indenture between the Company and Chemical Bank dated as of July 1, 1988 (Series A and B Medium-Term Notes).

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*Incorporated herein by reference.
**Filed herewith.

EXHIBIT INDEX (continued)

	Previously Filed*		
Exhibit	With Registration Number	As Exhibit	
4(d)-1	1-3701 (with 1992 Form 10-K)	4(j)-1	Credit Agreements between the Company and Toronto-Dominion (Texas), Inc., The Toronto-Dominion Bank Houston Agency, The Bank of New York, CIBC, Inc. and Citicorp USA, Inc. with Toronto-Dominion (Texas), Inc. as agent, dated as of October 1, 1992.
4(d)-2	**		First Amendment to Credit Agreements between the Company and Toronto-Dominion (Texas), Inc., The Toronto-Dominion Bank Houston Agency, The Bank of New York, CIBC, Inc. and Citicorp USA, Inc. with Toronto-Dominion (Texas), Inc. as agent, dated as of July 26, 1995.
4(d)-3	**		Second Amendment to Credit Agreements between the Company and Toronto-Dominion (Texas), Inc., The Toronto-Dominion Bank Houston Agency, The Bank of New York, CIBC, Inc. and Citicorp USA, Inc. with Toronto-Dominion (Texas), Inc. as agent, dated as of July 26, 1995.
4(e)-1	1-3701 (with 1992 Form 10-K)	4(k)-1	Credit Agreements between the Company and Seattle-First National Bank, West One Bank Idaho, N.A., First Interstate Bank of Washington, N.A., First Security Bank of Idaho, N.A., U.S. Bank of Washington, N.A., and Washington Trust Bank with Seattle-First National Bank as agent, dated as of December 10, 1992.
4(e)-2	**		Third Amendment to Credit Agreements between the Company and Seattle-First National Bank, West One Bank Idaho, N.A., First Interstate Bank of Washington, N.A., First Security Bank of Idaho, N.A., U.S. Bank of Washington, N.A., and Washington Trust Bank with Seattle-First National Bank as agent, dated as of November 21, 1994.
4(f)-1	1-3701 (with Form 8-K dated February 16, 1990)	4(n)	Rights Agreement, dated as of February 16, 1990, between the Company and the Bank of New York as successor Rights Agent.
4(f)-2	1-3701 (with 1994 First Quarter Form 10-Q)	4(b)	Amendment No. 1 to Rights Agreement, dated as of May 10, 1994.
4(f)-3	1-3701 (with 1994 Third Quarter Form 10-Q)	4(b)	Amendment No. 2 to Rights Agreement, dated as of June 27, 1994.
10(a)-1	2-13788	13(e)	Power Sales Contract (Rocky Reach Project) with Public Utility District No. 1 of Chelan County, Washington, dated as of November 14, 1957.
10(a)-2	2-60728	10(b)-1	Amendment to Power Sales Contract (Rocky Reach Project) with Public Utility District No. 1 of Chelan County, Washington, dated as of June 1, 1968.

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*Incorporated herein by reference.
**Filed herewith.

EXHIBIT INDEX (continued)

	Previously Filed*		
Exhibit	With Registration Number	As Exhibit	
10(b)-1	2-13421	13(d)	Power Sales Contract (Priest Rapids Project) with Public Utility District No. 2 of Grant County, Washington, dated as of May 22, 1956.
10(b)-2	2-60728	5(d)-1	Second Amendment to Power Sales Contract (Priest Rapids Project) with Public Utility District No. 2 of Grant County, Washington, dated as of December 19, 1977.
10(c)-1	2-60728	5(e)	Power Sales Contract (Wanapum Project) with Public Utility District No. 2 of Grant County, Washington, dated as of June 22, 1959.
10(c)-2	2-60728	5(e)-1	First Amendment to Power Sales Contract (Wanapum Project) with Public Utility District No. 2 of Grant County, Washington, dated as of December 19, 1977.
10(d)-1	2-60728	5(g)	Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963.
10(d)-2	2-60728	5(g)-1	Amendment to Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965.
10(d)-3	2-60728	5(h)	Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963.
10(d)-4	2-60728	5(h)-1	Amendment to Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965.
10(e)	2-60728	5(i)	Canadian Entitlement Exchange Agreement executed by Bonneville Power Administration Columbia Storage Power Exchange and the Company, dated as of August 13, 1964.
10(f)	2-60728	5(j)	Pacific Northwest Coordination Agreement, dated as of September 15, 1964.
10(g)-1	2-60728	5(k)	Ownership Agreement between the Company, Pacific Power & Light Company, Puget Sound Power & Light Company, Portland General Electric Company, Seattle City Light, Tacoma City Light and Grays Harbor and Snohomish County Public Utility Districts as owners of the Centralia Steam Electric Generating Plant, dated as of May 15, 1969.

