CONFORMED

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED **DECEMBER 31, 2002** OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE TRANSITION PERIOD FROM ______ TO ______

Commission file number 1-3701

AVISTA CORPORATION

(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

Web site: http://www.avistacorp.com

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
7 7/8% Trust Originated Preferred Securities, Series A	New York 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 (§ 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. [ ]

Indicate by check mark whether the Registrant is an accelerated filer (as defined in Rule 12b-2 of the Act):

Yes [X] No [ ]

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 $660,054,800, based on the last reported sale price thereof on the consolidated tape on June 28, 2002.

As of February 28, 2003, 48,118,294 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 8, 2003	Part III, Items 10, 11, 12 and 13

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* = not an applicable item in the 2002 calendar year for the Company

AVISTA CORPORATION

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 the average rate at which a particular generating source produces energy over a period of time
AFUCE	- - Allowance for Funds Used to Conserve Energy; a carrying charge similar to AFUDC (see below) for conservation-related capital expenditures
AFUDC	- - Allowance for Funds Used During Construction; represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period
APB	- - Accounting Principles Board
Avista Capital	- - Parent company to the Company's non-utility businesses
Avista Corp.	- - Avista Corporation, the Company
BPA	- - Bonneville Power Administration
Capacity	- - the rate at which a particular generating source produces energy, measured in KW or MW
Centralia	- - the coal-fired Centralia Power Plant in western Washington State
Colstrip	- - the coal-fired Colstrip Generating Plant in southeastern Montana
Coyote Springs 2	- - the natural gas-fired Coyote Springs 2 Generating Plant located near Boardman, Oregon
CFTC	- - U.S. Commodity Futures Trading Commission
CPUC	- - California Public Utilities Commission
CT	- - combustion turbine
Energy	- - the amount of electricity produced or consumed over a period of time, measured in KWH or MWH
EITF	- - Emerging Issues Task Force
ERM	- - the Energy Recovery Mechanism in the State of Washington
FASB	- - Financial Accounting Standards Board
FERC	- - Federal Energy Regulatory Commission
IPUC	- - Idaho Public Utilities Commission
KV	- - Kilovolt - a measure of capacity on transmission lines
KW, KWH	- - Kilowatt, kilowatt-hour, 1000 watts or 1000 watt hours
MTN	- - Medium-Term Note
MW, MWH	- - Megawatt, megawatt-hour, 1000 KW or 1000 KWH

OPUC	- - Oregon Public Utility Commission
PCA	- - the Power Cost Adjustment mechanism in the State of Idaho
PGA	- - Purchased Gas Adjustment
PUD	- - Public Utility District
PURPA	- - the Public Utilities Regulatory Policies Act of 1978
RTO	- - Regional Transmission Organization
SFAS	- - Statement of Financial Accounting Standards
SMD	- - Standard Market Design
Therm	- - Unit of measurement for natural gas; a therm is equal to approximately one hundred cubic feet (volume) or 100,000 BTUs (energy)
VAR	- - Value-at-Risk, measures the expected risk of portfolio loss under hypothetical adverse price movements, over a given time interval within a given confidence level
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
WECC	- - Western Electricity Coordinating Council
WUTC	- - Washington Utilities and Transportation Commission

AVISTA CORPORATION

PART I

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Forward-looking statements should be read with the cautionary statements and important factors included in this Annual Report on Form 10-K at Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations - Safe Harbor for Forward-Looking Statements." Forward-looking statements are all statements other than statements of historical fact, including without limitation those that are identified by the use of words such as, but not limited to, "will," "anticipates," "seeks to," "estimates," "expects," "intends," "plans," "predicts," and similar expressions. Such statements are inherently subject to a variety of risks and uncertainties that could cause actual results to differ materially from those expressed. Most of these risks and uncertainties are beyond the Company's control.

Available Information

The Web site address of Avista Corporation (Avista Corp. or the Company) is http://www.avistacorp.com. Avista Corp. makes available free of charge, on or through its Web site, its annual, quarterly and current reports, and any amendments to those reports, as soon as reasonably practicable after electronically filing such reports with the Securities and Exchange Commission. Information contained on Avista Corp.'s Web site is not part of this report.

Item 1. Business

Company Overview

Avista Corp. was incorporated in the State of Washington in 1889. Avista Corp. is an energy company engaged in the generation, transmission and distribution of energy as well as other energy-related businesses. As of December 31, 2002, the Company's employees included approximately 1,410 people in its utility operations and approximately 540 people in its subsidiary businesses. The Company's corporate headquarters are in Spokane, Washington, which serves as the Inland Northwest center for manufacturing, transportation, health care, education, communication, agricultural, financial and service businesses.

The Company's operations are exposed to risks, including, but not limited to, the price and supply of purchased power, fuel and natural gas, recoverability of power and natural gas costs, streamflow and weather conditions, the effects of changes in legislative and governmental regulations, availability of generation facilities, competition, technology and availability of funding. Also, like other utilities, the Company's facilities and operations may be exposed to terrorism risks. In addition, the energy business exposes the Company to the financial, liquidity, credit and commodity price risks associated with wholesale purchases and sales.

The Company is organized into four lines of business – Avista Utilities, Energy Trading and Marketing, Information and Technology, and Other. Avista Capital, a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies engaged in the non-utility lines of business. As of December 31, 2002, the Company had common equity investments of $457.6 million and $255.2 million in Avista Utilities and Avista Capital, respectively.

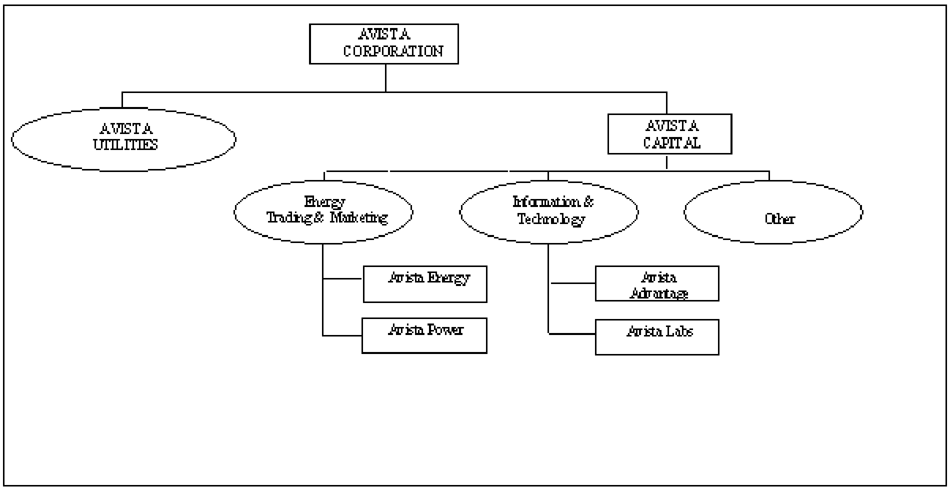
Avista Utilities, an operating division of Avista Corp. and not a separate entity, represents the regulated utility operations. Avista Utilities generates, transmits and distributes electricity and distributes natural gas. Avista Utilities also engages in wholesale purchases and sales of electric capacity and energy. Avista Utilities seeks to maintain a strong, low-cost and efficient electric and natural gas utility business focused on providing reliable, high quality service to its customers. The utility business is expected to grow modestly, consistent with historical trends. Expansion is expected to result primarily from economic growth in its service territory. It is Avista Utilities' strategy to own or control a sufficient amount of resources to meet its retail and wholesale energy requirements on an average annual basis.

The Energy Trading and Marketing line of business includes Avista Energy, Inc. (Avista Energy) and Avista Power, LLC (Avista Power). Avista Energy is an electricity and natural gas marketing and trading business, operating primarily within the Western Electricity Coordinating Council (WECC) geographical area, which is comprised of eleven Western states. Avista Energy focuses on asset-backed optimization of combustion turbines and hydroelectric assets owned by other entities, long-term electric supply contracts, natural gas storage, and electric and natural gas transmission and transportation arrangements. Avista Energy's marketing efforts are driven by its base of knowledge and experience in the operation of both electric energy and natural gas physical systems in the WECC, as well as its relationship-focused approach with its customers. Avista Power was originally formed to develop and own generation assets. During 2001, the Company decided that Avista Power would no longer pursue the development of additional non-regulated generation projects. Avista Power continues to manage the generation assets it currently owns, primarily its 49 percent interest in a 270 megawatt (MW) natural gas-fired combustion turbine plant in northern Idaho (Lancaster Project), which commenced commercial operation in September 2001.

The Information and Technology line of business includes Avista Advantage, Inc. (Avista Advantage) and Avista Laboratories, Inc. (Avista Labs). Avista Advantage is a provider of internet-based facility intelligence, cost management, billing and information services to retail customers throughout North America. Avista Advantage remains focused on growing revenue, improving margins, reducing fixed and variable costs and improving client satisfaction. Avista Labs has patented and developed a modular air-cooled, self-hydrating Proton Exchange Membrane (PEM) fuel cell that delivers reliable and clean distributed power solutions. In addition to developing its modular fuel cell products, Avista Labs is contracting with selected market channels to deliver system solutions to industrial, commercial and residential markets. Avista Labs holds a 70 percent equity interest in H2fuel, LLC, a developer of fuel processors for the production of hydrogen. Avista Corp. continues discussions with selected companies in its search for a financial partner for Avista Labs with the goal of owning less than 20 percent of this company.

The Other line of business includes Avista Ventures, Inc. (Avista Ventures), Avista Capital (parent company only amounts), Pentzer Corporation (Pentzer) and several other subsidiaries. The Company continues to limit its future investment in this line of business.

The Company's current lines of business, and the companies included within them, are illustrated below:



o - - denotes a business entity.

O - denotes an operating division or line of business.

See "Item 6. Selected Financial Data" and "Schedule of Information by Business Segments in the Consolidated Financial Statements" for information with respect to the operating performance of each business segment.

AVISTA CORPORATION

Avista Utilities

General

Avista Utilities generates, transmits and distributes electricity and distributes natural gas. Retail electric and natural gas customers include residential, commercial and industrial classifications. Avista Utilities also engages in wholesale purchases and sales of electric capacity and energy as part of its resource management and load-serving obligations.

Avista Utilities provides electric and natural gas distribution and transmission services in a 26,000 square mile area in eastern Washington and northern Idaho with a population of approximately 813,000. It also provides natural gas distribution service in a 4,000 square mile area in northeast and southwest Oregon and in the South Lake Tahoe region of California, with the population in these areas approximating 611,000. At the end of 2002, Avista Utilities supplied retail electric service to approximately 320,000 customers in eastern Washington and northern Idaho and retail natural gas service to approximately 290,000 customers in parts of Washington, Idaho, Oregon and California.

Avista Utilities anticipates residential and commercial electric load growth to average between 2.5 and 3.5 percent annually for the next four years, primarily due to expected increases in both population and the number of businesses in its service territory. The number of electric customers is expected to increase; however, the average annual usage by residential customers is not expected to change significantly. For the next four years, Avista Utilities expects natural gas load growth to average between 3.0 and 4.0 percent annually in its service territory. The natural gas load growth is primarily due to expected conversions from electric space, oil space and electric water heating to natural gas, and increases in both population and the number of businesses in Avista Utilities' service territories. These electric and natural gas load growth projections are based on purchased economic forecasts, publicly available studies, and internal analysis of company-specific data, such as energy consumption patterns and internal business plans. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Future Outlook" for additional information.

During 2001 and 2002, Avista Utilities experienced decreased loads and decreased use per customer with respect to both electric and natural gas retail sales. The decrease in use per customer appears to be primarily due to a response to the increase in rates and the resulting conservation efforts of individual customers. The decrease in use per customer in 2002 and 2001 as compared to 2000 also appears to reflect milder weather in 2002 and 2001 as compared to 2000. The decrease in total kilowatt-hours (kWhs) and therms sold primarily relates to industrial customers and appears to reflect a general downturn in the economy of Avista Utilities' service territory. However, as described above, based on economic forecasts, publicly available studies and internal analysis of company-specific data, the Company does not expect the trend of declining loads to continue over the next four years.

Electric Operations

In addition to providing electric transmission and distribution services, Avista Utilities generates electricity for sales to customers. Avista Utilities owns and operates eight hydroelectric projects, a wood-waste fueled generating station, a two-unit natural gas-fired combustion turbine (CT) generating facility and two small generating facilities. It also owns a 15 percent share in a two-unit coal-fired generating facility and leases and operates a two-unit natural gas-fired CT generating facility. In mid-2003, it is expected that the natural gas-fired Coyote Springs 2 Generation Project (Coyote Springs 2) will be placed into operation. Avista Utilities has a 50 percent ownership interest (140 MW) in Coyote Springs 2. In addition to company-owned resources, Avista Utilities has a number of long-term power purchase and exchange contracts that increase its available resources. See "Item 2. Properties" for further information with respect to generation properties.

Historically, Avista Utilities' electric rates to retail customers have been among the lowest of investor-owned utilities in the United States, due primarily to its large proportion of hydroelectric resources as compared to other investor-owned utilities. Retail electric rates remain low, relative to other investor-owned utilities in the United States, even after the enactment of rate increases in 2001 and 2002. See "Regulatory Issues-Power Cost Deferrals" and "Regulatory Issues-General Rate Cases" for further information.

Avista Utilities sells and purchases electric capacity and energy to and from utilities and other entities in the wholesale market under long-term contracts having terms of more than one year. In addition, Avista Utilities engages in an ongoing process of resource optimization which involves short-term purchases and sales in the wholesale market in pursuit of an economic selection of resources to serve retail and wholesale loads. Avista Utilities makes continuing projections of (1) future retail and wholesale loads based on, among other things, forward estimates of factors such as customer usage and weather as well as historical data and contract terms and (2) resource availability based on, among other things, estimates of streamflows, generating unit availability, historic and forward market information and experience. On the basis of these continuing projections, Avista Utilities makes purchases and sales of energy on an annual, quarterly, monthly, daily and hourly basis to match actual resources to actual energy requirements. This process includes hedging transactions.

Participants in the electric wholesale market include other utilities, federal marketing agencies and power marketers. The electric wholesale market has changed significantly over the last few years with respect to market participants involved, level of activity, variability in market prices, liquidity, Federal Energy Regulatory Commission (FERC)-imposed price caps and counterparty credit issues. During 2000 and the first half of 2001, the electric wholesale market in the WECC region was more turbulent than previously experienced and marked by significant volatility, service disruptions and defaults by certain participants. During the second half of 2001 and 2002 wholesale market prices and volatility both decreased to levels similar to those experienced before 2000. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Power Market Issues” for more information.

Challenges facing Avista Utilities’ electric operations include, among other things, the timing of the recovery of deferred power supply costs, changes in the availability of and volatility in the prices of power and fuel, generating unit availability, legislative and governmental regulations, potential tax law changes, customer response to price increases and surcharges, streamflows and weather conditions. Avista Utilities may also be exposed to refunds for wholesale power sales depending on the outcome of the FERC’s retroactive price cap proceeding for the Pacific Northwest; however, Avista Utilities would have the opportunity to assert offsetting claims. See “Industry Restructuring,” “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Power Market Issues” and “Note 1 of Notes to Consolidated Financial Statements” for additional information.

Electric Requirements

The peak electric load requirement for 2002 was 1,855 MW (including retail native load of 1,389 MW, long-term wholesale obligations of 320 MW and short-term wholesale obligations of 146 MW). This peak occurred on July 12, 2002 at which time the maximum resource capacity available from Avista Utilities was 2,287 MW. The maximum resource capacity included 1,362 MW of company-owned electric generation, 119 MW of long-term hydroelectric contracts, 210 MW of other long-term wholesale purchases and 596 MW of short-term wholesale purchases. Variations in energy usage by Avista Utilities’ customers occur from year to year, from season to season and hour to hour as a result of varying weather conditions and other energy usage behaviors. This necessitates a continual balancing of loads and resources, and requires both purchases and sales of energy for annual, quarterly, monthly, daily and hourly periods in order to meet electric requirements and to prudently manage and optimize available resources.

Electric Resources

General Avista Utilities’ diverse electric resource mix of hydroelectric projects, thermal generating facilities, and power purchases and exchanges, enables it to remain a low-cost and reliable provider of electric energy. At the end of 2002, Avista Utilities’ facilities had a total net capability of approximately 1,511 MW, of which 64 percent was hydroelectric and 36 percent was thermal. See “Avista Utilities Operating Statistics – Electric Operations” for energy resource statistics.

Hydroelectric Resources Hydroelectric generation is Avista Utilities’ lowest cost source per MWh of electricity and the availability of hydroelectric generation has a significant effect on its total power supply costs. Under normal streamflow and operating conditions, Avista Utilities projects that it would be able to meet approximately one-half of its total electric requirements (both retail and long-term wholesale) with its own hydroelectric generation and long-term hydroelectric contracts with certain Public Utility Districts in Washington state. Total hydroelectric resource generation (both company-owned and purchased under long-term hydroelectric contracts) was 4.8 million MWhs in 2002, compared to 3.2 million MWhs in 2001 and 4.7 million MWhs in 2000.

Total hydroelectric resources (including resources purchased under long-term hydroelectric contracts) generate 550 average megawatts (aMW) (or 4.8 million MWhs) annually under normal streamflow conditions. Hydroelectric resources generated 553 aMW during 2002. The streamflows to company-owned hydroelectric projects were 112 percent, 56 percent and 86 percent of normal in 2002, 2001 and 2000, respectively. In a “critical water” year (defined by the Northwest Power Pool as the worst water conditions on record), Avista Utilities would expect hydroelectric generation of 400 aMW, 150 aMW below normal. Hydroelectric generation for the year 2001 was 369 aMW, which was 181 aMW below normal and the lowest level in the 73 years in which records have been kept. The combination of low hydroelectric production and other factors resulted in Avista Utilities incurring power supply costs during the second half of 2000 and the year 2001 significantly in excess of the amount of power supply costs recovered through retail rates in effect at the time. See “Regulatory Issues – Power Cost Deferrals” and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Avista Utilities-Regulatory Matters” for more information.

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The following table shows Avista Utilities' hydroelectric generation (in thousands of MWhs) during the years ended December 31:

	2002	2001	2000
Noxon Rapids	1,816	1,021	1,635
Cabinet Gorge	1,085	694	1,057
Post Falls	87	67	88
Upper Falls	75	66	76
Monroe Street	105	89	109
Nine Mile	126	99	135
Long Lake	511	370	511
Little Falls	205	158	208
Total company-owned hydroelectric generation	4,010	2,564	3,819
Long-term hydroelectric contracts	837	631	929
Total hydroelectric generation	4,847	3,195	4,748

Thermal Resources Avista Utilities owns a 15 percent interest in a twin-unit, coal-fired generating facility, the Colstrip 3 & 4 Generating Project (Colstrip) in southeastern Montana. Additionally, Avista Utilities owns a wood-waste-fired generating facility known as the Kettle Falls Generating Station (Kettle Falls) in northeastern Washington and a two-unit natural gas-fired CT generating facility, located in northeast Spokane (Northeast CT). Avista Utilities also leases and operates a two-unit natural gas-fired CT generating facility in northern Idaho (Rathdrum CT). In addition, Avista Utilities owns two small generating facilities (Boulder Park and Kettle Falls CT) that were placed into service in 2002.

Avista Utilities owns a 50 percent interest in the natural gas-fired Coyote Springs 2 located near Boardman, Oregon. It is expected that Coyote Springs 2 will be placed into operation in the middle of 2003. In January 2003, Avista Power's 50 percent ownership interest in Coyote Springs 2 was transferred to Avista Corp. for inclusion in Avista Utilities' power generation resource portfolio. In May 2002, a transformer at Coyote Springs 2 failed and caught fire resulting in the release of an estimated 17,000 gallons of coolant oil. The Company worked closely with the appropriate environmental agencies to complete a satisfactory cleanup of the oil. In December 2002, the replacement transformer was received, but it was determined to be damaged. The problems with the transformer have delayed the scheduled completion of Coyote Springs 2 from the third quarter of 2002 to the middle of 2003.

Until May 2000, Avista Utilities had a 15 percent interest in a twin-unit, coal-fired generating facility, the Centralia Power Plant (Centralia) in western Washington. In May 2000, the owners of Centralia sold the plant to TransAlta. Avista Utilities is purchasing energy from TransAlta to replace the output from Centralia for the period from July 1, 2000 through December 31, 2003, excluding April, May and June of each year. Avista Utilities receives approximately 200 megawatts per hour during the term of the contract.

Fuel Supply for Thermal Resources Coyote Springs 2, which will be operated by Portland General Electric, will be supplied with natural gas under natural gas supply contracts through October 2004, and transportation agreements with unilateral renewal rights are in place.

Colstrip, which is operated by PPL Global, Inc., is supplied with fuel from adjacent coal reserves under coal supply and transportation agreements in effect through December 2019.

Kettle Falls' primary fuel is wood-waste generated as a by-product from forest industry operations within 100 miles of the plant. Natural gas may be used as an alternate fuel. A combination of long-term contracts plus spot purchases provides Avista Utilities the flexibility to meet expected future fuel requirements for the plant.

The Northeast CT, Rathdrum CT, Boulder Park and Kettle Falls CT are generating units that are primarily used for peaking electric requirements. Due to the shortage of hydroelectric generation during 2000 and 2001 and the relative operating cost compared to higher wholesale market prices, the Northeast CT and Rathdrum CT units were operated on a more frequent basis. These generating facilities have access to natural gas supplies that are adequate to meet their respective operating needs.

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The following table shows Avista Utilities' thermal generation (in thousands of MWhs) during the years ended December 31:

	2002	2001	2000
Centralia	—	—	493
Colstrip	1,397	1,617	1,473
Kettle Falls	261	361	370
Northeast CT and Rathdrum CT	39	1,023	817
Boulder Park and Kettle Falls CT	17	—	—
Total thermal generation	1,714	3,001	3,153

Purchases, Exchanges and Sales Avista Utilities purchases power under various long-term contracts. Avista Utilities also enters into a significant number of short-term sales and purchases with terms of up to one year.

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), Avista Utilities is required to purchase generation from qualifying facilities, including small hydroelectric and cogeneration projects, at rates approved by the Washington Utilities and Transportation Commission (WUTC) and the Idaho Public Utilities Commission (IPUC). These contracts expire at various times through 2022.

See "Avista Utilities Operating Statistics – Electric Operations - Electric Energy Resources" for more detailed information with respect to purchased power and power from exchanges in 2002, 2001 and 2000.

Future Resource Needs

Avista Utilities has operational strategies to ensure that it has available resources sufficient to meet the increased demand for energy. The following is a forecast of Avista Utilities' average energy requirements and resources for the period 2003 through 2005:

Forecasted Electric Energy Requirements and Resources
(aMW)

	2003	2004	2005
Requirements:			
System load	1,010	1,039	1,070
Contracts for power sales	21	1	1
Total Requirements	1,031	1,040	1,071
Resources:			
System and contract hydro (1)	458	550	550
Company owned thermal generation (2)	301	365	362
Contracts for purchased power	261	216	217
Total Resources	1,020	1,131	1,129
Surplus (Deficit) Resources	(11)	91	58
Additional available capacity (3)	274	274	274
Total surplus resources	263	365	332

(1) Preliminary forecasts and snowpack conditions indicate streamflows are expected to be approximately 70 percent of normal in 2003. Avista Utilities currently estimates that hydroelectric generation will be 458 aMW in 2003, which is 92 aMW below normal. The forecasts for 2004 and 2005 assume normal water conditions, which is the mean of the 60 years between 1928 and 1988.

(2) Forecast assumes that Coyote Springs 2 will be placed in operation in mid-2003.

(3) Forecast assumes no generation from the Northeast CT, Rathdrum CT, Kettle Falls CT and Boulder Park, which are generally only used to meet electric load requirements due to either below normal hydroelectric generation and increased loads, and/or when operating costs are lower than short-term wholesale market prices. The combined maximum capacity of the Northeast CT, Rathdrum CT, Kettle Falls CT and Boulder Park is 274 MW.

Significant Customer A contract with Potlatch Corporation (Potlatch), expired on December 31, 2001. Potlatch's Lewiston, Idaho facility has electric requirements of about 100 aMW. The facility also produces approximately 60 aMW of self-generation. The parties have agreed that Potlatch will receive electric service from Avista at the retail tariff rates established for large industrial customers. Potlatch is currently using its generation for its own electric requirements, which results in a net electric requirement on Avista Utilities' system of approximately 40 aMW. In December 2002, Potlatch filed a complaint with the IPUC requesting that Avista Utilities be required to purchase its self-generation at a rate equivalent to Avista Utilities' avoided costs. Hearings before the IPUC are currently scheduled for June 2003.

Hydroelectric Relicensing

Avista Corp. is a licensee under the Federal Power Act, which regulates certain of its hydroelectric generation resources, as administered by the FERC. Avista Corp.'s licensed projects are subject to the provisions of Part I of the Federal Power 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. All but the Little Falls Plant of the Company's hydroelectric plants are regulated by the FERC through project licenses issued for 30-50 year periods.

In February 2000, Avista Utilities received a 45-year operating license from the FERC for the Cabinet Gorge and Noxon Rapids Hydroelectric Generating Projects. The Clark Fork Settlement Agreement that was entered into during 1999 and incorporated into the FERC license, preserved the projects' economic peaking and load following operations. Also, as part of the Clark Fork Settlement Agreement, Avista Utilities initiated implementation of protection, mitigation and enhancement measures in March 1999. Measures in the agreement, which cost approximately $4.7 million annually, address issues related to fisheries, water quality, wildlife, recreation, land use, cultural resources and erosion. Recovery of previously deferred hydroelectric relicensing costs, as well as estimated levels of ongoing costs associated with implementation of the Clark Fork Settlement Agreement, were addressed by both the WUTC and IPUC and received favorable regulatory recovery treatment. Costs of approximately $15 million deferred during the licensing phase were allowed in rate base and are being amortized over the 45-year license term. See "Item 2. Properties - Avista Utilities" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Future Outlook" for additional information.

The issue of high levels of dissolved gas which exceed Idaho and federal water quality standards downstream of the Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) during spill periods continues to be studied, as agreed to in the Clark Fork Settlement Agreement and incorporated in the renewed FERC license. To date, intensive biological studies in the lower Clark Fork River and Lake Pend Oreille have documented minimal biological effects of high dissolved gas levels on free ranging fish. Under the terms of the Clark Fork Settlement Agreement, the Company developed an abatement and mitigation strategy during 2002 with the other signatories to the agreement. In December 2002, the Company submitted its plan for review and approval by the other signatories as well as the FERC. The structural alternative proposed in the plan provides for the modification of the two existing diversion tunnels built when Cabinet Gorge was originally constructed. The costs of modifications to the first tunnel are currently estimated to be $37 million (including allowance for funds used during construction (AFUDC) and inflation) and would be incurred between 2004 and 2009. The second tunnel would be modified only after evaluation of the performance of the first tunnel and such modifications would commence no later than 10 years following the completion of the first tunnel. It is currently estimated that the costs to modify the second tunnel would be $23 million (including AFUDC and inflation). As part of the plan, the Company will also provide $0.5 million annually commencing as early as 2004, as mitigation for aquatic resources that might be adversely affected by high dissolved gas levels. Mitigation funds will continue until the modification of the second tunnel commences or if the second tunnel is not modified to an agreed upon point in time commensurate with the biological effects of high dissolved gas levels. The Company will seek regulatory recovery of the costs for the modification of Cabinet Gorge and the mitigation payments.

The Company operates six hydroelectric plants on the Spokane River, and five of these (Long Lake, Nine Mile, Upper Falls, Monroe Street and Post Falls) are under one FERC license and referred to herein as the Spokane River Project. The sixth, Little Falls, operates under separate Congressional authorization and is not licensed by the FERC. The license for the Spokane River Project expires in August 2007; the Company filed a Notice of Intent to Relicense on July 29, 2002. The formal consultation process involving planning and information gathering with stakeholder groups is underway. The Company's goal is to develop with the stakeholders a comprehensive and cost-effective settlement agreement to be filed as part of the Company's license application to the FERC in July 2005.

Natural Gas Operations

Avista Utilities provides natural gas distribution services to retail customers in parts of Washington, Idaho, Oregon and California. Natural gas commodity costs in excess of the amount recovered in current rates are deferred and recovered in future periods with applicable regulatory approval through adjustments to rates. Market prices for natural gas continue to be competitive compared to alternative fuel sources for residential, commercial and industrial customers. Avista Utilities believes that natural gas should sustain its market advantage based on the levels of existing reserves and potential natural gas development in the future. Growth has occurred in the natural gas business in recent years due to increased demand for natural gas in new construction, as well as conversions from electric space, oil space and electric water heating to natural gas.

Avista Utilities makes sales and provides transportation service directly to large natural gas customers. The majority of Avista Utilities' large industrial customers purchase their own natural gas requirements through natural gas marketers. For these customers, Avista Utilities provides transportation from its pipeline interconnection to the customers' premises. Thirteen of Avista Utilities' largest natural gas customers are provided natural gas transportation service under individual contracts. These negotiated contracts were entered into to retain these customers who can either by-pass Avista Utilities' distribution system or have competitive alternative fuel capability. All individual contracts are subject to regulatory review and approval. The competitive nature of the natural gas spot 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 when economic. The total volume transported on behalf of transportation customers for 2002, 2001 and 2000 was 174.9, 180.9 and 224.8 million therms, which represented approximately 34 percent, 33 percent and 38 percent of Avista Utilities' total system deliveries, respectively.

Challenges facing Avista Utilities' natural gas operations include, among other things, volatility in the price of natural gas, the timing of recovery of increased commodity costs, customer response to changes in prices, changes in the availability of natural gas, legislative and governmental regulations and weather conditions.

Natural Gas Resources

Natural Gas Supply Natural gas supplies are available from domestic and Canadian sources through both long- and short-term, or spot market, purchases. Avista Utilities has capacity delivery rights on seven pipelines and owns natural gas storage facilities. A diverse portfolio of natural gas resources allows Avista Utilities to capture market opportunities that benefit its natural gas customers.

The Company's energy trading and marketing subsidiary, Avista Energy, is responsible for the daily management and optimization of these resources for the requirements of customers in the states of Washington, Idaho and Oregon under an agreement with Avista Utilities. Under this relationship, Avista Utilities retains ownership of its transportation, storage and long-term contracts and Avista Energy acts as an agent to optimize these important resources. See "Regulatory Issues: Natural Gas Benchmark Mechanism" and "Note 1 of Notes to Consolidated Financial Statements" for additional information.

Approximately 25 percent of Avista Utilities' natural gas supplies are obtained from domestic sources, with the remaining 75 percent from Canadian sources. Nearly all natural gas purchased from Canadian sources is contracted in U.S. dollars, limiting any foreign currency exchange exposure. Canadian natural gas supplies are not considered to be at greater risk of non-delivery than supplies from the United States.

Jackson Prairie Natural Gas Storage Project (Jackson Prairie) Avista Utilities owns a one-third interest in Jackson Prairie, an underground natural gas storage field located near Chehalis, Washington. Jackson Prairie has a total peak day deliverability of 8.8 million therms, with a total working natural gas inventory of 190.3 million therms. The role of Jackson Prairie in providing flexible natural gas supplies is important to Avista Utilities' natural gas operations. It enables Avista Utilities to place natural gas into storage when prices are low or to meet minimum natural gas purchasing requirements, as well as to meet high demand periods or to withdraw natural gas from storage when spot prices are high. During 1999, the capacity at Jackson Prairie was increased. This increased capacity is being operated and managed by Avista Energy for a ten-year period with Avista Energy incurring the associated costs of the increased capacity. During 2002, a multi-year project to further increase the capacity at Jackson Prairie commenced. Avista Utilities has contracted to release a total of approximately 37 percent of its Jackson Prairie capacity to two other utilities. One of these contracts requires two-years notice for termination and one contract is renewed on a year-to-year basis.

Regulatory Issues

Avista Corp., as a regulated public utility, is currently subject to regulation by state utility commissions with respect to prices, accounting, the issuance of securities, and other matters. The retail electric and natural gas operations are subject to the jurisdiction of the WUTC, the IPUC, the Oregon Public Utility Commission (OPUC) and the California Public Utilities Commission (CPUC). The Company is also subject to the jurisdiction of the FERC for its wholesale natural gas rates charged for the release of capacity from Jackson Prairie, and for electric transmission service and wholesale electric sales.

In each regulatory jurisdiction, rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are currently determined on a “cost of service” basis and are 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 of utility plant. As the energy business is restructured, traditional “cost of service” ratemaking may evolve into some other form of ratemaking. Rates for electric and natural gas transmission services are based on the “cost of service” principles and are set forth in tariffs on file with the FERC. See “Note 1 of Notes to Consolidated Financial Statements” for additional information about regulation, depreciation and deferred income taxes. See “Industry Restructuring” for additional information about deregulation, as well as changes with respect to transmission and wholesale electricity markets.

Power Cost Deferrals Avista Utilities defers the recognition in the income statement of certain power supply costs as approved by the WUTC. A portion of power supply costs are recorded as a deferred charge on the balance sheet for future review and the opportunity for recovery through retail rates. The deferred power supply costs include certain differences between actual power supply costs incurred by Avista Utilities and the costs included in base retail rates. This difference in power supply costs primarily results from changes in short-term wholesale market prices, changes in the level of hydroelectric generation and changes in the level of thermal generation (including changes in fuel prices). Avista Utilities accrues interest on deferred power costs in the Washington jurisdiction at a rate, which is adjusted semi-annually, of 8.9 percent as of December 31, 2002. Total deferred power costs were $123.7 million for Washington customers as of December 31, 2002, a decrease from $140.2 million as of December 31, 2001.

In June 2002, the WUTC issued an order that became effective July 1, 2002 with respect to a general electric rate case filed by Avista Utilities in December 2001. Rate increases previously approved by the WUTC totaling 31.2 percent (a 25 percent temporary surcharge approved in September 2001 for the recovery of deferred power costs and a 6.2 percent increase approved in March 2002) were restructured. The general increase to base retail rates was 19.3 percent (or $45.7 million in annual revenues) and the remaining 11.9 percent represents the continued recovery of deferred power costs over a period currently projected to continue into 2009.

In the June 2002 rate order, the WUTC approved the establishment of an Energy Recovery Mechanism (ERM). The ERM replaced a series of temporary power cost deferral mechanisms that were in place in Washington since mid-2000. The ERM allows Avista Utilities to increase or decrease electric rates periodically with WUTC approval to reflect changes in power supply costs. The ERM provides for Avista Utilities to incur the cost of, or receive the benefit from, the first $9 million in annual power supply costs above or below the amount included in base retail rates. Because the ERM was implemented on July 1, 2002, the Company’s expense or benefit was limited to $4.5 million for 2002. Under the ERM, 90 percent of annual power supply costs exceeding or below the initial $9 million ($4.5 million for 2002) is deferred for future surcharge or rebate to Avista Utilities’ customers. The remaining 10 percent is an expense of, or benefit to, the Company.

Avista Utilities has a power cost adjustment (PCA) mechanism in Idaho that allows it to modify electric rates periodically with IPUC approval to recover or rebate a portion of the difference between actual and allowed net power supply costs. The PCA mechanism allows for the deferral of 90 percent of the difference between actual net power supply expenses and the authorized level of net power supply expenses approved in the last Idaho general rate case. Avista Utilities accrues interest on deferred power costs in the Idaho jurisdiction at a rate, which is adjusted annually, of 2 percent as of December 31, 2002. Avista Utilities anticipates making a filing with the IPUC requesting that the interest rate be modified to more closely approximate Avista Utilities’ costs of short-term borrowings until the current PCA surcharge is eliminated. In October 2002, the IPUC issued an order extending a 19.4 percent PCA surcharge for Idaho electric customers. The PCA surcharge will remain in effect until October 2003. The IPUC directed Avista Utilities to file a status report 60 days before the PCA surcharge expires. If review of the status report and the actual balance of deferred power costs support continuation of the PCA surcharge, the IPUC has indicated that it anticipates the PCA surcharge will be extended for an additional period. Total deferred power costs for Idaho customers were $31.5 million as of December 31, 2002, a decrease from $73.1 million as of December 31, 2001.

See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Avista Utilities-Regulatory Matters” for additional information.

General Rate Cases On December 3, 2001, the Company filed a general electric rate case with the WUTC, as ordered by the WUTC in September 2001. Issues addressed included, among other things, the recovery of cash outlays for increased power supply costs and expenses related to building additional generation. The rate case requested by Avista Corp. proposed a 10.39 percent overall rate of return. In June 2002, the WUTC issued an order that became effective July 1, 2002 with respect to the general electric rate case. The order provides for an overall rate of return of 9.72 percent and a return on equity of 11.16 percent. The order provided for no incremental rate increase to Avista Utilities’

Washington electric customers above the rates in effect at the time; however, rate increases previously approved by the WUTC totaling 31.2 percent were restructured. For further information about this WUTC order, see “Power Cost Deferrals” above.

In Avista Utilities’ last general electric rate case in Idaho, the IPUC granted a rate increase of $9.3 million, or 7.6 percent, with an authorized overall rate of return of 8.98 percent and a return on equity of 10.75 percent, effective August 1999.

Avista Utilities is currently planning to file a natural gas general rate case in Oregon during the first half of 2003. The Company regularly reviews the need for natural gas or electric rate changes in each state in which it provides service.

Purchased Gas Adjustment (PGA or Natural Gas Trackers) Natural gas trackers are supplemental tariffs designed to pass through to customers changes in purchased natural gas costs, and do not normally result in any changes in net income. During the fourth quarter of 2002, Avista Utilities adjusted its natural gas rates in all jurisdictions in response to a decrease in current and projected natural gas costs. Natural gas rates were decreased 17.4 percent, 15.5 percent, 7.1 percent and 16.2 percent in Washington, Idaho, Oregon and California, respectively. Total deferred natural gas costs were $11.5 million as of December 31, 2002, a decrease from $52.7 million as of December 31, 2001.

Natural Gas Benchmark Mechanism The IPUC, WUTC and OPUC approved Avista Utilities’ Natural Gas Benchmark Mechanism in 1999. The mechanism eliminated the majority of natural gas procurement operations within Avista Utilities and consolidated gas procurement operations under Avista Energy, the Company’s non-regulated subsidiary. The ownership of the natural gas assets remains with Avista Utilities; however, the assets are managed by Avista Energy through an Agency Agreement. Avista Utilities continues to manage natural gas procurement for its California operations, which currently represents approximately four percent of its total natural gas therm sales.

The Natural Gas Benchmark Mechanism provides benefits to retail customers and allows Avista Energy to retain a portion of the benefits associated with asset optimization and the efficiencies gained in purchasing natural gas for Avista Utilities. In the first quarter of 2002, the IPUC and the OPUC approved the continuation of the Natural Gas Benchmark Mechanism and related Agency Agreement through March 31, 2005. In January 2003, the WUTC approved the continuation of the Natural Gas Benchmark Mechanism and related Agency Agreement through January 29, 2004. Hearings will be held before the WUTC during 2003 to determine whether or not the Natural Gas Benchmark Mechanism and related Agency Agreement will be extended beyond January 29, 2004.

Industry Restructuring

Federal Level

Industry restructuring to open the electric wholesale energy market to competition was initially promoted by federal legislation. The Energy Policy Act of 1992 (Energy Act) amended provisions of the Public Utility Holding Company Act of 1935 (PUHCA) and the Federal Power Act to remove certain barriers to a competitive wholesale market. The Energy Act expanded the authority of the FERC to issue orders requiring electric utilities to transmit power and energy to or for wholesale purchasers and sellers, and to require electric utilities to enlarge or construct additional transmission capacity for the purpose of providing these services. It also created “exempt wholesale generators”, a new class of independent power plant owners that are able to sell generation only at the wholesale level. This permits public utilities and other entities to participate through subsidiaries in the development of independent electric generating plants for sales to wholesale customers without being required to register under the PUHCA.

FERC Order No. 888, issued in April 1996, requires public utilities operating under the Federal Power Act to provide access to their transmission systems to third parties pursuant to the terms and conditions of the FERC’s pro-forma open access transmission tariff. FERC Order No. 889, the companion rule to Order No. 888, requires public utilities to establish an Open Access Same-Time Information System (OASIS) to provide transmission customers with information about available transmission capacity and other information by electronic means. It also requires each public utility subject to the rule to functionally separate its transmission and wholesale power merchant functions. The FERC issued its initial order accepting the non-rate terms and conditions of Avista Utilities’ open access transmission tariff in November 1996. Avista Utilities filed its “Procedures for Implementing Standards of Conduct under FERC Order No. 889” with the FERC in December 1996 and adopted these Procedures effective January 1997. FERC Orders No. 888 and No. 889 have not had a material effect on Avista Utilities’ operating results.