*Incorporated herein by reference.
**Filed herewith.

EXHIBIT INDEX (continued)

Exhibit	Previously Filed* With Registration Number	Previously Filed* As Exhibit	
10(g)-3	1-3701 (with Form 10-K for 1991)	10(h)-3	Centralia Fuel Supply Agreement between PacifiCorp Electric Operations, as the Seller, and the Company, Puget Sound Power & Light Company, Portland General Electric Company, Seattle City Light, Tacoma City Light and Grays Harbor and Snohomish County Public Utility Districts, as the Buyers of coal for the Centralia Steam Electric Generating Plant, dated as of January 1, 1991.
10(h)-1	2-47373	13(y)	Agreement between the Company, Bonneville Power Administration and Washington Public Power Supply System for purchase and exchange of power from the Nuclear Project No. 1 (Hanford), dated as of January 6, 1973.
10(h)-2	2-60728	5(m)-1	Amendment No. 1 to the Agreement between the Company between the Company, Bonneville Power Administration and Washington Public Power Supply System for purchase and exchange of power from the Nuclear Project No. 1 (Hanford), dated as of May 8, 1974.
10(h)-3	1-3701 (with Form 10-K for 1986)	10(i)-3	Agreement between Bonneville Power Administration, the Montana Power Company, Pacific Power & Light, Portland General Electric, Puget Sound Power & Light, the Company and the Supply System for relocation costs of Nuclear Project No. 1 (Hanford) dated as of July 9, 1986.
10(i)-1	2-60728	5(n)	Ownership Agreement of Nuclear Project No. 3, sponsored by Washington Public Power Supply System, dated as of September 17, 1973.
10(i)-2	1-3701 (with Form 10-Q for quarter ended September 30, 1985)	1	Settlement Agreement and Covenant Not to Sue executed by the United States Department of Energy acting by and through the Bonneville Power Administration and the Company, dated as of September 17, 1985, describing the settlement of Project 3 litigation.
10(i)-3	1-3701 (with Form 10-Q for quarter ended September 30, 1985)	2	Agreement to Dismiss Claims and Covenant Not to Sue between the Washington Public Power Supply System and the Company, dated as of September 17, 1985, describing the settlement of Project 3 litigation with the Supply System.
10(i)-4	1-3701 (with Form 10-Q for quarter ended September 30, 1985)	3	Agreement among Puget Sound Power & Light Company, the Company, Portland General Electric Company and PacifiCorp, dba Pacific Power & Light Company, agreeing to execute contemporaneously an irrevocable offer, to and for the benefit of the Bonneville Power Administration, dated as of September 17, 1985.

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*Incorporated herein by reference.
**Filed herewith.

THE WASHINGTON WATER POWER COMPANY

EXHIBIT INDEX (continued)