Avista Corp. is negotiating with nine other utilities in the western United States in the possible formation of a Regional Transmission Organization (RTO), RTO West, a non-profit organization. The potential formation of RTO West is in response to a FERC order requiring all utilities subject to FERC regulation to file a proposal to form a RTO, or a description of efforts to participate in a RTO, and any existing obstacles to RTO participation. RTO West filed its Stage 2 proposal with the FERC in March 2002 and received limited approval from the FERC of this initial plan in September 2002. The FERC's goal with respect to the formation of RTOs is to promote efficiency in wholesale electricity markets and in the operation of transmission systems by way of standardized and independent operation of transmission systems.

Avista Corp. and two other utilities have also taken steps toward the formation of a for-profit Independent Transmission Company, TransConnect, which would be a member of RTO West, serve portions of five states and own or lease the high voltage transmission facilities of the participating utilities. TransConnect filed its proposal with the FERC in November 2001 and received limited approval from the FERC in September 2002.

The final proposals must be approved by the FERC, the boards of directors of the filing companies and regulators in various states. The companies' decision to move forward with the formation of TransConnect or RTO West will ultimately depend on the conditions related to the formation of the entities, as well as the economics and conditions imposed in the regulatory approval process. If TransConnect were formed, it could result in Avista Utilities divesting its electric transmission assets. The formation of RTO West or TransConnect could have an impact on the Company's transmission costs.

On July 31, 2002, the FERC issued a Notice of Proposed Rulemaking proposing a Standard Market Design (SMD) that would significantly alter the markets for wholesale electricity and transmission and ancillary services in the United States. The new SMD would establish a generation adequacy requirement for "load-serving entities" and a standard platform for the sale of electricity and transmission services. Under the new SMD, Independent Transmission Providers would administer spot markets for wholesale power, ancillary services and transmission congestion rights, and electric utilities, including Avista Utilities, would be required to transfer control over transmission facilities to the applicable Independent Transmission Provider. As the SMD proposal develops, the Company continues to assess the impact the SMD would have on its operations as well as how the SMD would impact the RTO West and TransConnect proposals. The Company is subject to state regulation in each of the states in which it operates. State regulatory agencies are actively involved in the SMD rulemaking process and there have been significant concerns at the state and regional level raised with the FERC with respect to the SMD, particularly in the western United States. In February 2003, Avista Utilities and several other western utilities filed comments with the FERC expressing their concerns with respect to the SMD proposal.

The North American Electric Reliability Council and the WECC have undertaken initiatives to establish a series of security coordinators to oversee the reliable operation of the regional transmission system. Accordingly, Avista Utilities, in cooperation with other utilities in the Pacific Northwest, established the Pacific Northwest Security Coordinator (PNSC), which oversees daily and short-term operations of the Northwest sub-regional transmission grid and has limited authority to direct certain actions of control area operators in the case of a pending transmission system emergency. Avista Utilities executed its service agreement with the PNSC in September 1998.

State Level

Further competition may be introduced by state action. Competition for retail customers is not generally allowed in Avista Utilities' service territory. While the Energy Act precludes the FERC from mandating retail wheeling, state regulators and legislators could open service territories to full competition at the retail level. Legislative action at the state level would be required for full retail wheeling and customer choice to occur in Washington and Idaho. For the past several years, the legislatures and public utility commissions in Washington and Idaho have conducted a series of hearings and several studies regarding electric industry restructuring. Issues such as unbundling, deregulation, reliability and consumer protection were examined. Impacts on customer service quality and system reliability (generation, transmission and distribution) were considered on a "macro" basis under various restructuring scenarios. Public policy makers in Washington and Idaho continue to examine other states' experiences with restructuring, while cognizant that the Pacific Northwest generally benefits from the lowest electric rates in the country. There is generally no movement toward deregulation in Washington or Idaho.

AVISTA CORPORATION

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 Avista Utilities has an ownership interest were designed to comply with all applicable environmental laws. Furthermore, the Company conducts periodic reviews of all its facilities and operations to respond to or anticipate emerging environmental issues. The Company's Board of Directors has an Environmental Committee to deal specifically with these issues.

Air Quality The most significant impact on the Company related to the Clean Air Act (CAA) and the 1990 Clear Air Act Amendments (CAAA) pertains to Colstrip, which is a "Phase II" coal-fired plant under the CAAA. Colstrip is not expected to be required to implement any additional sulfur dioxide (SO2) mitigation in the foreseeable future in order to continue operations. Avista Utilities' other thermal projects 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 operating permit for the Rathdrum CT was renewed in 2000 and the operating permit for Kettle Falls was renewed in 2002.

During 2001, Avista Corp. extended the operating hours of the Northeast CT with an agreement with the Spokane County Air Pollution Control Authority (SCAPCA) under a special operating order called an Assurance of Discontinuance (AOD). The SCAPCA has allowed for continued operation of the Northeast CT upon the condition that a payment of $150 for each hour of operation will be paid into a mitigation fund for assistance to low-income customers and the payment of $10,000 for each day of operation to fund an environmental offset project. The AOD allows Avista Utilities to use the Northeast CT to temporarily bring on added generating capacity for the benefit of its customers and the region during a time of increased energy demand and limited energy resources. Extended operation of the Northeast CT was approved after the SCAPCA determined, through air emission modeling and projections, that extended operation of the turbine would not adversely impact air quality. The AOD and associated funding of the environmental offset project will be in effect until a new air permit is issued by the SCAPCA. The Company expects to be issued a new permit for operation of the Northeast CT in 2003.

Water Quality The issue of high levels of dissolved gas which exceed Idaho and federal water quality standards downstream of Cabinet Gorge during spill periods continues to be studied, as agreed to in the Clark Fork Settlement Agreement and incorporated in the renewed FERC license. See "Hydroelectric Relicensing" for further information.

In June 2001, Avista Development received official notice that it had been designated as a potentially liable party with respect to contaminated sites on the Spokane River. The Department of Ecology (DOE) discovered PCBs in fish and sediments in the Spokane River in the 1970s and 1980s. In the 1990s, the DOE performed subsequent sampling of the river and identified potential sources of the PCBs, including the Spokane Industrial Park and a number of other entities in the area. The Consent Decree and Scope of Work for the remedial investigation and feasibility study of the site were finalized during the fourth quarter of 2002. It is currently expected that the actual cleanup of PCB sediments in the Spokane River will be coordinated to the extent possible with the EPA's separate plan to remove heavy metals from the Spokane River, contamination that resulted from decades of mining upstream at locations in Idaho and is in not related to the activities of Avista Development. See "Spokane River" in "Note 28 of the Notes to Consolidated Financial Statements" for additional information.

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Future Outlook" and "Note 28 of the Notes to Consolidated Financial Statements" for additional information with respect to environmental issues.

AVISTA UTILITIES OPERATING STATISTICS

	Years Ended December 31,		
	2002	2001	2000
ELECTRIC OPERATIONS			
ELECTRIC OPERATING REVENUES (Dollars in Thousands):			
Residential	$ 196,156	$ 158,847	$ 158,065
Commercial	194,732	155,371	149,770
Industrial	68,096	80,433	82,992
Public street and highway lighting	4,683	3,790	3,612
Total retail revenues	463,667	398,441	394,439
Wholesale revenues	64,082	480,903	864,754
Other revenues	56,392	42,861	28,062
Total electric operating revenues	$ 584,141	$ 922,205	$ 1,287,255
ELECTRIC ENERGY SALES (Thousands of MWhs):			
Residential	3,203	3,219	3,279
Commercial	2,837	2,882	2,886
Industrial	1,519	1,892	2,048
Public street and highway lighting	25	25	25
Total retail energy sales	7,584	8,018	8,238
Wholesale energy sales	2,216	6,262	15,807
Total electric energy sales	9,800	14,280	24,045
ELECTRIC ENERGY RESOURCES (Thousands of MWhs):			
Hydro generation (from Company facilities)	4,010	2,564	3,819
Thermal generation (from Company facilities)	1,714	3,001	3,153
Purchased power – long-term hydro	837	631	929
Purchased power – wholesale	3,732	8,065	16,111
PURPA and other contracts	96	559	595
Power exchanges	17	(104)	67
Total power resources	10,406	14,716	24,674
Energy losses and Company use	(606)	(436)	(629)
Total energy resources (net of losses)	9,800	14,280	24,045
NUMBER OF ELECTRIC CUSTOMERS (Average for Period):			
Residential	279,735	276,845	273,219
Commercial	35,910	35,454	35,060
Industrial	1,420	1,434	1,254
Public street and highway lighting	413	402	392
Total electric retail customers	317,478	314,135	309,925
Wholesale	46	44	58
Total electric customers	317,524	314,179	309,983
ELECTRIC RESIDENTIAL SERVICE AVERAGES:			
Annual use per customer (KWh)	11,450	11,629	12,003
Revenue per KWh (in cents)	6.12	4.93	4.82
Annual revenue per customer	$ 701.22	$ 573.77	$ 578.53
ELECTRIC AVERAGE HOURLY LOAD (aMW)	935	975	1,012
RESOURCE AVAILABILITY at time of system peak (MW):			
Total requirements (winter):			
Retail native load	1,346	1,500	1,491
Wholesale obligations	297	1,734	2,338
Total requirements (winter)	1,643	3,234	3,829
Total resource availability (winter)	2,213	3,553	4,194
Total requirements (summer):			
Retail native load	1,389	1,379	1,473
Wholesale obligations	466	1,332	2,756
Total requirements (summer)	1,855	2,711	4,229
Total resource availability (summer)	2,287	2,927	4,656

AVISTA CORPORATION

AVISTA UTILITIES OPERATING STATISTICS

	Years Ended December 31,		
	2002	**2001**	**2000**
NATURAL GAS OPERATIONS			
NATURAL GAS OPERATING REVENUES (Dollars in Thousands):			
Residential	$183,964	$179,584	$128,240
Commercial	104,974	104,012	69,982
Industrial	7,127	11,130	7,680
Total retail natural gas revenues	296,065	294,726	205,902
Wholesale revenues	695	1,762	5,691
Transportation revenues	9,664	8,576	10,242
Other revenues	3,399	3,579	3,011
Total natural gas operating revenues	$309,823	$308,643	$224,846
THERMS DELIVERED (Thousands of Therms):			
Residential	199,686	198,413	212,198
Commercial	126,220	126,869	135,126
Industrial	11,243	15,523	18,350
Total retail sales	337,149	340,805	365,674
Wholesale sales	2,306	4,831	4,034
Transportation sales	174,891	180,918	224,803
Interdepartmental sales and Company use	2,145	15,430	1,391
Total therms delivered	516,491	541,984	595,902
SOURCES OF NATURAL GAS SUPPLY (Thousands of Therms):			
Purchases	344,793	348,620	372,795
Storage – injections	(53)	(62)	(467)
Storage – withdrawals	60	54	403
Natural gas for transportation	174,891	180,918	224,803
Interdepartmental transportation	1,513	14,662	589
Distribution system losses	(4,713)	(2,208)	(2,221)
Total natural gas supply	516,491	541,984	595,902
NUMBER OF NATURAL GAS CUSTOMERS (Average for Period):			
Residential	254,700	249,650	242,983
Commercial	30,823	30,355	29,739
Industrial	315	328	334
Total retail customers	285,838	280,333	273,056
Wholesale customers	1	2	2
Transportation customers	88	86	96
Total natural gas customers	285,927	280,421	273,154
NATURAL GAS RESIDENTIAL SERVICE AVERAGES:			
Washington and Idaho			
Annual use per customer (therms)	841	852	950
Revenue per therm (in cents)	93.05	89.24	57.82
Annual revenue per customer	$ 782.16	$ 760.02	$ 549.07
Oregon and California			
Annual use per customer (therms)	679	688	730
Revenue per therm (in cents)	90.00	93.44	66.83
Annual revenue per customer	$ 610.68	$ 643.31	$ 487.80
NET SYSTEM MAXIMUM CAPABILITY (Thousands of Therms):			
Net system maximum demand (winter)	2,253	2,236	2,347
Net system maximum firm contractual capacity (winter)	4,340	4,320	4,320
HEATING DEGREE DAYS: (1)			
Spokane, WA			
Actual	6,818	6,800	7,176
30 year average	6,842	6,842	6,842
% of average	100%	99%	105%
Medford, OR			
Actual	4,230	4,143	4,388
30 year average	4,611	4,611	4,611
% of average	92%	90%	95%

(1) Heating degree days are the measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day falls below 65 degrees Fahrenheit (annual degree days below historic indicate warmer than average temperatures).

AVISTA CORPORATION

Energy Trading and Marketing Line of Business

The Energy Trading and Marketing line of business includes Avista Energy and Avista Power, both wholly owned subsidiaries of Avista Capital.

Avista Energy

Avista Energy is an electricity and natural gas marketing and trading business, operating primarily within the WECC. Avista Energy focuses on asset-backed optimization of combustion turbines and hydroelectric assets owned by other entities, long-term electric supply contracts, natural gas storage, and electric and natural gas transmission and transportation arrangements. Avista Energy's marketing efforts are driven by its base of knowledge and experience in the operation of both electric energy and natural gas physical systems in the WECC, as well as its relationship-focused approach with its customers. Avista Energy's headquarters are in Spokane, Washington, and it also has an office in Vancouver, British Columbia, Canada.

Avista Energy accounted for energy commodity trading activity in compliance with Emerging Issues Task Force (EITF) Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" through December 31, 2002 for contracts entered into on or prior to October 25, 2002. In October 2002, the EITF rescinded Issue No. 98-10. As such, Avista Energy is required to account for energy trading contracts that meet the definition of a derivative at market value in compliance with Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities." This applies to all existing contracts as of January 1, 2003 as well as to all new contracts entered into subsequent to October 25, 2002. The transition from EITF Issue No. 98-10 to accrual based accounting resulted in the adjustment of the contracts that are not considered derivatives from their market value to their cost basis. The changes are anticipated to primarily affect the timing of the recognition of income or loss in earnings, and not change the underlying economics or cash flows of transactions entered into by Avista Energy. The changes could result in a significant increase in the volatility of reported earnings on a quarter-to-quarter and year-to-year basis. See " Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies" and "Note 2 of the Notes to Consolidated Financial Statements" for further details.

Avista Energy trades electricity and natural gas, along with derivative commodity instruments including futures, options, swaps and other contractual arrangements. Most transactions are conducted on a largely unregulated "over-the-counter" basis, there being no central clearing mechanism (except in the case of specific instruments traded on the commodity exchanges). Avista Energy's trading operations are affected by, among other things, volatility of prices within the electric energy and natural gas markets, the demand for and availability of energy, lower unit margins on new sales contracts, FERC-ordered price caps, deregulation of the electric utility industry, the creditworthiness of counterparties and the reduced liquidity in energy markets. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Business Risks" for further information.

The following table provides operating statistics for Avista Energy for the years ended December 31:

	2002	2001	2000
Gross Realized Sales Transactions (dollars in thousands):			
Electric	$1,417,499	$3,380,058	$4,721,291
Natural Gas	958,183	1,619,285	1,751,264
Other	—	1,612	58,996
Total gross settled transactions	$2,375,682	$5,000,955	$6,531,551
Gross Realized Sales Volume:			
Electricity (thousands of MWhs)	40,426	47,927	105,548
Natural gas (thousands of dekatherms)	225,983	248,193	273,448
Coal (thousands of tons)	—	—	3,514

In April 1997, Avista Energy entered into a scheduling and marketing services agreement with Chelan County Public Utility District (PUD), located in Washington State. The agreement allows Avista Energy to market, on a "real-time" basis, a portion of the output from Chelan County PUD's hydroelectric resources and to jointly market energy products and services to other utilities in the region.

In September 1999, Avista Energy began managing Avista Utilities' natural gas storage assets, transportation contracts and natural gas purchasing operations. Under an Agency Agreement, Avista Energy serves as agent for

Avista Utilities, managing its pipeline transportation rights and natural gas storage assets, as well as purchasing natural gas for Avista Utilities' retail customers. The assets continue to be owned by Avista Utilities; however, they are fully integrated operationally into Avista Energy's portfolio. The Natural Gas Benchmark Mechanism allows Avista Energy the opportunity to retain a portion of the benefits associated with asset optimization and the efficiencies gained in purchasing natural gas for Avista Utilities. The Natural Gas Benchmark Mechanism and related Agency Agreement expires in March 2005 in Idaho and Oregon. In January 2003, the WUTC approved the continuation of the Natural Gas Benchmark Mechanism and related Agency Agreement through January 2004. Hearings will be held before the WUTC during 2003 to determine whether or not the Natural Gas Benchmark Mechanism and related Agency Agreement will be extended beyond January 29, 2004.

Avista Energy is subject to the various risks inherent in commodity trading including, particularly, market risk, liquidity risk, commodity risk and credit risk, as well as possible new risks resulting from the imposition of market controls by federal and state regulatory agencies. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Power Market Issues and Future Outlook," and "Notes 1, 2, 8 and 9 of Notes to Consolidated Financial Statements" for additional information regarding the market and credit risks inherent in the energy trading business, Avista Energy's risk management policies and procedures, accounting practices, and positions held by Avista Energy as of December 31, 2002.

Avista Capital provides guarantees for Avista Energy's credit agreement and, in the course of business, may provide guarantees to other parties with whom Avista Energy may be doing business. Avista Capital had $64.6 million of performance guarantees related to energy trading contracts outstanding as of December 31, 2002.

Avista Power

Avista Power was originally formed to develop and own generation assets. During 2001, the Company decided that Avista Power would no longer pursue the development of additional non-regulated generation projects due to changing market conditions and as part of Avista Corp.'s overall business strategy. Avista Power is a 49 percent owner of the Lancaster Project, which commenced commercial operation in September 2001. All of the output from the Lancaster Project is contracted to Avista Energy for 25 years. In addition, Avista Power and co-owner Mirant have substantially completed the construction of Coyote Springs 2. In January 2003, Avista Power's 50 percent ownership interest in Coyote Springs 2 was transferred to Avista Corp. for inclusion in Avista Utilities' power generation resource portfolio.

Information and Technology Line of Business

The Information and Technology line of business includes Avista Advantage and Avista Labs. Avista Advantage and Avista Labs are majority-owned and wholly-owned subsidiaries of Avista Capital, respectively.

Avista Advantage

Avista Advantage is a provider of internet-based facility intelligence, cost management, billing and information services to retail customers throughout North America. Avista Advantage's solutions are designed to provide multi-site companies with critical and easy-to-access information that enables them to proactively manage and reduce their facility-related expenses.

Avista Advantage analyzes and presents consolidated bills on-line, and pays utility and other facility-related expenses for multi-site customers. Information gathered from invoices, providers and other customer-specific data allows Avista Advantage to provide its customers with in-depth analytical support, real-time reporting and consulting services with regard to facility-related energy, waste, repair and maintenance, and telecom expenses.

Avista Advantage has secured five patents on its two critical business systems, the Facility IQ system, which provides operational information drawn from facility bills, and the AviTrack database, which processes and reports on information gathered from service providers to ensure customers are receiving the most effective services at the proper price. Avista Advantage is not aware of any claimed or threatened infringement on any of its patents issued to date and will continue to expand and protect its existing patents, as well as file additional patent applications for new products, services and process enhancements.

As of December 31, 2002, Avista Advantage serviced 247 customers, having 98,251 billed sites throughout North America. This is an increase from 203 customers and 79,749 billed sites as of December 31, 2001. As of December

31, 2000, Avista Advantage serviced 135 customers and 46,127 billed sites. During 2002, Avista Advantage processed $4.9 billion of bills, an increase from $4.3 billion in 2001 and $1.1 billion in 2000.

Avista Labs

Avista Labs is continuing to have discussions with selected companies in its search for a financial partner while moving forward with developing and selling its commercial fuel cell products. The Company has a goal of reducing its ownership interest in Avista Labs to less than 20 percent. Avista Labs has patented and developed a modular, air- cooled, self-hydrating Proton Exchange Membrane (PEM) fuel cell technology that provides reliable and clean distributed power solutions. Avista Labs also holds a 70 percent equity interest in H2fuel, LLC, a developer of fuel processors for the production of hydrogen. The remaining interest is owned by Unitel Fuels Technologies, LLC. H2fuel, LLC does not require any additional funding at this time.

In 2002, Avista Labs offered three PEM fuel cell products for commercial sale: a 100 watt system, a 500 watt system and a 1 kW system. Avista Labs is selling its fuel cell products directly and through selected market channels to industrial, commercial and government customers for premium and backup power. Avista Labs completed commercial transactions for the sale of 98 units during 2002. As of December 31, 2002, 174 units were installed in 42 locations throughout North and South America and Europe.

As of December 31, 2002, Avista Labs has been granted nine patents, with 805 issued claims recognizing and protecting the unique attributes of its fuel cell system, its modular approach to the design of fuel cell systems generally, the method used for rapidly energizing its hydrogen sensor, and its method for power conversion using ultracapacitors in tandem with fuel cells. In 2002, Avista Labs received a notice of allowance of an additional patent with 25 claims protecting its design for a hydrogen sensor circuit with a method for temperature and humidity compensation, and has 20 more patent applications pending or in process directed to its unique approach in fuel cells, power conversion and other components.

Alliances in bringing Avista Labs' products to market include distribution agreements with Aperion Power Systems, LLC, Automated Railway Maintenance Systems, Inc., and SGS Futures, spa., and a joint marketing agreement with AirGas, Inc. Avista Labs continues to pursue additional partners for the distribution of its products. Avista Labs' products are assembled primarily through outsourced manufacturing under contracts. In September 2002, Avista Labs entered into a strategic supply agreement with 3M Company for the purchase of membrane electrode assemblies (MEAs) for integration into its fuel cell products.

Other Line of Business

The Other line of business includes several subsidiaries, including Avista Ventures, Pentzer, Avista Development and Avista Services. The operations of Avista Capital that are not included through its subsidiaries are reported in this line of business. Prior to 1999, Pentzer was the parent company to the majority of Avista Corp.'s other subsidiary businesses, controlling interests in a broad range of middle market companies. Beginning in 2000, the focus of this line of business was changed to invest in business opportunities that have potential value to the Company's energy-related businesses. The Company continues to limit its future investment in this line of business.

Discontinued Operations — Avista Communications

Avista Communications, formerly part of the Information and Technology line of business, provided local dial tone, data transport, internet services, voice messaging and other telecommunications services to several communities in the western United States. In September 2001, Avista Corp. decided that it would dispose of substantially all of the assets of Avista Communications. As such, these operations are reported as a discontinued operation. Avista Corp. began its divestiture of this business during the fourth quarter of 2001. The divestiture of operating assets was completed by the end of 2002. Certain liabilities of the operations remain to be settled.

AVISTA CORPORATION

Item 2. Properties

Avista Utilities

Avista Utilities' electric properties, located in the States of Washington, Idaho, Montana and Oregon, include the following:

Generation Properties (1)

	No. of Units	Nameplate Rating (MW) (2)	Present Capability (MW) (3)
Hydroelectric Generating Stations (River)			
Washington:			
Long Lake (Spokane)	4	70.0	88.0
Little Falls (Spokane)	4	32.0	36.0
Nine Mile (Spokane)	4	26.4	24.5
Upper Falls (Spokane)	1	10.0	10.2
Monroe Street (Spokane)	1	14.8	15.0
Idaho:			
Cabinet Gorge (Clark Fork)	4	245.1	246.0
Post Falls (Spokane)	6	14.8	18.0
Montana:			
Noxon Rapids (Clark Fork)	5	466.2	527.0
Total Hydroelectric		879.3	964.7
Thermal Generating Stations			
Washington:			
Kettle Falls	1	50.7	50.0
Kettle Falls CT	1	6.9	6.9
Northeast (Spokane) CT	2	61.8	66.8
Boulder Park	6	24.6	24.6
Idaho:			
Rathdrum CT (1)	2	166.5	176.0
Montana:			
Colstrip (Units 3 and 4) (4)	2	233.4	222.0
Total Thermal		543.9	546.3
Total Generation Properties		1,423.2	1,511.0

(1) All generation properties are owned by the Company with the exception of the Rathdrum CT, which is leased from WP Funding LP. New accounting guidance was recently issued relating to the identification of, and accounting for, special-purpose entities such as WP Funding LP. See "Note 2 of the Notes to Consolidated Financial Statements" for further information. This interpretation will require the Company to begin consolidating WP Funding LP into its financial statements effective July 1, 2003.

(2) Nameplate Rating, also referred to as "installed capacity", is the manufacturer's assigned power capability under specified conditions.

(3) Present capability is the maximum capacity of the plant without exceeding approved limits of temperature, stress and environmental conditions.

(4) Jointly owned; data refers to Avista Utilities' 15 percent interest.

Generation Property under Development

In mid-2003, it is expected that the natural gas-fired Coyote Springs 2 will be placed into operation. Avista Utilities has a 50 percent ownership interest (140 MW) in Coyote Springs 2.

Electric Distribution and Transmission Plant

Avista Utilities operates approximately 12,200 miles of primary and secondary electric distribution lines and an electric transmission system of approximately 595 miles of 230 kV line and 1,528 miles of 115 kV line. Avista Utilities also owns a 10 percent interest in 495 miles of a 500 kV line between Colstrip, Montana and Townsend, Montana. The transmission and distribution system also includes numerous substations with transformers, switches, monitoring and metering devices, and other equipment related to its operation.

The 230 kV lines are used to transmit power from Avista Utilities' Noxon Rapids and Cabinet Gorge hydroelectric generating stations to major load centers in its service area, as well as to transfer power between points of interconnection with adjoining electric transmission systems. These lines interconnect with the Bonneville Power Administration (BPA) at five locations and at one location each with PacifiCorp, NorthWestern Energy and Idaho Power Company. The BPA interconnections serve as points of delivery for power from the Colstrip generating station, as well as for the interchange of power with entities within and outside the Pacific Northwest. The interconnection with PacifiCorp is used to integrate Mid-Columbia hydroelectric generating facilities to Avista Utilities' loads, as well as for the interchange of power with entities within and outside the Pacific Northwest.

The 115 kV lines provide for transmission of energy and the integration of the Spokane River hydroelectric and Kettle Falls wood-waste generating stations with service-area load centers. These lines interconnect with BPA at nine locations, Grant County PUD, Seattle City Light and Tacoma City Light at two locations each and one interconnection each with Chelan County PUD, PacifiCorp and NorthWestern Energy.

Avista Corp. is negotiating with nine other utilities in western United States in the possible formation of RTO West, a non-profit organization. Avista Corp. and two other utilities have also taken steps toward the formation of a for-profit Independent Transmission Company, TransConnect, which would be a member of RTO West, serve portions of five states and own or lease the high voltage transmission facilities of the participating utilities. See "Item 1. Business – Avista Utilities – Industry Restructuring" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Power Market Issues" for more information.

Natural Gas Plant

Avista Utilities has natural gas distribution mains of approximately 2,542 miles in Washington, 1,436 miles in Idaho, 1,699 miles in Oregon and 233 miles in California as of December 31, 2002. The natural gas distribution system includes numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment related to its operation.

Avista Utilities, Northwest Pipeline and Puget Sound Energy each own a one-third undivided interest in Jackson Prairie, which has a total peak day deliverability of 8.8 million therms, with a total working natural gas inventory of 190.3 million therms. Avista Utilities has contracted to release a total of approximately 37 percent of its Jackson Prairie capacity to two other utilities. One of these contracts requires two-years notice for termination and one contract is renewed on a year-to-year basis.

Item 3. Legal Proceedings

See "Note 28 of Notes to Consolidated Financial Statements" for additional information.

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 28, 2003, there were approximately 17,131 registered shareholders of the Company’s no par value Common Stock.

The Board of Directors considers the level of dividends on the Company’s common stock on a regular basis, taking into account numerous factors including, without limitation, the Company’s results of operations, cash flows and financial condition, as well as the success of the Company’s strategies and general economic and competitive conditions. The Company’s net income available for dividends is derived primarily from the operations of Avista Utilities and Avista Energy.

Avista Energy holds a significant portion of the cash and cash equivalents reflected on the Consolidated Balance Sheet. Covenants in Avista Energy’s credit agreement restrict the amount of cash dividends that can be distributed to Avista Capital and ultimately to Avista Corp. During 2002, in accordance with the modified covenants of its credit agreement, Avista Energy paid $116.4 million in dividends to Avista Capital. In January 2003, Avista Energy paid $2.1 million in dividends to Avista Capital.

For additional information, refer to “Notes 1, 24 and 27 of Notes to Consolidated Financial Statements.” For high and low stock price information, refer to “Note 30 of Notes to Consolidated Financial Statements.”

AVISTA CORPORATION

Item 6. Selected Financial Data

(in thousands, except per share data and ratios)	Years Ended December 31, 2002	2001	2000	1999	1998
Operating Revenues:					
Avista Utilities	$ 893,964	$1,230,847	$ 1,512,101	$1,115,647	$1,049,212
Energy Trading and Marketing (net margin on trading activities)	54,207	134,266	307,746	(17,942)	48,624
Information and Technology	17,630	13,815	5,732	2,266	1,318
Other	14,645	16,385	32,937	122,303	231,483
Total	$ 980,446	$1,395,313	$ 1,858,516	$1,222,274	$1,330,637
Income (Loss) from Operations (pre-tax):					
Avista Utilities	$ 149,180	$ 114,927	$ 3,177	$ 142,567	$ 143,153
Energy Trading and Marketing	29,211	94,669	250,196	(97,785)	22,826
Information and Technology	(18,818)	(29,872)	(26,424)	(8,966)	(4,979)
Other	(14,886)	(10,432)	(9,861)	(423)	12,033
Total	$ 144,687	$ 169,292	$ 217,088	$ 35,393	$ 173,033
Income (Loss) from Continuing Operations:					
Avista Utilities	$ 36,382	$ 24,164	$ (38,781)	$ 59,573	$ 56,297
Energy Trading and Marketing	22,425	63,246	161,753	(60,739)	14,116
Information and Technology	(12,117)	(19,384)	(19,032)	(5,989)	(3,221)
Other	(12,380)	(8,421)	(2,885)	35,817	11,124
Total	$ 34,310	$ 59,605	$ 101,055	$ 28,662	$ 78,316
Income (loss) from discontinued operations	1,145	(47,449)	(9,376)	(2,631)	(177)
Net Income before cumulative effect of accounting change	$ 35,455	$ 12,156	$ 91,679	$ 26,031	$ 78,139
Cumulative effect of accounting change	(4,148)	—	—	—	—
Net income	$ 31,307	$ 12,156	$ 91,679	$ 26,031	$ 78,139
Preferred stock dividend requirements	2,402	2,432	23,735	21,392	8,399
Income available for common stock	$ 28,905	$ 9,724	$ 67,944	$ 4,639	$ 69,740
Average common shares outstanding, basic	47,823	47,417	45,690	38,213	54,604
Average common shares outstanding, diluted	47,874	47,435	46,103	38,325	54,658
Common shares outstanding at year-end	48,044	47,633	47,209	35,648	40,454
Earnings per Common Share:					
Avista Utilities	$ 0.71	$ 0.46	$ (1.37)	$ 1.00	$ 0.88
Energy Trading and Marketing	0.47	1.33	3.51	(1.59)	0.26
Information and Technology	(0.25)	(0.41)	(0.41)	(0.16)	(0.06)
Other	(0.26)	(0.18)	(0.06)	0.94	0.20
Earnings per common share from continuing operations, diluted	$ 0.67	$ 1.20	$ 1.67	$ 0.19	$ 1.28
Earnings (Loss) per common share from discontinued operations, diluted	0.02	(1.00)	(0.20)	(0.07)	—
Earnings per common share before cumulative effect of accounting change, diluted	$ 0.69	$ 0.20	$ 1.47	$ 0.12	$ 1.28
Cumulative effect of accounting change, diluted	(0.09)	—	—	—	—
Total earnings per common share, diluted	$ 0.60	$ 0.20	$ 1.47	$ 0.12	$ 1.28
Total earnings per common share, basic	0.60	0.21	1.49	0.12	1.28
Dividends paid per common share	0.48	0.48	0.48	0.48	1.05
Book value per common share at year-end	$ 14.84	$ 15.12	$ 15.34	$ 11.04	$ 12.07
Total Assets at Year-End:					
Avista Utilities	$2,184,008	$2,396,317	$ 2,143,791	$1,976,716	$2,004,935
Energy Trading and Marketing	1,349,626	1,506,185	10,271,834	1,595,470	955,615
Information and Technology	37,528	26,891	14,429	6,312	2,492
Other	42,866	86,514	96,362	114,929	285,625
Discontinued Operations	105	21,316	50,665	20,067	4,969
Total	$3,614,133	$4,037,223	$12,577,081	$3,713,494	$3,253,636
Long-Term Debt at Year-End	902,635	1,175,715	679,806	714,904	730,022
Company-Obligated Mandatorily Redeemable Preferred Trust Securities	100,000	100,000	100,000	110,000	110,000
Preferred Stock Subject to Mandatory Redemption	33,250	35,000	35,000	35,000	35,000
Convertible Preferred Stock	—	—	—	263,309	269,227
Common Equity	$ 712,791	$ 720,063	$ 724,224	$ 393,499	$ 488,034
Ratio of Earnings to Fixed Charges	1.58	1.84	3.45	1.66	2.66
Ratio of Earnings to Fixed Charges and Preferred Dividend Requirements	1.52	1.78	2.19	1.11	2.26

AVISTA CORPORATION

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Safe Harbor for Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Avista Corporation (Avista Corp. or the Company) is including the following cautionary statement to make applicable, and to take advantage of, the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of, the Company. Forward-looking statements include statements concerning plans, objectives, goals, strategies, projections of future events or performance, and underlying assumptions (many of which are based, in turn, upon further assumptions). Forward-looking statements are all statements other than statements of historical fact, including without limitation those that are identified by the use of words such as, but not limited to, "will," "anticipates," "seeks to," "estimates," "expects," "intends," "plans," "predicts," and similar expressions. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature. All such subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are also expressly qualified by these cautionary statements.

Such statements are inherently subject to a variety of risks and uncertainties that could cause actual results to differ materially from those expressed. Most of these risks and uncertainties are beyond the Company's control. Such risks and uncertainties include, among others:

- changes in the utility regulatory environment in the individual states in which the Company operates and the United States in general. This can impact allowed rates of return, financings, or industry and rate structures;
- the impact of regulatory and legislative decisions including Federal Energy Regulatory Commission (FERC) price controls, and including possible retroactive price caps and resulting refunds;
- the impact from the potential formation of a Regional Transmission Organization and/or an Independent Transmission Company;
- the impact from the implementation of the FERC's proposed Standard Market Design;
- the availability and prices of purchased energy, volatility and illiquidity in wholesale energy markets;
- wholesale and retail competition (including but not limited to electric retail wheeling and transmission costs);
- future streamflow conditions that affect the availability of hydroelectric resources;
- outages at any company-owned generating facilities;
- unanticipated delays or changes in construction costs with respect to present or prospective generating facilities;
- changes in weather conditions that can affect customer demand, result in natural disasters and/or customer outages, and affect the availability of hydroelectric resources;
- changes in industrial, commercial and residential growth and demographic patterns in the Company's service territory;
- the loss of significant customers and/or suppliers;
- failure to deliver on the part of any parties from which the Company purchases and/or sells capacity or energy;
- changes in the creditworthiness of customers and energy trading counterparties;
- the Company's ability to obtain financing through the issuance of debt and/or equity securities, which can be affected by various factors including the Company's credit ratings, interest rate fluctuations and other capital market conditions;
- changes in future economic conditions in the Company's service territory and the United States in general, including inflation or deflation and monetary policy;
- the continuing impact of the September 11, 2001 terrorist attacks as well as the potential for future terrorist attacks, particularly with respect to utility plant assets;
- changes in tax rates and/or policies;
- research and development findings for the Information and Technology companies;
- changes in, and compliance with, environmental and endangered species laws, regulations, decisions and policies, including present and potential environmental remediation costs;
- the outcome of legal and regulatory proceedings concerning the Company or affecting directly or indirectly its operations;
- employee issues, including changes in collective bargaining unit agreements, strikes, work stoppages or the loss of any of the Company's key executives;
- changes in actuarial assumptions and the return on assets with respect to the Company's pension plan, which can impact future funding obligations, costs and pension plan liabilities;
- increasing health care costs and the resulting effect on health insurance premiums paid for employees and the

obligation to provide postretirement health care benefits;

- increasing costs of insurance and the ability to obtain insurance.

The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including without limitation management's examination of historical operating trends, data contained in the Company's records and other data available from third parties. However, there can be no assurance that the Company's expectations, beliefs or projections will be achieved or accomplished. Furthermore, any forward-looking statement speaks only as of the date on which such statement is made. The Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the Company's business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

The following discussion and analysis is provided for the consolidated financial condition and results of operations of Avista Corp., including its subsidiaries. This discussion focuses on significant factors concerning the Company's financial condition and results of operations and should be read along with the consolidated financial statements.

Avista Corp. Lines of Business

Avista Corp. is an energy company engaged in the generation, transmission and distribution of energy as well as other energy-related businesses. The Company is organized into four lines of business – Avista Utilities, Energy Trading and Marketing, Information and Technology, and Other. Avista Utilities, an operating division of Avista Corp. and not a separate entity, represents the regulated utility operations. Avista Capital, a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies engaged in the non-utility lines of business. As of December 31, 2002, the Company had common equity investments of $457.6 million and $255.2 million in Avista Utilities and Avista Capital, respectively.

Avista Utilities generates, transmits and distributes electricity and distributes natural gas. Avista Utilities owns and operates eight hydroelectric projects, a wood-waste fueled generating station, a two-unit natural gas-fired combustion turbine (CT) generating facility and two small generating facilities. It also owns a 15 percent share in a two-unit coal-fired generating facility and leases and operates a two-unit natural gas-fired CT generating facility. At the end of 2002, Avista Utilities' facilities had a total net capability of approximately 1,511 megawatts (MW), of which 64 percent was hydroelectric and 36 percent was thermal. In mid-2003, it is expected that the natural gas-fired Coyote Springs 2 Generation Project (Coyote Springs 2) will be placed into operation. Avista Utilities has a 50 percent ownership interest (140 MW) in Coyote Springs 2.

In addition to company owned resources, Avista Utilities has a number of long-term power purchase and exchange contracts that increase its available resources. Avista Utilities sells and purchases electric capacity and energy to and from utilities and other entities in the wholesale market under long-term contracts having terms of more than one year. In addition, Avista Utilities engages in an ongoing process of resource optimization which involves short-term purchases and sales in the wholesale market in pursuit of an economic selection of resources to serve retail and wholesale loads. Avista Utilities makes continuing projections of (1) future retail and wholesale loads based on, among other things, forward estimates of factors such as customer usage and weather as well as historical data and contract terms and (2) resource availability based on, among other things, estimates of streamflows, generating unit availability, historic and forward market information and experience. On the basis of these continuing projections, Avista Utilities makes purchases and sales of energy on an annual, quarterly, monthly, daily and hourly basis to match actual resources to actual energy requirements. This process includes hedging transactions.

The Energy Trading and Marketing line of business is comprised of Avista Energy, Inc. (Avista Energy) and Avista Power, LLC (Avista Power). Avista Energy is an electricity and natural gas marketing and trading business, operating primarily in the Western Electricity Coordinating Council (WECC) geographical area, which is comprised of eleven Western states. Avista Power was originally formed to develop and own generation assets. During 2001, the Company decided that Avista Power would no longer pursue the development of additional non-regulated generation projects.

The Information and Technology line of business is comprised of Avista Advantage, Inc. (Avista Advantage) and Avista Laboratories, Inc. (Avista Labs). Avista Advantage is a provider of internet-based facility intelligence, cost management, billing and information services to retail customers throughout North America. Its primary product lines include consolidated billing, resource accounting, energy analysis, load profiling and maintenance and repair billing services. Avista Labs has patented and developed a modular air-cooled, self-hydrating Proton Exchange Membrane (PEM) fuel cell that delivers reliable and clean distributed power solutions. In addition to developing its modular fuel cell products, Avista Labs is contracting with selected market channels to deliver system solutions to industrial, commercial and residential markets. Avista Labs holds a 70 percent equity interest in H2fuel, LLC, a developer of fuel processors for the production of hydrogen. Avista Corp. is currently seeking a financial partner for Avista Labs with the goal of reducing its ownership interest to less than 20 percent of this company.

The Other line of business includes several subsidiaries, including Avista Ventures, Inc. (Avista Ventures), Avista Capital (parent company only amounts), Pentzer Corporation (Pentzer), Avista Development and Avista Services. The Company continues to limit its future investment in this line of business.