Exhibit	Previously Filed* With Registration Number	Previously Filed* As Exhibit	
10(j)-2	2-66184	5(r)	Service Agreement (Natural Gas Storage Service), dated as of August 27, 1979, between the Company and Nation.
10(j)-3	2-60728	5(s)	Service Agreement (Liquefaction-Storage Natural Gas Service), dated as of December 7, 1977, between the Company and Northwest Pipeline Corporation.
10(j)-4	1-3701(with 1989 Form 10-K)	10(k)-4	Amendment dated as of January 1, 1990, to Firm Transportation Agreement, dated as of June 15, 1988, between the Company and Northwest Pipeline Corporation.
10(j)-6	1-3701 (with 1992 Form 10-K)	10(k)-6	Firm Transportation Service Agreement, dated as of April 25, 1991, between the Company and Pacific Gas Transmission Company.
10(j)-7	1-3701 (with 1992 Form 10-K)	10(k)-7	Service Agreement Applicable to Firm Transportation Service, dated June 12, 1991, between the Company and Alberta Natural Gas Company Ltd.
10(j)-8	1-3701 (with 1992 Form 10-K)	10(k)-8	Natural Gas Sale and Purchase Agreement, dated October 31, 1991, between the Company and AEC Oil and Gas Company.
10(j)-9	1-3701 (with 1992 Form 10-K)	10(k)-9	Natural Gas Purchase Contract, dated December 11, 1991 between the Company and Grand Valley Gas Company and Amerada Hess Canada Ltd.
10(j)-10	1-3701 (with 1992 Form 10-K)	10(k)-10	Natural Gas Purchase Contract, dated December 13, 1991, between the Company and Grand Valley Gas Company and PanCanadian Petroleum Limited.
10(k)-1	1-3701 (with Form 8-K for August 1976)	13(b)	Letter of Intent for the Construction and Ownership of Colstrip Units No. 3 and 4, sponsored by The Montana Power Company, dated as of April 16, 1974.
10(k)-2	1-3701 (with 1981 Form 10-K)	10(s)-7	Ownership and Operation Agreement for Colstrip Units No. 3 and 4, sponsored by The Montana Power Company, dated as of May 6, 1981.
10(k)-3	1-3701 (with 1981 Form 10-K)	10(s)-2	Coal Supply Agreement for Colstrip Units No. 3 and 4 between The Montana Power Company, Puget Sound Power & Light Company, Portland General Electric Company, Pacific Power & Light Company, Western Energy Company and the Company, dated as of July 2, 1980.

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* Incorporated herein by reference.
** Filed herewith.

EXHIBIT INDEX (continued)

Exhibit	Previously Filed* With Registration Number	Previously Filed* As Exhibit	
10(k)-4	1-3701 (with 1981 Form 10-K)	10(s)-3	Amendment No. 1 to Coal Supply Agreement for Colstrip Units No. 3 and 4, dated as of July 10, 1981.
10(k)-5	1-3701 (with 1988 Form 10-K)	10(l)-5	Amendment No. 4 to Coal Supply Agreement for Colstrip Units No. 3 and 4, dated as of January 1, 1988.
10(l)-1	1-3701 (with 1986 Form 19-K)	10(n)-2	Lease Agreement between the Company and IRE-4 New York, Inc., dated as of December 15, 1986, relating to the Company's central operating facility.
10(m)	1-3701 (with 1983 Form 10-K)	10(v)	Supplemental Agreement No. 2, Skagit/Hanford Project, dated as of December 27, 1983, relating to the termination of the Skagit/Hanford Project.
10(n)	1-3701 (with 1986 Form 10-K)	10(p)-l	Agreement for Purchase and Sale of Firm Capacity and Energy between Puget Sound Power & Light Company and the Company, dated as of August 1, 1986.
10(o)	1-3701 (with 1991 Form 10-K)	10(q)-1	Electric Service and Purchase Agreement between Potlatch Corporation and the Company, dated as of January 3, 1991.
10(p)	1-3701 (with 1992 Form 10-K)	10(r)-1	Power Sale Agreement between the Company and the Northern California Power Agency dated October 11, 1991.
10(q)	1-3701 (with 1992 Form 10-K)	10(s)-1	Agreements for Purchase and Sale of Firm Capacity between the Company and Portland General Electric Company dated March and June 1992.
10(r)-1	1-3701 (with 1994 Form 10-K)	10(s)-1	Employment Agreement between the Company and Paul A. Redmond. (***)
10(r)-2	1-3701 (with 1994 Form 10-K)	10(s)-2	Employment Agreement between the Company and W. Lester Bryan. (***)
10(r)-3	1-3701 (with 1994 Form 10-K)	10(s)-3	Employment Agreement between the Company and Nancy Racicot. (***)
10(r)-4	1-3701 (with 1994 Form 10-K)	10(s)-4	Employment Agreement between the Company and Jon E. Eliassen. (***)

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  * Incorporated herein by reference.
 ** Filed herewith.
*** Management contracts or compensatory plans filed as exhibits by reference per Item 601(10)(iii) of Regulation S-K.

EXHIBIT INDEX (continued)

Exhibit	Previously Filed* With Registration Number	Previously Filed* As Exhibit	
10(r)-5	1-3701 (with 1994 Form 10-K)	10(s)-5	Employment Agreement between the Company and Robert D. Fukai. (***)
10(r)-6	**		Executive Officers' 1995 Incentive Plan. (***)
10(r)-7	1-3701 (with 1992 Form 10-K)	10(t)-7	Executive Deferral Plan of the Company. (***)
10(r)-8	1-3701 (with 1992 Form 10-K)	10(t)-8	The Company's Unfunded Outside Director Retirement Plan. (***)
10(r)-9	1-3701 (with 1992 Form 10-K)	10(t)-9	The Company's Unfunded Supplemental Executive Retirement Plan. (***)
10(r)-10	1-3701 (with 1992 Form 10-K)	10(t)-10	The Company's Unfunded Supplemental Executive Disability Plan. (***)
10(r)-11	1-3701 (with 1992 Form 10-K)	10(t)-11	Income Continuation Plan of the Company.(***)
10(s)-1	1-3701 (with 1994 Form 10-K)	10(t)-1	Employment Agreement between the Company, Sierra Pacific Resources, Sierra Pacific Power Company, Resources West and Paul A. Redmond. (***)
10(s)-2	1-3701 (with 1994 Form 10-K)	10(t)-2	Employment Agreement between the Company, Sierra Pacific Resources, Sierra Pacific Power Company, Resources West and Walter M. Higgins.
12	**		Statement re computation of ratio of earnings to fixed charges and preferred dividend requirements.
21	**		Subsidiaries of Registrant.
27	**		Financial Data Schedule.

- ----------------
  * Incorporated herein by reference.
 ** Filed herewith.
*** Management contracts or compensatory plans filed as exhibits by reference per Item 601(10)(iii) of Regulation S-K.

Exhibit 4(d)-2

FIRST AMENDMENT dated as of July 26, 1995 (the "Amendment"), to the $40,000,000 Revolving Credit Agreement, dated as of October 1, 1992 (the "Agreement"), among THE WASHINGTON WATER POWER COMPANY, a Washington corporation (the "Borrower"), the banks parties thereto (the "Banks") and TORONTO DOMINION (TEXAS), INC., as agent for the Banks (in such capacity, the "Agent").

A. The Borrower has requested that the Banks amend certain provisions of the Agreement. The Banks are willing to enter into this Amendment, subject to the terms and conditions set forth herein.

B. Capitalized terms used and not otherwise defined herein shall have the meanings assigned to them in the Agreement.

Accordingly, in consideration of the mutual agreements contained in this Amendment and other good and valuable consideration, the sufficiency and receipt of which are hereby acknowledged, the parties hereto hereby agree as follows:

SECTION 1. Amendment of Section 1.01. The definition of "Expiration Date" in Section 1.01 of the Agreement is hereby amended to read in its entirety as follows:

"Expiration Date" shall mean July 24, 1996.

SECTION 2. Amendment of Section 2.05(a). Section 2.05(a) of the Agreement is hereby amended by replacing the reference to ".20" with ".10%".

SECTION 3. Representations and Warranties. The Borrower represents and warrants to the Agent and to each of the Banks that:

(a) This Amendment, and the Agreement as amended hereby, have been duly authorized, executed and delivered by it and constitute its legal, valid and binding obligations enforceable in accordance with their terms except as such enforceability may be limited by bankruptcy, insolvency, reorganization, moratorium or other laws affecting the enforcement of creditors' rights generally, or by general equity principles, including but not limited to principles governing the availability of the remedies of specific performance and injunctive relief.

(b) The representations and warranties set forth in Article III of the Agreement and in the other Loan Documents before and after giving effect to this Amendment are true and correct in all material respects with the same effect as if made on the date hereof, except to the extent such representations and warranties expressly relate to an earlier date, in which case they were true and correct in all material respects on and as of such earlier date.