Avista Communications, Inc. (Avista Communications), formerly part of the Information and Technology line of business, provided local dial tone, data transport, internet services, voice messaging and other telecommunications services to several communities in the western United States. In September 2001, Avista Corp. decided that it would dispose of substantially all of the assets of Avista Communications. As such, these operations are reported as a discontinued operation. Avista Corp. began its divestiture of this business during the fourth quarter of 2001, and the divestiture of operating assets was complete by the end of 2002. Certain liabilities of the operations remain to be settled.

Avista Utilities — Regulatory Matters

Beginning in the second quarter of 2000, the price of power in the wholesale markets of the western United States increased considerably and became much more volatile. While prices and volatility decreased during the second half of 2001, the effects of contracts entered into during the period of high wholesale prices continue to have an impact on Avista Corp.'s financial condition, results of operations and cash flows. In the second half of 2000 and continuing through 2001, Avista Utilities was required to purchase above-normal amounts of power in the wholesale market to meet its retail demand. This was primarily due to the reduced availability of hydroelectric resources as a result of low streamflow conditions. The combination of high wholesale market prices and increased amounts required to be purchased increased power supply costs to amounts far in excess of the amounts recovered from retail customers under rates in effect at the time.

The Company has had a power cost deferral mechanism in place in Washington as authorized by the Washington Utilities and Transportation Commission (WUTC) since the middle of 2000. The Company has had a power cost deferral mechanism in place in Idaho as authorized by the Idaho Public Utilities Commission (IPUC) since 1989. Avista Utilities defers the recognition in the income statement of certain power supply costs that are in excess of the level currently recovered from retail customers. A portion of power supply costs are recorded as a deferred charge on the balance sheet for future review and the opportunity for recovery through retail rates. The specific power costs deferred are a percentage of the difference between certain actual power supply costs incurred by Avista Utilities and the costs included in base retail rates. This difference is primarily related to changes in short-term wholesale market prices, changes in the level of hydroelectric generation and changes in the level of thermal generation (including changes in fuel prices). Avista Utilities accrues interest on deferred power costs in the Washington jurisdiction at a rate, which is adjusted semi-annually, of 8.9 percent as of December 31, 2002. Avista Utilities accrues interest on deferred power costs in the Idaho jurisdiction at a rate, which is adjusted annually, of 2 percent as of December 31, 2002. Avista Utilities anticipates making a filing with the IPUC requesting that the interest rate be modified to more closely approximate Avista Utilities' costs of short-term borrowings until the current surcharge is eliminated.

In June 2002, the WUTC issued an order that became effective July 1, 2002 with respect to a general electric rate case filed by Avista Utilities in December 2001. The order provides for an overall rate of return of 9.72 percent and a return on equity of 11.16 percent. The order provided for no incremental rate increase to Avista Utilities' Washington electric customers above the rates in effect at the time. Rate increases previously approved by the WUTC totaling 31.2 percent (a 25 percent temporary surcharge approved in September 2001 for the recovery of deferred power costs and a 6.2 percent increase approved in March 2002) were restructured. The general increase to base retail rates is 19.3 percent (or $45.7 million in expected annual revenues) and the remaining 11.9 percent represents the continued recovery of deferred power costs over a period currently projected to continue into 2009.

In the June 2002 rate order, the WUTC approved the establishment of an Energy Recovery Mechanism (ERM). The ERM replaced a series of temporary power cost deferral mechanisms that were in place in Washington since mid-2000. The ERM allows Avista Utilities to increase or decrease electric rates periodically with WUTC approval to reflect changes in power supply costs. The ERM provides for Avista Utilities to incur the cost of, or receive the benefit from, the first $9 million in annual power supply costs above or below the amount included in base retail rates. Under the ERM, 90 percent of the power supply costs exceeding or below the initial $9 million will be deferred for future surcharge or rebate to Avista Utilities' customers. The remaining 10 percent will be an expense of, or benefit to, the Company. Because the ERM was implemented on July 1, 2002, the Company's expense or benefit was limited to $4.5 million plus the remaining 10 percent of all costs above the amount included in base retail rates for 2002.

The Company expensed the initial $4.5 million in power supply costs above the amount included in base retail rates plus 10 percent of all costs exceeding the initial $4.5 million under the ERM during 2002. The Company currently expects to expense the first $9 million of power supply costs above the amount included in base retail rates under the ERM during the first quarter of 2003 as well as 10 percent of any costs exceeding the first $9 million for the year of 2003. The Company also expects to expense the first $9 million of power supply costs above the amount included in base retail rates in 2004 as well as 10 percent of any costs exceeding the first $9 million. The majority of these costs relate to fuel contracts entered during 2001 that expire in 2004 for the Company's thermal generating units.

Avista Utilities has a power cost adjustment (PCA) mechanism in Idaho that allows it to modify electric rates periodically with IPUC approval to recover or rebate a portion of the difference between actual and allowed net power supply costs. The PCA mechanism allows for the deferral of 90 percent of the difference between certain actual net power supply expenses and the authorized level of net power supply expense approved in the last Idaho general rate case. In October 2002, the IPUC issued an order extending a 19.4 percent PCA surcharge for Idaho electric customers. In the order, the IPUC removed $0.9 million of costs associated with three small generation projects from the PCA. The Company will have the opportunity to address the recovery of these costs in a future rate proceeding. The IPUC also ordered that $0.6 million in fuel costs would receive additional review as part of the next PCA filing. The PCA surcharge will remain in effect until October 2003. The IPUC directed Avista Utilities to file a status report 60 days before the current PCA surcharge expires. If review of the status report and the actual balance of deferred power costs support continuation of the PCA surcharge, the IPUC has indicated that it anticipates the PCA surcharge will be extended for an additional period.

The following table shows activity in deferred power costs for Washington and Idaho during 2001 and 2002 (dollars in thousands):

	Washington	Idaho	Total
Deferred power costs as of December 31, 2000	$ 34,580	$ 2,693	$ 37,273
Activity from January 1 – December 31, 2001:			
Power costs deferred	167,196	73,677	240,873
Unrealized loss on fuel contracts (1)	8,232	4,077	12,309
Interest and other net additions	16,027	5,643	21,670
Amortization of deferred credit	(53,794)	(6,927)	(60,721)
Recovery of deferred power costs through retail rates	(10,223)	(6,076)	(16,299)
Write-off deferred power costs	(21,780)	—	(21,780)
Deferred power costs as of December 31, 2001	140,238	73,087	213,325
Activity from January 1 – December 31, 2002:			
Power costs deferred	22,423	13,471	35,894
Unrealized gain on fuel contracts (1)	(7,068)	(3,485)	(10,553)
Interest and other net additions	6,726	888	7,614
Amortization of deferred credit	—	(27,711)	(27,711)
Recovery of deferred power costs through retail rates	(38,570)	(24,732)	(63,302)
Deferred power costs as of December 31, 2002	$123,749	$ 31,518	$155,267

(1) Unrealized gains and losses on fuel contracts are not included in the ERM and PCA mechanism until the contracts are settled or realized.

During a year having normal streamflow conditions, Avista Utilities would expect to have generation from its hydroelectric resources (both owned and purchased under long-term hydroelectric contracts) of approximately 550 aMW. For 2002, streamflow conditions were 112 percent of normal and hydroelectric generation was 553 aMW (101 percent of normal). Hydroelectric generation for the year 2001 was 369 aMW (67 percent of normal), which was 181 aMW below normal and the lowest level in the 73 years in which records have been kept. Preliminary forecasts and snowpack conditions indicate streamflow conditions for 2003 are expected to be approximately 70 percent of normal. Avista Utilities currently estimates that hydroelectric generation will be 458 aMW (83 percent of normal) in 2003. Below normal hydroelectric generation will cause Avista Utilities to either increase its output from thermal generation resources or purchase energy in the wholesale market, or Avista Utilities will have less surplus energy available to sell in the wholesale market. The Company will choose the most appropriate cost-effective resources to meet its customer demand. Under the ERM and the PCA mechanism, 90 percent of any costs exceeding the first $9 million in Washington and 90 percent of any costs incurred above the amount included in base retail rates in Idaho will be deferred for future recovery. In each instance, the remaining 10 percent will be an expense to the Company. Based on current projections, total deferred power costs are expected to be approximately $166 million at the end of 2003.

Avista Utilities is currently planning to file a natural gas general rate case in Oregon during the first half of 2003. The Company regularly reviews the need for natural gas or electric rate changes in each state in which it provides service.

During the second half of 2002, Avista Utilities adjusted its natural gas rates in response to a decrease in current and projected natural gas costs. During the fourth quarter of 2002, natural gas rate decreases of 17.4 percent, 15.5 percent, 7.1 percent and 16.2 percent were approved and implemented in Washington, Idaho, Oregon and California, respectively. These natural gas rate decreases are designed to pass through changes in purchased natural gas costs to customers and reduce operating revenues and resource costs with no change in Avista Utilities' gross margin or net income. Total deferred natural gas costs were $11.5 million and $52.7 million as of December 31, 2002 and 2001, respectively.

Power Market Issues

Avista Utilities and Avista Energy participate directly and indirectly in the power markets in the United States. Developments in these markets, particularly in the western part of the United States, have affected both Avista Utilities and Avista Energy. Federal and state officials including, but not limited to, the FERC and the California Public Utility Commission (CPUC), commenced reviews in 2000 to determine the causes of the changes in the wholesale energy markets to develop legal and regulatory remedies to address alleged market failures or abuses and large defaults by certain parties in the wholesale markets. The proceedings are continuing and their ultimate outcome and the resulting impact on the Company cannot be predicted at this time.

California Energy Crisis

In early 2001, California's two largest utilities, Southern California Edison (SCE) and Pacific Gas & Electric Company (PG&E), defaulted on payment obligations owed to various energy sellers, including the California Power Exchange (CalPX), California Independent System Operator (CalISO), and Automated Power Exchange (APX). Consequently, CalPX, CalISO and APX defaulted on their payment obligations to Avista Energy. PG&E and CalPX filed voluntary petitions under chapter 11 of the bankruptcy code for protection from creditors. On March 1, 2002, SCE paid its past due obligations to the CalPX and various other creditors; however, these funds did not flow directly to Avista Energy. As of December 31, 2002, Avista Energy's accounts receivable outstanding related to defaulting parties in California did not exceed its reserves for uncollected amounts, cost of collection, and refunds. Avista Energy is currently pursuing recovery of the defaulted obligations. Reserves for defaulted payments established in 2000 and 2001 accounted for the majority of the Company's increase in the total allowance for doubtful accounts. The allowance for doubtful accounts was $46.9 million as of December 31, 2002 compared to $50.2 million as of December 31, 2001 and $14.4 million as of December 31, 2000.

In July 2001, the FERC issued an order to commence a fact-finding hearing to determine if refunds should be owed and, if so, the amounts of such refunds for sales during the period from October 2, 2000 to June 20, 2001 in the California spot market. The order provides that any refunds owed could be offset against unpaid energy debts due to the same party. However, the FERC announced that it is considering changing the method used to determine natural gas costs for calculating refunds in this proceeding, which could delay their findings. Furthermore, on November 20, 2002, the FERC issued a Discovery Order, which reopened the evidentiary record and allowed parties in the proceeding to conduct additional discovery for the period January 1, 2000 to June 20, 2001. The November 20, 2002 Discovery Order required that, by no later than March 3, 2003, the market participants provide relevant documents to support any proposed recommendations to the FERC. The Discovery Order also affords parties in this proceeding the opportunity to respond by March 20, 2003 to submissions made by March 3, 2003. On December 12, 2002, the FERC Administrative Law Judge issued a Certification of Proposed Findings on California Refund Liability detailing the proposed refund amounts, which was presented to the FERC for consideration.

Several parties filed documents with the FERC on March 3, 2003 presenting supplemental information regarding alleged improper market conduct and requests for refunds and other relief under the additional discovery procedures set forth in both the California and Pacific Northwest refund proceedings. The filing parties include the California Parties (a joint filing including the Attorney General of the State of California, the California Electricity Oversight

Board, the CPUC, and PG&E), the City of Tacoma and Port of Seattle (jointly), the City of Seattle, and the Washington State Attorney General. The filing parties, with the exception of the Washington State Attorney General, have made specific allegations with regard to many companies, including Avista Corp. and Avista Energy.

Avista Corp. and Avista Energy will file reply comments in response to the allegations of the parties by March 20, 2003. Based upon an initial review of the filings, there are no new allegations or information not known to and addressed by the FERC Trial Staff in a separate investigation of Avista Corp. and Avista Energy.

As explained at “Federal Energy Regulatory Commission Inquiry” in “Note 28 of the Notes to Consolidated Financial Statements” regarding the investigation of Avista Corp. and Avista Energy, the FERC Trial Staff concluded that: 1) There was no evidence that any executives or employees of Avista Utilities or Avista Energy knowingly engaged in or facilitated any improper trading strategy and 2) There was no evidence that Avista Utilities or Avista Energy engaged in any efforts to manipulate the western energy markets during 2000 and 2001. An agreement in resolution, including these findings, was filed with the FERC’s administrative law judge in January 2003. Avista Corp., Avista Energy and the FERC Staff have requested that the administrative law judge certify the agreement in resolution and forward it to the FERC for approval.

Pacific Northwest Refund Proceedings

The July 2001 FERC order also directed an evidentiary proceeding to explore wholesale power market issues in the Pacific Northwest to determine whether there were excessive charges for spot market sales in the Pacific Northwest during the period from December 25, 2000 to June 20, 2001. Based on their application of selected retroactive pricing methods, certain parties asserted claims for significant refunds from Avista Energy and lesser refunds from Avista Utilities. Avista Energy and Avista Utilities joined with numerous other wholesale market participants to oppose proposals by parties for retroactive price caps and refund claims. In September 2001, the FERC’s administrative law judge for this proceeding issued a recommendation that the FERC should not order refunds for the Pacific Northwest for the period in question and that the FERC should take no further action on these matters. On December 19, 2002, the FERC issued a Discovery Order that reopened the evidentiary record and allowed parties in the proceeding to conduct additional discovery for the period January 1, 2000 to June 20, 2001. The December 19, 2002 Discovery Order required that, by no later than March 3, 2003, the market participants provide relevant documents to support any proposed recommendations to the FERC. The Discovery Order also affords parties in this proceeding the opportunity to respond by March 20, 2003 to submissions made by March 3, 2003. The Company cannot predict when the FERC will issue a decision in the Pacific Northwest refund proceeding. If retroactive price caps or refunds are imposed, Avista Utilities and Avista Energy could assert offsetting claims in the Pacific Northwest refund proceeding.

See further information under “Federal Energy Regulatory Commission Inquiry,” “U.S. Commodity Futures Trading Commission (CFTC) Subpoena,” “California Energy Markets” and “Washington Consumer Class Action Lawsuit” in “Note 28 of the Notes to Consolidated Financial Statements.”

Regional Transmission Organizations

Avista Corp. is negotiating with nine other utilities in the western United States in the possible formation of a Regional Transmission Organization (RTO), RTO West, a non-profit organization. The potential formation of RTO West is in response to a FERC order requiring all utilities subject to FERC regulation to file a proposal to form a RTO, or a description of efforts to participate in a RTO, and any existing obstacles to RTO participation. RTO West filed its Stage 2 proposal with the FERC in March 2002 and received limited approval from the FERC of this initial plan in September 2002. The FERC’s goal with respect to the formation of RTOs is to promote efficiency in wholesale electricity markets and in the operation of transmission systems by way of standardized and independent operation of transmission systems.

Avista Corp. and two other western utilities have also taken steps toward the formation of a for-profit Independent Transmission Company, TransConnect, which would be a member of RTO West, serve portions of five states and own or lease the high voltage transmission facilities of the participating utilities. TransConnect filed its proposal with the FERC in November 2001 and received limited approval from the FERC in September 2002.

The final proposals must be approved by the FERC, the boards of directors of the filing companies and regulators in various states. The companies’ decision to move forward with the formation of TransConnect or RTO West will ultimately depend on the conditions related to the formation of the entities, as well as the economics and conditions imposed in the regulatory approval process. If TransConnect were formed, it could result in Avista Utilities divesting its electric transmission assets. The formation of RTO West or TransConnect could have an impact on the Company’s transmission costs.

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Standard Market Design

On July 31, 2002, the FERC issued a Notice of Proposed Rulemaking proposing a Standard Market Design (SMD) that would significantly alter the markets for wholesale electricity and transmission and ancillary services in the United States. The new SMD would establish a generation adequacy requirement for "load-serving entities" and a standard platform for the sale of electricity and transmission services. Under the new SMD, Independent Transmission Providers would administer spot markets for wholesale power, ancillary services and transmission congestion rights, and electric utilities, including Avista Utilities, would be required to transfer control over transmission facilities to the applicable Independent Transmission Provider. As the SMD proposal develops, the Company continues to assess the impact the SMD would have on its operations as well as how the SMD would impact the RTO West and TransConnect proposals. The Company is subject to state regulation in each of the states in which it operates. State regulatory agencies are actively involved in the SMD rulemaking process and there have been significant concerns at the state and regional level raised with the FERC with respect to the SMD, particularly in the western United States. In February 2003, Avista Utilities and several other western utilities filed comments with the FERC expressing their concerns with respect to the SMD proposal.

Results of Operations

Overall Operations

Diluted earnings (loss) per common share by business segments

The following table presents diluted earnings (loss) per common share by business segments for the years ended December 31:

	2002	2001	2000
Avista Utilities	$ 0.71	$ 0.46	$(1.37)
Energy Trading and Marketing	0.47	1.33	3.51
Information and Technology	(0.25)	(0.41)	(0.41)
Other	(0.26)	(0.18)	(0.06)
Earnings per common share from continuing operations	0.67	1.20	1.67
Earnings (loss) per common share from discontinued operations	0.02	(1.00)	(0.20)
Earnings per common share before cumulative effect of accounting change	0.69	0.20	1.47
Loss per common share from cumulative effect of accounting change	(0.09)	—	—
Total earnings per common share, diluted	$ 0.60	$ 0.20	$ 1.47

2002 compared to 2001

Income from continuing operations was $34.3 million for 2002 compared to $59.6 million for 2001. The decrease was primarily due to reduced net income recorded by the Energy Trading and Marketing line of business. Energy Trading and Marketing recorded net income of $22.4 million for 2002 compared to $63.2 million for 2001. The primary reason for the decrease in net income was a reduction in Avista Energy's net margin. During the second half of 2001 and 2002, prices, trading volumes and volatility in wholesale energy markets in the western United States decreased relative to the first half of 2001, which reduced Avista Energy's earnings potential. Net income recorded by Avista Utilities was $36.4 million for 2002, compared to $24.2 million for 2001. The increase for Avista Utilities is primarily due to an increase in gross margin (operating revenues less resource costs) primarily due to an electric rate increase in Washington, partially offset by an increase in other operating expenses.

The Information and Technology line of business incurred a net loss of $12.1 million for 2002 compared to $19.4 million for 2001. The decrease in the net loss was primarily due to a decrease in operating expenses.

The Other line of business incurred a net loss of $12.4 million for 2002 compared to $8.4 million for 2001. The increase in the net loss was primarily due to litigation costs and settlements.

The discontinued operations of Avista Communications recorded net income of $1.1 million for 2002 compared to a net loss of $47.4 million for 2001. Net income for 2002 was primarily due to the settlement of contracts and liabilities as well as the favorable settlement of a lawsuit. The significant loss for 2001 was primarily due to asset impairment charges of $58.4 million.

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Total revenues decreased $414.9 million for 2002 compared to 2001. Avista Utilities' revenues decreased $336.9 million, or 27 percent, primarily due to decreased wholesale electric revenues, partially offset by increased retail electric revenues. Wholesale sales volumes decreased primarily due to the expiration of several wholesale electric sales contracts. The decrease in wholesale revenues also reflected a decrease in wholesale prices. The increase in retail electric revenues was primarily a result of higher rates approved by state regulatory commissions to recover deferred power costs as well as the general electric rate case order approved by the WUTC in June 2002. Revenues from Energy Trading and Marketing decreased $80.1 million, or 60 percent, primarily due to decreased energy commodity prices and trading volumes, as well as reduced market volatility. Revenues from the Information and Technology companies increased 28 percent to $17.6 million primarily as a result of customer growth at Avista Advantage. Revenues from the Other line of business decreased $1.7 million reflecting decreased activity in this line of business.

Total resource costs (all from Avista Utilities) decreased $396.5 million for 2002 compared to 2001 primarily due to reduced power purchase expenses, decreased cost of natural gas purchased to serve retail customers and decreased fuel for generation expenses. Power purchase expenses, natural gas purchased and fuel for generation decreased due to lower wholesale market prices, increased hydroelectric generation, reduced wholesale sales obligations and decreased thermal generation. The net amortization of deferred power and natural gas costs was $68.5 million for 2002, compared to net deferrals of $210.5 million for 2001.

Operations and maintenance expenses decreased $2.7 million primarily due to reduced expenses for Information and Technology. During 2002, Avista Advantage and Avista Labs focused on reducing operating expenses by improving efficiencies and reducing the workforce.

Administrative and general expenses decreased $0.5 million; however, there were significant fluctuations within each business segment. The net decrease was due to reduced expenses for Energy Trading and Marketing as well as Information and Technology, partially offset by increased expenses for Avista Utilities and Other. The decrease for Energy Trading and Marketing was primarily a result of reduced incentive compensation expenses resulting from decreased earnings as well as reduced professional fees. The decrease for Information and Technology was consistent with the decrease in operations and maintenance expenses. The increase for Avista Utilities was primarily due to initiatives implemented during the third quarter of 2001 designed to temporarily reduce certain operating expenses to improve liquidity and operating cash flows. These initiatives resulted in significantly reduced expenses for 2001. Cost reduction measures were not as restrictive during 2002 as the second half of 2001. The increase in administrative and general expenses for Avista Utilities was also due to increased pension, health care, legal and general insurance costs. Administrative and general expenses for the Other business segment increased due to litigation costs and settlements.

Depreciation and amortization increased $1.3 million due to an increase for Avista Utilities partially offset by decreases for each of the other business segments. The decreases for the other business segments were primarily due to the requirement of Statement of Financial Accounting Standards (SFAS) No. 142 "Goodwill and Other Intangible Assets" that goodwill no longer be amortized effective January 1, 2002.

Taxes other than income taxes increased $8.1 million primarily due to increased retail electric revenues and related taxes for Avista Utilities. The increase for Avista Utilities was partially offset by a decrease for Energy Trading and Marketing due to a decrease in the net margin on energy trading activities.

Interest expense decreased $1.1 million for 2002 compared to 2001. The average balance of debt outstanding was relatively consistent for 2001 and 2002 with increasing balances outstanding during 2001 and decreasing balances outstanding during 2002. The amount of debt outstanding increased substantially during 2001 with the issuance of $400.0 million of Unsecured Senior Notes in April 2001 and $150.0 million of First Mortgage Bonds in December 2001. During 2002, the Company repurchased $203.6 million of long-term debt. The Company expects interest expense to continue to decline in 2003 due to the effect of debt repurchases in 2002, expected debt repurchases in 2003 and scheduled debt maturities in 2003.

Capitalized interest decreased $3.0 million for 2002 compared to 2001 primarily due to the fact that the Company did not capitalize any interest related to Coyote Springs 2 subsequent to September 30, 2002 because the project was substantially completed. A decrease in capital expenditures for Avista Utilities also contributed to the decrease in capitalized interest.

Other income-net decreased $3.2 million primarily due to reduced interest income partially offset by impairment charges recorded during 2001.

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Income taxes decreased $4.4 million for 2002 compared to 2001, primarily due to decreased earnings before income taxes, partially offset by an increase in state income taxes. The effective tax rate was 46.6 percent for 2002 compared to 36.6 percent for 2001. The increase in the effective tax rate was due to increased state income tax expense as well as decreased earnings and the increased effect of permanent tax differences, such as accelerated tax depreciation, resulting from the Company's previous transition to SFAS No. 109, "Accounting for Income Taxes."

In April 2002, the Company completed its transitional test of goodwill related to the adoption of SFAS No. 142. Accordingly, the Company determined that $6.4 million of goodwill related to Advanced Manufacturing and Development, a subsidiary of Avista Ventures, was impaired. The Company recorded this impairment of $4.1 million, net of tax, as a cumulative effect of accounting change in the Consolidated Statement of Income and Comprehensive Income.

2001 compared to 2000

Income from continuing operations was $59.6 million for 2001 compared to $101.1 million for 2000. The decrease was primarily due to reduced net income recorded by the Energy Trading and Marketing line of business, partially offset by an increase in net income from Avista Utilities. Also contributing to the decline in income from continuing operations was an increase in interest expense and $21.8 million of deferred power costs written off during 2001. The Energy Trading and Marketing line of business recorded net income of $63.2 million in 2001 compared to $161.8 million in 2000. The primary reason for the decrease in net income was a reduction in the mark-to-market adjustment for the change in the fair value position of Avista Energy's energy commodity portfolio. During the second half of 2001, volatility in wholesale energy markets in the western United States decreased, which reduced Avista Energy's earnings potential. Net income recorded by Avista Utilities was $24.2 million in 2001, an increase from a net loss of $38.8 million in 2000. Avista Utilities' net loss for 2000 was primarily due to unprecedented sustained peaks in electric energy prices compounded by a wholesale short position.

The Information and Technology line of business incurred a net loss of $19.4 million for 2001 compared to $19.0 million for 2000 as Avista Advantage and Avista Labs continued to grow their operations.

The Other line of business incurred a net loss of $8.4 million for 2001 compared to $2.9 million for 2000. The increase in the net loss from 2000 was primarily a result of increased interest expense on intercompany borrowings between Avista Capital and Avista Corp. that is eliminated in the consolidated financial statements.

The discontinued operations of Avista Communications incurred a net loss of $47.4 million for 2001 compared to a net loss of $9.4 million for 2000. The significant loss from Avista Communications was primarily due to pre-tax asset impairment charges of $58.4 million recorded during the third quarter of 2001.

Total revenues decreased $463.2 million in 2001 compared to 2000. Avista Utilities' revenues decreased $281.3 million, or 19 percent, primarily due to decreased wholesale electric sales partially offset by increased retail revenues from both electric and natural gas sales. The increase in retail revenues is primarily a result of higher rates approved by state regulatory agencies to recover deferred power and natural gas costs. Revenues from the Energy Trading and Marketing line of business decreased $173.5 million, or 56 percent, due to a decrease in unrealized gains. Revenues from the Information and Technology companies increased 141 percent to $13.8 million primarily as a result of customer growth at Avista Advantage. Revenues from the Other line of business decreased $16.6 million, or 50 percent, reflecting decreased activity in this line of business.

Avista Utilities' resource costs decreased $396.5 million in 2001 compared to 2000, or 32 percent, primarily due to reduced wholesale power purchases.

Administrative and general expenses decreased $15.7 million in 2001 compared to 2000 primarily due to reduced expenses for Avista Utilities and Energy Trading and Marketing. This was primarily a result of company-wide initiatives to reduce expenses. This was also due to decreased incentive compensation expense based on lower earnings by both Avista Energy and the Company.

Interest expense increased $38.2 million in 2001 compared to 2000, primarily due to higher levels of outstanding debt during the year. Long-term debt and short-term borrowings outstanding as of December 31, 2001 increased $320.2 million from December 31, 2000.

Capitalized interest increased $7.1 million from 2000 to 2001 primarily due to increased capitalized interest for Coyote Springs 2.

Income taxes decreased $42.6 million in 2001 compared to 2000, primarily due to decreased earnings before income taxes. The effective tax rate was 36.6 percent for 2001 compared to 43.2 percent for 2000. The higher effective tax rate in 2000 was primarily due to higher state income taxes.

Preferred stock dividend requirements decreased from 2000 due to the conversion of all outstanding shares of Series L Preferred Stock into shares of common stock, which resulted in a one-time charge of $21.3 million for preferred stock dividend requirements in 2000.

Avista Utilities

2002 compared to 2001

Avista Utilities recorded net income of $36.4 million for 2002 compared to $24.2 million for 2001. Avista Utilities' income from operations was $149.2 million for 2002 compared to $114.9 million for 2001. This increase was primarily due to an increase in gross margin (operating revenues less resource costs). Avista Utilities' operating revenues decreased $336.9 million and resource costs decreased $396.5 million resulting in an increase of $59.6 million in gross margin for 2002 as compared to 2001. The increase in gross margin was partially offset by an increase in administrative and general expenses, depreciation and amortization and taxes other than income taxes. The general electric rate increase of 19.3 percent in Washington base retail rates effective July 1, 2002 contributed to the increase in gross margin.

Retail electric revenues increased $65.2 million for 2002 from 2001. This increase was primarily due to the electric surcharges implemented to recover deferred power costs and the June 2002 Washington electric rate increase, partially offset by decreased use per customer and total kWhs sold. The increase in retail electric revenues was also due to refunds to customers in January 2001 of the gain on the sale of Avista Utilities' interest in the Centralia Power Plant (Centralia) that reduced revenues for 2001. During 2001 and 2002, Avista Utilities experienced decreased loads and decreased use per customer with respect to electric retail sales. The decrease in use per customer appears to be primarily due to a response to the increase in electric rates and the resulting conservation efforts of individual customers. The decrease in use per customer also appears to reflect milder weather in 2002 and 2001 as compared to 2000. The decrease in total kWhs sold primarily relates to industrial customers and appears to reflect a general downturn in the economy of eastern Washington and northern Idaho.

Wholesale electric revenues decreased $416.8 million, or 87 percent, reflecting wholesale sales volumes which decreased 65 percent from 2001 and average sales prices that were 62 percent lower than the prior year. Average wholesale prices decreased to $28.92 per MWh for 2002 from $76.80 per MWh for 2001 reflecting decreased electric prices in the western United States. Wholesale sales volumes decreased primarily due to the expiration of several wholesale electric sales contracts, including two 100 MW index-based sales contracts that expired in July 2001. The extent of future wholesale transactions will be based on the availability of resources owned or controlled by Avista Utilities and changes to loads of Avista Utilities' customers and contractual obligations.

Other electric revenues increased $13.5 million primarily due to the sale of natural gas purchased for electric generation that was not used in generation. Avista Utilities operated less thermal generation in 2002 as compared to 2001 based on lower retail demand, increased hydroelectric generation and decreased wholesale market prices.

Natural gas revenues increased $1.2 million for 2002 from 2001 due to a slight increase in retail and transportation revenues, partially offset by a decrease in wholesale natural gas revenues. Retail rates were increased during 2001 to recover deferred natural gas costs. During the fourth quarter of 2002, retail rates for natural gas were reduced in response to a decrease in current and projected natural gas costs. During 2001 and 2002, Avista Utilities experienced decreased loads and decreased use per customer with respect to natural gas retail sales. The decrease in use per customer appears to be primarily due to a response to the increase in natural gas rates during 2001 and the resulting conservation efforts of individual customers. The decrease in use per customer also appears to reflect milder weather in 2002 and 2001 as compared to 2000. The decrease in total therms sold primarily relates to industrial customers and appears to reflect a general downturn in the economy of Avista Utilities' service territory.

Power purchased for 2002 decreased $593.0 million, or 84 percent, compared to 2001 due to the decreased volume and price of power purchases. Average purchased power prices for 2002 were $24.64 per MWh or 68 percent lower than $77.40 per MWh for 2001 and volumes purchased decreased 49 percent compared to 2001. The decrease in the volume of purchased power was primarily the result of decreases in the volume of wholesale electric sales and increased hydroelectric resource availability to meet retail demand.

Net amortization of deferred power costs was $26.3 million in 2002 compared to net deferrals of $202.8 million in 2001. During 2002, Avista Utilities recovered (collected as revenue) $38.6 million of previously deferred power costs in Washington and $24.7 million in Idaho. During 2002, Avista Utilities deferred $22.4 million of power costs in Washington and $13.5 million in Idaho. During 2002, $27.7 million of a deferred credit was offset against the Idaho share of deferred power costs. The deferred credit relates to funds received in December 1998 in which the Company assigned and transferred certain rights under a long-term power sales contract with Portland General Electric (PGE) to a funding trust. Total deferred power costs were $155.3 million as of December 31, 2002. See further description of issues related to deferred power costs in the section "Avista Utilities – Regulatory Matters."

During 2002, Avista Utilities had $42.2 million of net amortization of deferred natural gas costs compared to net deferrals of $7.7 million in 2001. Total deferred natural gas costs were $11.5 million as of December 31, 2002.

The cost of fuel for generation for 2002 decreased $63.4 million from 2001 primarily due to a decrease in thermal generation as well as a decrease in the average cost of natural gas used for generation. Thermal generation decreased 43 percent primarily due to increased hydroelectric generation and wholesale market prices that were generally below the cost of operating the thermal generating units.

The expense for natural gas purchased for 2002 decreased $50.0 million compared to 2001 primarily due to the decreased average cost of natural gas.

Other fuel costs for 2002 increased $34.6 million compared to 2001. This was due to an increase in natural gas purchased as fuel for electric generation that was not used. This excess natural gas was sold with the associated revenues reflected as other electric revenues. Other fuel costs exceeded the revenues from selling the excess natural gas. This excess cost is accounted for under the ERM in Washington and the PCA in Idaho.

2001 compared to 2000

Avista Utilities recorded net income of $24.2 million in 2001 compared to a net loss of $38.8 million in 2000. Avista Utilities' income from operations was $114.9 million for 2001 compared to $3.2 million for 2000. This increase was primarily due to an increase in gross margin (operating revenues less resource costs). Avista Utilities' operating revenues decreased $281 million and resource costs decreased $396 million resulting in an increase of $115 million in gross margin for 2001 as compared to 2000.

Based on views of streamflows, historic wholesale market prices and energy availability in the second quarter of 2000, Avista Utilities entered into contracts and sold call options for fixed-price power for delivery without making matching purchases at the same time. Avista Utilities also made certain short-term sales at fixed prices that were offset by purchases at prices indexed to the market price at the time of delivery. Certain of these wholesale trading positions were outside normal operating guidelines. Avista Utilities was required to buy additional power not only to meet its obligations to its retail and long-term wholesale customers, but also to cover its wholesale trading positions. An orderly process to complete the necessary power purchases was impeded by the rapid escalation of market prices and lack of liquidity in the power markets during the second quarter of 2000. These purchases were made at fixed prices significantly higher than the related selling prices and at index, which settled at unprecedented levels in June 2000. The pricing of these purchases caused the majority of Avista Utilities' net loss for 2000.

Avista Utilities' short position was compounded by the May 2000 sale of its interest in Centralia to TransAlta, which reduced its system capacity by 200 megawatts. Based on historical trends and Avista Utilities' views on power prices and availability of power for May and June 2000, Avista Utilities did not seek to replace Centralia generation for those two months with firm commitments. Avista Utilities entered into a three-and-one-half-year contract to purchase 200 megawatts from TransAlta beginning in July 2000.

Retail electric revenues increased $4.0 million for 2001 from 2000. This increase was primarily due to the electric surcharges implemented in Washington and Idaho to recover deferred power costs, partially offset by decreased use per customer and kWh sold. Wholesale electric revenues decreased $383.9 million, or 44 percent, while wholesale sales volumes decreased 60 percent from 2000, reflecting average sales prices that were 40 percent higher than the prior year. Wholesale sales volumes decreased due to management's decision in 2000 to reduce power imbalance volume limits (the difference between projected load obligations and projected resource availability). This decision was based on the emergent market price volatility, and Avista Utilities' strategy to focus primarily on energy transactions necessary to efficiently manage power resources to meet retail customer loads and wholesale obligations.

Natural gas revenues increased $83.8 million for 2001 from 2000 due to increased prices approved by state commissions to recover increased natural gas costs partially offset by decreased therm sales, primarily due to both decreased retail and transportation customer volumes.

Power purchased during 2001 decreased $364.2 million, or 34 percent compared to 2000 primarily due to the decreased volume of power purchases, partially offset by higher average prices. Average purchased power prices for 2001 were 28 percent higher than for 2000; however, volumes purchased decreased 48 percent. The decrease in the volume of purchased power was primarily the result of decreases in the volume of wholesale electric sales.

During 2001 Avista Utilities deferred $145.4 million (net of the $21.8 million write-off) in power costs in Washington and $73.7 million in Idaho. The total balance of deferred power costs was $140.2 million for Washington and $73.1 million for Idaho as of December 31, 2001. In September 2001, the WUTC approved a temporary electric surcharge of 25 percent. In 2001, revenue collected under the Washington surcharge was $10.2 million, and $53.8 million of a deferred credit on the Company's balance sheet relating to funds received from a power sales contract with PGE in 1998 was offset against deferred power costs. In October 2001, the IPUC approved a PCA surcharge and the extension of a previously approved PCA surcharge for a total of 19.4 percent. In 2001, revenue collected under the Idaho PCA surcharges was $6.1 million, and $6.9 million of a deferred credit on the Company's balance sheet relating to funds received from a power sales contract with PGE in 1998 was offset against deferred power costs. In March 2002, the WUTC issued an order approving the prudence and recoverability of 90 percent of deferred power supply costs incurred during the period from July 1, 2000 through December 31, 2001. This resulted in the Company recording an additional expense for $21.8 million (representing the 10 percent of costs not recoverable) of power supply costs previously deferred through 2001. Additionally, the order also provided that one-fifth of the 25 percent electric surcharge will be applied to offset the Company's general operating costs and the remainder will continue to be applied as a recovery of deferred power costs. The WUTC order also approved a 6.2 percent (or $14.7 million in annual revenues) increase in base retail rates. See further description of issues related to deferred power costs in the section "Avista Utilities – Regulatory Matters."

Avista Utilities deferred, net of amortization, $7.7 million of purchased natural gas costs during 2001 and total deferred natural gas costs were $52.7 million as of December 31, 2001. In July 2001, the Company filed requests for purchased gas cost adjustments (PGA) with the WUTC and the IPUC in order to recover certain deferred natural gas costs related to Washington and Idaho natural gas purchases. The Washington PGA increase of 12.2 percent approved by the WUTC and the Idaho PGA increase of 11.5 percent approved by the IPUC became effective in August 2001.

The cost of fuel for generation for 2001 increased $12.9 million from 2000 primarily due to an increase in natural gas-fired combustion turbine plant generation and partially due to the increased cost of natural gas. Natural gas costs were relatively high compared to historical prices during the first half of 2001 before declining in the second half of 2001.

The expense for natural gas purchased for resale for 2001 increased $50.8 million compared to 2000 due to the increased cost of natural gas partially offset by a decrease in total therms sold. Consistent with changes in fuel for generation, natural gas costs declined during the second half of 2001 as compared to the first half of the year.

As part of the strategy to mitigate the decline in electric resources caused by poor hydroelectric conditions and volatile energy markets, Avista Utilities had several buy-back and rebate programs for residential, commercial and industrial customers during 2001. The programs were designed to encourage conservation and decrease average customer usage.

Energy Trading and Marketing

Energy Trading and Marketing includes the results of Avista Energy and Avista Power.

Avista Energy is an electricity and natural gas marketing and trading business, operating primarily within the WECC. Avista Energy focuses on asset-backed optimization of combustion turbines and hydroelectric assets owned by other entities, long-term electric supply contracts, natural gas storage, and electric and natural gas transmission and transportation arrangements. Avista Energy's marketing efforts are driven by its base of knowledge and experience in the operation of both electric energy and natural gas physical systems in the WECC, as well as its relationship-focused approach with its customers.

In June 2002, the Emerging Issues Task Force (EITF) reached a partial consensus on Issue No. 02-3 regarding the accounting for contracts involved in energy trading and risk management activities. The partial consensus required that all gains and losses arising from energy trading contracts (whether realized or unrealized) accounted for under EITF Issue No. 98-10 “Accounting for Contracts Involved in Energy Trading and Risk Management Activities” were to be presented on a net basis in the income statement beginning in the third quarter of 2002. Reclassification of all historical comparable periods was required. Avista Energy historically presented unrealized gains and losses on energy trading contracts on a net basis. However, realized contracts were presented on a gross basis for both operating revenues and resource costs. The implementation of EITF Issue 02-3 resulted in reduced operating revenues and resource costs as compared to historical periods with no impact on the Company’s net income or financial condition.