(c) Before and after giving effect to this Amendment, no Default or Event of Default has occurred and is continuing.

(d) As of the date hereof, the Borrower has performed all obligations to be performed on its part as set forth in the Agreement and the other Loan Documents.

SECTION 4. Conditions to Effectiveness. The amendments to the Agreement set forth in this Amendment shall become effective when the Agent shall have received (a) counterparts of this Amendment which, when taken together, bear the signatures of the Borrower and each of the Banks under the Agreement and (b) evidence satisfactory to it that the Amendment has been (or will prior to any borrowing under the Agreement have been) duly authorized by the Board of Directors of the Borrower.

SECTION 5. Agreement. Except as specifically amended hereby, the Agreement shall continue in full force and effect in accordance with the provisions thereof as in existence on the date hereof. After the date hereof, any reference to the Agreement shall mean the Agreement as amended hereby.

SECTION 6. Applicable Law. THIS AMENDMENT SHALL BE CONSTRUED IN ACCORDANCE WITH AND GOVERNED BY THE LAWS OF THE STATE OF NEW YORK.

SECTION 7. Counterparts. This Amendment may be executed in two or more counterparts, each of which shall constitute an original, but all of which when taken together shall constitute but one contract.

SECTION 8. Expenses. The Borrower agrees to reimburse the Agent for its reasonable out-of-pocket expenses in connection with this Amendment, including the reasonable fees, charges and disbursements of Cravath, Swaine & Moore, counsel for the Agent.

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be duly executed by their respective authorized officers as of the day and year first written above.

THE WASHINGTON WATER POWER
COMPANY, as the Borrower,

by /s/ Ronald R. Peterson

Name: Ronald R. Peterson
Title: Treasurer

TORONTO DOMINION (TEXAS),
INC., as Agent,

by /s/ Sophia D. Sgarbi

Name: Sophia D. Sgarbi
Title: Vice President

THE TORONTO-DOMINION BANK,
HOUSTON AGENCY,

by /s/ Sophia D. Sgarbi

Name: Sophia D. Sgarbi
Title: Manager Syndications & Credit
Administration

THE BANK OF NEW YORK,

by /s/ Daniel T. Gates

Name: Daniel T. Gates
Title: Vice President

CIBC INC.,

by /s/ P. Saggau

Name: P. Saggau
Title: Vice President

CITICORP USA,

by /s/ Mark Lyons

Name: Mark Lyons
Title: Vice President

Exhibit 4(d)-3

SECOND AMENDMENT dated as of July 26, 1995 (the "Amendment"), to the $50,000,000 Revolving Credit Agreement, dated as of October 1, 1992, as amended (the "Agreement"), among THE WASHINGTON WATER POWER COMPANY, a Washington corporation (the "Borrower"), the banks parties thereto (the "Banks") and TORONTO DOMINION (TEXAS), INC., as agent for the Banks (in such capacity, the "Agent").

A. The Borrower has requested that the Banks amend certain provisions of the Agreement. The Banks are willing to enter into this Amendment, subject to the terms and conditions set forth herein.

B. Capitalized terms used and not otherwise defined herein shall have the meanings assigned to them in the Agreement.

Accordingly, in consideration of the mutual agreements contained in this Amendment and other good and valuable consideration, the sufficiency and receipt of which are hereby acknowledged, the parties hereto hereby agree as follows:

SECTION 1. Amendment of Section 1.01. The definition of "Expiration Date" in Section 1.01 of the Agreement is hereby amended to read in its entirety as follows:

"Expiration Date" shall mean July 24, 1996.

SECTION 2. Amendment of Section 2.05(a). Section 2.05(a) of the Agreement is hereby amended by replacing the reference to ".1875" with ".10%".

SECTION 3. Representations and Warranties. The Borrower represents and warrants to the Agent and to each of the Banks that:

(a) This Amendment, and the Agreement as amended hereby, have been duly authorized, executed and delivered by it and constitute its legal, valid and binding obligations enforceable in accordance with their terms except as such enforceability may be limited by bankruptcy, insolvency, reorganization, moratorium or other laws affecting the enforcement of creditors, rights generally, or by general equity principles, including but not limited to principles governing the availability of the remedies of specific performance and injunctive relief.