Avista Energy accounted for energy commodity trading activity in compliance with EITF Issue No. 98-10 through December 31, 2002 for contracts entered into on or prior to October 25, 2002. Under EITF 98-10, Avista Energy recognized revenue based on the change in the market value of outstanding derivative commodity sales contracts, net of future servicing costs and reserves, in addition to revenue related to settled contracts. In October 2002, the EITF rescinded Issue No. 98-10. As such, Avista Energy is required to account for energy trading contracts that meet the definition of a derivative at market value in compliance with SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities.” This applies to all existing contracts as of January 1, 2003 as well as to all new contracts entered into subsequent to October 25, 2002. Contracts not meeting the definition of a derivative are no longer accounted for at market value and include Avista Energy’s Agency Agreement with Avista Utilities, natural gas storage contracts, tolling agreements and natural gas transportation agreements. The transition from EITF Issue No. 98-10 to accrual based accounting resulted in the adjustment of the contracts that are not considered derivatives from their market value to their cost basis. Any gain or loss on contracts that are not considered derivatives will not be recognized until the contract is settled or realized. The Company anticipates that the changes will primarily affect the timing of the recognition of income or loss in earnings, and not change the underlying economics or cash flows of transactions entered into by Avista Energy. The changes could result in a significant increase in the volatility of reported earnings on a quarter-to-quarter and year-to-year basis. On January 1, 2003, Avista Energy recorded as a cumulative effect of accounting change a charge of approximately $1.2 million (net of tax) related to the transition from EITF 98-10 to SFAS No. 133. See “Critical Accounting Policies” and “Note 2 of the Notes to Consolidated Financial Statements” for further details.

Derivative commodity instruments in the energy trading portfolio are marked to estimated fair market value on a daily basis (mark-to-market accounting), which causes earnings variability. Market prices are utilized in determining the value of electric, natural gas and related derivative commodity instruments. For natural gas commodity instruments, these market prices are generally available through three years. For electric commodity instruments, these market prices are generally available through two years. For longer-term positions and certain short-term positions for which market prices are not available, models based on forward price curves are utilized. These models incorporate a variety of estimates and assumptions, the ultimate outcomes of which are beyond Avista Energy’s control including, among others, estimates and assumptions as to demand growth, fuel price escalation, availability of existing generation and costs of new generation. Actual experience can vary significantly from these estimates and assumptions.

Avista Energy trades electricity and natural gas, along with derivative commodity instruments including futures, options, swaps and other contractual arrangements. Most transactions are conducted on a largely unregulated “over-the-counter” basis, there being no central clearing mechanism (except in the case of specific instruments traded on the commodity exchanges). Avista Energy’s trading operations are affected by, among other things, volatility of prices within the electric energy and natural gas markets, the demand for and availability of energy, lower unit margins on new sales contracts, FERC-ordered price caps, deregulation of the electric utility industry, the creditworthiness of counterparties and the reduced liquidity in energy markets. See “Business Risk” for further information.

2002 compared to 2001

Energy Trading and Marketing’s net income was $22.4 million for 2002, compared to $63.2 million for 2001. The primary reason for the decrease in net income was a decrease in the net margin on energy trading activities. Net margin on energy trading activities, which is reported as operating revenues, was $54.2 million for 2002 compared to $134.3 million for 2001.

Realized gains decreased to $141.6 million for 2002 from $164.5 million for 2001. Realized gains represent the net gain on contracts that have settled. The decrease was primarily due to a decrease in the underlying commodity values that settled and a decrease in the volume of transactions. The decrease in the volume of transactions was primarily due to reduced liquidity in wholesale markets, fewer creditworthy counterparties participating in the wholesale markets and a decrease in the volatility of prices in the wholesale markets. The total mark-to-market adjustment for Energy Trading and Marketing was an unrealized loss of $87.4 million for 2002 compared to an unrealized loss of $30.2 million for 2001. The increase in the unrealized loss is primarily due to the settlement of contracts and the realization of previously unrealized gains and decreased volatility in the wholesale energy markets. During 2002, the change in the total unrealized gain attributable to market prices and other market changes was $49.7 million, a decrease from $120.6 million in 2001.

Administrative and general expenses decreased $11.7 million, or 35 percent, from 2001 primarily due to reduced incentive compensation expense based on lower earnings in 2002. Reduced professional fees also contributed to the decrease in administrative and general expenses. Professional fees were high during 2001 due to expenses associated with the California energy crisis (see “Power Market Issues”) and a CFTC investigation that was resolved in 2001 related to certain trades in 1998.

Energy Trading and Marketing’s total assets decreased $156.6 million from December 31, 2001 to December 31, 2002 primarily due to a decrease in total current and non-current energy commodity assets. This decrease in commodity assets reflects the settlement of contracts and a decrease in commodity prices during 2002.

2001 compared to 2000

Energy Trading and Marketing’s net income was $63.2 million for 2001, compared to $161.8 million for 2000. The primary reason for the decrease in net income was a decrease in the mark-to-market adjustment for the change in the fair value position of Avista Energy’s energy commodity portfolio. The mark-to-market adjustment was an unrealized loss of $30.2 million for 2001 compared to an unrealized gain of $176.8 million for 2000. The decrease is primarily due to a significant amount of contracts settled during 2001 and the realization of previous unrealized gains. Volatility in energy markets and increased commodity prices during 2000 resulted in significant unrealized gains during 2000. These unrealized gains were partially realized during 2001. Realized gains increased to $164.5 million in 2001 from $130.9 million in 2000.

Administrative and general expenses decreased $7.8 million or 19 percent from 2000 primarily due to reduced incentive compensation expense based on lower earnings in 2001.

Expenses associated with the exit of Avista Energy’s operations in Houston and Boston during the first half of 2000 totaled $7.9 million in 2000.

During 2001 the Company recorded an impairment charge of $8.2 million related to three turbines owned by Avista Power which is reflected in the line item other income-net in the Consolidated Statements of Income and Comprehensive Income. The Company originally planned to use these turbines in a non-regulated generation project. During 2001, the Company decided that it would no longer pursue the development of additional non-regulated generation projects. As such, the Company wrote down the carrying value of the turbines to estimated fair value less selling costs.

Energy Trading and Marketing’s total assets decreased $8.8 billion from December 31, 2000 to December 31, 2001 primarily due to a decrease in total current and non-current energy commodity assets. This decrease in commodity assets primarily reflected the settlement of a significant amount of contracts during 2001 and a decrease in the forward price and estimated value of natural gas and electricity from December 31, 2000 to December 31, 2001.

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Energy trading activities and positions

The following summarizes information with respect to Avista Energy's trading activities during 2002 (dollars in thousands):

	Natural Gas Assets net of Liabilities	Electric Assets net of Liabilities	Total Unrealized Gain (Loss) (4)
Fair value of contracts as of December 31, 2001	$ 38,392	$ 148,325	$ 186,717
Less contracts settled during 2002 (1)	(33,334)	(108,276)	(141,610)
Fair value of new contracts when entered into during 2002 (2)	—	—	—
Change in fair value due to changes in valuation techniques (3)	—	—	—
Change in fair value attributable to market prices and other market changes	29,662	20,032	49,694
Fair value of contracts as of December 31, 2002	$ 34,720	$ 60,081	$ 94,801

(1) Contracts settled during 2002 include those contracts that were open in 2001 but settled during 2002 as well as new contracts entered into and settled during 2002. Amount represents realized gains associated with these settled transactions.

(2) Avista Energy has not entered into any origination transactions during 2002 in which dealer profit or mark-to-market gain or loss was recorded at inception.

(3) During 2002, Avista Energy did not experience a change in fair value as a result of changes in valuation techniques.

(4) Change in unrealized gain (loss) does not reconcile to totals for the Energy Trading and Marketing segment due to an intercompany elimination between Avista Energy and Avista Power related to Avista Energy's contract for the output from the Lancaster Project that is 49 percent owned by Avista Power.

The following discloses summarized information with respect to valuation techniques and contractual maturities of Avista Energy's energy commodity contracts outstanding as of December 31, 2002 (dollars in thousands):

	Less than one year	Greater than one and less than three years	Greater than three and less than five years	Greater than five years	Total
Natural gas assets (liabilities), net (1)					
Prices from other external sources (2)	$25,622	$ 2,144	$ —	$ —	$27,766
Fair value based on valuation models (3)	6,345	(1,351)	1,184	776	6,954
Total natural gas assets (liabilities), net	$31,967	$ 793	$1,184	$ 776	$34,720
Electric assets (liabilities), net (1)					
Prices from other external sources (2)	$30,659	$21,688	$ —	$ —	$52,347
Fair value based on valuation models (4)	(1,929)	5,415	9,304	(5,056)	7,734
Total electric assets (liabilities), net	$28,730	$27,103	$9,304	$(5,056)	$60,081

(1) Reflects commodity contracts outstanding and accounted for under EITF 98-10 as of December 31, 2002 with the exception of contracts entered into subsequent to October 25, 2002. The table does not reflect any adjustment for the transition to SFAS No. 133 for contracts not meeting the definition of a derivative. Effective January 1, 2003, contracts that were entered into on or prior to October 25, 2002 and not meeting the definition of a derivative are accounted for on an accrual basis. Contracts not meeting the definition of a derivative include Avista Energy's Agency Agreement with Avista Utilities, natural gas storage contracts, tolling agreements and natural gas transportation agreements.

(2) Fair value is determined based upon actively traded, "over-the-counter" market quotes received from third party brokers. For natural gas assets and liabilities, these market quotes are generally available through three years. For electric assets and liabilities, these market quotes are generally available through two years.

(3) Represents contracts for delivery at basis locations not actively traded in the "over-the-counter" markets. In addition, this includes all contracts with a delivery period greater than three years, for which active quotes are not available. These internally developed market curves are based upon published New York Mercantile Exchange prices through seven years, as well as basis spreads using historical and broker estimates. After seven years, an escalation is used to estimate the valuation.

(4) Represents contracts for delivery at basis locations not actively traded in the "over-the-counter" markets. In addition, this includes all contracts with a delivery period greater than two years, for which active quotes are not available. These internally developed market curves are determined using a production cost model with

inputs for assumptions related to power prices (including, without limitation, natural gas prices, generation on line, transmission constraints, future demand and weather).

Avista Energy conducts frequent stress tests on the valuation of its portfolio. By changing the input assumptions to the internally developed market curves, these stress tests attempt to capture Avista Energy's sensitivity to changes in portfolio valuation. These stress tests indicate that, for the portfolio valued under internally developed market curves, the valuations can be reasonably certain to be within a 20 percent range, upwards or downwards, of the reported values listed above.

Avista Power

Avista Power is a 49 percent owner of a 270 MW natural gas-fired combustion turbine plant in northern Idaho (Lancaster Project), which commenced commercial operation in September 2001. All of the output from the Lancaster Project is contracted to Avista Energy for 25 years. In addition, Avista Power and its co-owner, an affiliate of Mirant Americas Development, Inc. (Mirant), have substantially completed the construction of Coyote Springs 2. In January 2003, Avista Power's 50 percent ownership interest in Coyote Springs 2 was transferred to Avista Corp. for inclusion in Avista Utilities' power generation resource portfolio. See "New Generation Resource – Avista Utilities" for further information.

Information and Technology

The Information and Technology line of business includes the results of Avista Advantage and Avista Labs (including its 70 percent equity interest in H2fuel, LLC). Avista Advantage remains focused on growing revenue, improving margins, reducing fixed and variable costs and improving client satisfaction. Avista Corp. continues discussions with selected companies in its search for a financial partner for Avista Labs with the goal of reducing its ownership interest in Avista Labs to less than 20 percent.

2002 compared to 2001

Information and Technology's net loss was $12.1 million for 2002 compared to $19.4 million for 2001. Operating revenues for this line of business increased $3.8 million and operating expenses decreased $7.2 million, as compared to 2001. Avista Advantage accounted for the increase in revenues primarily due to the expansion of its customer base. The decrease in operating expenses reflects reduced expenses for Avista Advantage and Avista Labs due to improved efficiencies, a reduction in the number of employees and a focus on reducing operating expenses. Certain non-recurring items in both periods also contributed to the decrease in operating expenses.

2001 compared to 2000

Information and Technology's net loss was $19.4 million for 2001 compared to $19.0 million for 2000. Operating revenues and expenses in 2001 for this line of business increased $8.1 million and $11.5 million, respectively, as compared to 2000. Avista Advantage accounted for the increase in revenues primarily due to the expansion of its customer base. The increase in operating expenses reflected expansion of operations for Avista Advantage and further fuel cell development by Avista Labs.

Other

The Other line of business includes several subsidiaries, including Avista Ventures, Pentzer, Avista Development and Avista Services. The operations of Avista Capital that are not included through its subsidiaries are reported in this line of business.

2002 compared to 2001

The net loss before cumulative effect of accounting change from this line of business was $12.4 million for 2002, compared to $8.4 million for 2001. The increase in the net loss was primarily due to a decrease in income from operations and partially due to an increase in interest expense as well as a reduction in gains on the disposition of assets. Operating revenues from this line of business decreased $1.7 million and operating expenses increased $2.7 million, respectively, for 2002 as compared to 2001. The decrease in income from operations was primarily due to an increase in litigation costs and settlements as well as an increase in the loss from Advanced Manufacturing and Development, a subsidiary of Avista Ventures, from $4.5 million in 2001 to $5.1 million in 2002.

AVISTA CORPORATION

2001 compared to 2000

The net loss from this line of business was $8.4 million for 2001, compared to $2.9 million for 2000. The increase in the net loss from 2000 was primarily a result of increased interest expense on intercompany borrowings between Avista Capital and Avista Corp. that is eliminated in the consolidated financial statements. Operating revenues and expenses from this line of business decreased $16.6 million and $16.0 million, respectively, during 2001 as compared to 2000, reflecting reduced activities in this line of business.

Discontinued Operations

In September 2001, the Company reached a decision that it would dispose of substantially all of the assets of Avista Communications. The divestiture of operating assets was complete by the end of 2002. Certain liabilities of the operations remain to be settled. In October 2001, minority shareholders of Avista Communications acquired ownership of its Montana and Wyoming operations as well as its dial-up internet access operations in Spokane, Washington and Coeur d'Alene, Idaho. In December 2001, Avista Communications completed the sale of the assets and customer accounts of its Yakima and Bellingham, Washington operations to Advanced Telcom Group, Inc. In April 2002, Avista Communications completed the transfer of voice and integrated services customer accounts in Spokane, Washington and Lewiston and Coeur d'Alene, Idaho to certain subsidiaries of XO Communications, Inc. In December 2002, the Company completed the sale of substantially all of the remaining assets of Avista Communications to FiberLink LLC.

2002 compared to 2001

Net income for 2002 was $1.1 million, compared to a net loss of $47.4 million for 2001. Net income for 2002 was primarily due to the settlement of contracts and liabilities during the period as well as the favorable settlement of a lawsuit during the period. The significant net loss for 2001 was due to asset impairment charges of $58.4 million recorded during the third quarter of 2001.

2001 compared to 2000

The net loss for 2001 was $47.4 million, compared to a net loss of $9.4 million for 2000. The significant net loss for 2001 was due to asset impairment charges. The loss from operations for Avista Communications was $21.1 million for 2001 compared to $15.4 million for 2000.

Earnings Outlook

The Company expects to report consolidated earnings in the range of $0.80 to $1.00 per diluted share in 2003. This expectation is for earnings before the cumulative effect of changes in accounting principles. This estimate includes earnings ranging from $0.60 to $0.80 for Avista Utilities and $0.20 to $0.30 for Energy Trading and Marketing and a loss ranging from $0.10 to $0.15 for Information and Technology. The 2003 projection includes uncertainties surrounding reduced activity in the wholesale energy markets and increased expenses, such as pension, health care and insurance costs. The projection for 2003 anticipates that the Company will expense the first $9 million plus 10 percent of any additional power supply costs above the amount allowed in base retail electric rates for Washington customers. The Company anticipates that the change in accounting for Avista Energy's energy trading activities from EITF Issue No. 98-10 to SFAS No. 133 could result in a significant increase in the volatility of reported earnings on a quarter-to-quarter and year-to-year basis. These projections are subject to a variety of risks and uncertainties that could cause actual results to differ from this estimate, including those described above and listed under "Safe Harbor for Forward-Looking Statements" and "Future Outlook-Business Risks." See "Liquidity and Capital Resources" for additional information.

New Generation Resource – Avista Utilities

Construction has been substantially completed on the 280 MW combined cycle natural gas-fired turbine power plant at Coyote Springs 2 located near Boardman, Oregon which was 50 percent owned by Avista Power and 50 percent owned by Mirant and was included in the Energy Trading and Marketing line of business as of December 31, 2002. The Company's ownership interest in the plant was transferred from Avista Power to Avista Corp. in January 2003 to be operated as an asset of Avista Utilities. Avista Corp. and Mirant are both current with respect to their obligations to share equally in the costs of construction of the plant. Avista Corp. and Mirant will share equally in the costs of operation and output from Coyote Springs 2. In May 2002, a transformer at the site failed and caught fire resulting in the release of an estimated 17,000 gallons of coolant oil. The Company worked closely with the appropriate environmental agencies to complete a satisfactory cleanup of the oil. While the cause of the failure is still being investigated, the Company anticipates the cost of the cleanup as well as the cost of replacing the damaged transformer will be considered covered losses under the relevant insurance policies. Additionally, the Company continues to evaluate the merits of possible claims against those parties that may be responsible for the transformer failure. In December 2002, the replacement transformer was received in a damaged condition. The problems with the transformer have delayed the scheduled completion of the project from the third quarter of 2002 to the middle of 2003. As of December 31, 2002, the Company had invested $109.0 million in Coyote Springs 2, including capitalized interest.

New Accounting Standards

See "Note 2 of the Notes to Consolidated Financial Statements."

Critical Accounting Policies

Use of estimates

The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect amounts reported in the consolidated financial statements. Changes in these estimates and assumptions are considered reasonably possible and may have a material impact on the consolidated financial statements and thus actual results could differ from the amounts reported and disclosed herein.

Regulatory Accounting

The Company prepares its consolidated financial statements in accordance with the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." The Company prepares its financial statements in accordance with SFAS No. 71 because (i) the Company'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 Company'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 can be charged to and collected from customers at levels that will recover the Company's costs. SFAS No. 71 requires the Company to reflect the impact of regulatory decisions in its financial statements. SFAS No. 71 requires that certain costs and/or obligations (such as incurred power and natural gas costs not currently recovered through rates, but expected to be recovered in the future) are reflected as deferred charges on the balance sheet. These costs and/or obligations are not reflected in the statement of income until the period during which 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 SFAS No. 71 with respect to all or a portion of the Company's regulated operations, the Company could be required to write off its regulatory assets. The Company could also be precluded from the future deferral 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.

In accordance with SFAS No. 71, profits recognized by Avista Energy on natural gas sales to Avista Utilities, including gains and losses on natural gas contracts, are not eliminated in the consolidated financial statements. This is due to the fact that costs incurred by Avista Utilities for natural gas purchases to serve retail customers and for fuel for electric generation are expected to be recovered through future retail rates.

The Company's primary regulatory assets include power and natural gas deferrals, investment in exchange power, regulatory assets for deferred income taxes, unamortized debt expense, regulatory asset offsetting energy commodity derivative liabilities (see "Utility Energy Commodity Derivative Assets and Liabilities" for further information), demand side management programs, conservation programs and the provision for postretirement benefits. Deferred credits include regulatory liabilities created when Centralia was sold and the gain on the general office building sale/leaseback, which is being amortized over the life of the lease.

Avista Utilities Energy Commodity Derivative Assets and Liabilities

SFAS No. 133 as amended by SFAS No. 138, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. It requires the recording of all derivatives as either assets or liabilities in the balance sheet measured at estimated fair value and the recognition of the unrealized gains and losses. In certain defined conditions, a derivative may be specifically designated as a hedge for a particular exposure. The accounting for derivatives depends on the intended use of the derivatives and the resulting designation.

Avista Utilities enters into forward contracts to purchase or sell energy. Under forward contracts, Avista Utilities commits to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. Certain of these forward contracts are considered derivative instruments. Avista Utilities also records derivative commodity assets and liabilities for over-the-counter and exchange-traded derivative instruments as well as certain long-term contracts. In conjunction with the issuance of SFAS No. 133, the WUTC and the IPUC issued accounting orders requiring Avista Utilities to offset any derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement. The order provides for Avista Utilities to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Consolidated Statements of Income and Comprehensive Income. Such realized gains or losses are recognized in the period of settlement subject to current or future recovery in retail rates.

Avista Utilities believes that substantially all of its purchases and sales contracts for both capacity and energy qualify as normal purchases and sales under SFAS No. 133 and are not required to be recorded as derivative commodity assets and liabilities. Contracts that are not considered derivatives under SFAS No. 133 are generally accounted for at cost until they are settled unless there is a decline in the fair value of the contract that is determined to be other than temporary.

Interpretations that may be issued by the Derivatives Implementation Group, a task force created to assist the Financial Accounting Standards Board (FASB) in answering questions that companies have in implementing SFAS No. 133, may change the conclusions that the Company has reached regarding accounting for energy contracts. As a result, the accounting treatment and financial statement impact could change in future periods.

Avista Energy Trading Activities

Avista Energy accounted for energy commodity trading activity in compliance with EITF Issue No. 98-10 through December 31, 2002 for contracts entered into on or prior to October 25, 2002. Under EITF 98-10, Avista Energy recognized revenue based on the change in the market value of outstanding derivative commodity sales contracts, net of future servicing costs and reserves, in addition to revenue related to settled contracts. In October 2002, the EITF rescinded Issue No. 98-10. As such, Avista Energy is required to account for energy trading contracts that meet the definition of a derivative at market value in compliance with SFAS No. 133. This applies to all existing contracts as of January 1, 2003 as well as to all new contracts entered into subsequent to October 25, 2002. Contracts not meeting the definition of a derivative are no longer accounted for at market value and include Avista Energy's Agency Agreement with Avista Utilities, natural gas storage contracts, tolling agreements and natural gas transportation agreements. The transition from EITF Issue No. 98-10 to accrual based accounting resulted in the adjustment of the contracts that are not considered derivatives from their market value to their cost basis. Any gain or loss on contracts that are not considered derivatives will not be recognized until the contract is settled or realized. The Company anticipates that the changes will primarily affect the timing of the recognition of income or loss in earnings, and not change the underlying economics or cash flows of transactions entered into by Avista Energy. The changes could result in a significant increase in the volatility of reported earnings on a quarter-to-quarter and year-to-year basis. On January 1, 2003, Avista Energy recorded as a cumulative effect of accounting change a charge of approximately $1.2 million (net of tax) related to the transition from EITF 98-10 to SFAS No. 133.

Market prices are utilized in determining the value of the electric, natural gas and related derivative commodity instruments. For natural gas commodity instruments, these market prices are generally available through three years. For electric commodity instruments, these market prices are generally available through two years. For longer-term positions and certain short-term positions for which market prices are not available, a model to estimate forward price curves is utilized. These models incorporate a variety of estimates and assumptions, the ultimate outcomes of which are beyond Avista Energy's control including, among others, estimates and assumptions as to demand growth, fuel price escalation, availability of existing generation and costs of new generation. Actual experience can vary significantly from these estimates and assumptions. Gains and losses on electric, natural gas and related derivative commodity instruments utilized for trading are recognized as income on a current basis (the mark-to-market method) and are included in the Consolidated Statements of Income and Comprehensive Income in operating revenues on a net basis, and in the Consolidated Balance Sheets as current or non-current energy commodity assets or liabilities. Contracts in a receivable position, as well as the options held, are reported as assets. Similarly, contracts in a payable position, as well as options written, are reported as liabilities. Net cash flows are recognized in the period of settlement.

AVISTA CORPORATION

Pension Plans and Other Postretirement Benefit Plans

The Company has a defined benefit 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 amounts that 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 income tax purposes. The Company made $12 million in cash contributions to the pension plan in 2002 and did not make any cash contributions to the pension plan in 2001. The Company expects to contribute approximately $12 million to the pension plan in 2003. Pension fund assets are invested primarily in marketable debt and equity securities. The Company’s pension plan currently has assets with a fair value that is less than the present value of the accumulated benefit obligation under the plan. In 2002, the Company recorded an additional minimum liability for the unfunded accumulated benefit obligation of $33.4 million and an intangible asset of $6.4 million (representing the amount of unrecognized prior service cost) related to the pension plan. This resulted in a charge to other comprehensive income of $17.6 million, net of taxes.

The Company’s pension costs (including the Supplemental Executive Retirement Plan (SERP)) were $10.3 million, $4.8 million and $2.1 million for 2002, 2001 and 2000, respectively. Of these pension costs, approximately 70 percent are expensed and approximately 30 percent are capitalized. The Company’s costs for the pension plan are determined in part by actuarial formulas and are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. Pension costs are affected by actual employee demographics (including age, compensation and the length of service by employees), the amount of cash contributions the Company makes to the pension plan and the return on pension plan assets. Changes made to the provisions of the pension plan may also impact current and future pension costs. Pension plan costs may also be significantly affected by changes in key actuarial assumptions, including the expected return on pension plan assets, the discount rate used in determining the projected benefit obligation and pension costs as well as the assumed rate of increase in employee compensation. The change in pension plan obligations associated with these factors may not be immediately recognized as pension costs in the Consolidated Statement of Income and Comprehensive Income, but generally are recognized in future years over the remaining average service period of pension plan participants. As such, significant portions of pension costs recorded in any period may not reflect the actual level of cash benefits provided to pension plan participants.

The Company has not made any changes to pension plan provisions in 2002, 2001 and 2000 that have had any significant effect on recorded pension plan amounts. The Company has revised the key assumptions of expected return on pension plan assets and the discount rate in 2002 as compared to 2001 and 2000. Such changes had an effect on reported pension costs in 2002 and will have an impact on future years given the cost recognition approach described above. However, in determining pension obligation and costs amounts, these assumptions can change from period to period, and such changes could result in material changes to future pension costs and funding requirements.

The following chart reflects the sensitivities associated with a change in certain actuarial assumptions by the indicated percentage (dollars in thousands):

Actuarial Assumption	Change in Assumption	Impact on Projected Benefit Obligation	Impact on Pension Liability	Impact on Pension Cost
Expected long-term return on plan assets	-0.5%	$ —	$ —*	$ 769
Expected long-term return on plan assets	+0.5%	—	—*	(770)
Discount rate	-0.5%	17,184	11,450	1,598
Discount rate	+0.5%	(15,396)	(15,396)	(1,411)

* As the Company has already recorded an additional minimum liability for the unfunded accumulated benefit obligation during 2002, changes in the expected return on plan assets would not have an impact on the total pension liability.

In selecting a discount rate, the Company considers yield rates for highly rated corporate bond portfolios with maturities similar to that of the expected term of pension benefits. The Company reduced the discount rate in 2002 from 7.25 percent to 6.75 percent.

In selecting an assumed long-term rate of return on plan assets, the Company considered past performance and economic forecasts for the types of investments held by the plan. The market value of the Company’s plan assets has been affected by a decline in equity markets beginning in 2000. For the past three years the fair value of plan assets has decreased $16.7 million, $9.3 million and $1.0 million in 2002, 2001 and 2000, respectively. In its 2002 actuarial valuation, the Company decreased the expected long-term rate of return on plan assets from 9 percent to 8 percent as a result of continued declines in general equity and bond market returns. Reported pension costs are expected to increase in 2003 and future years as the result of this changed assumption. The projected increased pension costs and contributions have been incorporated in the earnings outlook for 2003.

The Company also has a SERP that provides additional pension benefits to executive officers of the Company. The SERP is intended to provide benefits to executive officers whose benefits under the pension plan are reduced due to the application of Section 415 of the Internal Revenue Code of 1986 and the deferral of salary under deferred compensation plans. In 2002, the Company recorded an additional minimum liability for the unfunded accumulated benefit obligation of $0.7 million related to the SERP. In 2001, the Company recorded an additional minimum liability for the unfunded accumulated benefit obligation of $1.1 million related to the SERP. This resulted in a charge to other comprehensive income of $0.5 million and $0.7 million, net of taxes, for 2002 and 2001, respectively.

The Company provides certain health care and life insurance benefits for substantially all of its retired employees. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. The Company elected to amortize the transition obligation of $34.5 million over a period of twenty years, beginning in 1993.

Assumed health care cost trend rates have a significant effect on the amounts reported for the postretirement plans. 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, 2002 by $2.0 million and the service and interest cost by $0.2 million. A one-percentage-point decrease in the assumed health care cost trend rate for each year would decrease the accumulated postretirement benefit obligation as of December 31, 2002 by $1.7 million and the service and interest cost by $0.2 million.

Liquidity and Capital Resources

Review of Cash Flow Statement

Continuing Operating Activities Net cash provided by continuing operating activities was $331.3 million for 2002 compared to net cash used in continuing operating activities of $76.1 million for 2001. The primary reason for the increase in net cash provided by continuing operating activities was power and natural gas cost amortization, net of deferrals and interest, of $68.5 million for 2002 compared to net deferrals of $210.5 million for 2001. This was primarily due to increased retail rates approved by the respective utility commissions to recover increased deferred power and natural gas costs incurred during 2000 and 2001. Net power and natural gas cost amortizations and deferrals are non-cash items that are added back or deducted from net income to determine net cash flows from operating activities using the indirect method. Net cash provided by working capital components was $110.0 million for 2002, compared to $108.3 million of net cash used for 2001. The increase in other current liabilities is primarily due to an increase in deposits held from other parties from $15.7 million as of December 31, 2001 to $92.7 million as of December 31, 2002. Significant changes in non-cash items also included a $57.2 million change in energy commodity assets and liabilities, representing the increase in the unrealized loss on energy trading activities for Energy Trading and Marketing from $30.2 million in 2001 to $87.4 million in 2002. The $119.4 million change in the provision for deferred income taxes was primarily due to changes in deferred power and natural gas cost amortizations and deferrals described above.

Continuing Investing Activities Net cash used in continuing investing activities was $48.3 million for 2002, a decrease compared to $218.4 million for 2001. This was due to a decrease in other capital expenditures and utility property construction expenditures, partially offset by a decrease in the proceeds from property sales and sales of subsidiary investments. Other capital expenditures during 2001 were primarily for the construction of Coyote Springs 2 and the purchase of four turbines by Avista Power that were planned to be used in a non-regulated generation project. In 2001, proceeds from property sales and sale of subsidiary investments were $76.0 million, primarily related to the sale of the 50 percent interest in Coyote Springs 2 and three of Avista Power's turbines. Utility property construction expenditures decreased to $64.2 million for 2002 compared to $119.9 million for 2001.

Continuing Financing Activities Net cash used in continuing financing activities was $284.7 million for 2002 compared to net cash provided of $285.7 million for 2001. During 2002, short-term borrowings decreased $45.1 million and the Company repurchased $203.6 million of long-term debt scheduled to mature in future years. The Company paid net premiums of $9.5 million to repurchase long-term debt in 2002. The decrease in short-term borrowings reflects a decrease in the amount outstanding under Avista Corp.'s line of credit as well as the repayment of a short-term note at Avista Capital. The overall decrease in borrowings during 2002 reflects increased cash flows from operations primarily related to the recovery of deferred power and natural gas costs as well as a general rate increase for Washington electric customers that was partially used to repurchase long-term debt. Cash dividends from Avista Energy were also a significant source of funds used by Avista Corp. to repurchase long-term debt during 2002.

In 2001, the Company issued $550.0 million of long-term debt. During 2001, short-term borrowings decreased $88.1 million, $89.0 million of Medium-Term Notes matured and the Company also legally defeased $50.0 million of Medium-Term Notes scheduled to mature in 2002. The overall increase in borrowings during 2001 was due to increased cash needs to fund capital expenditures and increased power and natural gas costs.

Discontinued Operations Net cash provided by discontinued operations was $16.8 million for 2002 compared to $17.2 million of net cash used in discontinued operations for 2001. The change was primarily due to a decrease in operating costs and capital expenditures by Avista Communications as the Company decided to dispose of the operations. Net cash provided by discontinued operations in 2002 primarily represented the disposal of assets and the settlement of deferred tax assets.

Overall Liquidity

During 2002, the Company's overall liquidity improved compared to 2001. The general electric rate case order issued by the WUTC in June 2002 should allow the Company to continue to improve its liquidity. The general electric rate case order provided for the restructuring and continuation of previously approved rate increases totaling 31.2 percent (a 25 percent temporary surcharge approved in September 2001 and a 6.2 percent increase approved in March 2002). The general increase to base retail rates is 19.3 percent (or $45.7 million in annual revenues) and the remaining 11.9 percent represents the continued recovery of deferred power costs over a period currently projected to extend into 2009. Additionally, the Company has a PCA surcharge of 19.4 percent in place in Idaho. See further details in the section "Avista Utilities - Regulatory Matters."

In addition to rate surcharges and increases, the Company has taken other steps to improve its liquidity. The Company completed the sale of 50 percent of its interest in the Coyote Springs 2 project to Mirant during the fourth quarter of 2001. The Company received $53.6 million in proceeds from Mirant. In addition, Mirant provided the majority of the remaining funds to complete the project. The Company also sold three turbines owned by Avista Power with $22.7 million of proceeds received during the fourth quarter of 2001 and $22.7 million of proceeds received during 2002. Additionally, 2002 operating budgets were designed to control costs and the Company significantly reduced capital expenditures from the amount originally budgeted. The Company's disposal of Avista Communications reduces future cash investments in the Information and Technology line of business. The Company continues discussions with selected companies in its search for a financial partner for Avista Labs with the goal of reducing its ownership interest to less than 20 percent.

Covenants in Avista Energy's credit agreement restrict the amount of cash dividends that can be distributed to Avista Capital and ultimately to Avista Corp. During 2002, in accordance with the modified covenants of its credit agreement, Avista Energy paid $116.4 million in dividends to Avista Capital.

These measures are largely related to the Company's efforts to improve its liquidity and cash flows and should provide the Company the ability to maintain access to adequate levels of credit with its banks.

During the second half of 2000 and the year 2001, the Company's cash outlays for purchased power exceeded the related amounts paid to the Company by its retail customers. This condition was primarily due to the reduced availability of hydroelectric resources compared to historical periods, increased prices in the wholesale market and increased volumes purchased to meet retail customer demand. In addition to operating expenses, the Company has continuing commitments for capital expenditures for construction, improvement and maintenance of facilities. In 2001, the Company incurred substantial levels of indebtedness, both short and long-term, to finance these requirements and to otherwise maintain adequate levels of working capital. Debt service is another significant cash requirement.

If Avista Utilities' power and natural gas costs were to significantly exceed the levels currently recovered from retail customers, its cash flows would be negatively affected. Factors that could cause purchased power costs to exceed the levels currently recovered from customers include, but are not limited to, a return to high prices in wholesale markets combined with an increased need to purchase power in the wholesale markets. Current FERC imposed price caps limit wholesale market prices to $250 per MWh. Factors beyond the Company's control that could result in an increased need to purchase power in the wholesale markets include, but are not limited to, increases in demand (either due to weather or customer growth), low availability of hydroelectric resources, outages at generating facilities and failure of third parties to deliver on energy or capacity contracts.

Capital Resources

The Company incurred significant indebtedness to support capital expenditures, to fund power and natural gas costs that were in excess of the amount recovered currently through rates and to maintain working capital through the end of 2001. However, as of December 31, 2002, the Company's total debt outstanding was $1,004.5 million, a decrease of $248.1 million from $1,252.6 million as of December 31, 2001. The decrease was primarily due to the repurchase of long-term debt and partially due to a decrease in short-term borrowings. This was made possible by improved operating cash flows from both Avista Utilities and Avista Energy. The Company needs to finance capital expenditures and obtain additional working capital from time to time. The cash requirements to service the indebtedness, both short-term and long-term, reduces the amount of cash flow available to fund working capital, purchased power and natural gas costs, capital expenditures, dividends and other corporate requirements.

The Company generally 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 depending on a variety of factors. Cash provided by utility operating activities and cash generated by Avista Energy are expected to be the Company's primary source of funds for operating needs, dividends and capital expenditures for 2003. Cash flows from operations have improved primarily from the recovery of deferred power and natural gas costs and from the electric rate increase in Washington and the continuation of the PCA surcharge in Idaho. This should allow the Company to continue to reduce total debt outstanding. Capital expenditures are expected to be funded either with cash flows from operations or on an interim basis with short-term borrowings.

On May 21, 2002, the Company entered into a committed line of credit with various banks in the total amount of $225.0 million. The committed line of credit, which expires on May 20, 2003, replaced the $220.0 million committed line of credit that expired on May 29, 2002. As of December 31, 2002, the Company had borrowed $30.0 million under this committed line of credit. Under this committed line of credit, the Company may have up to $50.0 million in letters of credit outstanding. As of December 31, 2002, there was $14.3 million of letters of credit outstanding. The Company's obligation under the committed line of credit is secured with First Mortgage Bonds in the amount of the commitment. The Company is currently in discussions with its banks and believes that the committed line of credit will be renewed for an additional year by the May 20, 2003 expiration date.

The committed line of credit agreement contains customary covenants and default provisions, including covenants not to permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be, at the end of any fiscal quarter, greater than 65 percent. As of December 31, 2002, the Company was in compliance with this covenant with a ratio of 54.3 percent. The committed line of credit also has a covenant requiring the ratio of "earnings before interest, taxes, depreciation and amortization" to "interest expense" of Avista Utilities for the year ending December 31, 2002 to be greater than 1.6 to 1. As of December 31, 2002, the Company was in compliance with this covenant with a ratio of 2.04 to 1.

Any default on its committed line of credit or other financing arrangements could result in cross-defaults to other agreements and could induce vendors and other counterparties to demand collateral. In the event of default, it would be difficult for the Company to obtain financing on any reasonable terms to pay creditors or fund operations, and the Company would likely be prohibited from paying dividends on its common stock. As of December 31, 2002, Avista Corp. was in compliance with the covenants of all of its financing agreements.

During 2002, the Company repurchased $133.8 million of Medium-Term Notes scheduled to mature in 2003, $59.8 million of Unsecured Senior Notes scheduled to mature in 2008 and $10.0 million of Medium-Term Notes scheduled to mature in 2028. In accordance with regulatory accounting practices under SFAS No. 71, total net premiums paid to repurchase debt were $9.5 million and are being amortized over the average remaining maturity of outstanding debt.

The Mortgage and Deed of Trust securing the Company's First Mortgage Bonds contains limitations on the amount of First Mortgage Bonds which may be issued based on, among other things, a 70 percent debt-to-collateral ratio and a 2.00 to 1 net earnings to First Mortgage Bond interest ratio. Under various financing agreements, the Company is also restricted as to the amount of additional First Mortgage Bonds that it can issue. As of December 31, 2002, the Company could issue $109.4 million of additional First Mortgage Bonds under the most restrictive of these financing agreements.

If market conditions warrant during 2003, the Company may issue long-term debt and repurchase outstanding long-term debt to reduce its overall debt service costs.

The Company is restricted under various agreements and its Restated Articles of Incorporation as to the additional preferred stock it can issue. As of December 31, 2002, approximately $267.1 million of additional preferred stock could be issued at an assumed dividend rate of 6.95 percent with a maturity date later than June 1, 2008.

In July 2001, the Company filed a registration statement on Form S-3 with the Securities and Exchange Commission for the purpose of issuing up to 3.7 million shares of common stock. No common stock has been issued and the Company currently does not have any plans to issue common stock under this registration statement.

Inter-Company Debt; Subordination

As part of its on-going cash management practices and operations, Avista Corp. from time to time makes unsecured short-term loans to, and borrowings from, Avista Capital. In turn, Avista Capital from time to time makes unsecured short-term loans to, and borrowings from, its subsidiaries. As of December 31, 2002, Avista Corp. held short-term notes of Avista Capital in the principal amount of $137.3 million; and Avista Capital held, among other notes, $109.0 million in principal amount of short-term notes of Avista Power, issued primarily for the construction of Coyote Springs 2. The inter-company borrowings associated with Coyote Springs 2 were satisfied with the transfer of the interest in the plant from Avista Power to Avista Corp. in January 2003.

In addition, Avista Capital from time to time guarantees the indebtedness and other obligations of its subsidiaries. See "Energy Trading and Marketing Operations" and "Contractual Obligations" for further information.

The credit arrangements of Avista Capital's subsidiaries generally provide that any indebtedness owed by such entity to its corporate parent will be subordinated to the indebtedness outstanding under such credit arrangements.

The right of Avista Corp., as a shareholder, to receive assets of any of its direct or indirect subsidiaries upon the subsidiary's liquidation or reorganization (and the consequent right of the holders of debt securities and other creditors of Avista Corp. to participate in those assets) is junior to the claims against such assets of that subsidiary's creditors. As a result, the obligations of Avista Corp. to its debt securityholders and other unrelated creditors are effectively subordinated in right of payment to all indebtedness and other liabilities and commitments (including trade payables and lease obligations) of Avista Corp.'s direct and indirect subsidiaries. Similarly, the obligations of Avista Capital to its creditors are effectively subordinated in right of payment to all indebtedness and other liabilities and commitments of its direct and indirect subsidiaries.