(b) The representations and warranties set forth in Article III of the Agreement and in the other Loan Documents before and after giving effect to this Amendment are true and correct in all material respects with the same effect as if made on the date hereof, except to the extent such representations and warranties expressly relate to an earlier date, in which case they were true and correct in all material respects on and as of such earlier date.

(c) Before and after giving effect to this Amendment, no Default or Event of Default has occurred and is continuing.

(d) As of the date hereof, the Borrower has performed all obligations to be performed on its part as set forth in the Agreement and the other Loan Documents.

SECTION 4. Conditions to Effectiveness. The amendments to the Agreement set forth in this Amendment shall become effective when the Agent shall have received (a) counterparts of this Amendment which, when taken together, bear the signatures of the Borrower and each of the Banks under the Agreement and (b) evidence satisfactory to it that the Amendment has been (or will prior to any borrowing under the Agreement have been) duly authorized by the Board of Directors of the Borrower.

SECTION 5. Agreement. Except as specifically amended hereby, the Agreement shall continue in full force and effect in accordance with the provisions thereof as in existence on the date hereof. After the date hereof, any reference to the Agreement shall mean the Agreement as amended hereby.

SECTION 6. Applicable Law. THIS AMENDMENT SHALL BE CONSTRUED IN ACCORDANCE WITH AND GOVERNED BY THE LAWS OF THE STATE OF NEW YORK.

SECTION 7. Counterparts. This Amendment may be executed in two or more counterparts, each of which shall constitute an original, but all of which when taken together shall constitute but one contract.

SECTION 8. Expenses. The Borrower agrees to reimburse the Agent for its reasonable out-of-pocket expenses in connection with this Amendment, including the reasonable fees, charges and disbursements of Cravath, Swaine & Moore, counsel for the Agent.

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be duly executed by their respective authorized officers as of the day and year first written above.

THE WASHINGTON WATER POWER
COMPANY, as the Borrower,

by /s/ Ronald R. Peterson

Name: Ronald R. Peterson
Title: Treasurer

TORONTO DOMINION (TEXAS),
INC., as Agent,

by /s/ Sophia D. Sgarbi

Name: Sophia D. Sgarbi
Title: Vice President

THE TORONTO-DOMINION BANK,
HOUSTON AGENCY,

by /s/ Sophia D. Sgarbi

Name: Sophia D. Sgarbi
Title: Manager Syndications & Credit
Administration

THE BANK OF NEW YORK,

by /s/ Daniel T. Gates

Name: Daniel T. Gates
Title: Vice President

CIBC INC.,

by /s/ P. Saggau

Name: P. Saggau
Title: Vice President

CITICORP USA,

by /s/ Mark Lyons

Name: Mark Lyons
Title: Vice President

Exhibit 4(e)-2

THIRD AMENDMENT
TO
REVOLVING CREDIT AGREEMENT

THIS AGREEMENT dated as of November 21, 1994, AMENDS that certain Revolving Credit Agreement between The Washington Water Power Company ("Borrower"); Seattle-First National Bank, West One Bank Idaho, N.A., First Interstate Bank of Washington, N.A., First Security Bank of Idaho, N.A., U.S. Bank of Washington, N.A. and Washington Trust Bank (the "Banks"); and Seattle-First National Bank, as Agent for the Banks (the "Agent") dated as of December 10, 1992 (the "Credit Agreement"), as previously amended on March 1, 1993 and January 21, 1994.

WHEREAS, pursuant to Section 2.10 of Credit Agreement, the Borrower requested the extension of the Expiration Date; and

WHEREAS, the Banks would agree to the requested extension only if the Borrower agreed to the following amendment;

THEREFORE, in consideration of the mutual covenants it is HEREBY AGREED as follows:

1. The Definition of "Applicable Margin" contained in Section 1 is hereby amended to read as follows:

"Applicable Margin" shall mean on any date, with respect to Eurodollar Loans or ABR Loans, as the case may be, the applicable spreads set forth below based upon the Rating Level on that date:

	Eurodollar Loan Spread	ABR Loan Spread
Rating Level 1	0.35%	0.0%
Rating Level 2	0.45%	0.0%
Rating Level 3	0.75%	0.5%

Each change in the Applicable Margin shall apply to all Eurodollar Loans that are outstanding at any time during the period commencing on the effective date of such change and ending on the date immediately preceding the effective date of the next such change.