Pension Plan

As of December 31, 2002, the Company's pension plan had assets with a fair value that was less than the present value of the accumulated benefit obligation under the plan. In 2002, the Company recorded an additional minimum liability for the unfunded accumulated benefit obligation of $33.4 million and an intangible asset of $6.4 million (representing the amount of unrecognized prior service cost) related to the pension plan. This resulted in a charge to other comprehensive income of $17.6 million, net of taxes. The Company does not expect the current pension plan funding deficit to have a material adverse impact on its financial condition, results of operations or cash flows. The Company's funding policy is to contribute amounts that are not less than the minimum amounts required to be funded under the Employee Retirement Income Security Act. The Company made $12 million in cash contributions to the pension plan in 2002 and did not make any cash contributions to the pension plan in 2001. The Company expects to contribute approximately $12 million to the pension plan in 2003. The Company is funding the pension plan at what it believes to be an adequate level. The increased funding and pension costs have been factored into the Company's earnings outlook for 2003.

Off-Balance Sheet Arrangements

Avista Receivables Corp. (ARC), formerly known as WWP Receivables Corp., is a wholly owned, bankruptcy-remote subsidiary of the Company formed in 1997 for the purpose of acquiring or purchasing interests in certain accounts receivable, both billed and unbilled, of the Company. On May 29, 2002, ARC, the Company and a third-party financial institution entered into a three-year agreement whereby ARC can sell without recourse, on a revolving basis, up to $100.0 million of those receivables. ARC is obligated to pay fees that approximate the purchaser's cost of issuing commercial paper equal in value to the interests in receivables sold. As of December 31, 2002, $65.0 million in receivables were sold pursuant to the agreement. ARC will not be consolidated in accordance with a recently issued FASB interpretation related to special-purpose entities.

WP Funding LP is an entity that was formed for the purpose of acquiring the natural gas-fired combustion turbine generating facility in Rathdrum, Idaho (Rathdrum CT). WP Funding LP purchased the Rathdrum CT from the Company with funds provided by unrelated investors of which 97 percent represented debt and 3 percent represented equity. The Company operates the Rathdrum CT and leases it from WP Funding LP and currently makes lease payments of $4.5 million per year. The total amount of WP Funding LP debt outstanding that is not included on the Company's balance sheet was $54.5 million as of December 31, 2002. The lease term expires in February 2020; however, the current debt matures in October 2005 and will need to be refinanced at that time. The FASB has issued an interpretation relating to the identification of, and accounting for, special-purpose entities such as WP Funding LP. See "Note 2 of the Notes to Consolidated Financial Statements" for further information. This interpretation will require the Company to begin consolidating WP Funding LP into its financial statements effective July 1, 2003, whereby the $54.5 million of debt will be included in the Company's capitalization and the book value of the Rathdrum CT will be included in utility plant. The equity investment of the unrelated investors will be reported as a minority interest. Based on current information, the difference between the book value of the debt and equity of WP Funding LP and the book value of the Rathdrum CT is approximately $15.5 million ($10.1 million, net of taxes). The Company intends to request regulatory accounting orders to record this amount as a regulatory asset upon the consolidation of WP Funding LP.

Total Company Capitalization

The Company's consolidated capital structure, including the current portion of long-term debt and short-term borrowings was 54.3 percent debt, 5.4 percent preferred trust securities, 1.8 percent preferred stock and 38.5 percent common equity as of December 31, 2002, compared to 59.4 percent debt, 4.7 percent preferred trust securities, 1.7 percent preferred stock and 34.2 percent common equity as of December 31, 2001. The Company's consolidated debt decreased by $248 million due to both the repurchase of long-term debt and a decrease in short-term borrowings. The Company's consolidated common equity decreased $7.3 million during 2002 to $712.8 million as of December 31,

2002. This decrease is primarily due to dividends and other comprehensive loss, partially offset by net income and the issuance of common stock through the Dividend Reinvestment Plan and employee benefit plans. The significant other comprehensive loss of $20.3 million for 2002 was primarily related to the recording of an unfunded accumulated benefit obligation for the pension plan. The Company has a target capital structure of 50 percent total debt and 50 percent preferred trust securities, preferred stock and common equity. The Company plans to achieve this capital structure primarily with the reduction of total debt and the retention of net earnings.

Credit Ratings

The Company's credit ratings were downgraded during the fourth quarter of 2001 resulting in an overall corporate credit rating that is below investment grade. The downgrade was due to liquidity concerns primarily related to the significant amount of purchased power and natural gas costs incurred and the resulting increase in debt levels and debt service costs. The following table summarizes the Company's current credit ratings:

	Standard & Poor's	Moody's	Fitch, Inc.
Avista Corporation			
Corporate/Issuer rating	BB+	Ba1	BB+
Senior secured debt	BBB-	Baa3	BBB-
Senior unsecured debt	BB+	Ba1	BB+
Preferred stock	BB-	Ba3	BB
Avista Capital I*			
Preferred Trust Securities	BB-	Ba2	BB+
Avista Capital II*			
Preferred Trust Securities	BB-	Ba2	BB
Rating outlook	Stable**	Negative	Stable

* Only assets are subordinated debentures of Avista Corporation

** Changed to stable from negative on December 18, 2002

These security ratings are not recommendations to buy, sell or hold securities. The ratings are subject to change or withdrawal at any time by the respective credit rating agencies. Each credit rating should be evaluated independently of any other rating.

Avista Utilities Operations

Capital expenditures for Avista Utilities were $282.8 million for the 2000-2002 period. This excludes Coyote Springs 2, which was included in Energy Trading and Marketing. During the 2003-2005 period, utility capital expenditures are expected to be in the range of $90 to $110 million per year and long-term debt maturities and preferred stock sinking fund requirements total $137 million. During this period, internally generated funds and short-term borrowing arrangements are expected to be sufficient to fund the Company's capital expenditures, maturing long-term debt and preferred stock sinking fund requirements. 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.

Avista Utilities' planned capital expenditures include an expansion and enhancement of its 230 kV transmission system at an estimated total cost of $85 to $100 million that is expected to be completed by the end of 2006. To the extent that Avista Utilities chooses to or is required to divest of its transmission assets, it would expect to recover these costs.

Avista Utilities held cash deposits from other parties in the amount of $17.5 million as of December 31, 2002, which is included in cash and cash equivalents with a corresponding amount in other current liabilities in the Consolidated Balance Sheet. These amounts are subject to return if conditions warrant because of continuing portfolio value fluctuations with those parties or substitution of collateral.

As of December 31, 2002, Avista Utilities had $37.0 million in cash and temporary investments, including the $17.5 million of cash deposits from other parties.

See "Notes 6, 15, 16, 17, 20, 21, 22, 23 and 24 of Notes to Consolidated Financial Statements" for additional details related to financing activities.

Energy Trading and Marketing Operations

Avista Energy funds its ongoing operations with a combination of internally generated cash and a bank line of credit. On June 28, 2002 Avista Energy and its subsidiary, Avista Energy Canada, Ltd., as co-borrowers, renewed their credit agreement with a group of banks in the aggregate amount of $110.0 million expiring June 30, 2003. This credit agreement may be terminated by the banks at any time and all extensions of credit under the agreement are payable upon demand, in either case at the lenders' sole discretion. This agreement also provides, on an uncommitted basis, for the issuance of letters of credit to secure contractual obligations to counterparties. This facility is guaranteed by Avista Capital and secured by Avista Energy's assets. The maximum amount of credit extended by the banks for the issuance of letters of credit is the subscribed amount of the facility less the amount of outstanding cash advances, if any. The maximum amount of credit extended by the banks for cash advances is $30.0 million. As of December 31, 2002, there were no cash advances (demand notes payable) outstanding and letters of credit outstanding under the facility totaled $17.4 million.

The Avista Energy credit agreement contains customary covenants and default provisions, including covenants to maintain "minimum net working capital" and "minimum net worth" as well as a covenant limiting the amount of indebtedness which the co-borrowers may incur. Avista Energy was in compliance with the covenants of its credit agreement as of December 31, 2002.

Avista Energy believes that it will have access to credit facilities beyond the June 30, 2003 expiration date of its current uncommitted credit agreement.

Avista Capital provides guarantees for Avista Energy's credit agreement and, in the course of business, may provide guarantees to other parties with whom Avista Energy may be doing business. Avista Capital had $64.6 million of performance guarantees related to energy trading contracts outstanding as of December 31, 2002.

Periodically, Avista Capital may lend funds to Avista Energy to support its short-term cash and collateral needs. Avista Energy's obligations to repay loans to Avista Capital are subordinate to any obligations of Avista Energy to the banks under the credit agreements. As of December 31, 2002, there were no loans between Avista Capital and Avista Energy outstanding.

Avista Energy manages collateral requirements with counterparties by providing letters of credit, providing guarantees from Avista Capital, cash deposited with counterparties and offsetting transactions with counterparties. Cash deposited with counterparties totaled $35.7 million as of December 31, 2002, and is included in prepayments and other current assets in the Consolidated Balance Sheet. Avista Energy held cash deposits from other parties in the amount of $75.2 million as of December 31, 2002, which is included in cash and cash equivalents with a corresponding amount in other current liabilities in the Consolidated Balance Sheet. These amounts are subject to return if conditions warrant because of continuing portfolio value fluctuations with those parties or substitution of collateral.

As of December 31, 2002, Avista Energy had $148.9 million in cash, including the $75.2 million of cash deposits from other parties. Covenants in Avista Energy's credit agreement restrict the amount of cash dividends that can be distributed to Avista Capital and ultimately to Avista Corp. During 2002, in accordance with the modified covenants of its credit agreement, Avista Energy paid $116.4 million in dividends to Avista Capital. In January 2003, Avista Energy paid $2.1 million in dividends to Avista Capital.

Capital expenditures for the Energy Trading and Marketing companies were $239.6 million for the 2000-2002 period, primarily due to Avista Power's investment in Coyote Springs 2 as well as the purchase of turbines during 2001. Capital expenditures are expected to be less than $1.0 million per year in this line of business during the 2003-2005 period.

Information and Technology Operations

Capital expenditures for the Information and Technology line of business were $14.7 million for the 2000-2002 period. The 2003-2005 capital expenditures are expected to be between $3.0 and $4.0 million per year. Avista Advantage and Avista Labs expect to support these capital requirements through a combination of funding from Avista Corp. and third party equity investment. Two venture capital firms made minority interest investments totaling $3.4 million in Avista Advantage during the fourth quarter of 2000. As of December 31, 2002, the Information and Technology companies had $0.1 million in cash and cash equivalents and $0.6 million in debt outstanding. The Company continues discussions with selected companies in its search for a financial partner for Avista Labs with the goal of reducing its ownership interest in Avista Labs to less than 20 percent.

AVISTA CORPORATION

Other Operations

Capital expenditures for these companies were $1.8 million for the 2000-2002 period. The 2003-2005 capital expenditures are not expected to be material. As of December 31, 2002, this line of business had $0.4 million in cash and cash equivalents and temporary investments, with $0.2 million in debt outstanding. In October 2001, Avista Capital entered into a one-year $20 million promissory note collateralized by certain receivables. The note was extended in October 2002 and paid off in December 2002.

Contractual Obligations

The following table provides a summary of the Company's future contractual obligations as of December 31, 2002 (dollars in millions):

	2003	2004	2005	2006	2007	Thereafter
Avista Utilities:						
Long-term debt maturities	$ 71	$ 30	$ 30	$ 38	$ 26	$ 780
Short-term debt (1)	95	—	—	—	—	—
Preferred stock redemptions	2	2	2	2	25	—
Preferred trust securities	—	—	—	—	—	100
Energy purchase contracts (2)	390	290	148	113	115	892
Public Utility District contracts (2)	4	3	3	3	3	22
Operating lease obligations (3)	12	10	7	7	7	65
Capital lease obligations (3)	—	—	—	—	—	—
Other obligations (4)	10	12	12	12	12	185
Avista Capital (consolidated):						
Long-term debt maturities	1	—	—	—	—	—
Physical energy contracts (5)	936	324	206	188	126	393
Financial energy contracts (5)	961	89	3	12	—	—
Operating lease obligations (3)	3	3	2	1	—	1
Capital lease obligations (3)	1	—	—	—	—	—
Total cash requirements	$2,486	$763	$413	$376	$314	$2,438

(1) Represents $30 million outstanding under a $225 million line of credit and $65 million outstanding under a $100 million accounts receivable financing facility.

(2) All of the energy purchase contracts were entered into as part of Avista Utilities' obligation to serve its retail natural gas and electric customers' energy requirements. As a result, these costs are generally recovered either through base retail rates or adjustments to retail rates as part of the power and natural gas cost adjustment mechanisms.

(3) Includes the interest component of the lease obligation.

(4) Represents operational agreements, settlements and other contractual obligations with respect to generation, transmission and distribution facilities.

(5) Represents Avista Energy's contractual commitments under energy contracts in future periods. Avista Energy also has sales commitments related to energy commodities in future periods.

As of December 31, 2002, Avista Corp. did not have any commitments outstanding with equity triggers. When the Company's corporate credit rating was reduced to below investment grade in October 2001, additional collateral requirements due to rating triggers were met and further requirements are not currently anticipated. The Company does not expect any material impact from rating triggers; remaining triggers primarily relate to changes in pricing under certain financing agreements.

Additional Financial Data

As of December 31, 2002, the total long-term debt of the Company and its consolidated subsidiaries, as shown in the Company's consolidated financial statements, was $902.6 million. Of such amount, $605.3 million represents long-term unsecured and unsubordinated indebtedness of the Company, and $298.5 million represents secured indebtedness of the Company. The unamortized debt discount was $2.2 million. Other long-term debt was $1.0 million. Consolidated long-term debt does not include the Company's subordinated indebtedness held by the issuers of Company-obligated preferred trust securities. In addition to long-term secured indebtedness, $30.0 million of the

Company’s short-term debt outstanding under or backed by its $225.0 million committed line of credit is secured indebtedness. The current portion of long-term debt was $71.9 million as of December 31, 2002, of which $15.0 million was secured indebtedness.

Future Outlook

Business Strategy

Avista Corp. intends to continue to focus on its core energy-related businesses. Avista Corp. intends to focus on improving cash flows and earnings, controlling costs and reducing debt while working to restore an investment grade credit rating. Avista Utilities seeks to maintain a strong, low-cost and efficient electric and natural gas utility business focused on providing reliable, high quality service to its customers. The utility business is expected to grow modestly, consistent with historical trends. Expansion is expected to result primarily from economic growth in its service territory. It is Avista Utilities’ strategy to own or control a sufficient amount of resources to meet its retail and wholesale energy requirements on an average annual basis. Avista Energy works primarily within the WECC and focuses on asset-backed optimization of combustion turbines and hydroelectric assets owned by other entities, long-term electric supply contracts, natural gas storage, and electric and natural gas transmission and transportation arrangements. Avista Energy’s marketing efforts are driven by its base of knowledge and experience in the operation of both electric energy and natural gas physical systems in the WECC, as well as its relationship-focused approach with its customers. Avista Advantage remains focused on growing revenue, improving margins, reducing fixed and variable costs and improving client satisfaction. Avista Corp. continues discussions with selected companies in its search for a financial partner for Avista Labs with the goal of owning less than 20 percent of this company. Avista Labs continues to move forward with developing and selling its commercial fuel cell products. The Company plans to dispose of assets and phase out of operations in the Other business segment that are not related to its energy operations.

Competition

Avista Utilities competes to provide service to new retail electric customers with various rural electric cooperatives and public utility districts in and adjacent to its service territories. Alternate providers of power may also compete for sales to existing customers, including new market entrants as a result of deregulation. Competition for available electric resources can be critical to utilities as surplus power resources are absorbed by load growth. Avista Utilities’ natural gas distribution operations compete with other energy sources; however, natural gas continues to maintain a price advantage compared to heating oil, propane and other fuels, provided that the natural gas distribution system is proximate to prospective customers.

The Energy Policy Act of 1992 (Energy Act) amended provisions of the Public Utility Holding Company Act of 1935 (PUHCA) and the Federal Power Act to remove certain barriers to a competitive wholesale market. The Energy Act expanded the authority of the FERC to issue orders requiring electric utilities to transmit power and energy to or for wholesale purchasers and sellers, and to require electric utilities to enlarge or construct additional transmission capacity for the purpose of providing these services. It also created “exempt wholesale generators,” a new class of independent power plant owners that are able to sell generation only at the wholesale level. This permits public utilities and other entities to participate through subsidiaries in the development of independent electric generating plants for sales to wholesale customers without being required to register under the PUHCA.

Participants in the wholesale market include other utilities, federal marketing agencies and energy trading and marketing companies. The wholesale market has changed significantly over the last few years with respect to market participants involved, level of activity, variability in market prices, liquidity, FERC imposed price caps and counterparty credit issues. During 2000 and the first half of 2001, the electric wholesale market in the WECC region was more turbulent than previously experienced and marked by significant volatility, service disruptions and defaults by certain participants. During the second half of 2001 and 2002 wholesale market prices decreased to levels similar to those experienced before 2000. Many energy companies are facing liquidity issues, and counterparty credit exposure is of concern to all market participants. During 2002, electric and natural gas trading volumes have decreased, the energy markets are less volatile and fewer creditworthy counterparties are currently participating in the energy markets. Avista Corp. is actively monitoring energy industry developments with a focus on liquidity, volatility of energy trading markets and counterparty credit exposure.

The Avista Capital subsidiaries, particularly the Information and Technology companies, are subject to competition as they develop products and services and enter new markets. Competition from other companies in these emerging industries may mean challenges for a company to be the first to market a new product or service to gain the advantage in market share. In order for these new businesses to grow as planned, one significant challenge will be the availability of funding and resources to meet the capital needs. Other challenges will be rapidly advancing technologies, possibly making some of the current technology quickly obsolete, and requiring continual research and development for product advancement. In order for some of these subsidiaries to succeed, they will need to reduce costs of these emerging technologies to make them affordable to future customers.

Business Risk

The Company's operations are exposed to risks including, but not limited to, the price and supply of purchased power, fuel and natural gas, recoverability of power and natural gas costs, streamflow and weather conditions, the effects of changes in legislative and governmental regulations, availability of generation facilities, competition, technology and availability of funding. Also, like other utilities, the Company's facilities and operations may be exposed to terrorism risks. See further reference to risks and uncertainties under "Safe Harbor for Forward-Looking Statements."

As described under "Avista Corp. Lines of Business," hydroelectric conditions in 2001 were significantly below normal, leading to greater than normal reliance on purchased power. Hydroelectric generation was slightly above normal in 2002 and current forecasts indicate that hydroelectric generation will be approximately 83 percent of normal in 2003. The earnings impact of these factors is mitigated by regulatory mechanisms that are intended to defer increased power supply costs for recovery in future periods. Avista Utilities is not able to fully predict how the combination of energy resources, energy loads, prices, rate recovery and other factors will ultimately drive deferred power costs and the timing of recovery of these costs in future periods. Current estimates and projections by the Company indicate that deferred power costs will be recovered by 2009. See further information at "Avista Utilities - - Regulatory Matters."

Challenges facing Avista Utilities' electric operations include, among other things, the timing of the recovery of deferred power and natural gas costs, changes in the availability of and volatility in the prices of power and fuel, generating unit availability, legislative and governmental regulations, potential tax law changes, customer response to price increases and surcharges, streamflows and weather conditions.

Natural gas commodity prices increased dramatically during 2000 and remained at relatively high levels during the first half of 2001 before declining in the second half of the year. Natural gas commodity prices during 2002 were generally lower than during 2000 and the first half of 2001. Natural gas commodity prices have increased towards the end of 2002 and into 2003. Market prices for natural gas continue to be competitive compared to alternative fuel sources for residential, commercial and industrial customers. Avista Utilities believes that natural gas should sustain its market advantage based on the levels of existing reserves and the potential for natural gas development in the future. Growth has occurred in the natural gas business in recent years due to increased demand for natural gas in new construction, as well as conversions from electric space, oil space and electric water heating to natural gas. Challenges facing Avista Utilities' natural gas operations include, among other things, volatility in the price of natural gas, changes in the availability of natural gas, legislative and governmental regulations, weather conditions and the timing of recovery for increased commodity costs. Avista Utilities' natural gas business also faces the potential for large natural gas customers to by-pass its natural gas system. To reduce the potential for such by-pass, Avista Utilities 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 individual contracts, subject to state regulatory review and approval. Avista Utilities has long-term transportation contracts with seven of its largest industrial customers, which reduces the risk of these customers by-passing the system in the foreseeable future.

Avista Energy trades electricity and natural gas, along with derivative commodity instruments, including futures, options, swaps and other contractual arrangements. As a result of these trading activities, Avista Energy is subject to various risks, including commodity price risk and credit risk, as well as possible new risks resulting from the recent imposition of market controls by federal and state agencies. The FERC is conducting separate proceedings related to market controls within California and within the Pacific Northwest that include proposals by certain parties to retroactively impose price caps. As a result, certain parties have asserted claims for significant refunds from Avista Energy and lesser refunds from Avista Utilities which could result in liabilities for refunding revenues recognized in prior periods. Avista Energy and Avista Utilities have joined other parties in opposing these proposals. The California proceedings provide that any refunds owed could be offset against unpaid energy debts due to the same party. Avista Energy has fully reserved for all defaulted obligations from California parties and believes that any refunds imposed would not exceed its uncollected receivables. If retroactive price caps or refunds were imposed in the Pacific Northwest, Avista Energy and Avista Utilities could assert offsetting claims for certain transactions. See "Power Market Issues" for further information with respect to the FERC refund proceedings.

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In connection with matching loads and resources, Avista Utilities engages in wholesale sales and purchases of electric capacity and energy and, accordingly, is also subject to commodity price risk, credit risk and other risks associated with these activities.

Commodity Price Risk. Both Avista Utilities and Avista Energy are subject to energy commodity price risk. The price of power in wholesale markets is affected primarily by production costs and by other factors including streamflows, the availability of hydroelectric and thermal generation and transmission capacity, weather and the resulting retail loads, and the price of coal, natural gas and oil to operate thermal generating units. Any combination of these factors that results in a shortage of energy generally causes the market price of power to move upward. Additionally, the FERC imposed a price mitigation plan in the western United States in June 2001.

Price risk is, in general, the risk of fluctuation in the market price of the commodity needed, held or traded. In the case of electricity, prices can be affected by the adequacy of generating reserve margins, scheduled and unscheduled outages of generating facilities, availability of streamflows for hydroelectric generation, the price of thermal generating plant fuel, and disruptions or constraints to transmission facilities. Demand changes (caused by variations in the weather and other factors) can also affect market prices. Price risk also includes the risk of fluctuation in the market price of associated derivative commodity instruments (such as options and forward contracts). Price risk may also be influenced to the extent that the performance or non-performance by market participants of their contractual obligations and commitments affect the supply of, or demand for, the commodity. Wholesale market prices for power and natural gas in the western United States and western Canada were significantly higher in 2000 and the first half of 2001 than at any time in history, with unprecedented levels of volatility. Prices and volatility decreased considerably during the second half of 2001 and 2002 relative to 2000 and the first half of 2001.

Credit Risk. Credit risk relates to the risk of loss that Avista Utilities and/or Avista Energy would incur as a result of non-performance by counterparties of their contractual obligations to deliver energy and make financial settlements. Credit risk includes not only the risk that a counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to circumstances that relate to other market participants that have a direct or indirect relationship with such counterparty. Avista Utilities and Avista Energy seek to mitigate credit risk by applying specific eligibility criteria to existing and prospective counterparties and by actively monitoring current credit exposures. These policies include an evaluation of the financial condition and credit ratings of counterparties, collateral requirements or other credit enhancements, such as letters of credit or parent company guarantees, and the use of standardized agreements that allow for the netting or offsetting of positive and negative exposures associated with a single counterparty. However, despite mitigation efforts, defaults by counterparties periodically occur. Avista Energy experienced payment receipt defaults from certain parties impacted by the California energy crisis. Avista Energy and Avista Corp. (through the Avista Utilities division) have engaged in physical and financial transactions with Enron Corporation (Enron) and certain of its affiliates and experienced disruptions to forward contract commitments as a result of Enron’s December 2001 bankruptcy. The Enron bankruptcy and other changes, uncertainties and regulatory proceedings have resulted in reduced liquidity in the energy markets. See “Enron Corporation” in “Note 28 of Notes to Consolidated Financial Statements” for more information.

A trend of declining credit quality was evident during 2002, particularly in the energy industry. Rating agencies have downgraded the credit ratings of several of the counterparties of Avista Energy and Avista Utilities. Avista Energy and Avista Utilities regularly evaluate counterparties’ credit exposure for future settlements and delivery obligations. Avista Energy and Avista Utilities have taken a conservative position by reducing or eliminating open (unsecured) credit limits for parties perceived to have increased default risk. Counterparty collateral is used to offset the Company’s credit risk where unsettled net positions and future obligations by counterparties to pay Avista Utilities and/or Avista Energy or deliver to Avista Utilities and/or Avista Energy warrant.

Avista Energy has concentrations of suppliers and customers in the electric and natural gas industries including electric utilities, natural gas distribution companies, and other energy marketing and trading companies. In addition, Avista Energy has concentrations of credit risk related to geographic location as Avista Energy operates in the western United States and western Canada. These concentrations of counterparties and concentrations of geographic location may impact Avista Energy’s overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

Credit risk also involves the exposure that counterparties perceive related to performance by Avista Utilities and Avista Energy to perform deliveries and settlement of energy transactions. These counterparties may seek assurance of performance in the form of letters of credit, prepayment or cash deposits, and, in the case of Avista Energy, parent company performance guarantees. In periods of price volatility, the level of exposure can change significantly, with the result that sudden and significant demands may be made against the Company’s capital resource reserves (credit facilities and cash). Avista Utilities and Avista Energy actively monitor the exposure to possible collateral calls and take steps to minimize capital requirements.

In conjunction with the valuation of their commodity derivative instruments and accounts receivable, Avista Utilities and Avista Energy maintain credit reserves that are based on management's evaluation of the credit risk of the overall portfolio. Based on these policies, exposures and credit reserves, the Company does not anticipate a materially adverse effect on its financial condition or results of operations as a result of counterparty nonperformance.

Other Operating Risks. In addition to commodity price risk, Avista Utilities' commodity positions are subject to operational and event risks including, among others, increases in load demand, transmission or transport disruptions, fuel quality specifications, forced outages at generating plants and disruptions to information systems and other administrative tools required for normal operations. Avista Utilities also has exposure to weather conditions and natural disasters that can cause physical damage to property, requiring immediate repairs to restore utility service.

The emergence of terrorism threats, both domestic and foreign, is a risk to the entire utility industry, including Avista Utilities. Potential disruptions to operations or destruction of facilities from terrorism are not readily determinable. The Company has taken various steps to mitigate terrorism risks and to prepare contingency plans in case its facilities are targeted.

Interest Rate Risk. The Company is subject to the risk of fluctuating interest rates in the normal course of business. The Company manages interest rate risk by taking advantage of market conditions when timing the issuance of long-term financings and optional debt redemptions and through the use of fixed rate long-term debt with varying maturities. The interest rate on $40 million of Company-Obligated Mandatorily Redeemable Preferred Trust Securities — Series B is adjusted quarterly, reflecting current market conditions. In order to lower interest payments during a period of declining interest rates, Avista Corp. entered into an interest rate swap agreement, effective July 17, 2002, that terminates on June 1, 2008. This interest rate swap agreement effectively changes the interest rate on $25 million of Unsecured Senior Notes from a fixed rate of 9.75 percent to a variable rate based on LIBOR. Additionally, amounts borrowed under the Company's $225.0 million line of credit have a variable interest rate.

The Company's credit ratings were downgraded during the fourth quarter of 2001 resulting in an overall corporate credit rating that is below investment grade. These downgrades increased the cost of debt and other securities going forward and may affect the Company's ability to issue debt and equity securities at reasonable interest rates and prices. The downgrades also required the Company to provide letters of credit and/or collateral to certain parties.

Foreign Currency Risk. The Company has investments in Canadian companies through Avista Energy Canada, Ltd. and its subsidiary, Copac Management, Inc. The Company's exposure to foreign currency risk and other foreign operations risk was immaterial to the Company's consolidated results of operations and financial position during 2002 and is not expected to change materially in the near future.

Risk Management

Risk Policies and Oversight. Avista Utilities and Avista Energy use a variety of techniques to manage risks. The Company has risk management oversight for these risks for each area of the Company's energy-related businesses. The Company has a Risk Management Committee, separate from the units that create such risk exposure and that is overseen by the Audit Committee of the Company's Board of Directors, to monitor compliance with the Company's risk management policies and procedures. Avista Utilities and Avista Energy have policies and procedures in place to manage the risks, both quantitative and qualitative, inherent in their businesses. The Company's Risk Management Committee reviews the status of risk exposures through regular reports and meetings and it monitors compliance with the Company's risk management policies and procedures on a regular basis. Nonetheless, adverse changes in commodity prices, generating capacity, customer loads, regulation and other factors may result in losses in earnings, cash flows and/or fair values.

*Quantitative Risk Measurements.*Avista Utilities has volume limits for its imbalance between projected loads and resources. Normal operations result in seasonal mismatches between power loads and available resources. Avista Utilities is able to vary the operation of its generating resources to help match hourly, daily and weekly load fluctuations. Avista Utilities uses the wholesale power markets to sell projected resource surpluses and obtain resources when deficits are projected in the 18-month forward planning horizon. Any imbalance is required to remain within limits, or management action or decisions are triggered to address larger imbalance situations. Volume limits for forward periods are based on monthly and quarterly averages that may vary materially from the actual load and resource variations within any given month or operating day. Future projections of resources are updated as forecasted streamflows and other factors differ from prior estimates. Forward power markets may be illiquid, and market products available may not match Avista Utilities' desired transaction size and shape. Therefore, open imbalance positions exist at any given time.

Avista Energy measures the risk in its power and natural gas portfolio daily utilizing a Value-at-Risk (VAR) model, monitoring its risk in comparison to established thresholds. VAR measures the expected portfolio loss under hypothetical adverse price movements, over a given time interval within a given confidence level. Avista Energy also measures its open positions in terms of volumes at each delivery location for each forward time period. The extent of open positions is included in the risk management policy and is measured with stress tests and VAR modeling.

The VAR computations are based on a historical simulation, utilizing price movements over a specified period to simulate forward price curves in the energy markets to estimate the potential unfavorable impact of price movement in the portfolio of transactions scheduled to settle within the following eight calendar quarters. The quantification of market risk using VAR provides a consistent measure of risk across Avista Energy's continually changing portfolio. VAR represents an estimate of reasonably possible net losses in earnings that would be recognized on its portfolio assuming hypothetical movements in future market rates and is not necessarily indicative of actual results that may occur.

Avista Energy's VAR computations utilize several key assumptions, including a 95 percent confidence level for the resultant price movement and holding periods of one and three days. The calculation includes derivative commodity instruments held for trading purposes and excludes the effects of embedded physical options in the trading portfolio.

As of December 31, 2002, Avista Energy's estimated potential one-day unfavorable impact on net margin was $0.7 million, as measured by VAR, related to its commodity trading and marketing business, compared to $0.4 million as of December 31, 2001. The average daily VAR for 2002 was $0.6 million. Avista Energy was in compliance with its one-day VAR limits during 2002. Changes in markets inconsistent with historical trends or assumptions used could cause actual results to exceed predicted limits. Market risks associated with derivative commodity instruments held for purposes other than trading were not material as of December 31, 2002.

For forward transactions that settle beyond the next eight calendar quarters, Avista Energy applies other risk measurement techniques, including price sensitivity stress tests, to assess the future market risk. Volatility in longer-dated forward markets tends to be significantly less than near-term markets.

Economic and Load Growth

Avista Utilities, along with others in the service area, is continuing its efforts to facilitate expansion of existing businesses and to attract new businesses to the Inland Northwest. Agriculture, mining and lumber were the primary industries for many years; today health care, education, financial, electronic and other manufacturing, tourism and the service sectors have become important industries that operate in Avista Utilities' service area. Avista Utilities also anticipates moderate economic growth to continue in its Oregon service area.

Avista Utilities anticipates residential and commercial electric load growth to average between 2.5 and 3.5 percent annually for the next four years, primarily due to increases in both population and the number of businesses in its service territory. The number of electric customers is expected to increase and the average annual usage by residential customers is expected to remain steady.

Avista Utilities anticipates natural gas load growth to average between 3.0 and 4.0 percent annually for the next four years. The anticipated natural gas load growth is primarily due to expected conversions from electric space, oil space and electric water heating to natural gas, and increases in both population and the number of businesses in its service territory.

During 2001 and 2002, Avista Utilities experienced decreased loads and decreased use per customer with respect to both electric and natural gas retail sales. The decrease in use per customer appears to be primarily due to a response to the increase in rates and the resulting conservation efforts of individual customers. The decrease in use per customer in 2002 and 2001 as compared to 2000 also appears to reflect milder weather in 2002 and 2001 as compared to 2000. The decrease in total kWhs and therms sold primarily relates to industrial customers and appears to reflect a general downturn in the economy of the Company's service territory. However, as described above, based on economic forecasts, publicly available studies and internal analysis of company-specific data, the Company does not expect the trend of declining loads to continue over the next four years.

The forward-looking projections set forth above regarding retail sales growth are based, in part, upon purchased economic forecasts and publicly available population and demographic studies. The expectations regarding retail sales growth are also based upon various assumptions including, without limitation, assumptions relating to weather and economic and competitive conditions, internal analysis of company-specific data, such as energy consumption patterns and internal business plans, and an assumption that Avista Utilities 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.

Information Services Contract

Electronic Data Systems (EDS) has performed certain information services for the Company since 1992. The Company's current contract with EDS expires in August 2005. In order to increase flexibility and increase efficiencies, the Company is currently negotiating to extend and restructure its contract with EDS. The Company believes that any changes to the contract with EDS will not have any material impact on its financial condition or results of operations and will not result in any disruption to its business operations.

Environmental Issues

Since December 1991, a number of species of fish in the Northwest, including the Snake River sockeye salmon and fall chinook salmon, the Kootenai River white sturgeon, the upper Columbia River steelhead, the upper Columbia River spring chinook salmon and the bull trout, have been listed as threatened or endangered under the Federal Endangered Species Act. Thus far, measures that were adopted and implemented to save the Snake River sockeye salmon and fall chinook salmon have not directly impacted generation levels at any of Avista Utilities' hydroelectric dams. Avista Utilities does, however, purchase power from four projects on the Columbia River that are directly impacted by ongoing mitigation measures for salmon and steelhead. The reduction in generation at these projects is relatively minor, resulting in minimal economic impact on Avista Utilities at this time. It is currently not possible to accurately predict the likely economic costs to the Company resulting from all future actions.

The Company received a new FERC operating license for the Cabinet Gorge and Noxon Rapids hydroelectric projects in March 2001 that incorporates a comprehensive settlement agreement. The restoration of native salmonid fish, in particular bull trout, is a principal focus of the agreement. The result is a collaborative bull trout recovery program with the U.S. Fish and Wildlife Service, Native American tribes and the states of Idaho and Montana on the lower Clark Fork River, consistent with requirements of the FERC license.

The issue of high levels of dissolved gas which exceed Idaho and federal water quality standards downstream of the Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) during spill periods continues to be studied, as agreed to in the Clark Fork Settlement Agreement and incorporated into the recently renewed FERC license. To date, intensive biological studies in the lower Clark Fork River and Lake Pend Oreille have documented minimal biological effects of high dissolved gas levels on free ranging fish. Under the terms of the Clark Fork Settlement Agreement, the Company developed an abatement and mitigation strategy during 2002 with the other signatories to the agreement. In December 2002, the Company submitted its plan for review and approval by the other signatories as well as the FERC. The structural alternative proposed in the plan provides for the modification of the two existing diversion tunnels built when Cabinet Gorge was originally constructed. The costs of modifications to the first tunnel are currently estimated to be $37 million (including AFUDC and inflation) and would be incurred between 2004 and 2009. The second tunnel would be modified only after evaluation of the performance of the first tunnel and such modifications would commence no later than 10 years following the completion of the first tunnel. It is currently estimated that the costs to modify the second tunnel would be $23 million (including AFUDC and inflation). As part of the plan, the Company will also provide $0.5 million annually commencing as early as 2004, as mitigation for aquatic resources that might be adversely affected by high dissolved gas levels. Mitigation funds will continue until the modification of the second tunnel commences or if the second tunnel is not modified to an agreed upon point in time commensurate with the biological effects of high dissolved gas levels. The Company will seek regulatory recovery of the costs for the modification of Cabinet Gorge and the mitigation payments.

See "Note 28 of Notes to Consolidated Financial Statements" for additional information.

Dividends

The Board of Directors considers the level of dividends on the Company's common stock on a regular basis, taking into account numerous factors including, without limitation, the Company's results of operations, cash flows and financial condition, as well as the success of the Company's strategies and general economic and competitive conditions. The Company’s net income available for dividends is derived primarily from the operations of Avista Utilities and Avista Energy.

Avista Energy holds a significant portion of cash and cash equivalents reflected on the Consolidated Balance Sheet. Covenants in Avista Energy’s credit agreement restrict the amount of cash dividends that can be distributed to Avista Capital and ultimately to Avista Corp. During 2002, in accordance with the modified covenants of its credit agreement, Avista Energy paid $116.4 million in dividends to Avista Capital. In January 2003, Avista Energy paid $2.1 million in dividends to Avista Capital.

Item 7a. Quantitative and Qualitative Disclosures About Market Risk

See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations: Future Outlook: Business Risk and Risk Management.”

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

Avista Corporation
Spokane, Washington

We have audited the accompanying consolidated balance sheets and statements of capitalization of Avista Corporation and subsidiaries (the Company) as of December 31, 2002 and 2001, and the related consolidated statements of income and comprehensive income, stockholders' equity, and cash flows, which include the schedule of information by business segments, for each of the three years in the period ended December 31, 2002. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2002 and 2001, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As described in Note 2 to the consolidated financial statements, during 2002, the Company changed its method of accounting for goodwill to conform to Statement of Financial Accounting Standards No. 142, also, as described in Note 2 to the consolidated financial statements, the Company changed its presentation of energy trading activities in accordance with Emerging Issues Task Force Issue No. 02-3.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 7, 2003
(March 3, 2003, as to Note 28)

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CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
Avista Corporation

For the Years Ended December 31
Dollars in thousands, except per share amounts

	2002	2001	2000
OPERATING REVENUES	$ 980,446	$1,395,313	$1,858,516
OPERATING EXPENSES:			
Resource costs	453,525	849,996	1,246,459
Operations and maintenance	122,920	125,656	129,708
Administrative and general	118,766	119,216	134,912
Depreciation and amortization	73,275	71,981	65,936
Taxes other than income taxes	67,273	59,172	54,608
Restructuring and exit costs	—	—	9,805
Total operating expenses	835,759	1,226,021	1,641,428
INCOME FROM OPERATIONS	144,687	169,292	217,088
OTHER INCOME (EXPENSE):			
Interest expense	(105,336)	(106,480)	(68,255)
Capitalized interest	7,486	10,498	3,359
Net interest expense	(97,850)	(95,982)	(64,896)
Other income-net	17,467	20,681	25,861
Total other income (expense)-net	(80,383)	(75,301)	(39,035)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	64,304	93,991	178,053
INCOME TAXES	29,994	34,386	76,998
INCOME FROM CONTINUING OPERATIONS	34,310	59,605	101,055
DISCONTINUED OPERATIONS (Note 3):			
Income (loss) before asset impairment charges, minority interest and income taxes	2,499	(21,130)	(15,367)
Asset impairment charges	—	(58,417)	—
Minority interest	—	4,319	2,454
Income tax benefit (expense)	(1,354)	27,779	3,537
INCOME (LOSS) FROM DISCONTINUED OPERATIONS	1,145	(47,449)	(9,376)
NET INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	35,455	12,156	91,679
CUMULATIVE EFFECT OF ACCOUNTING CHANGE (net of tax) (Note 2)	(4,148)	—	—
NET INCOME	31,307	12,156	91,679
DEDUCT-Preferred stock dividend requirements	2,402	2,432	23,735
INCOME AVAILABLE FOR COMMON STOCK	$ 28,905	$ 9,724	$ 67,944
Weighted-average common shares outstanding (thousands), Basic	47,823	47,417	45,690
EARNINGS PER COMMON SHARE, BASIC (Note 25):			
Earnings per common share from continuing operations	$ 0.67	$ 1.21	$ 1.69
Earnings (loss) per common share from discontinued operations	0.02	(1.00)	(0.20)
Earnings per common share before cumulative effect of accounting change	0.69	0.21	1.49
Loss per common share from cumulative effect of accounting change	(0.09)	—	—
Total earnings per common share, basic	$ 0.60	$ 0.21	$ 1.49
Weighted-average common shares outstanding (thousands), Diluted	47,874	47,435	46,103
EARNINGS PER COMMON SHARE, DILUTED (Note 25):			
Earnings per common share from continuing operations	$ 0.67	$ 1.20	$ 1.67
Earnings (loss) per common share from discontinued operations	0.02	(1.00)	(0.20)
Earnings per common share before cumulative effect of accounting change	0.69	0.20	1.47
Loss per common share from cumulative effect of accounting change	(0.09)	—	—
Total earnings per common share, diluted	$ 0.60	$ 0.20	$ 1.47
Dividends paid per common share	$ 0.48	$ 0.48	$ 0.48
NET INCOME	$ 31,307	$ 12,156	$ 91,679
OTHER COMPREHENSIVE INCOME (LOSS):			
Foreign currency translation adjustment	8	(221)	(82)
Unfunded accumulated benefit obligation - net of tax	(18,081)	(740)	—
Unrealized loss on interest rate swap agreements - net of tax	(1,258)	—	—

Unrealized investments gains (losses) - net of tax	(934)	1,585	(475)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(20,265)	624	(557)
COMPREHENSIVE INCOME	$ 11,042	$ 12,780	$ 91,122

The Accompanying Notes are an Integral Part of These Statements.

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CONSOLIDATED BALANCE SHEETS
Avista Corporation

As of December 31
Dollars in thousands

	2002	2001
ASSETS:		
CURRENT ASSETS:		
Cash and cash equivalents	$ 186,369	$ 171,221
Temporary investments	—	1,872
Accounts and notes receivable-less allowances of $46,909 and $50,211, respectively	321,091	388,083
Energy commodity assets	365,477	477,037
Materials and supplies, fuel stock and natural gas stored	22,047	21,776
Taxes receivable	—	32,348
Prepayments and other current assets	73,633	19,364
Assets held for sale from discontinued operations	105	21,316
Total current assets	968,722	1,133,017
NET UTILITY PROPERTY:		
Utility plant in service	2,370,811	2,277,779
Construction work in progress	17,581	54,964
Total	2,388,392	2,332,743
Less: Accumulated depreciation and amortization	824,688	767,101
Total net utility property	1,563,704	1,565,642
OTHER PROPERTY AND INVESTMENTS:		
Investment in exchange power-net	40,833	43,314
Non-utility properties and investments-net	204,522	230,800
Non-current energy commodity assets	348,309	383,497
Other property and investments-net	12,702	13,620
Total other property and investments	606,366	671,231
DEFERRED CHARGES:		
Regulatory assets for deferred income tax	139,138	149,033
Other regulatory assets	29,735	192,760
Utility energy commodity derivative assets	60,322	1,889
Power and natural gas deferrals	166,782	265,063
Unamortized debt expense	51,128	41,222
Other deferred charges	28,236	17,366
Total deferred charges	475,341	667,333
TOTAL ASSETS	$3,614,133	$4,037,223
LIABILITIES AND CAPITALIZATION:		
CURRENT LIABILITIES:		
Accounts payable	$ 340,651	$ 367,899
Energy commodity liabilities	304,781	373,837
Current portion of long-term debt	71,901	1,827
Short-term borrowings	30,000	75,099
Interest accrued	20,307	18,583
Other current liabilities	172,138	84,587
Liabilities of discontinued operations	1,052	6,642
Total current liabilities	940,830	928,474
NON-CURRENT LIABILITIES AND DEFERRED CREDITS:		
Deferred revenue	672	35,824
Non-current energy commodity liabilities	314,204	299,980
Utility energy commodity derivative liabilities	50,058	159,418
Deferred income taxes	454,147	517,428
Other non-current liabilities and deferred credits	105,546	65,321
Total non-current liabilities and deferred credits	924,627	1,077,971
CAPITALIZATION (See Consolidated Statements of Capitalization)	1,748,676	2,030,778
COMMITMENTS AND CONTINGENCIES (See Notes to Consolidated Financial Statements)		
TOTAL LIABILITIES AND CAPITALIZATION	$3,614,133	$4,037,223

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF CAPITALIZATION
Avista Corporation

As of December 31
Dollars in thousands, except per share amounts

	2002	2001
LONG-TERM DEBT:		
First Mortgage Bonds:		
Secured Medium-Term Notes:		
Series A - 6.25% to 7.90% due 2003 through 2023	$ 89,500	$ 104,500
Series B - 6.50% to 7.89% due 2005 through 2010	59,000	59,000
Total secured medium-term notes	148,500	163,500
First Mortgage Bonds - 7.75% due 2007	150,000	150,000
Total first mortgage bonds	298,500	313,500
Unsecured Pollution Control Bonds:		
Colstrip 1999A, due 2032	66,700	66,700
Colstrip 1999B, due 2034	17,000	17,000
6% Series due 2023	4,100	4,100
Total unsecured pollution control bonds	87,800	87,800
Unsecured Notes:		
Unsecured Medium-Term Notes:		
Series A - 7.94% to 8.99% due 2003 through 2007	3,000	13,000
Series B - 6.75% to 8.23% due 2003 through 2023	74,000	79,000
Series C - 5.99% to 8.02% due 2007 through 2028	99,000	109,000
Series D - 9.125% due 2003	—	175,000
Total unsecured medium-term notes	176,000	376,000
Unsecured 9.75% Senior Notes due 2008	341,529	400,000
Total unsecured notes	517,529	776,000
Other long-term debt	967	962
Unamortized debt discount	(2,161)	(2,547)
Total long-term debt	902,635	1,175,715
COMPANY-OBLIGATED MANDATORILY REDEEMABLE PREFERRED TRUST SECURITIES:		
7.875%, Series A, due 2037	60,000	60,000
Floating Rate, Series B, due 2037	40,000	40,000
Total company-obligated mandatorily redeemable preferred trust securities	100,000	100,000
PREFERRED STOCK-CUMULATIVE:		
10,000,000 shares authorized:		
Subject to mandatory redemption:		
$6.95 Series K; 332,500 and 350,000 shares outstanding ($100 stated value)	33,250	35,000
COMMON EQUITY:		
Common stock, no par value; 200,000,000 shares authorized; 48,044,208 and 47,632,678 shares outstanding	623,092	617,737
Note receivable from employee stock ownership plan	(4,146)	(5,679)
Capital stock expense and other paid in capital	(11,928)	(11,924)
Accumulated other comprehensive loss	(20,364)	(99)
Retained earnings	126,137	120,028
Total common equity	712,791	720,063
TOTAL CAPITALIZATION	$1,748,676	$2,030,778

The Accompanying Notes are an Integral Part of These Statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS
Increase (Decrease) in Cash and Cash Equivalents
Avista Corporation

For the Years Ended December 31
Dollars in thousands

	2002	2001	2000
CONTINUING OPERATING ACTIVITIES:			
Net income	$ 31,307	$ 12,156	$ 91,679
Loss (income) from discontinued operations	(1,145)	47,449	9,376
Cumulative effect of accounting change	4,148	—	—
Non-cash items included in net income:			
Depreciation and amortization	73,275	71,981	65,936
Provision for deferred income taxes	(40,287)	79,141	79,274
Power and natural gas cost amortizations (deferrals), net	68,481	(210,540)	(70,250)
Amortization of debt expense	8,861	5,639	3,409
Impairment of non-operating assets	—	8,240	—
Energy commodity assets and liabilities	87,403	30,238	(174,680)
Other	(10,763)	(12,096)	(32,470)
Changes in working capital components:			
Sale of customer accounts receivable-net	(10,000)	(5,000)	35,000
Accounts and notes receivable	80,203	457,924	(338,512)
Materials and supplies, fuel stock and natural gas stored	(271)	(853)	7,037
Other current assets	(21,921)	15,058	(45,271)
Accounts payable	(27,248)	(518,369)	363,790
Other current liabilities	89,275	(57,038)	89,772
NET CASH PROVIDED BY (USED IN) CONTINUING OPERATING ACTIVITIES	331,318	(76,070)	84,090
CONTINUING INVESTING ACTIVITIES:			
Utility property construction expenditures (excluding AFUDC)	(64,207)	(119,905)	(98,680)
Other capital expenditures	(19,390)	(162,279)	(73,515)
Changes in other property and investments	1,438	10,163	2,106
Repayments received on notes receivable	33,752	1,000	1,297
Proceeds from property sales and sale of subsidiary investments	586	75,953	105,228
Assets acquired and investments in subsidiaries	(461)	(23,321)	(1,496)
NET CASH USED IN CONTINUING INVESTING ACTIVITIES	(48,282)	(218,389)	(65,060)
CONTINUING FINANCING ACTIVITIES:			
Increase (decrease) in short-term borrowings	(45,099)	(88,061)	42,126
Redemption of preferred trust securities	—	—	(10,000)
Proceeds from issuance of long-term debt	621	550,457	224,000
Redemption and maturity of long-term debt	(204,014)	(140,208)	(54,283)
Redemption of preferred stock	(1,750)	—	—
Issuance of common stock	7,035	8,267	4,532
Repurchase of common stock	—	—	(1,907)
Cash dividends paid	(25,456)	(25,110)	(28,304)
Premiums paid for the redemption of long-term debt	(9,456)	—	—
Long-term debt and short-term borrowing issuance costs	(6,534)	(19,693)	(850)
NET CASH PROVIDED BY (USED IN) CONTINUING FINANCING ACTIVITIES	(284,653)	285,652	175,314
NET CASH PROVIDED BY (USED IN) CONTINUING OPERATIONS	(1,617)	(8,807)	194,344
NET CASH PROVIDED BY (USED IN) DISCONTINUED OPERATIONS	16,765	(17,210)	(37,094)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	15,148	(26,017)	157,250
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	171,221	197,238	39,988
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 186,369	$ 171,221	$ 197,238
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) during the period:			
Interest	$ 95,801	$ 98,571	$ 61,774
Income taxes	7,428	(35,874)	(6,855)
Non-cash financing and investing activities:			
Accounts receivable from sale of non-operating assets	—	22,665	—
Series L preferred stock converted to common stock	—	—	271,286
Unrealized loss on interest rate swap agreements	(1,936)	—	—
Unrealized investment gains (losses)	(1,436)	2,437	(475)
Intangible asset related to pension plan	6,366	—	—
Unfunded accumulated benefit obligation	(34,164)	(1,139)	3,500

The Accompanying Notes are an Integral Part of These Statements.

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CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
Avista Corporation

For the Years Ended December 31
Dollars in thousands

	Preferred Stock Series K		Convertible Preferred Stock, Series L		Common Stock	
	Shares	Amount	Shares	Amount	Shares	Amount
Balance as of December 31, 1999	350,000	$35,000	1,508,210	$ 263,309	35,648,239	$318,731
Net income						
Conversion of convertible preferred stock into common stock			(1,508,210)	(263,309)	11,410,047	289,118
Repurchase of common stock					(45,975)	(1,488)
Stock issued under compensatory plans					70,742	1,192
Employee Investment Plan (401-K)					97,478	2,614
Dividend Reinvestment Plan					28,158	574
Repayments of note receivable						
Foreign currency translation adjustment						
Unrealized investment loss-net						
Cash dividends paid (common stock)						
Cash dividends paid (preferred stock)						
ESOP dividend tax savings						
Balance as of December 31, 2000	350,000	$35,000	—	$ —	47,208,689	$610,741
Net income						
Stock issued under compensatory plans					91,128	1,763
Employee Investment Plan (401-K)					172,681	2,823
Dividend Reinvestment Plan					160,180	2,410
Repayments of note receivable						
Foreign currency translation adjustment						
Unfunded accumulated benefit obligation						
Unrealized investment gain-net						
Cash dividends paid (common stock)						
Cash dividends paid (preferred stock)						
ESOP dividend tax savings						
Balance as of December 31, 2001	350,000	$35,000	—	$ —	47,632,678	$617,737
Net income						
Stock issued under compensatory plans					2,730	74
Employee Investment Plan (401-K)					227,585	3,046
Dividend Reinvestment Plan					181,215	2,235
Redemption of preferred stock	(17,500)	(1,750)				
Repayments of note receivable						
Foreign currency translation adjustment						
Unfunded accumulated benefit obligation						
Unrealized investment gain-net						
Unrealized loss on interest rate swap						
Cash dividends paid (common stock)						
Cash dividends paid (preferred stock)						
ESOP dividend tax savings						
Balance as of December 31, 2002	332,500	$33,250	—	$ —	48,044,208	$623,092

[Additional columns below]

[Continued from above table, first column(s) repeated]

For the Years Ended December 31
Dollars in thousands

	Note Receivable from Employee Stock Ownership Plan	Capital Stock Expense and Other Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
Balance as of December 31, 1999	$(8,240)	$ (4,347)	$ (166)	$ 87,521	$691,808
Net income				91,679	91,679
Conversion of convertible preferred stock into common stock		(8,009)		(17,868)	(68)
Repurchase of common stock				(419)	(1,907)
Stock issued under compensatory plans		689		101	1,982
Employee Investment Plan (401-K)		(29)			2,585
Dividend Reinvestment Plan					574
Repayments of note receivable	1,200				1,200
Foreign currency translation adjustment			(82)		(82)

Unrealized investment loss-net			(475)		(475)
Cash dividends paid (common stock)				(22,616)	(22,616)
Cash dividends paid (preferred stock)				(5,600)	(5,600)
ESOP dividend tax savings				144	144
Balance as of December 31, 2000	$(7,040)	$(11,696)	$ (723)	$132,942	$759,224
Net income				12,156	12,156
Stock issued under compensatory plans		(228)		(14)	1,521
Employee Investment Plan (401-K)					2,823
Dividend Reinvestment Plan					2,410
Repayments of note receivable	1,361				1,361
Foreign currency translation adjustment			(221)		(221)
Unfunded accumulated benefit obligation			(740)		(740)
Unrealized investment gain-net			1,585		1,585
Cash dividends paid (common stock)				(22,765)	(22,765)
Cash dividends paid (preferred stock)				(2,432)	(2,432)
ESOP dividend tax savings				141	141
Balance as of December 31, 2001	$(5,679)	$(11,924)	$ (99)	$120,028	$755,063
Net income				31,307	31,307
Stock issued under compensatory plans		(4)			70
Employee Investment Plan (401-K)					3,046
Dividend Reinvestment Plan					2,235
Redemption of preferred stock					(1,750)
Repayments of note receivable	1,533				1,533
Foreign currency translation adjustment			8		8
Unfunded accumulated benefit obligation			(18,081)		(18,081)
Unrealized investment gain-net			(934)		(934)
Unrealized loss on interest rate swap			(1,258)		(1,258)
Cash dividends paid (common stock)				(22,955)	(22,955)
Cash dividends paid (preferred stock)				(2,402)	(2,402)
ESOP dividend tax savings				159	159
Balance as of December 31, 2002	$(4,146)	$(11,928)	$(20,364)	$126,137	$746,041

The Accompanying Notes are an Integral Part of These Statements.

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SCHEDULE OF INFORMATION BY BUSINESS SEGMENTS
Avista Corporation

For the Years Ended December 31
Dollars in thousands

	2002	2001	2000
OPERATING REVENUES:			
Avista Utilities	$ 893,964	$1,230,847	$ 1,512,101
Energy Trading and Marketing (net margin on trading activities)	54,207	134,266	307,746
Information and Technology	17,630	13,815	5,732
Other	14,645	16,385	32,937
Total operating revenues	$ 980,446	$1,395,313	$ 1,858,516
RESOURCE COSTS (AVISTA UTILITIES):			
Avista Utilities:			
Power purchased	$ 115,282	$ 708,321	$ 1,072,475
Natural gas purchased	170,662	220,692	169,924
Fuel for generation	18,531	81,949	69,077
Power and natural gas cost amortizations (deferrals), net	68,481	(210,540)	(70,250)
Other fuel costs	77,885	43,269	1,187
Other regulatory amortizations, net	(15,157)	(19,494)	(10,525)
Other resource costs	17,841	25,799	14,571
Total resource costs (Avista Utilities)	$ 453,525	$ 849,996	$ 1,246,459
AVISTA UTILITIES GROSS MARGIN:	$ 440,439	$ 380,851	$ 265,642
OPERATIONS AND MAINTENANCE EXPENSES:			
Avista Utilities	$ 97,668	$ 97,831	$ 95,117
Energy Trading and Marketing	—	—	249
Information and Technology	10,559	12,607	6,611
Other	14,693	15,218	27,731
Total operations and maintenance expenses	$ 122,920	$ 125,656	$ 129,708
ADMINISTRATIVE AND GENERAL EXPENSES:			
Avista Utilities	$ 63,751	$ 53,416	$ 62,111
Energy Trading and Marketing	21,820	33,494	41,256
Information and Technology	19,855	23,918	22,329
Other	13,340	8,388	9,216
Total administrative and general expenses	$ 118,766	$ 119,216	$ 134,912
DEPRECIATION AND AMORTIZATION EXPENSES:			
Avista Utilities	$ 66,243	$ 61,383	$ 57,479
Energy Trading and Marketing	1,227	2,188	2,466
Information and Technology	4,376	5,403	2,169
Other	1,429	3,007	3,822
Total depreciation and amortization expenses	$ 73,275	$ 71,981	$ 65,936
INCOME FROM OPERATIONS (PRE-TAX):			
Avista Utilities	$ 149,180	$ 114,927	$ 3,177
Energy Trading and Marketing	29,211	94,669	250,196
Information and Technology	(18,818)	(29,872)	(26,424)
Other	(14,886)	(10,432)	(9,861)
Total income from operations	$ 144,687	$ 169,292	$ 217,088
INCOME FROM CONTINUING OPERATIONS:			
Avista Utilities	$ 36,382	$ 24,164	$ (38,781)
Energy Trading and Marketing	22,425	63,246	161,753
Information and Technology	(12,117)	(19,384)	(19,032)
Other	(12,380)	(8,421)	(2,885)
Total income from continuing operations	$ 34,310	$ 59,605	$ 101,055
ASSETS:			
Avista Utilities	$2,184,008	$2,396,317	$ 2,143,791
Energy Trading and Marketing	1,349,626	1,506,185	10,271,834
Information and Technology	37,528	26,891	14,429
Other	42,866	86,514	96,362
Discontinued Operations	105	21,316	50,665
Total assets	$3,614,133	$4,037,223	$12,577,081

CAPITAL EXPENDITURES:			
Avista Utilities	$ 64,207	$ 119,905	$ 98,680
Energy Trading and Marketing	17,531	157,020	65,095
Information and Technology	1,626	4,644	8,409
Other	233	615	976
Total capital expenditures	$ 83,597	$ 282,184	$ 173,160

The Accompanying Notes are an Integral Part of These Statements.

AVISTA CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corporation (Avista Corp. or the Company) is an energy company engaged in the generation, transmission and distribution of energy as well as other energy-related businesses. The utility portion of the Company, doing business as Avista Utilities, an operating division of Avista Corp. and not a separate entity, represents the regulated utility operations. Avista Utilities provides electric and natural gas distribution and transmission services in eastern Washington and northern Idaho. Avista Utilities also provides natural gas distribution service in northeast and southwest Oregon and in the South Lake Tahoe region of California. Avista Capital, a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies engaged in the other non-utility lines of business.

The Company's operations are exposed to risks including, but not limited to, the effects of legislative and governmental regulations, the price and supply of purchased power, fuel and natural gas, recoverability of power and natural gas costs, streamflow and weather conditions, availability of generation facilities, competition, technology and availability of funding. In addition, the energy business exposes the Company to the financial, liquidity, credit and commodity price risks associated with wholesale purchases and sales.

Basis of Reporting

The consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries. 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 10).

Use of Estimates

The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect amounts reported in the consolidated financial statements. Changes in these estimates and assumptions are considered reasonably possible and may have a material impact on the consolidated financial statements and thus actual results could differ from the amounts reported and disclosed herein.

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, Montana, Oregon and California. The Company is subject to federal regulation by the FERC.

Business Segments

Financial information for each of the Company's lines of business is reported in the Schedule of Information by Business Segments. Such information is an integral part of these consolidated financial statements. The business segment presentation reflects the basis currently used by the Company's management to analyze performance and determine the allocation of resources. Avista Utilities' business is managed based on the total regulated utility operation. The Energy Trading and Marketing line of business operations primarily include non-regulated electricity and natural gas marketing and trading activities including derivative commodity instruments such as futures, options, swaps and other contractual arrangements. The Information and Technology line of business operations includes utility internet billing services and fuel cell technology. The Other line of business includes other investments and operations of various subsidiaries as well as the operations of Avista Capital on a parent company only basis.

Avista Utilities Operating Revenues

Operating revenues for Avista Utilities related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. The determination of the energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, the amount of energy delivered to customers since the date of the last meter reading is estimated and the corresponding unbilled revenue is estimated and recorded. Accounts receivable includes unbilled energy revenues of $6.1 million

AVISTA CORPORATION

(net of $40.9 million of unbilled receivables sold) and $11.1 million (net of $46.6 million of unbilled receivables sold) as of December 31, 2002 and 2001, respectively. See Note 6 for information with respect to the sale of accounts receivable.

Avista Energy Operating Revenues

Avista Energy followed the mark-to-market method of accounting for energy contracts entered into for trading and price risk management purposes in compliance with Emerging Issues Task Force (EITF) Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" through December 31, 2002 for contracts entered into on or prior to October 25, 2002. Avista Energy recognized revenue based on the change in the market value of outstanding derivative commodity sales contracts, net of future servicing costs and reserves, in addition to revenue related to settled contracts. For all contracts entered into subsequent to October 25, 2002 and for all contracts beginning January 1, 2003, Avista Energy follows Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities." See Note 2 for a discussion of the rescission of EITF Issue No. 98-10 in October 2002.

Research and Development Expenses

Company-sponsored research and development expenditures are expensed as incurred. The majority of the Company's research and development expenses are related to the Information and Technology line of business. Research and development expenses totaled $3.8 million, $8.4 million and $8.1 million in 2002, 2001 and 2000, respectively.

Advertising Expenses

The Company expenses advertising costs as incurred. Advertising expenses totaled $1.3 million, $1.8 million and $1.2 million in 2002, 2001 and 2000, respectively.

Taxes other than income taxes

Taxes other than income taxes include state excise taxes, city occupational and franchise taxes, real and personal property taxes and certain other taxes not based on net income. These taxes are generally based on revenues or the value of property. Utility related taxes collected from customers are recorded as both operating revenue and expense and totaled $33.1 million, $26.3 million and $23.5 million in 2002, 2001 and 2000, respectively.

Other Income-Net

Other income-net consisted of the following items for the years ended December 31 (dollars in thousands):

	2002	2001	2000
Interest income	$ 7,716	$ 19,049	$ 10,351
Interest on power and natural gas deferrals	9,597	12,995	1,473
Impairment of non-operating assets	—	(8,240)	—
Net gain (loss) on the disposition of assets	(33)	2,884	21,048
Minority interest	242	217	694
Other expense	(8,064)	(10,839)	(10,234)
Other income	8,009	4,615	2,529
Total	$17,467	$ 20,681	$ 25,861

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 were examined with all issues resolved, and all payments made, through the 1998 return.

The Company accounts for income taxes using the liability method. Under the liability method, a deferred tax asset or liability is determined based on the enacted tax rates that will be in effect when the differences between the financial statement carrying amounts and tax basis of existing assets and liabilities are expected to be reported in the Company's consolidated income tax returns. The deferred tax expense for the period is equal to the net change in the deferred tax asset and liability accounts from the beginning to the end of the period. The effect on deferred taxes of a change in tax rates is recognized in income in the period that includes the enactment date.

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Stock-Based Compensation

The Company follows the disclosure only provisions of SFAS No. 123, “Accounting for Stock-Based Compensation.” Accordingly, employee stock options are accounted for under Accounting Principle Board Opinion (APB) No. 25, “Accounting for Stock Issued to Employees.” Stock options are granted at exercise prices not less than the fair value of common stock on the date of grant. Under APB No. 25, no compensation expense is recognized pursuant to the Company’s stock option plans.

If compensation expense for the Company’s stock option plans were determined consistent with SFAS No. 123, net income and earnings per common share would have been the following pro forma amounts for the years ended December 31:

	2002	2001	2000
Net income (dollars in thousands):			
As reported	$31,307	$12,156	$91,679
Pro forma	$28,256	$ 9,355	$89,850
Basic earnings per common share			
As reported	$ 0.60	$ 0.21	$ 1.49
Pro forma	$ 0.54	$ 0.15	$ 1.45
Diluted earnings per common share			
As reported	$ 0.60	$ 0.20	$ 1.47
Pro forma	$ 0.54	$ 0.15	$ 1.43

Comprehensive Income

The Company’s comprehensive income is comprised of net income, foreign currency translation adjustments, unfunded accumulated benefit obligation, unrealized gains and losses on interest rate swap agreements and unrealized gains and losses on investments available-for-sale.

Foreign Currency Translation Adjustment

The assets and liabilities of Avista Energy Canada, Ltd. and its subsidiary, Copac Management, Inc. are denominated in Canadian dollars and translated to United States dollars at exchange rates in effect on the balance sheet date. Revenues and expenses are translated using an average exchange rate. Translation adjustments resulting from this process are reflected as a component of other comprehensive income in the Consolidated Statements of Comprehensive Income.

Earnings Per Common Share

Basic earnings per common share is computed by dividing income available for common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per common share is calculated by dividing income available for common stock by diluted weighted average common shares outstanding during the period, including common stock equivalent shares outstanding using the treasury stock method, unless such shares are anti-dilutive. Common stock equivalent shares include shares issuable upon exercise of stock options and convertible stock. See Note 25 for earnings per common share calculations.

Cash and Cash Equivalents

For the purposes of the Consolidated Statements of Cash Flows, the Company considers all temporary investments with a purchased maturity of three months or less to be cash equivalents. Cash and cash equivalents include cash deposits from counterparties. See Note 9 for further information with respect to cash deposits from counterparties.

Temporary Investments

Temporary investments consist of marketable equity securities classified as “available for sale.” The Company did not have any temporary investments in marketable equity securities as of December 31, 2002. The unrealized gain on temporary investments totaled $1.4 million as of December 31, 2001, net of taxes, and is reflected as a component of accumulated other comprehensive income in the Consolidated Statements of Capitalization.

Allowance for Doubtful Accounts

The Company maintains an allowance for doubtful accounts to sufficiently provide for estimated and potential losses on accounts receivable. The Company determines the allowance for utility and other customer accounts receivable based on historical write-offs as compared to accounts receivable and operating revenues. Additionally, the Company establishes specific allowances for certain individual accounts.

The following table documents the activity in the allowance for doubtful accounts during the years ended December 31 (dollars in thousands):

	2002	2001	2000
Allowance as of the beginning of the year	$50,211	$14,404	$ 4,267
Additions expensed during the year	3,469	39,947	11,835
Net deductions	(6,771)	(4,140)	(1,698)
Allowance as of the end of the year	$46,909	$50,211	$14,404

Inventory

Inventory consists primarily of materials and supplies, fuel stock and natural gas stored. Inventory is recorded at the lower of cost or market, primarily using the average cost method.

Utility Plant in Service

The cost of additions to utility plant in service, including an allowance for funds used during construction and replacements of units of property and improvements, 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 non-cash item in the Consolidated Statements of Income and Comprehensive Income in the line item capitalized interest. 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 is placed in service. Cash inflow related to AFUDC does not occur until the related utility plant is placed in service.

The effective AFUDC rate was 9.72 percent for the second half of 2002, 9.03 percent for the first half of 2002 and 2001, and 10.67 percent in 2000. 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 expense is estimated by a method of depreciation accounting utilizing unit rates for hydroelectric plants and composite rates for other utility plant. 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 9 percent. For utility operations, the ratio of depreciation provisions to average depreciable property was 2.92 percent in 2002, 2.84 percent in 2001 and 2.72 percent in 2000.

The average service lives and remaining average service lives, respectively, for the following broad categories of utility property are: electric thermal production - 35 and 14 years; hydroelectric production - 100 and 76 years; electric transmission - 60 and 25 years; electric distribution - 40 and 28 years; and natural gas distribution property - 44 and 27 years.

Goodwill

Goodwill arising from acquisitions represents the excess of the purchase price over the estimated fair value of net assets acquired. The Company evaluates goodwill for impairment on at least an annual basis. Goodwill is included in non-utility properties and investments-net in the Consolidated Balance Sheets and totaled $7.3 million and $13.7 million as of December 31, 2002 and 2001, respectively. The level of goodwill as of December 31, 2002 and 2001 was supported by the value attributed to the operations acquired. See Note 2 for changes in accounting for goodwill effective January 1, 2002.

Regulatory Deferred Charges and Credits

The Company prepares its consolidated financial statements in accordance with the provisions of SFAS No. 71, “Accounting for the Effects of Certain Types of Regulation.” The Company prepares its financial statements in accordance with SFAS No. 71 because (i) the Company’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 Company’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 can be charged to and collected from customers at levels that will recover the Company's costs. SFAS No. 71 requires the Company to reflect the impact of regulatory decisions in its financial statements. SFAS No. 71 requires that certain costs and/or obligations (such as incurred power and natural gas costs not currently recovered through rates, but expected to be recovered in the future) are reflected as deferred charges on the balance sheet. These costs and/or obligations are not reflected in the statement of income until the period during which 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 SFAS No. 71 with respect to all or a portion of the Company's regulated operations, the Company could be required to write off its regulatory assets. The Company could also be precluded from the future deferral 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 power and natural gas deferrals (see "Power Cost Deferrals" and "Natural Gas Cost Deferrals" below for further information), investment in exchange power (see "Investment in Exchange Power-Net" below for further information), regulatory assets for deferred income taxes (see Note 13 for further information), unamortized debt expense (see "Unamortized Debt Expense" below for further information), regulatory asset offsetting energy commodity derivative liabilities (see Note 7 for further information), demand side management programs, conservation programs and the provision for postretirement benefits. Those items without a specific line on the Consolidated Balance Sheets are included in other regulatory assets. Other regulatory assets consisted of the following as of December 31 (dollars in thousands):

	2002	2001
Regulatory asset offsetting energy commodity derivative liabilities	$ —	$157,529
Regulatory asset for postretirement benefit obligation	4,728	5,200
Demand side management and conservation programs	23,733	28,813
Other	1,274	1,218
Total	$29,735	$192,760

Deferred credits include, among other items, regulatory liabilities created when the Centralia Power Plant (Centralia) was sold and the gain on the general office building sale/leaseback which is being amortized over the life of the lease, and are included on the Consolidated Balance Sheets as other non-current liabilities and deferred credits.

Investment in Exchange Power-Net

The investment in exchange power represents the Company's previous investment in Washington Public Power Supply System Project 3 (WNP-3), a nuclear project that was terminated prior to completion. Under a settlement agreement with the Bonneville Power Administration in 1985, Avista Utilities began receiving power in 1987, for a 32.5-year period, related to its investment in WNP-3. Through a settlement agreement with the Washington Utilities and Transportation Commission (WUTC) in the Washington jurisdiction, Avista Utilities is amortizing the recoverable portion of its investment in WNP-3 (recorded as investment in exchange power) over a 32.5 year period beginning in 1987. For the Idaho jurisdiction, Avista Utilities has fully amortized the recoverable portion of its investment in exchange power.

Unamortized Debt Expense

Unamortized debt expense includes debt issuance costs that are amortized over the life of the related debt, as well as premiums paid to repurchase debt, which are amortized over the average remaining maturity of outstanding debt in accordance with regulatory accounting practices under SFAS No. 71.

Natural Gas Benchmark Mechanism

The Idaho Public Utilities Commission (IPUC), WUTC and Oregon Public Utilities Commission (OPUC) approved Avista Utilities' Natural Gas Benchmark Mechanism in 1999. The mechanism eliminated the majority of natural gas procurement operations within Avista Utilities and consolidated gas procurement operations under Avista Energy, the Company's non-regulated subsidiary. The ownership of the natural gas assets remains with Avista Utilities; however, the assets are managed by Avista Energy through an Agency Agreement. Avista Utilities continues to manage natural gas procurement for its California operations, which currently represents approximately four percent of its total natural gas therm sales.

The Natural Gas Benchmark Mechanism provides benefits to retail customers and allows Avista Energy to retain a portion of the benefits associated with asset optimization and the efficiencies gained in purchasing natural gas for

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Avista Utilities. In the first quarter of 2002, the IPUC and the OPUC approved the continuation of the Natural Gas Benchmark Mechanism and related Agency Agreement through March 31, 2005. In January 2003, the WUTC approved the continuation of the Natural Gas Benchmark Mechanism and related Agency Agreement through January 29, 2004. Hearings will be held before the WUTC during 2003 to determine whether or not the Natural Gas Benchmark Mechanism and related Agency Agreement will be extended beyond January 29, 2004.

In accordance with SFAS No. 71, profits recognized by Avista Energy on natural gas sales to Avista Utilities, including gains and losses on natural gas contracts, are not eliminated in the consolidated financial statements. This is due to the fact that costs incurred by Avista Utilities for natural gas purchases to serve retail customers and for fuel for electric generation are expected to be recovered through future retail rates.

Avista Utilities' natural gas purchases from Avista Energy totaled $114.8 million, $249.8 million and $175.9 million in 2002, 2001 and 2000, respectively. These costs are reflected as resource costs in the Consolidated Statements of Income and Comprehensive Income.

Power Cost Deferrals

Avista Utilities defers the recognition in the income statement of certain power supply costs as approved by the WUTC. Deferred power supply costs are recorded as a deferred charge on the balance sheet for future review and the opportunity for recovery through retail rates. The power supply costs deferred include certain differences between actual power supply costs incurred by Avista Utilities and the costs included in base retail rates. This difference in power supply costs primarily results from changes in short-term wholesale market prices, changes in the level of hydroelectric generation and changes in the level of thermal generation (including changes in fuel prices). Avista Utilities accrues interest on deferred power costs in the Washington jurisdiction at a rate, which is adjusted semi-annually, of 8.9 percent as of December 31, 2002. Total deferred power costs for Washington customers were $123.7 million and $140.2 million as of December 31, 2002 and 2001, respectively.

In June 2002, the WUTC issued an order that became effective July 1, 2002. The order provides for an overall rate of return of 9.72 percent and a return on equity of 11.16 percent. The order provided for no incremental rate increase to Avista Utilities' Washington electric customers above the rates in effect at that time. Rate increases previously approved by the WUTC totaling 31.2 percent (a 25 percent temporary surcharge approved in September 2001 for the recovery of deferred power costs and a 6.2 percent increase approved in March 2002) were restructured. The general increase to base retail rates was 19.3 percent (or $45.7 million in annual revenues) and the remaining 11.9 percent represents the continued recovery of deferred power costs over a period currently projected to continue into 2009.

In the June 2002 rate order, the WUTC approved the establishment of an Energy Recovery Mechanism (ERM). The ERM replaced a series of temporary deferral mechanisms that were in place in Washington since mid-2000. The ERM allows Avista Utilities to increase or decrease electric rates periodically with WUTC approval to reflect changes in power supply costs. The ERM provides for Avista Utilities to incur the cost of, or receive the benefit from, the first $9 million in annual power supply costs above or below the amount included in base retail rates. As the ERM was implemented on July 1, 2002, the Company's expense or benefit was limited to $4.5 million for 2002. Under the ERM, 90 percent of annual power supply costs exceeding or below the initial $9 million ($4.5 million for 2002) will be deferred for future surcharge or rebate to Avista Utilities' customers. The remaining 10 percent will be an expense of, or benefit to, the Company.

Avista Utilities has a power cost adjustment (PCA) mechanism in Idaho that allows it to modify electric rates periodically with IPUC approval to recover or rebate a portion of the difference between actual and allowed net power supply costs. The PCA mechanism allows for the deferral of 90 percent of the difference between actual net power supply expenses and the authorized level of net power supply expenses approved in the last Idaho general rate case. Avista Utilities accrues interest on deferred power costs in the Idaho jurisdiction at a rate, which is adjusted annually, of 2 percent as of December 31, 2002. In October 2002, the IPUC issued an order extending a 19.4 percent PCA surcharge for Idaho electric customers. The PCA surcharge will remain in effect until October 2003. The IPUC directed Avista Utilities to file a status report 60 days before the PCA surcharge expires. If review of the status report and the actual balance of deferred power costs support continuation of the PCA surcharge, the IPUC has indicated that it anticipates the PCA surcharge will be extended for an additional period. Total deferred power costs for Idaho customers were $31.5 million and $73.1 million as of December 31, 2002 and 2001, respectively.

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Natural Gas Cost Deferrals

Under established regulatory practices in each respective state, Avista Utilities is allowed to adjust its natural gas rates periodically (with appropriate regulatory approval) 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. Total deferred natural gas costs were $11.5 million and $52.7 million as of December 31, 2002 and 2001, respectively.

Deferred Revenue

In December 1998, the Company received cash proceeds of $143.4 million from a transaction in which the Company assigned and transferred certain rights under a long-term power sales contract to a funding trust. The proceeds were recorded as deferred revenue and were being amortized into revenues over the 16-year period of the long-term sales contract. Pursuant to the WUTC order in September 2001, the Company was directed to offset $53.8 million of the Washington share of the deferred revenue against deferred power costs. The IPUC order in October 2001 directed the Company to amortize the remaining Idaho share ($34.6 million) of the deferred revenue against deferred power costs over the 15-month period between October 2001 and December 2002. The balance was fully amortized as of December 31, 2002.

Reclassifications

Certain prior period amounts were reclassified to conform to current statement format. These reclassifications were made for comparative purposes and to conform to changes in accounting standards and have not affected previously reported total net income or common equity.

NOTE 2. NEW ACCOUNTING STANDARDS

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 142, "Goodwill and Other Intangible Assets" which applies to acquired intangible assets whether acquired singly, as part of a group, or in a business combination. This statement requires that goodwill not be amortized; however, goodwill for each reporting unit must be evaluated for impairment on at least an annual basis using a two-step approach. The first step used to identify potential impairment compares the estimated fair value of a reporting unit to its carrying amount, including goodwill. If the fair value of a reporting unit is less than its carrying amount, the second step of the impairment evaluation, which compares the implied fair value of goodwill to its carrying amount, is performed to determine the amount of the impairment loss, if any. This statement also provides standards for financial statement disclosures of goodwill and other intangible assets and related impairment losses. The Company adopted this statement on January 1, 2002.

In April 2002, the Company completed its transitional test of goodwill. Accordingly, the Company determined that goodwill related to Advanced Manufacturing and Development, a subsidiary of Avista Ventures included in the Other business segment, was impaired. This was due to a change in forecasted earnings based on the decline in the performance of the business. The fair value of the reporting unit was determined using the present value of projected future cash flows. The Company recorded an impairment of $4.1 million, net of taxes, as a cumulative effect of accounting change in the Consolidated Statement of Income and Comprehensive Income.

Goodwill amortization was $1.8 million, net of taxes, for 2001. Net income and basic and diluted earnings per common share would have been $14.0 million, $0.24 and $0.24, respectively, excluding goodwill amortization for 2001. Goodwill amortization was $2.2 million, net of taxes, for 2000. Net income and basic and diluted earnings per common share would have been $93.9 million, $1.54 and $1.52, respectively, excluding goodwill amortization for 2000.

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. This statement requires the recording of the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the associated costs of the asset retirement obligation will be capitalized as part of the carrying amount of the related long-lived asset. The liability will be accreted to its present value each period and the related capitalized costs will be depreciated over the useful life of the related asset. Upon retirement of the asset, the Company will either settle the retirement obligation for its recorded amount or incur a gain or loss. The adoption of this statement on January 1, 2003 did not have a material impact on the Company's financial condition or results of operations. The Company recovers certain asset retirement costs through rates charged to customers as a portion of its depreciation expense. As of December 31, 2002, the Company had estimated retirement costs of $185.4 million included in accumulated depreciation.

In June 2002, the FASB issued SFAS No. 146, “Accounting for Costs Associated with Exit or Disposal Activities” which nullifies EITF Issue No. 94-3, “Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring).” This statement requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred. Under EITF Issue No. 94-3, a liability for an exit cost was recognized at the date of an entity’s commitment to an exit plan. This statement also requires the initial measurement of the liability at fair value. This statement is effective for exit or disposal activities that are initiated after December 31, 2002. The adoption of this statement did not have any impact on the Company’s financial condition or results of operations.