2. The Definition of "Commitment Fee" contained in Section 1 is hereby amended to read as follows:

"Commitment Fee" shall mean with respect to each Bank that per annum fee equal to the applicable rate set forth below based upon the Borrower's Rating Level on that date:

Rating Level 1	0.15%
Rating Level 2	0.1875%
Rating Level 3	0.30%

as applied in accordance with Section 2.6(a).

3. The Expiration Date is extended to December 10, 1997, pursuant to Section 2.10 of the Credit Agreement in the same manner and to the same extent as if there had been no amendment of the Credit Agreement.

4. Except as expressly amended by this Agreement, the Credit Agreement shall continue in full force and effect.

5. This Agreement may be executed in multiple counterparts, including signed facsimile copies followed by delivery to the Agent of the original signed counterpart.

Dated and signed as of this 21st day of November, 1994.

Borrower:

THE WASHINGTON WATER POWER COMPANY

By /s/ Ronald R. Peterson

Name: Ronald R. Peterson
Title: Treasurer

Agent:

SEATTLE-FIRST NATIONAL BANK, as agent for the Banks

By /s/ Dora A. Brown

Name: Dora A. Brown
Title: Assistant Vice President

Exhibit 10(r)(6)

1995 EXECUTIVE OFFICER INCENTIVE PLAN

This plan provided the opportunity in 1995 for executive officers including Mr. Redmond to earn annual incentives in addition to their salaries. The Compensation Committee each year establishes the target amounts as a specified percentage of the executive officer's salary. For 1995, such percentages ranged from 35% to 40% for executive officers and 50% for Mr. Redmond. In the event that various goals (as more fully described under Annual Incentives) are achieved, an executive officer may be entitled to receive the full award and, in the event that certain performance goals have been exceeded, an executive officer may be entitled to receive up to 150% of such targeted percentage.

ANNUAL INCENTIVES

Each year, the Committee establishes short-term financial goals which relate to one or more indicators of corporate financial performance. Generally, incentive awards are paid to participating executives under the Executive Incentive Compensation Plan only when the pre-designated financial goals and the individual performance goals are achieved. Because the Merger was expected to be consummated during 1995, the Committee did not establish formal corporate financial goals for a performance period which was expected to be less than one year, but instead based the annual incentive award upon the overall financial performance of the Company and the individual performance of each executive. In reviewing the Company's overall financial performance, the Committee considered such corporate performance measures as earnings per share growth, internal cash generation, share price appreciation, return on common equity, book value, dividend payout ratio and cost management. The evaluation of each executive included a determination of factors including sustained performance of each executive's individual accountabilities, the impact of such individual performance on the business results of the Company, effective leadership of transition efforts, the level of the executive's responsibility, initiative, business judgment, technical expertise, management skills, and strategic direction. The relative importance of each of these factors was discretionary on the part of the Committee, and no particular formulas or weights were applied.

Payouts under the Executive Incentive Compensation Plan are normally made 50% in cash and 50% in Company Common Stock, consistent with the philosophy of the Committee that payment of a portion of the short-term incentive opportunity in the form of Company Common Stock helps strike a balance between the focus of executives on short-term and long-term corporate financial results. Nevertheless, because executive officers who would have otherwise received stock as compensation within six months prior to the effective date of the Merger could have been subject to adverse consequences under the federal securities laws, stock could not be granted for 1995 performance, and all incentive awards for 1995 were paid in cash.

LONG-TERM INCENTIVES

No long-term goals were established for 1995 because it was assumed the Merger would close before year-end.