In December 2002, the FASB issued SFAS No. 148, “Accounting for Stock-Based Compensation – Transition and Disclosure” which amends SFAS No. 123 “Accounting for Stock-Based Compensation.” This statement provides alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based compensation. In addition, this statement requires the disclosure of pro forma net income and earnings per common share had the Company adopted the fair value method of accounting for stock-based compensation in a more prominent place in the financial statements (Note 1). This statement also requires the disclosure of pro forma net income and earnings per common share in interim as well as annual financial statements. The alternative transition methods and annual financial statement disclosures are effective for fiscal years ending after December 15, 2002. Interim disclosures are required for periods ending after December 15, 2002. The adoption of this statement affects the Company’s disclosures. As the Company has not elected to adopt the fair value method of accounting for stock-based compensation, the adoption of this statement does not have any impact on the Company’s financial condition or results of operations.

In June 2002, the EITF reached a partial consensus on Issue No. 02-3 regarding the accounting for contracts involved in energy trading and risk management activities. The partial consensus required that all gains and losses arising from energy trading contracts (whether realized or unrealized) accounted for under EITF Issue No. 98-10 were to be presented on a net basis in the income statement beginning in the third quarter of 2002. Reclassification of all historical comparable periods was required. This applied to the activities of Avista Energy; Avista Utilities does not have energy trading contracts that were accounted for under EITF Issue No. 98-10. Avista Energy historically presented unrealized gains and losses on energy trading contracts on a net basis. However, realized contracts were presented on a gross basis for both operating revenues and resource costs. The implementation of EITF Issue 02-3 resulted in reduced operating revenues and resource costs as compared to historical periods with no impact on the Company’s net income or financial condition.

Avista Energy accounted for energy commodity trading activity in compliance with EITF Issue No. 98-10 through December 31, 2002 for contracts entered into on or prior to October 25, 2002. Under EITF 98-10, Avista Energy recognized revenue based on the change in the market value of outstanding derivative commodity sales contracts, net of future servicing costs and reserves, in addition to revenue related to settled contracts. In October 2002, the EITF rescinded Issue No. 98-10. As such, Avista Energy is required to account for energy trading contracts that meet the definition of a derivative at market value in compliance with SFAS No. 133. This applies to all existing contracts as of January 1, 2003 as well as to all new contracts entered into subsequent to October 25, 2002. Contracts not meeting the definition of a derivative are no longer accounted for at market value and include Avista Energy’s Agency Agreement with Avista Utilities, natural gas storage contracts, tolling agreements and natural gas transportation agreements. The transition from EITF Issue No. 98-10 to accrual based accounting resulted in the adjustment of the contracts that are not considered derivatives from their market value to their cost basis. Any gain or loss on contracts that are not considered derivatives will not be recognized until the contract is settled or realized. The Company anticipates that the changes will primarily affect the timing of the recognition of income or loss in earnings, and not change the underlying economics or cash flows of transactions entered into by Avista Energy. The changes could result in a significant increase in the volatility of reported earnings on a quarter-to-quarter and year-to-year basis. On January 1, 2003, Avista Energy recorded as a cumulative effect of accounting change a charge of approximately $1.2 million (net of tax) related to the transition from EITF 98-10 to SFAS No. 133.

In November 2002, the FASB issued Interpretation No. 45, “Guarantor’s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.” This interpretation clarifies the requirements of SFAS No. 5, “Accounting for Contingencies” relating to a guarantor’s accounting for, and disclosure of, the issuance of certain types of guarantees. This interpretation requires that upon issuance of a guarantee, the guarantor must recognize a liability for the fair value of the obligation it assumes under that guarantee. The initial recognition and measurement provisions of this interpretation are to be applied on a prospective basis to guarantees issued or modified subsequent to December 31, 2002 and are not expected to have a material impact on the Company's financial condition or results of operations. The disclosure requirements of this interpretation are effective for financial statements issued for periods that end after December 15, 2002. See Note 19 for disclosure of the Company's guarantees.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities." In general, a variable interest entity does not have equity investors with voting rights or it has equity investors that do not provide sufficient financial resources for the entity to support its activities. Variable interest entities are commonly referred to as special purpose entities or off-balance sheet structures; however, this FASB interpretation applies to a broader group of entities. This interpretation requires a variable interest entity to be consolidated by the primary beneficiary of that entity. The primary beneficiary is subject to a majority of the risk of loss from the variable interest entity's activities or it is entitled to receive a majority of the entity's residual returns. The interpretation also requires disclosure of variable interest entities that a company is not required to consolidate but in which it has a significant variable interest. The consolidation requirements of this interpretation apply immediately to variable interest entities created after January 31, 2003 and apply to existing entities for the first fiscal year or interim period beginning after June 15, 2003. Certain disclosure requirements apply to all financial statements issued after January 31, 2003, regardless of when the variable interest entity was established.

The application of this FASB interpretation will require the Company to consolidate WP Funding LP effective July 1, 2003. WP Funding LP is an entity that was formed for the purpose of acquiring the natural gas-fired combustion turbine generating facility in Rathdrum, Idaho (Rathdrum CT). WP Funding LP purchased the Rathdrum CT from the Company with funds provided by unrelated investors of which 97 percent represented debt and 3 percent represented equity. The Company operates the Rathdrum CT and leases it from WP Funding LP and currently makes lease payments of $4.5 million per year. The total amount of WP Funding LP debt outstanding that is not included on the Company's balance sheet was $54.5 million as of December 31, 2002. The lease term expires in February 2020; however, the current debt matures in October 2005 and will need to be refinanced at that time. Based on current information, the difference between the book value of the debt and equity of WP Funding LP and the book value of the Rathdrum CT is approximately $15.5 million ($10.1 million, net of taxes). The Company intends to request regulatory accounting orders to record this amount as a regulatory asset upon the consolidation of WP Funding LP.

NOTE 3. DISCONTINUED OPERATIONS

In September 2001, the Company reached a decision that it would dispose of substantially all of the assets of Avista Communications. In October 2001, minority shareholders of Avista Communications acquired ownership of its Montana and Wyoming operations as well as its dial-up internet access operations in Spokane, Washington and Coeur d'Alene, Idaho. In December 2001, Avista Communications completed the sale of the assets and customer accounts of its Yakima and Bellingham, Washington operations to Advanced Telcom Group, Inc. In April 2002, Avista Communications completed the transfer of voice and integrated services customer accounts in Spokane, Washington and Lewiston and Coeur d'Alene, Idaho to certain subsidiaries of XO Communications, Inc. In December 2002, the Company completed the sale of substantially all of the remaining assets of Avista Communications to FiberLink LLC. The divestiture of the operating assets of Avista Communications was substantially complete by the end of 2002. Certain liabilities of the operations remain to be settled.

Revenues for Avista Communications were $3.5 million, $11.5 million and $5.9 million in 2002, 2001 and 2000, respectively. Total assets of $21.3 million as of December 31, 2001 were comprised of $16.6 million of deferred tax assets, $3.2 million of fixed assets and $1.5 million of current assets including accounts receivable, cash, inventory and prepaid expenses.

Concurrent with the decision to dispose of Avista Communications, the Company assessed the carrying value of assets and goodwill of Avista Communications. The assets and goodwill of Avista Communications were written down to the estimated fair value based upon the planned disposal of the assets. The total charges of $58.4 million incurred in 2001 were comprised of the following: $48.2 million for asset impairment, $7.1 million for goodwill impairment and $3.1 million for exit costs and other costs to sell Avista Communications.

NOTE 4. IMPAIRMENT OF NON-OPERATING ASSETS

In 2001, the Company recorded an impairment charge related to three turbines owned by Avista Power. The Company originally planned to use the turbines in a non-regulated generation project. Due to changing market conditions the Company decided to no longer pursue the development of additional non-regulated generation projects. The Company wrote down the carrying value of the turbines to estimated fair value less selling costs. This resulted in a charge of $8.2 million for 2001 included in other income-net in the Consolidated Statements of Income and Comprehensive Income.

NOTE 5. RESTRUCTURING AND EXIT COSTS

In November 1999, Avista Energy redirected its focus away from national energy trading toward a more regional-based energy marketing and trading effort in the western United States. The downsizing plan called for the shutting down of operations in Houston and Boston during the first half of 2000 and eliminating approximately 80 positions. In the fourth quarter of 1999, Avista Energy recorded a charge of $9.3 million for expenses related to employee terminations and recorded $33.6 million of goodwill impairment. Avista Energy sold its eastern United States power book during the first quarter of 2000 for a $1.5 million loss, but did not find a buyer for its natural gas or coal contracts in the eastern United States. The remaining eastern United States natural gas contracts, primarily for transportation and storage, were managed out of the Spokane office until the last of the contracts expired in 2002. In addition to the restructuring charges previously reserved and paid, other transition costs of $6.4 million for 2000 were incurred for closing the Houston and Boston offices and phasing out operations in the eastern United States.

In the first quarter of 2000, it was announced that Pentzer would be redirecting its focus. Pentzer recorded a charge of $1.9 million for expenses related to employee terminations, which were paid during 2000.

NOTE 6. ACCOUNTS RECEIVABLE SALE

In 1997, Avista Receivables Corp. (ARC), formerly known as WWP Receivables Corp., was formed as a wholly owned, bankruptcy-remote subsidiary of the Company for the purpose of acquiring or purchasing interests in certain accounts receivable, both billed and unbilled, of the Company. On May 29, 2002, ARC, the Company and a third-party financial institution entered into a three-year agreement whereby ARC can sell without recourse, on a revolving basis, up to $100.0 million of those receivables. ARC is obligated to pay fees that approximate the purchaser’s cost of issuing commercial paper equal in value to the interests in receivables sold. On a consolidated basis, the amount of such fees is included in operating expenses of the Company. As of December 31, 2002 and 2001, $65.0 million and $75.0 million, respectively, in accounts receivables were sold.

NOTE 7. UTILITY ENERGY COMMODITY DERIVATIVE ASSETS AND LIABILITIES

SFAS No. 133, as amended by SFAS No. 138, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. It requires the recording of all derivatives as either assets or liabilities in the balance sheet measured at estimated fair value and the recognition of the unrealized gains and losses. In certain defined conditions, a derivative may be specifically designated as a hedge for a particular exposure. The accounting for derivatives depends on the intended use of the derivatives and the resulting designation.

Avista Utilities enters into forward contracts to purchase or sell energy. Under forward contracts, Avista Utilities commits to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. Certain of these forward contracts are considered derivative instruments. Avista Utilities also records derivative commodity assets and liabilities for over-the-counter and exchange-traded derivative instruments as well as certain long-term contracts. These contracts are entered into to manage Avista Utilities’ loads and resources as discussed in Note 8. In conjunction with the issuance of SFAS No. 133, the WUTC and the IPUC issued accounting orders requiring Avista Utilities to offset any derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement. The order provides for Avista Utilities to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Consolidated Statements of Income and Comprehensive Income. Such realized gains or losses are recognized in the period of settlement subject to current or future recovery in retail rates. Avista Energy accounted for derivative commodity instruments using the mark-to-market method of accounting under EITF Issue No. 98-10 through December 31, 2002, which was rescinded in October 2002 as discussed in Note 2. See Note 8 for details of Avista Energy’s disclosures of derivative commodity instruments.

Avista Utilities believes substantially all of its purchases and sales contracts for both capacity and energy qualify as normal purchases and sales under SFAS No. 133 and are not required to be recorded as derivative commodity assets and liabilities. Contracts that are not considered derivatives under SFAS No. 133 are generally accounted for at cost until they are settled unless there is a decline in the fair value of the contract that is determined to be other than temporary.

As of December 31, 2002, the utility derivative commodity asset balance was $60.3 million, the derivative commodity liability balance was $50.1 million and the offsetting net regulatory liability was $10.2 million. As of December 31, 2001, the utility derivative commodity asset balance was $1.9 million, the derivative commodity liability balance was $159.4 million and the offsetting net regulatory asset was $157.5 million. Utility derivative assets and liabilities, as well as the offsetting net regulatory asset or liability, can change significantly from period to period due to the settlement of contracts, the entering of new contracts and changes in commodity prices. The derivative commodity asset balance is included in Deferred Charges – Utility energy commodity derivative assets and the derivative commodity liability balance is included in Non-Current Liabilities and Deferred Credits – Utility energy commodity derivative liabilities on the Consolidated Balance Sheet. The offsetting net regulatory asset is included in Deferred Charges – Other regulatory assets and the offsetting net regulatory liability is included in Non-Current Liabilities and Deferred Credits – Other non-current liabilities and deferred credits on the Consolidated Balance Sheet.

Interpretations that may be issued by the Derivatives Implementation Group, a task force created to assist the FASB in answering questions that companies have in implementing SFAS No. 133, may change the conclusions that the Company has reached regarding accounting for energy contracts. As a result, the accounting treatment and financial statement impact could change in future periods.

NOTE 8. ENERGY COMMODITY TRADING

The Company’s energy-related businesses are exposed to risks relating to, but not limited to, changes in certain commodity prices and counterparty performance. In order to manage the various risks relating to these exposures, Avista Utilities utilizes electric, natural gas and related derivative commodity instruments, such as forwards, futures, swaps and options, and Avista Energy engages in the trading of such instruments. Avista Utilities and Avista Energy have policies and procedures to manage risks inherent in these activities. The Company has a Risk Management Committee, separate from the units that create such risk exposure, that is overseen by the Audit Committee of the Company’s Board of Directors, to monitor compliance with the Company’s risk management policies and procedures.

Avista Utilities

Avista Utilities sells and purchases electric capacity and energy at wholesale to and from utilities and other entities under long-term contracts having terms of more than one year. In addition, Avista Utilities engages in an ongoing process of resource optimization which involves short-term purchases and sales in the wholesale market in pursuit of an economic selection of resources to serve retail and wholesale loads. Avista Utilities makes continuing projections of (1) future retail and wholesale loads based on, among other things, forward estimates of factors such as customer usage and weather as well as historical data and contract terms and (2) resource availability based on, among other things, estimates of streamflows, generating unit availability, historic and forward market information and experience. On the basis of these continuing projections, Avista Utilities purchases and sells energy on an annual, quarterly, monthly, daily and hourly basis to match actual resources to actual energy requirements. This process includes hedging transactions.

Avista Utilities manages the impact of fluctuations in electric energy prices by establishing volume limits for the imbalance between projected loads and resources and through the use of derivative commodity instruments for hedging purposes. Any imbalance is required to remain within limits, or management action or decisions are triggered to address larger imbalance situations and manage the exposure to market risk. Avista Energy is responsible for the daily management of natural gas supplies to meet the requirements of Avista Utilities’ customers in the states of Washington, Idaho and Oregon.

In addition, Avista Utilities utilizes derivative commodity instruments for hedging price risk associated with natural gas. The Risk Management Committee has limited the types of commodity instruments Avista Utilities may use to those related to electricity and natural gas commodities and those instruments are to be used for hedging price fluctuations associated with the management of energy resources owned or controlled by Avista Utilities. The market values of natural gas derivative commodity instruments held by Avista Utilities as of December 31, 2002 and 2001, were a $24.6 million net liability and a $133.2 million net liability, respectively. The significant liability position as of December 31, 2001 was a result of forward commitments to purchase natural gas entered into during 2000 and the first part of 2001 at prices in excess of the market price for natural gas as of December 31, 2001. The decrease from December 31, 2001 to December 31, 2002 reflects the settlement of contracts during the period as well as an increase in the forward price of natural gas. Realized losses are reflected as adjustments through purchased gas cost adjustments, the ERM or the PCA mechanism.

Avista Energy

Avista Energy accounted for energy commodity trading activity in compliance with EITF Issue No. 98-10 through December 31, 2002 for contracts entered into on or prior to October 25, 2002. In October 2002, the EITF rescinded Issue No. 98-10. As such, Avista Energy is required to account for energy trading contracts that meet the definition of a derivative in compliance with SFAS No. 133 effective January 1, 2003 for all contracts entered into prior to October 25, 2002, and effective immediately for all contracts entered into subsequent to October 25, 2002. Contracts not meeting the definition of a derivative are accounted for on an accrual basis. See Note 2 for further details.

Avista Energy purchases natural gas and electricity from producers and other trading companies, and its customers include commercial and industrial end-users, electric utilities, natural gas distribution companies, and other trading companies. Avista Energy's marketing and energy risk management services are provided through the use of a variety of derivative commodity contracts to purchase or supply natural gas and electric energy at specified delivery points and at specified future dates. Avista Energy trades natural gas and electricity derivative commodity instruments on national exchanges and through other unregulated exchanges and brokers from whom these commodity derivatives are available, and therefore experiences net open positions in terms of price, volume, and specified delivery point. The open positions expose Avista Energy to the risk that fluctuating market prices may adversely impact its financial condition or results of operations. However, the net open position is actively managed with strict policies designed to limit the exposure to market risk and requires daily reporting to management of potential financial exposure.

Avista Energy measures the risk in its electric and natural gas portfolio daily utilizing a Value-at-Risk (VAR) model, monitoring its risk in comparison to established thresholds. VAR measures the expected portfolio loss under hypothetical adverse price movements, over a given time interval within a given confidence level. Avista Energy also measures its open positions in terms of volumes at each delivery location for each forward time period. The extent of open positions is included in the risk management policy and is measured with stress tests and VAR modeling.

Derivative commodity instruments sold and purchased by Avista Energy include: forward contracts, which involve physical delivery of an energy commodity; futures contracts, which involve the buying or selling of natural gas or electricity at a fixed price; over-the-counter swap agreements, which require Avista Energy to receive or make payments based on the difference between a specified price and the actual price of the underlying commodity; and options, which mitigate price risk by providing for the right, but not the requirement, to buy or sell energy-related commodities at a fixed price. Foreign currency risks are primarily related to Canadian exchange rates and are managed using standard instruments available in the foreign currency markets.

Avista Energy's trading activities are subject to mark-to-market accounting, under which changes in the market value of outstanding electric, natural gas and related derivative commodity instruments are recognized as unrealized gains or losses in the period of change. Market prices are utilized in determining the value of the electric, natural gas and related derivative commodity instruments. For natural gas commodity instruments, these market prices are generally available through three years. For electric commodity instruments, these market prices are generally available through two years. For longer-term positions and certain short-term positions for which market prices are not available, a model to estimate forward price curves is utilized. Gains and losses on electric, natural gas and related derivative commodity instruments utilized for trading are recognized in income on a current basis (the mark-to-market method) and are included in the Consolidated Statements of Income and Comprehensive Income in operating revenues on a net basis, and in the Consolidated Balance Sheets as current or non-current energy commodity assets or liabilities. Contracts in a receivable position, as well as the options held, are reported as assets. Similarly, contracts in a payable position, as well as options written, are reported as liabilities. Net cash flows are recognized in the period of settlement.

Contract Amounts and Terms Under Avista Energy's derivative instruments, Avista Energy either (i) as "fixed price payor," is obligated to pay a fixed price or a fixed amount and is entitled to receive the commodity or a fixed amount or (ii) as "fixed price receiver," is entitled to receive a fixed price or a fixed amount and is obligated to deliver the commodity or pay a fixed amount or (iii) as "index price payor," is obligated to pay an indexed price or an indexed amount and is entitled to receive the commodity or a variable amount or (iv) as "index price receiver," is entitled to receive an indexed price or amount and is obligated to deliver the commodity or pay a variable amount.

The contract or notional amounts and terms of Avista Energy's derivative commodity investments outstanding as of December 31, 2002 are set forth below (in thousands of mmBTUs and MWhs):

	Fixed Price Payor	Fixed Price Receiver	Maximum Terms in Years	Index Price Payor	Index Price Receiver	Maximum Terms in Years
Energy commodities (volumes)						
Natural gas	91,194	86,400	7	620,490	610,946	2
Electric	92,063	91,091	14	259	19	2

Contract or notional amounts reflect the volume of transactions, but do not necessarily represent the dollar amounts exchanged by the parties to the derivative commodity instruments. Accordingly, contract or notional amounts do not accurately measure Avista Energy's exposure to market or credit risks. The maximum terms in years detailed above are not indicative of likely future cash flows as these positions may be offset in the markets at any time.

Estimated Fair Value The estimated fair value of Avista Energy's derivative commodity instruments outstanding as of December 31, 2002, and the average estimated fair value of those instruments held during the year ended December 31, 2002, are set forth below (dollars in thousands):

	Estimated Fair Value as of December 31, 2002				Average Estimated Fair Value for the year ended December 31, 2002			
	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities
Natural gas	$143,730	$ 38,198	$111,763	$ 35,445	$144,090	$ 50,945	$117,236	$ 38,103
Electric	221,747	310,111	193,018	278,759	223,534	287,010	167,197	247,476
Total	$365,477	$348,309	$304,781	$314,204	$367,624	$337,955	$284,433	$285,579

The weighted average term of Avista Energy's natural gas derivative commodity instruments as of December 31, 2002 was approximately 4 months. The weighted average term of Avista Energy's electric derivative commodity instruments as of December 31, 2002 was approximately 7 months. The change in the estimated fair value position of Avista Energy's energy commodity portfolio, net of the reserves for credit and market risk for 2002 was an unrealized loss of $91.9 million and is included in the Consolidated Statements of Income and Comprehensive Income in operating revenues. The change in the fair value position for 2001 was an unrealized loss of $30.2 million. In 2000, an unrealized gain of $176.8 million was recorded.

Avista Energy reports the net margin on trading activities in operating revenues in the Consolidated Statements of Income and Comprehensive Income. The following table presents the gross amount of realized sales contracts for Avista Energy in both the dollar amount and volume of transactions for the years ended December 31:

	2002	2001	2000
Gross Realized Sales Transactions (dollars in thousands):			
Electric	$1,417,499	$3,380,058	$4,721,291
Natural gas	958,183	1,619,285	1,751,264
Other	—	1,612	58,996
Total gross settled transactions	$2,375,682	$5,000,955	$6,531,551
Gross Realized Sales Volume:			
Electric (thousands of MWhs)	40,426	47,927	105,548
Natural gas (thousands of dekatherms)	225,983	248,193	273,448

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Market Risk

Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Market risk is influenced to the extent that the performance or nonperformance by market participants of their contractual obligations and commitments affect the supply of, or demand for, the commodity.

Avista Utilities and Avista Energy manage, on a portfolio basis, the market risks inherent in their activities subject to parameters established by the Company's Risk Management Committee. Market risks are monitored by the Risk Management Committee to ensure compliance with the Company's risk management policies. Avista Utilities measures exposure to market risk through daily evaluation of the imbalance between projected loads and resources. Avista Energy measures the risk in its portfolio on a daily basis utilizing a VAR model and monitors its risk in comparison to established thresholds.

Credit Risk

Credit risk relates to the risk of loss that Avista Utilities and/or Avista Energy would incur as a result of non-performance by counterparties of their contractual obligations to deliver energy and make financial settlements. Credit risk includes not only the risk that a counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to circumstances that relate to other market participants that have a direct or indirect relationship with such counterparty. Avista Utilities and Avista Energy seek to mitigate credit risk by applying specific eligibility criteria to existing and prospective counterparties and by actively monitoring current credit exposures. These policies include an evaluation of the financial condition and credit ratings of counterparties, collateral requirements or other credit enhancements, such as letters of credit or parent company guarantees, and the use of standardized agreements that allow for the netting or offsetting of positive and negative exposures associated with a single counterparty.

Avista Energy has concentrations of suppliers and customers in the electric and natural gas industries including electric utilities, natural gas distribution companies, and other energy marketing and trading companies. In addition, Avista Energy has concentrations of credit risk related to geographic location as Avista Energy operates in the western United States and western Canada. These concentrations of counterparties and concentrations of geographic location may impact Avista Energy's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

Credit risk also involves the exposure that counterparties perceive related to performance by Avista Utilities and Avista Energy to perform deliveries and settlement of energy transactions. These counterparties may seek assurance of performance in the form of letters of credit, prepayment or cash deposits, and, in the case of Avista Energy, parent company (Avista Capital) performance guarantees. In periods of price volatility, the level of exposure can change significantly, with the result that sudden and significant demands may be made against the Company's capital resource reserves (credit facilities and cash). Avista Utilities and Avista Energy actively monitor the exposure to possible collateral calls and take steps to minimize capital requirements.

Other Operating Risks

In addition to commodity price risk, Avista Utilities' commodity positions are subject to operational and event risks including, among others, increases in load demand, transmission or transport disruptions, fuel quality specifications, forced outages at generating plants and disruptions to information systems and other administrative tools required for normal operations. Avista Utilities also has exposure to weather conditions and natural disasters that can cause physical damage to property, requiring immediate repairs to restore utility service.

NOTE 9. CASH DEPOSITS WITH AND FROM COUNTERPARTIES

Cash deposits from counterparties totaled $92.7 million and $15.7 million as of December 31, 2002 and 2001, respectively, and are included in other current liabilities on the Consolidated Balance Sheets. These funds are held by Avista Utilities and Avista Energy to mitigate the potential impact of counterparty default risk. These amounts are subject to return if conditions warrant because of continuing portfolio value fluctuations with those parties or substitution of collateral.

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Cash deposited with counterparties totaled $35.7 million and $1.5 million as of December 31, 2002 and 2001, respectively, and are included in prepayments and other current assets on the Consolidated Balance Sheets.

As is common industry practice, Avista Utilities and Avista Energy maintain margin agreements with certain counterparties. Margin calls are triggered when exposures exceed predetermined contractual limits. Price movements in electricity and natural gas can generate exposure levels in excess of these contractual limits. From time to time, margin calls are made and/or received by Avista Utilities and Avista Energy. Negotiating for collateral in the form of cash, letters of credit, or parent company performance guarantees is a common industry practice.

NOTE 10. JOINTLY OWNED ELECTRIC FACILITIES

The Company has a 50 percent ownership interest in a combined cycle natural gas-fired turbine power plant, the Coyote Springs 2 Generation Plant (Coyote Springs 2) located in northcentral Oregon. It is expected that Coyote Springs 2 will commence operations in 2003. The Company’s investment in Coyote Springs 2 was $109.0 million as of December 31, 2002. The Company’s investment in Coyote Springs 2 was held by Avista Power as of December 31, 2002 and is included in Non-utility properties and investments in the Consolidated Balance Sheet. In January 2003, the Company’s ownership interest in the plant was transferred from Avista Power to Avista Corp. to be operated as an asset of Avista Utilities. The Company’s share of related fuel costs as well as operating and maintenance expenses for plant in service will be included in the corresponding accounts in the Consolidated Statements of Income and Comprehensive Income when Coyote Springs 2 commences operations.

The Company has a 15 percent ownership interest in a twin-unit coal-fired generating facility, the Colstrip Generating Project (Colstrip) located in southeastern Montana, and provides financing for its ownership interest in the project. The Company’s share of related fuel costs as well as operating and maintenance expenses for plant in service is included in the corresponding accounts in the Consolidated Statements of Income and Comprehensive Income. The Company’s share of utility plant in service for Colstrip was $316.0 million and accumulated depreciation was $158.6 million as of December 31, 2002.

NOTE 11. PROPERTY, PLANT AND EQUIPMENT

The balances of the major classifications of property, plant and equipment are detailed in the following table as of December 31 (dollars in thousands):

	2002	2001
Avista Utilities:		
Electric production	$ 740,736	$ 691,299
Electric transmission	295,284	288,739
Electric distribution	698,757	678,448
Construction work-in-progress (CWIP) and other	85,631	119,389
Electric total	1,820,408	1,777,875
Natural gas underground storage	18,285	18,130
Natural gas distribution	430,273	414,422
CWIP and other	44,675	46,404
Natural gas total	493,233	478,956
Common plant (including CWIP)	74,751	75,912
Total Avista Utilities	2,388,392	2,332,743
Energy Trading and Marketing	142,428	128,577
Information and Technology	15,294	16,030
Other	20,611	21,117
Total	$2,566,725	$2,498,467

Equipment under capital leases at Avista Utilities totaled $0.7 million as of December 31, 2002. The associated accumulated depreciation totaled $0.1 million as of December 31, 2002. Avista Utilities did not have any property, plant and equipment under capital leases as of December 31, 2001.

Property, plant, and equipment under capital leases at Avista Capital’s subsidiaries totaled $3.3 million and $5.4 million as of December 31, 2002 and 2001, respectively. The associated accumulated depreciation totaled $2.1 million and $2.6 million as of December 31, 2002 and 2001, respectively.

NOTE 12. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company has a defined benefit 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 amounts that 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 income tax purposes. Pension fund assets are invested primarily in marketable debt and equity securities. As of December 31, 2002, the Company’s pension plan had assets with a fair value that was less than the present value of the accumulated benefit obligation under the plan. In 2002, the Company recorded an additional minimum liability for the unfunded accumulated benefit obligation of $33.4 million and an intangible asset of $6.4 million (representing the amount of unrecognized prior service cost) related to the pension plan. This resulted in a charge to other comprehensive income of $17.6 million, net of taxes of $9.4 million. The pension plan was amended effective July 1, 2002 to provide a lump sum payment option for collectively bargained employees.

The Company also has a Supplemental Executive Retirement Plan (SERP) that provides additional pension benefits to executive officers of the Company. The SERP is intended to provide benefits to executive officers whose benefits under the pension plan are reduced due to the application of Section 415 of the Internal Revenue Code of 1986 and the deferral of salary under deferred compensation plans. In 2002, the Company recorded an additional minimum liability for the unfunded accumulated benefit obligation of $0.7 million related to the SERP. In 2001, the Company recorded an additional minimum liability for the unfunded accumulated benefit obligation of $1.1 million related to the SERP. This resulted in a charge to other comprehensive income of $0.5 million and $0.7 million, net of taxes, for 2002 and 2001, respectively.

The Company provides certain health care and life insurance benefits for substantially all of its retired employees. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. The Company elected to amortize the transition obligation of $34.5 million over a period of twenty years, beginning in 1993.

The following table sets forth the pension and postretirement plan disclosures as of December 31, 2002 and 2001 and for the years ended December 31, 2002, 2001 and 2000 (dollars in thousands):

	Pension Benefits		Post-retirement Benefits	
	2002	2001	2002	2001
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 210,510	$184,636	$ 36,355	$ 32,761
Service cost	6,734	5,716	304	460
Interest cost	15,119	14,293	2,184	2,567
Plan amendment	(2,530)	—	(5,821)	—
Actuarial loss (gain)	22,243	18,582	(660)	3,267
Benefits paid	(12,229)	(11,780)	(3,091)	(2,635)
Expenses paid	(1,462)	(937)	(209)	(65)
Benefit obligation as of end of year	$ 238,385	$210,510	$ 29,062	$ 36,355
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 153,705	$175,033	$ 13,969	$ 15,196
Actual return on plan assets	(16,677)	(9,313)	(1,451)	(902)
Employer contributions	12,000	—	—	511
Benefits paid	(11,441)	(11,078)	(1,008)	(771)
Expenses paid	(1,462)	(937)	(209)	(65)
Fair value of plan assets as of end of year	$ 136,125	$153,705	$ 11,301	$ 13,969
Funded status	$(102,260)	$ (56,805)	$(17,761)	$(22,386)
Unrecognized net actuarial loss (gain)	79,812	31,144	1,425	(429)
Unrecognized prior service cost	6,366	9,726	—	—
Unrecognized net transition obligation/(asset)	(2,671)	(3,757)	9,788	16,865
Accrued benefit cost	(18,753)	(19,692)	(6,548)	(5,950)
Additional minimum liability	(35,303)	(1,139)	—	—
Accrued benefit liability	$ (54,056)	$ (20,831)	$ (6,548)	$ (5,950)

	Pension Benefits		Post-retirement Benefits	
	2002	2001	2002	2001
Assumptions as of December 31				
Discount rate	6.75%	7.25%	6.75%	7.25%
Expected long-term return on plan assets	8.00%	9.00%	8.00%	9.00%
Rate of compensation increase	5.00%	5.00%		
Medical cost trend pre-age 65 – initial			9.00%	9.00%
Medical cost trend pre-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2007	2003
Medical cost trend post-age 65 – initial			10.00%	12.00%
Medical cost trend post-age 65 – ultimate			6.00%	6.00%
Ultimate medical cost trend year post-age 65			2007	2004

	2002	2001	2000	2002	2001	2000
Components of net periodic benefit cost:						
Service cost	$ 6,734	$ 5,716	$ 5,372	$ 304	$ 460	$ 601
Interest cost	15,119	14,293	13,412	2,184	2,567	2,407
Expected return on plan assets	(12,311)	(15,254)	(16,243)	(1,064)	(1,311)	(1,372)
Transition (asset)/obligation recognition	(1,086)	(1,086)	(1,086)	1,256	1,534	1,534
Amortization of prior service cost	831	989	1,548	—	—	—
Net gain recognition	1,021	139	(858)	—	(52)	(300)
Net periodic benefit cost	$ 10,308	$ 4,797	$ 2,145	$ 2,680	$ 3,198	$ 2,870

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. 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, 2002 by $2.0 million and the service and interest cost by $0.2 million. A one-percentage-point decrease in the assumed health care cost trend rate for each year would decrease the accumulated postretirement benefit obligation as of December 31, 2002 by $1.7 million and the service and interest cost by $0.2 million.

The Company has a salary deferral 401(k) plan that is a defined contribution plan and covers substantially all employees. Employees can make contributions to their respective accounts in the 401(k) plan on a pre-tax basis up to the maximum amount permitted by law. The Company matches a portion of the salary deferred by each participant according to the schedule in the 401(k) plan. Employer matching contributions of $3.4 million, $3.5 million, $3.3 million were expensed in 2002, 2001 and 2000, respectively.

NOTE 13. ACCOUNTING FOR INCOME TAXES

As of December 31, 2002 and 2001, the Company had net regulatory assets of $139.1 million and $149.0 million, respectively, related to the probable recovery of certain deferred tax liabilities from customers through future rates.

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and tax credit carryforwards. The net deferred income tax liability consisted of the following as of December 31 (dollars in thousands):

	2002	2001
Deferred tax assets:		
Allowance for doubtful accounts	$16,343	$17,431
Reserves not currently deductible	15,750	11,071
Contributions in aid of construction	9,709	9,176
Deferred compensation	4,112	4,481
Centralia sale regulatory liability	2,954	3,415
Unfunded accumulated benefit obligation	9,736	399
Other	7,172	9,544
Total deferred tax assets	65,776	55,517

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	2002	2001
Deferred tax liabilities:		
Differences between book and tax basis of utility plant	364,827	367,406
Power and natural gas deferrals	58,081	88,323
Unrealized energy commodity gains	34.231	66,401
Power exchange contract	44,533	34,444
Demand side management programs	5,064	5,679
Loss on reacquired debt	8,781	4,696
Other	4,406	5,996
Total deferred tax liabilities	519,923	572,945
Net deferred tax liability	$454,147	$517,428

The realization of deferred tax assets is dependent upon the ability to generate taxable income in future periods. The Company evaluated available evidence supporting the realization of its deferred tax assets and determined it is more likely than not that deferred tax assets will be realized.

A reconciliation of federal income taxes derived from statutory federal tax rates (35 percent in 2002, 2001 and 2000) applied to pre-tax income from continuing operations as set forth in the accompanying Consolidated Statements of Income and Comprehensive Income is as follows for the years ended December 31 (dollars in thousands):

	2002	2001	2000
Federal income taxes at statutory rates	$ 22,506	$ 32,897	$ 62,319
Increase (decrease) in tax resulting from:			
Accelerated tax depreciation	5,166	5,849	4,835
State income tax expense	2,348	(8,870)	3,712
Prior year audit adjustments	—	(395)	72
Other-net	(26)	4,905	6,060
Total income tax expense	$ 29,994	$ 34,386	$ 76,998
Income Tax Expense Consisted of the Following:			
Federal taxes currently provided	$ 70,281	$(44,755)	$ (4,839)
Deferred federal income taxes	(40,287)	79,141	81,837
Total income tax expense	$ 29,994	$ 34,386	$ 76,998
Income Tax Expense by Business Segment:			
Avista Utilities	$ 32,137	$ 20,177	$ (1,990)
Energy Trading and Marketing	12,311	32,489	95,266
Information and Technology	(7,144)	(11,977)	(10,138)
Other	(7,310)	(6,303)	(6,140)
Total income tax expense	$ 29,994	$ 34,386	$ 76,998

NOTE 14. ENERGY PURCHASE CONTRACTS

The Company has contracts related to the purchase of fuel for thermal generation, natural gas and hydroelectric power. The termination dates of the contracts range from one month to the year 2044. 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. Total expenses for power purchased, natural gas purchased, fuel for generation and other fuel costs were $382.4 million, $1,054.2 million and $1,312.7 million in 2002, 2001 and 2000, respectively. The following table details future contractual commitments for power resources (including transmission contracts) and natural gas resources (including transportation contracts) (dollars in thousands):

	2003	2004	2005	2006	2007	Thereafter	Total
Power resources	$194,873	$118,775	$ 65,349	$ 64,580	$ 66,476	$506,472	$1,016,525
Natural gas resources	195,580	171,470	82,393	48,175	48,172	385,375	931,165
Total	$390,453	$290,245	$147,742	$112,755	$114,648	$891,847	$1,947,690

All of the energy purchase contracts were entered into as part of Avista Utilities' obligation to serve its retail natural gas and electric customers' energy requirements. As a result, these costs are generally recovered either through base retail rates or adjustments to retail rates as part of the power and natural gas cost deferral and recovery mechanisms.

In addition, the Company has operational agreements, settlements and other contractual obligations with respect to its generation, transmission and distribution facilities. The expenses associated with these agreements are reflected as operation and maintenance expenses in the Consolidated Statements of Income and Comprehensive Income. The following table details future contractual commitments with respect to these agreements (dollars in thousands):

	2003	2004	2005	2006	2007	Thereafter	Total
Contractual obligations	$10,345	$12,406	$12,405	$12,406	$12,405	$185,353	$245,320

The Company has fixed contracts with certain Public Utility Districts (PUD) to purchase portions of the output of certain generating facilities. Although the Company has no investment in the PUD generating facilities, the fixed contracts obligate the Company to pay certain minimum amounts (based in part on the debt service requirements of the PUD) 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 resource costs in the Consolidated Statements of Income and Comprehensive Income. Expenses under these PUD contracts for 2002, 2001 and 2000, were $7.8 million, $7.4 million and $7.5 million, respectively.

Information as of December 31, 2002, pertaining to these PUD contracts is summarized in the following table (dollars in thousands):

	Company's Current Share of					
	Output	Kilowatt Capability	Annual Costs (1)	Debt Service Costs (1)	Bonds Outstanding	Expira-tion Date
Chelan County PUD:						
Rocky Reach Project	2.9%	37,000	$1,842	$ 623	$ 4,053	2011
Douglas County PUD:						
Wells Project	3.5	30,000	1,100	587	5,465	2018
Grant County PUD:						
Priest Rapids Project	6.1	55,000	1,768	910	9,662	2040
Wanapum Project	8.2	75,000	3,096	1,754	12,153	2040
Totals		197,000	$7,806	$3,874	$31,333	

(1) 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 2002. Debt service costs are included in annual costs.

The estimated aggregate amounts of required minimum payments (the Company’s share of existing debt service costs) under these PUD contracts are as follows (dollars in thousands):

	2003	2004	2005	2006	2007	Thereafter	Total
Minimum payments	$4,277	$3,249	$3,402	$2,759	$2,887	$22,041	$38,615

In addition, the Company will be required to pay its proportionate share of the variable operating expenses of these projects.

Avista Energy has contractual commitments to purchase energy commodities in future periods. The following table details future contractual commitments for Avista Energy’s physical and financial energy contracts (dollars in thousands):

	2003	2004	2005	2006	2007	Thereafter	Total
Physical contracts	$ 935,954	$323,700	$206,400	$188,174	$126,028	$393,106	$2,173,362
Financial contracts	960,700	89,008	2,505	11,842	—	—	1,064,055
Total	$1,896,654	$412,708	$208,905	$200,016	$126,028	$393,106	$3,237,417

Avista Energy also has sales commitments related to energy commodities in future periods.