EXHIBIT 12

THE WASHINGTON WATER POWER COMPANY

Computation of Ratio of Earnings to Fixed Charges and Preferred Dividend Requirements(1)
Consolidated
(Thousand of Dollars)

	YEARS ENDED DECEMBER 31				
	1995	1994	1993	1992	1991
Fixed charges, as defined:					
Interest on long-term debt	$ 55,580	$ 49,566	$ 47,129	$ 51,727	$ 52,801
Amortization of debt expenses and premium -- net	3,441	3,511	3,004	1,814	1,751
Interest portion of rentals	3,962	1,282	924	1,105	1,018
Total fixed charges	$ 62,983	$ 54,359	$ 51,057	$ 54,646	$ 55,570
Earnings, as defined:					
Net income from continuing ops.	$ 87,121	$ 77,197	$ 82,776	$ 72,267	$ 70,631
Add (deduct);					
Income tax expense	52,416	44,696	42,503	41,330	38,086
Total fixed charges above	62,983	54,359	51,057	54,646	55,570
Total earnings	$202,520	$176,252	$176,336	$168,243	$164,287
Ratio of earnings to fixed charges	3.22	3.24	3.45	3.08	2.96
Fixed charges and preferred dividend requirements:					
Fixed charges above	$ 62,983	$ 54,359	$ 51,057	$ 54,646	$ 55,570
Preferred dividend requirements(2)	14,612	13,668	12,615	10,716	14,302
Total	$ 77,595	$ 68,027	$ 63,672	$ 65,362	$ 69,872
Ratio of earnings to fixed charges and preferred dividend requirements	2.61	2.59	2.77	2.57	2.35

(1) Calculations have been restated to reflect the results from continuing operations (i.e. excluding discontinued coal mining operations).
(2) Preferred dividend requirements have been grossed up to their pre-tax level.

Exhibit 21

THE WASHINGTON WATER POWER COMPANY

SUBSIDIARIES OF REGISTRANT

Subsidiary	State of Incorporation
Pentzer Corporation	Washington
Washington Irrigation and Development Company	Washington
WP Finance Company	Washington
Altus Laboratories	Washington
Altus Energy Solutions	Washington

UT

THIS SCHEDULE CONTAINS SUMMARY FINANCIAL INFORMATION EXTRACTED FROM THE CONSOLIDATED FINANCIAL STATEMENTS OF THE WASHINGTON WATER POWER COMPANY, INCLUDED IN THE ANNUAL REPORT ON FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 1995, AND IS QUALIFIED IN ITS ENTIRETY BY REFERENCE TO SUCH FINANCIAL STATEMENTS.

1,000

12-MOS
DEC-31-1995
DEC-31-1995
PER-BOOK
1,357,418
227,457
183,972
330,055
0
2,098,902
582,946
9,148
125,031
717,125
85,000
50,000
651,775
29,500
18,484
0
41,669
0
3,528
5
501,816
2,098,902
755,009
52,416
565,169
565,169
189,840
8,719
198,559
59,022
87,121
9,123
77,998
68,392
31,236
132,232
1.41
1.41

LONG-TERM DEBT-NET DOES NOT MATCH THE AMOUNT REPORTED ON THE COMPANY'S CONSOLIDATED STATEMENT OF CAPITALIZATION AS LONG-TERM DEBT DUE TO THE OTHER CATEGORIES REQUIRED BY THIS SCHEDULE.
OTHER ITEMS CAPITAL AND LIABILITIES INCLUDES THE CURRENT LIABILITIES, DEFFERED CREDITS AND MINORITY INTEREST, LESS CERTAIN AMOUNTS INCLUDED UNDER LONG-TERM DEBT-CURRENT PORTION AND LEASES-CURRENT, FROM THE COMPANY'S CONSOLIDATED BALANCE SHEET.
THE COMPANY DOES NOT INCLUDE INCOME TAX EXPENSE AS AN OPERATING EXPENSE ITEM. IT IS INCLUDED ON THE COMPANY'S STATEMENTS AS A BELOW-THE-LINE-ITEM.
INCOME BEFORE INTEREST EXPENSE IS NOT A SPECIFIC LINE ITEM ON THE COMPANY'S INCOME STATEMENTS. THE COMPANY COMBINES TOTAL INTEREST EXPENSE AND OTHER INCOME TO CALCULATE INCOME BEFORE INCOME TAXES.