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NOTE 15. LONG-TERM DEBT

The following details the interest rate and maturity dates of Secured and Unsecured Medium-Term Notes outstanding as of December 31 (dollars in thousands):

	Secured Medium-Term Notes			Unsecured Medium-Term Notes		
Maturity Year	Interest Rate	2002	2001	Interest Rate	2002	2001
2002	—	$ —	$ *	—	$ —	$ *
2003	6.25%	15,000	15,000	6.75%-9.13%	56,250	190,000
2004	—	—	—	7.42%	30,000	30,000
2005	6.39%-6.68%	29,500	29,500	—	—	—
2006	7.89%-7.90%	30,000	30,000	8.14%	8,000	8,000
2007	—	—	—	5.99%-7.94%	26,000	26,000
2008	6.89%-6.95%	20,000	20,000	6.06%	25,000	25,000
2010	6.67%-6.90%	10,000	10,000	8.02%	25,000	25,000
2012	7.37%	7,000	7,000	8.05%	12,000	12,000
2018	7.26%-7.45%	27,500	27,500	—	—	—
2022	—	—	—	8.15%-8.23%	10,000	10,000
2023	7.18%-7.54%	24,500	24,500	7.99%	5,000	5,000
2028	—	—	—	6.37%-6.88%	35,000	45,000
Total		$163,500	$163,500		$232,250	$376,000

* In 2001, the Company legally defeased $50.0 million of Medium-Term Notes scheduled to mature in 2002.

During 2002, the Company repurchased $133.8 million of Medium-Term Notes scheduled to mature in 2003, $59.8 million of Unsecured Senior Notes scheduled to mature in 2008 and $10.0 million of Medium-Term Notes scheduled to mature in 2028. In accordance with regulatory accounting practices, total net premiums paid to repurchase debt were $9.5 million and are being amortized over the average remaining maturity of outstanding debt.

In addition to the required maturities documented in the table above, the Company has sinking fund requirements of $3.1 million in 2003, $3.0 million in each of 2004 and 2005, $2.7 million in 2006 and $2.4 million in 2007. Under its Mortgage and Deed of Trust, the Company's sinking fund requirements may be met by certification of property additions at the rate of 143 percent of requirements. All of the Company's utility plant is subject to the lien of the Mortgage and Deed of Trust securing outstanding First Mortgage Bonds.

In April 2001, the Company issued $400.0 million of 9.75 percent Senior Notes due in 2008. In December 2001, the Company issued $150.0 million of 7.75 percent First Mortgage Bonds due in 2007.

As of December 31, 2002, the Company had remaining authorization to issue up to $317.0 million of Unsecured Medium-Term Notes.

Under various financing agreements, the Company is restricted as to the amount of additional First Mortgage Bonds that it can issue. As of December 31, 2002, the Company could issue $109.4 million of additional First Mortgage Bonds under the most restrictive of these financing agreements.

In September 1999, $83.7 million of Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project), Series 1999A due 2032 and Series 1999B due 2034 were issued by the City of Forsyth, Montana. The proceeds of the bonds were utilized to refund the $66.7 million of 7.13 percent First Mortgage Bonds due 2013 and the $17.0 million of 7.40 percent First Mortgage Bonds due 2016. The Series 1999A and Series 1999B Bonds are backed by an insurance policy issued by AMBAC Assurance Corporation. In January 2002, the interest rate on the bonds was fixed for a period of seven years at a rate of 5.00 percent for Series 1999A and 5.13 percent for Series 1999B.

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Other long-term debt consisted of the following items as of December 31 (dollars in thousands):

	2002	2001
Notes payable	$ —	$ 688
Capital lease obligations	1,618	2,101
Subsidiary total debt	1,618	2,789
Less: current portion	651	1,827
Other long-term debt	$ 967	$ 962

NOTE 16. SHORT-TERM BORROWINGS

As of December 31, 2002, the Company maintained a committed line of credit with various banks in the total amount of $225.0 million that expires on May 20, 2003. The Company may have up to $50.0 million in letters of credit outstanding under this committed line of credit. As of December 31, 2002 and 2001, there were $14.3 million and $13.9 million of letters of credit outstanding, respectively. The Company pays commitment fees of up to 0.2 percent per annum on the average daily unused portion of the credit agreement, and utilization fees of up to 0.5 percent.

The committed line of credit agreement contains customary covenants and default provisions, including covenants not to permit the ratio of “consolidated total debt” to “consolidated total capitalization” of Avista Corp. to be greater than 65 percent at the end of any fiscal quarter. As of December 31, 2002, the Company was in compliance with this covenant with a ratio of 54.3 percent. The committed line of credit also has a covenant requiring the ratio of “earnings before interest, taxes, depreciation and amortization” to “interest expense” of Avista Utilities for the year ending December 31, 2002 to be greater than 1.6 to 1. As of December 31, 2002, the Company was in compliance with this covenant with a ratio of 2.04 to 1.

The Company had a commercial paper program that also provided for fixed-term loans during 2000 and 2001. None of these agreements were in place as of December 31, 2002 and 2001.

Balances and interest rates of bank borrowings under these arrangements were as follows as of and for the years ended December 31 (dollars in thousands):

	2002	2001	2000
Balance outstanding at end of period:			
Fixed-term loans	$ —	$ —	$ —
Commercial paper	—	—	11,160
Revolving credit agreement	30,000	55,000	152,000
Maximum balance outstanding during the period:			
Fixed-term loans	$ —	$ —	$ 80,000
Commercial paper	—	11,160	36,900
Revolving credit agreement	90,000	223,000	185,000
Average balance outstanding during the period:			
Fixed-term loans	$ —	$ —	$ 19,538
Commercial paper	—	558	16,833
Revolving credit agreement	47,027	108,996	84,255
Average interest rate during the period:			
Fixed-term loans	—%	—%	6.70%
Commercial paper	—	7.80	6.82
Revolving credit agreement	3.59	5.95	7.26
Average interest rate at end of period:			
Fixed-term loans	—%	—%	—%
Commercial paper	—	—	7.63
Revolving credit agreement	3.39	5.42	7.55

As of December 31, 2002, Avista Energy and its subsidiary, Avista Energy Canada, Ltd., as co-borrowers, had a credit agreement with a group of banks in the aggregate amount of $110.0 million, expiring June 30, 2003. This credit agreement may be terminated by the banks at any time and all extensions of credit under the agreement are payable upon demand, in either case at the lenders’ sole discretion. This agreement also provides, on an uncommitted basis, for the issuance of letters of credit to secure contractual obligations to counterparties. This facility is guaranteed by Avista Capital and secured by Avista Energy's assets. The maximum amount of credit extended by the banks for the issuance of letters of credit is the subscribed amount of the facility less the amount of outstanding cash advances, if any. The maximum amount of credit extended by the banks for cash advances is $30.0 million. No cash advances were outstanding as of December 31, 2002. Letters of credit in the aggregate amount of $17.4 million were outstanding as of December 31, 2002. Under a similar credit facility that expired in June 2002, there were no cash advances outstanding and $39.6 million in letters of credit were outstanding as of December 31, 2001.

The Avista Energy credit agreement contains customary covenants and default provisions, including covenants to maintain "minimum net working capital" and "minimum net worth", as well as a covenant limiting the amount of indebtedness which the co-borrowers may incur. Avista Energy was in compliance with the covenants of its credit agreement as of December 31, 2002. Covenants in Avista Energy's credit agreement also restrict the amount of cash dividends that can be distributed to Avista Capital and ultimately to Avista Corp. During 2002, Avista Energy paid $116.4 million in dividends to Avista Capital.

In October 2001, Avista Capital entered into a one-year $20 million promissory note collateralized by certain receivables. The note was extended in October 2002 and paid off during December 2002.

NOTE 17. INTEREST RATE SWAP AGREEMENTS

In order to lower interest payments during a period of declining interest rates, Avista Corp. entered into an interest rate swap agreement effective July 17, 2002 and terminating on June 1, 2008. This interest rate swap agreement effectively changes the interest rate on $25 million of Unsecured Senior Notes from a fixed rate of 9.75 percent to a variable rate based on LIBOR. This interest rate swap agreement is designated as a fair value hedge, which hedges the variability of the fair value of the long-term debt attributable to interest rate risk. This interest rate swap agreement meets the conditions of a highly effective fair value hedge in accordance with SFAS No. 133. As such, this hedge is accounted for by recording the fair value of the interest rate swap on the balance sheet as either an asset or liability with a corresponding offset recorded to mark the Unsecured Senior Notes to fair value. The fair value of the interest rate swap was a $1.4 million asset as of December 31, 2002, which is included in other deferred charges in the Consolidated Balance Sheet.

Rathdrum Power, LLC (RP LLC), an unconsolidated entity that is 49 percent owned by Avista Power, operates a 270 MW natural gas-fired combustion turbine plant in northern Idaho (Lancaster Project). As of December 31, 2002, RP LLC had $118.7 million of debt outstanding that is not included in the consolidated financial statements of the Company. There is no recourse to the Company with respect to this debt. RP LLC has entered into two interest rate swap agreements, maturing in 2006, to manage the risk that changes in interest rates may affect the amount of future interest payments. RP LLC agreed to pay fixed rates of interest with the differential paid or received under the interest rate swap agreements recognized as an adjustment to interest expense. These interest rate swap agreements are considered hedges against fluctuations in future cash flows associated with changes in interest rates in accordance with SFAS No. 133. The fair value of the interest rate swap agreements was determined by reference to market values obtained from various third party sources. Avista Power's 49 percent ownership interest in RP LLC is accounted for under the equity method of accounting. The effect on the financial statements for 2002 was a $1.3 million unrealized loss recorded as other comprehensive loss and a corresponding decrease in non-utility property and investments in the Consolidated Balance Sheet.

NOTE 18. LEASES

The Company has multiple lease arrangements involving various assets, with minimum terms ranging from one to twenty-five years and expiration dates from 2003 to 2020. The Company's most significant leased assets include the Rathdrum CT and the corporate office building. See Note 2 for a change in accounting with respect to the Rathdrum CT that will become effective July 1, 2003. Certain lease arrangements require the Company, upon the occurrence of specified events, to purchase the leased assets. The Company's management believes the likelihood of the occurrence of the specified events under which the Company could be required to purchase the leased assets is remote. Rental expense under operating leases for the years ended December 31, 2002, 2001 and 2000 was $21.7 million, $19.8 million and $16.2 million, respectively.

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Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year as of December 31, 2002 were as follows (dollars in thousands):

Year ending December 31:	2003	2004	2005	2006	2007	Thereafter	Total
Minimum payments required	$15,132	$13,117	$8,834	$8,163	$7,314	$65,515	$118,075

The payments under the Avista Corp. capital leases are $0.2 million in each of 2003, 2004 and 2005, and $0.1 million in 2006.

The payments under the Avista Capital subsidiaries' capital leases are $0.7 million in 2003, $0.3 million in 2004 and $0.1 million in 2005.

NOTE 19. GUARANTEES

The $110.0 million credit agreement of Avista Energy and its subsidiary, Avista Energy Canada, Ltd., as co-borrowers, is guaranteed by Avista Capital and secured by Avista Energy's assets. This credit agreement expires on June 30, 2003; however, it may be terminated by the banks at any time and all extensions of credit under the agreement are payable upon demand, in either case at the lenders' sole discretion. This agreement also provides, on an uncommitted basis, for the issuance of letters of credit to secure contractual obligations to counterparties. No cash advances were outstanding as of December 31, 2002. Letters of credit in the aggregate amount of $17.4 million were outstanding as of December 31, 2002. Under a similar credit facility that was guaranteed by Avista Capital that expired in June 2002, there were no cash advances outstanding and $39.6 million in letters of credit were outstanding as of December 31, 2001.

In the course of the energy trading business, Avista Capital provides guarantees to other parties with whom Avista Energy may be doing business. The face value of all performance guarantees issued by Avista Capital for energy trading contracts at Avista Energy was $451.7 million and $1.2 billion as of December 31, 2002 and 2001, respectively. At any point in time, Avista Capital is only liable for the outstanding portion of the guarantee, which was $64.6 million and $91.6 million as of December 31, 2002 and 2001, respectively. Most guarantees do not have set expiration dates; however, either party may terminate the guarantee at any time with minimal written notice.

Avista Power, through its equity investment in RP LLC, is a 49 percent owner of the Lancaster Project, which commenced commercial operation in September 2001. Commencing with commercial operations, all of the output from the Lancaster Project is contracted to Avista Energy for 25 years through a Power Purchase Agreement. Avista Corp. has guaranteed the Power Purchase Agreement with respect to the performance of Avista Energy.

NOTE 20. PREFERRED STOCK-CUMULATIVE

On September 15, 2002, the Company made a mandatory redemption of 17,500 shares of preferred stock for $1.75 million. On September 15, 2003, 2004, 2005 and 2006, the Company must redeem 17,500 shares at $100 per share plus accumulated dividends through a mandatory sinking fund. As such, redemption requirements are $1.75 million in each of the years 2003 through 2006. The 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. Upon involuntary liquidation, all preferred stock will be entitled to $100 per share plus accrued dividends.

NOTE 21. CONVERTIBLE PREFERRED STOCK

In December 1998, as part of a dividend restructuring plan, the Company issued 1,540,460 shares of its $12.40 Convertible Preferred Stock, Series L (Series L Preferred Stock), in exchange for 15,404,595 shares of common stock, on the basis of a one-tenth interest in one share of preferred stock for each share of common stock. The Series L Preferred Stock had a liquidation preference of $182.8125 per share.

During 1999, the Company repurchased the equivalent of 32,250 shares of the Series L Preferred Stock. In February 2000, the Company exercised its option to convert all the remaining outstanding shares of Series L Preferred Stock into common stock. One share of Series L Preferred Stock equaled 10 depositary shares, also known as RECONS (Return-Enhanced Convertible Securities). The RECONS were also converted into common stock on the same conversion date. Each of the RECONS was converted into the following: 0.7205 shares of common stock, representing the optional conversion price; plus 0.0361 shares of common stock, representing the optional conversion premium; plus the right to receive $0.21 in cash, representing an amount equivalent to accumulated and unpaid dividends up until, but excluding, the conversion date. Cash payments were made in lieu of fractional shares.

NOTE 22. COMPANY-OBLIGATED MANDATORILY REDEEMABLE PREFERRED TRUST SECURITIES

In 1997, Avista Capital I, a business trust, issued $60.0 million of Preferred Trust Securities with an annual distribution rate of 7.875 percent. Concurrent with the issuance of the Preferred Trust Securities, Avista Capital I issued $1.9 million of Common Trust Securities to the Company. The sole assets of Avista Capital I are the Company's 7.875 percent Junior Subordinated Deferrable Interest Debentures, Series A, with a principal amount of $61.9 million. These debt securities may be redeemed at the Company's option on or after January 15, 2002 and mature January 15, 2037. The Company has not redeemed any of these Preferred Trust Securities as of December 31, 2002.

In 1997, Avista Capital II, a business trust, issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly. The annual distribution rate paid during 2002 ranged from 2.30 percent to 2.96 percent. As of December 31, 2002, the annual distribution rate was 2.30 percent. Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $1.5 million of Common Trust Securities to the Company. The sole assets of Avista Capital II are the Company's Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million. These debt securities may be redeemed at the Company's option on or after June 1, 2007 and mature June 1, 2037. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities.

The Company has guaranteed the payment of distributions on, and redemption price and liquidation amount in respect of, the Preferred Trust Securities to the extent that Avista Capital I and Avista Capital II have funds available for such payments from the respective debt securities. Upon maturity or prior redemption of such debt securities, the Trust Securities will be mandatorily redeemed. The Consolidated Statements of Capitalization reflect only $100.0 million of Preferred Trust Securities as of December 31, 2002 and 2001 as all intercompany transactions have been eliminated.

NOTE 23. FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value of the Company's long-term debt (including current-portion, but excluding notes payable and other) as of December 31, 2002 and 2001 was estimated to be $1,001.2 million, or 103 percent of the carrying value, and $1,160.2 million, or 99 percent of the carrying value, respectively. The fair value of the Company's mandatorily redeemable preferred stock as of December 31, 2002 and 2001 was estimated to be $29.3 million, or 88 percent of the carrying value, and $17.5 million, or 50 percent of the carrying value, respectively. The fair value of the Company's preferred trust securities as of December 31, 2002 and 2001 was estimated to be $89.6 million, or 90 percent of the carrying value, and $84.6 million, or 85 percent of the carrying value, respectively. These estimates were based on available market information.

NOTE 24. 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 $14.1 million. 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 ($4.1 million as of December 31, 2002) 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 2002, the cost recorded for the Plan was $6.0 million. 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 $0.5 million, $1.6 million and $0.1 million, respectively during 2002.

In May 1999, the Company's Board of Directors authorized the Company to repurchase in the open market or through privately negotiated transactions up to an aggregate of 10 percent of its common stock and common stock equivalents over the next two years. The repurchased shares return to the status of authorized but unissued shares. During 1999 and 2000, the Company repurchased approximately 4.8 million common shares and 322,500 shares of Return-Enhanced Convertible Securities (equivalent to 32,250 shares of Convertible Preferred Stock, Series L). The combined repurchases of these two securities represented 9 percent of outstanding common stock and common stock equivalents. No common shares were repurchased during 2001 and 2002.

In November 1999, the Company adopted a shareholder rights plan pursuant to which holders of common stock outstanding on February 15, 1999, or issued thereafter, were 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 one-hundredth of a share of preferred stock of the Company, without par value, at a purchase price of $70, subject to certain adjustments, regulatory approval and other specified conditions. The Rights will be exercisable only if a person or group acquires 10 percent or more of the outstanding shares of common stock or commences a tender or exchange offer, the consummation of which would result in the beneficial ownership by a person or group of 10 percent or more of the outstanding shares of common stock. Upon any such acquisition, each Right will entitle its holder to purchase, at the purchase price, that number of shares of common stock or preferred stock of the Company (or, in the case of a merger of the Company into another person or group, common stock of the acquiring person or group) that has a market value at that time equal to twice the purchase price. In no event will the Rights be exercisable by a person that has acquired 10 percent or more of the Company's common stock. The Rights may be redeemed, at a redemption price of $0.01 per Right, by the Board of Directors of the Company at any time until any person or group has acquired 10 percent or more of the common stock. The Rights expire on March 31, 2009. This plan replaced a similar shareholder rights plan that expired in February 2000.

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

In March 2000, the Company began issuing shares of its common stock to the Employee Investment Plan rather than having the Plan purchase shares of common stock on the open market. In the fourth quarter of 2000, the Company also began issuing new shares of common stock for the Dividend Reinvestment and Stock Purchase Plan. During 2002, 2001 and 2000, a total of 408,799, 332,861 and 125,636 shares of common stock were issued, respectively, to these plans.

NOTE 25. EARNINGS PER COMMON SHARE

In February 2000, all outstanding shares of Series L Preferred Stock were converted into 11,410,047 shares of common stock. The weighted-average number of shares of common stock outstanding during 2000 related to the converted shares was 9,975,997. The cost of converting the Series L Preferred Stock into common stock totaled $21.3 million during the first quarter of 2000, with $18.1 million representing the optional conversion premium and $3.2 million attributable to the regular dividend on the preferred stock.

The following table presents the computation of basic and diluted earnings per common share for the years ended December 31 (in thousands, except per share amounts):

	2002	2001	2000
Numerator:			
Income from continuing operations	$34,310	$ 59,605	$101,055
Income (loss) from discontinued operations	1,145	(47,449)	(9,376)
Net income before cumulative effect of accounting change	35,455	12,156	91,679
Cumulative effect of accounting change	(4,148)	—	—
Net income	31,307	12,156	91,679
Deduct: Preferred stock dividend requirements	2,402	2,432	23,735
Income available for common stock	$28,905	$ 9,724	$ 67,944
Denominator:			
Weighted-average number of common shares outstanding-basic	47,823	47,417	45,690
Effect of dilutive securities:			
Restricted stock	2	5	101
Stock options	49	13	312
Weighted-average number of common shares outstanding-diluted	47,874	47,435	46,103

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	2002	2001	2000
Earnings per common share, basic:			
Earnings per common share from continuing operations	$ 0.67	$ 1.21	$ 1.69
Earnings (loss) per common share from discontinued operations	0.02	(1.00)	(0.20)
Earnings per common share before cumulative effect of accounting change	0.69	0.21	1.49
Loss per common share from cumulative effect of accounting change	(0.09)	—	—
Total earnings per common share, basic	$ 0.60	$ 0.21	$ 1.49
Earnings per common share, diluted:			
Earnings per common share from continuing operations	$ 0.67	$ 1.20	$ 1.67
Earnings (loss) per common share from discontinued operations	0.02	(1.00)	(0.20)
Earnings per common share before cumulative effect of accounting change	0.69	0.20	1.47
Loss per common share from cumulative effect of accounting change	(0.09)	—	—
Total earnings per common share, diluted	$ 0.60	$ 0.20	$ 1.47

NOTE 26. INFORMATION AND TECHNOLOGY SEGMENT INFORMATION

The Information and Technology line of business includes the results of Avista Advantage and Avista Labs. Additional financial information for each of these separate companies is provided as follows for the years ended December 31 (dollars in thousands):

	2002	2001	2000
Avista Advantage			
Operating Revenues	$ 16,911	$ 13,151	$ 4,971
Loss From Operations (pre-tax)	(6,363)	(15,098)	(14,482)
Net Loss	(4,253)	(10,748)	(11,022)
Avista Labs			
Operating Revenues	719	664	761
Loss From Operations (pre-tax)	(12,455)	(14,774)	(11,942)
Net Loss	(7,864)	(8,636)	(8,010)

NOTE 27. STOCK COMPENSATION PLANS

Avista Corp.

In 1998, the Company adopted and shareholders approved an incentive compensation plan, the Long-Term Incentive Plan (1998 Plan). Under the 1998 Plan, certain key employees, directors and officers of the Company and its subsidiaries may be granted stock options, stock appreciation rights, stock awards (including restricted stock) and other stock-based awards and dividend equivalent rights. The Company has available a maximum of 2.5 million shares of its common stock for grant under the 1998 Plan. The shares issued under the 1998 Plan are purchased by the trustee on the open market. Beginning in 2000, non-employee directors began receiving options under this plan.

In 2000, the Company adopted a Non-Officer Employee Long-Term Incentive Plan (2000 Plan), which was not required to be approved by shareholders. The provisions of the 2000 Plan are essentially the same as those under the 1998 Plan, except for the exclusion of directors and executive officers of the Company. The Company has available a maximum of 2.5 million shares of its common stock for grant under the 2000 Plan.

The Company accounts for stock based compensation using APB No. 25, “Accounting for Stock Issued to Employees,” which requires the recognition of compensation expense on the excess, if any, of the market price of the stock at the date of grant over the exercise price of the option. As the exercise price for options granted under the 1998 Plan and the 2000 Plan was equal to the market price at the date of grant, there was no compensation expense recorded by the Company. SFAS No. 123, “Accounting for Stock-Based Compensation,” requires the disclosure of pro forma net income and earnings per common share had the Company adopted the fair value method of accounting for stock options. Under this statement, the fair value of stock-based awards is calculated with option pricing models. These models require the use of subjective assumptions, including stock price volatility, dividend yield, risk-free interest rate and expected time to exercise. The fair value of options is estimated on the date of grant using the Black-Scholes option-pricing model.

As of December 31, 2002, there were 2.3 million shares available for future stock grants under the 1998 Plan and the 2000 Plan.

The following summarizes stock options activity under the 1998 Plan and the 2000 Plan for the years ended December 31:

	2002	2001	2000
Number of shares under stock options:			
Options outstanding at beginning of year	2,440,475	1,843,900	1,360,325
Options granted	569,800	781,900	623,200
Options exercised	—	(2,750)	(44,975)
Options canceled	(325,925)	(182,575)	(94,650)
Options outstanding at end of year	2,684,350	2,440,475	1,843,900
Options exercisable at end of year	1,192,775	883,075	581,025
Weighted average exercise price:			
Options granted	$ 10.51	$ 12.43	$ 23.03
Options exercised	—	$ 17.96	$ 18.53
Options canceled	$ 19.88	$ 19.22	$ 18.15
Options outstanding at end of year	$ 15.69	$ 17.49	$ 19.81
Options exercisable at end of year	$ 18.28	$ 19.28	$ 18.72
Weighted average fair value of options granted during the year	$ 3.43	$ 5.54	$ 12.02
Principal assumptions used in applying the Black-Scholes model:			
Risk-free interest rate	3.25%-4.96%	4.05%-5.13%	5.87%-6.87%
Expected life, in years	7	7	7
Expected volatility	47.13%	60.80%	58.47%
Expected dividend yield	4.61%	3.93%	2.34%

Information with respect to options outstanding and options exercisable as of December 31, 2002 was as follows:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)	Number of Shares	Weighted Average Exercise Price
$10.17-$11.68	542,800	$10.25	9.8	—	$ —
$11.69-$14.61	694,600	11.80	8.9	173,650	11.80
$14.62-$17.53	587,600	17.16	6.7	405,275	17.26
$17.54-$20.45	329,875	18.75	5.5	316,775	18.70
$20.46-$23.37	494,275	22.56	7.5	267,475	22.58
$26.29-$29.22	35,200	27.19	5.5	29,600	26.95
Total	2,684,350	$15.69	7.9	1,192,775	$18.28

Avista Capital Companies

Certain subsidiaries of Avista Capital have employee stock incentive plans under which certain employees and directors of the Company and the subsidiaries are granted options to purchase subsidiary shares at prices no less than the fair market value on the date of grant. Options outstanding under these plans usually vest over periods of between three and five years from the date granted and terminate ten years from the date granted. Upon termination of employment, vested options may be exercised and the related subsidiary shares may be, but are not required to be, repurchased by the applicable subsidiary at estimated fair value.

Non-Employee Director Stock Plan

In 1996, the Company adopted and shareholders approved the Non-Employee Director Stock Plan (1996 Director Plan). Under the 1996 Director Plan, directors who are not employees of the Company receive two-thirds of their annual retainer in Avista Corp. common stock. The Company acquires the common stock in the open market. The Company has available a maximum of 150,000 shares of its common stock under the 1996 Director Plan and there were 85,937 shares available for future compensation to non-employee directors as of December 31, 2002.

NOTE 28. COMMITMENTS AND CONTINGENCIES

The Company believes, based on the information presently known, that the ultimate liability for the matters discussed in this note, individually or in the aggregate, taking into account established accruals for estimated liabilities, will not be material to the consolidated financial condition of the Company, but could be material to results of operations or cash flows for a particular quarter or annual period. No assurance can be given, however, as to the ultimate outcome with respect to any particular issue.

Federal Energy Regulatory Commission Inquiry

In February 2002, the FERC issued an order commencing a fact-finding investigation of potential manipulation of electric and natural gas prices in the California energy markets by multiple companies. On May 8, 2002, the FERC requested data and information with respect to certain trading strategies that companies may have engaged in. Specifically, the requests inquired as to whether or not the Company engaged in certain trading strategies that were the same or similar to those used by Enron Corporation (Enron) and its affiliates. These requests were made to all sellers of wholesale electricity and/or ancillary services in the Western Interconnection during 2000 and 2001, including Avista Corp. and Avista Energy. On May 22, 2002, Avista Corp. and Avista Energy filed their responses to this request indicating that they had engaged in sound business practices in accordance with established market rules, and that no information was evident from business records or employee interviews that would indicate that Avista Corp. or Avista Energy, or its employees, were knowingly engaged in these trading strategies, or any variant of the strategies.

On June 4, 2002, the FERC issued an additional order to Avista Corp. and three other companies requiring these companies to show cause within ten days as to why their authority to charge market-based rates should not be revoked. In this order, the FERC alleged that Avista Corp. failed to respond fully and accurately to the data request made on May 8, 2002. On June 14, 2002, Avista Corp. provided additional information in response to the June 4, 2002 FERC order to establish that its initial response was appropriate and adequate.

On August 13, 2002, the FERC issued an order to initiate an investigation into possible misconduct by Avista Corp. and Avista Energy and two affiliates of Enron: Enron Power Marketing, Inc. (EPMI) and Portland General Electric Corporation (PGE). The purpose of the investigation was to determine whether Avista Corp. and Avista Energy engaged in or facilitated certain Enron trading strategies, whether Avista Corp.'s or Avista Energy's role in transactions with EPMI and PGE resulted in the circumvention of a code of conduct governing transactions with affiliates, and the imposition of any appropriate remedies such as refunds and revocation of market-based rates. The investigation also explored whether the companies provided all relevant information in response to the May 8, 2002 data request.

In December 2002, the FERC staff, Avista Corp. and Avista Energy filed a joint motion announcing that the parties have reached an agreement in principle. In the joint motion, the FERC Trial Staff states that its investigation found no evidence that: (1) any executives or employees of Avista Utilities or Avista Energy knowingly engaged in or facilitated any improper trading strategy; (2) Avista Utilities or Avista Energy engaged in any efforts to manipulate the western energy markets during 2000 and 2001; (3) Avista Utilities or Avista Energy withheld relevant information from the Commission's inquiry into the western energy markets for 2000 and 2001.

In December 2002, the FERC's administrative law judge approved the joint motion, suspending the procedural schedule in the FERC investigation regarding Avista Corp. and Avista Energy. In January 2003, the FERC staff, Avista Corp. and Avista Energy filed a completed agreement in resolution of the proceeding with the administrative law judge. The parties requested that the administrative law judge certify the agreement and forward it to the FERC for acceptance following a 30-day comment period.

On February 19, 2003 the City of Tacoma (Tacoma) and California Parties (the Office of the Attorney General, the CPUC, and the California Electricity Oversight Board, filing jointly) filed comments in opposition to the agreement in resolution between the FERC staff, Avista Corp. and Avista Energy. PGE filed comments supporting the agreement in resolution, but took exception to how certain transactions were reported. On March 3, 2003, Avista Corp. and Avista Energy filed joint reply comments in response to the concerns raised by Tacoma, the California Parties, and PGE. The FERC Trial Staff filed separate reply comments supporting the agreement in resolution and responding to Tacoma, the California Parties and PGE. The reply comments of Avista Corp., Avista Energy and the FERC Staff also reiterated the request that the administrative law judge certify the agreement in resolution and forward it to the FERC for approval.

U.S. Commodity Futures Trading Commission (CFTC) Subpoena

Beginning on June 17, 2002, the CFTC has issued several subpoenas directing Avista Corp. to produce certain materials, make employees available for questions and to respond to certain interrogatories. This relates to electricity and natural gas trades by Avista Corp. and any of its subsidiaries (including Avista Energy), involving “round trip trades,” “wash trades,” or “sell/buyback trades” and price reporting. The CFTC subpoena applies to both Avista Corp. and Avista Energy. The Company is cooperating with the CFTC and is providing the information requested by the CFTC.

Class Action Securities Litigation

On September 27, 2002, Ronald R. Wambolt filed a class action lawsuit in the United States District Court for the Eastern District of Washington against Avista Corp., Thomas M. Matthews, the former Chairman of the Board, President and Chief Executive Officer of the Company, Gary G. Ely, the current Chairman of the Board, President and Chief Executive Officer of the Company, and Jon E. Eliassen, the former Senior Vice President and Chief Financial Officer of the Company. On October 9, 2002, Gail West filed a similar class action lawsuit in the same court against the same parties. On November 7, 2002, Michael Atlas filed a similar class action lawsuit in the same court against the same parties. On November 21, 2002, Peter Arnone filed a similar class action lawsuit in the same court against the same parties. In their complaints, the plaintiffs assert violations of the federal securities laws in connection with alleged misstatements and omissions of material fact pursuant to Sections 10(b) and 20(a) of the Securities Exchange Act of 1934. In particular, the plaintiffs allege that the Company failed to disclose certain business practices that Avista Corp. was allegedly engaging in with EPMI and PGE. For further information see “Federal Energy Regulatory Commission Inquiry” above. The plaintiffs assert that such alleged misstatements and omissions have occurred in the Company’s filings with the Securities and Exchange Commission and other information made publicly available by the Company, including press releases. The class action lawsuits assert claims on behalf of all persons who purchased, converted, exchanged or otherwise acquired the Company’s common stock during the period between November 23, 1999 and August 13, 2002. On February 3, 2003, the court issued an order consolidating the complaints under the name “In re Avista Corp. Securities Litigation,” and on February 7, 2003 appointed the lead plaintiff and co-lead counsel. The Company intends to file a motion to dismiss these consolidated complaints and vigorously defend against these lawsuits.

California Energy Markets

In April 2002, several subsidiaries of Reliant Energy, Inc. (Reliant) and Duke Energy Corporation (Duke) filed cross-complaints against Avista Energy and numerous other participants in the California energy markets. The cross-complaints are for indemnification for any liability which may arise from original complaints filed against Reliant and Duke with respect to charges of unlawful and unfair business practices in the California energy markets under California law. Avista Energy has filed motions to dismiss the cross-complaints. In the meantime, the U.S. District Court has remanded the case to California State Court, which remand is itself the subject of an appeal to the United States Court of Appeals for the Ninth Circuit.

In March 2002, the Attorney General of the State of California (California AG) filed a complaint with the FERC against certain specific companies (not including Avista Corp. or its subsidiaries) and “all other public utility sellers” in California. The complaint alleges that sellers with market-based rates have violated their tariffs by not filing with the FERC transaction-specific information about all of their sales and purchases at market-based rates. As a result, all past sales should be subject to refund if found to be above just and reasonable levels. In May 2002, the FERC issued an order denying the claim to issue refunds. In July 2002, the California AG requested a rehearing on the FERC order, which request was denied in September 2002. The California AG filed a Petition for Review of the FERC’s decision with the United States Court of Appeals for the Ninth Circuit.

In April 2002, the California AG provided notice of intent to file a complaint against Avista Energy in the California State Court on behalf of the State of California. As of the filing date of this report, the California AG has not filed the threatened complaint against Avista Energy. Complaints have been filed against approximately a dozen other companies, many of which have filed motions to dismiss based upon federal preemption and primary jurisdiction arguments. The threatened complaint alleges that Avista Energy failed to file rates and changes to rates charged for each sale of wholesale electricity in California markets with the FERC as required by Federal Power Act regulations and FERC orders. The threatened complaint asserts that each violation of law, regulation and order is an unlawful and unfair business practice under the California Business and Professions Code, subject to a penalty of $2,500 per violation. The threatened complaint further alleges that certain rates charged for wholesale electricity sold in California exceeded a just and reasonable rate. As such, the threatened complaint alleges that these rates violate the Federal Power Act and are also a violation under the California Business and Professions Code, subject to penalty. A significant portion of the transactions involved in this threatened complaint are also the subject of FERC proceedings to examine potential refunds and in most cases are transactions for which Avista Energy is still owed payment.

Washington Consumer Class Action Lawsuit

On December 23, 2002, Nick A. Symonds filed a class action lawsuit in the United States District Court for the Western District of Washington against numerous purchasers and sellers of wholesale electricity and natural gas in the western United States, including Avista Utilities. The class action lawsuit asserts claims on behalf of all persons and businesses residing in Washington who were purchasers of electric and/or natural gas energy from any period beginning in January 2000 to the present. The complaint alleges that due to the deregulation of the California energy market, the defendants were able to unlawfully manipulate the wholesale energy market resulting in supply shortages and high energy prices across the western United States, including Washington. The complaint further alleges that high energy prices have resulted in profits for the defendants at the expense of rate-paying consumers in Washington. The complaint seeks treble damages, attorney fees and costs, and an order that defendants immediately remedy the alleged unlawful practices relating to the purchase and sale of wholesale energy that affects rate-paying consumers in Washington. The complaint further seeks an order enjoining the defendants from continuing any alleged unlawful practices relating to the purchase and sale of wholesale energy that affects rate-paying consumers in Washington. The Company intends to file a motion to dismiss this complaint and vigorously defend against this lawsuit.

Enron Corporation

On December 2, 2001, Enron and certain of its affiliates filed for protection under chapter 11 of the United States Bankruptcy Code. Both Avista Corp. and Avista Energy had done considerable business and had short-term and long-term contracts with Enron affiliates. The bankruptcy filing constituted an event of default under contracts between Avista Corp. and Avista Energy, respectively, and certain Enron affiliates, namely, EPMI, Enron North America Company (ENA) and Enron Canada Corp. (ECC), that are guaranteed by Enron. As a result, Avista Corp. and Avista Energy terminated all of these contracts and suspended trading activities with all Enron affiliates, including the final position that was terminated and a settlement agreement reached between Avista Corp. and EPMI in October 2002.

As of December 31, 2002, Avista Energy had net accounts receivable of $13.9 million from EPMI and ENA. Avista Corp.’s and Avista Energy’s contracts with each Enron affiliate provide that, upon termination, the net settlement of accounts receivable and accounts payable with such entity will be netted against the net mark-to-market value of the terminated forward contracts with such entity. It is estimated that for Avista Energy, netting the mark-to-market liability against the defaulted net accounts receivable will result in no significant loss due to non-collection from the Enron affiliates. The Company further estimates that the net mark-to-market liability to Enron affiliates with respect to the terminated forward contracts not yet settled (Avista Energy with EPMI and ENA) taken together, exceeds total net accounts receivable from these entities by less than $15 million.

In October 2002, Avista Corp. settled its remaining contract with EPMI with the approval of the U.S. Bankruptcy Court. In addition, Avista Corp. reached settlement agreements on all terminated positions with ECC and ENA. Avista Energy reached a settlement agreement on its terminated ECC positions. In each instance, the settlement agreements reached satisfy all of the Avista entity’s obligations and exposure to such Enron entity. Confidentiality provisions contained in the settlement agreements protect disclosure of the specific details of each settlement. None of the settlements individually, nor all of the settlements collectively, have had or are expected to have a material adverse impact on Avista Corp.’s or Avista Energy’s financial condition, results of operations or cash flows. All additional claims by the Enron entities for amounts that Avista Energy might owe with respect to the terminated forward contracts would be subject to any defenses and counterclaims which Avista Energy may have. Any residual obligation by Avista Energy for termination payments is not expected to have a material impact on the Company's financial condition, results of operations or cash flows. The Company continues to negotiate the settlement of other contracts with Enron affiliates.

The estimates of the mark-to-market values of terminated forward contracts are based on available broker quotes for the respective periods, and on assumptions as to future market prices and other information. While Avista Energy believes these assumptions are reasonable, they are subject to change and ultimately could be challenged by the Enron entities or their bankruptcy trustees, except as to those terminated forward contracts that have been fully settled by agreements among the parties as described above. The mark-to-market value of terminated contracts has not been firmly established and could result in undercollection that is not expected to be material to the financial condition, results of operations or cash flows of Avista Energy.

National Energy Production Corporation (NEPCO), a wholly owned subsidiary of Enron, was the contractor responsible for the engineering, procurement and construction of Coyote Springs 2. Avista Corp. owns 50 percent of Coyote Springs 2. NEPCO was not included in the initial bankruptcy filings made by Enron and its affiliates in December 2001. NEPCO subsequently filed for bankruptcy on May 20, 2002. However, Enron guaranteed NEPCO's obligations, and the bankruptcy filing by Enron was an event of default under the Coyote Springs 2 construction contract. As a result of this default and other defaults under the contract, NEPCO was removed as contractor for the project on April 15, 2002.

Avista Corp. is party to a power exchange arrangement which expires in 2016. Under this power exchange arrangement, EPMI purchases capacity from Avista Corp. and sells capacity to Spokane Energy LLC (Spokane Energy), a subsidiary of Avista Corp., formed in 1998 solely for the purpose of facilitating a long-term capacity contract between PGE and Avista Corp. The 1998 transaction resulted in the Company receiving $143.4 million in cash proceeds that was originally recorded as deferred revenue. Spokane Energy sells the related capacity to PGE. Subsequently, PGE became a subsidiary of Enron that has not been included in the bankruptcy filing to date. EPMI assisted in setting up the transaction structure and acts as an intermediary to abide by certain regulatory restrictions that currently prevent Spokane Energy and Avista Corp. from dealing directly with each other. The transaction is structured such that Spokane Energy bears full recourse risk for a loan (balance of $125.8 million as of December 31, 2002) that matures in January 2015 with no recourse to Avista Corp. related to the loan. EPMI is obligated to pay approximately $150,000 per month to Avista Corp. for its capacity purchase. EPMI defaulted on two payments to Avista Corp. prior to filing for bankruptcy. Such payments were accounted for and included in the settlement agreement reached between Avista Corp. and EPMI in October 2002.

Colorado River Commission of Nevada (CRCN) Complaint

On February 14, 2003, a complaint filed against Pioneer Companies, Inc. and numerous other defendants, including Avista Energy, was dismissed. The CRCN filed this complaint in the United States District Court for the District of Nevada in July 2002. CRCN is an agency of the State of Nevada, authorized to hold and administer rights to electric power generated on the Colorado River and from other sources. CRCN claimed it purchased power as a purported agent for Pioneer from numerous vendors, including Avista Energy. CRCN alleged that Pioneer had disavowed its contractual liability to pay for power due to be delivered for its benefit in the future, pursuant to transactions entered into for Pioneer's benefit by CRCN. CRCN alleged that it had funds available of approximately $35 million, resulting from the sale of options and energy originally secured by CRCN for the benefit of Pioneer, but believed the potential collective claims of all electricity vendors may have exceeded $100 million. Accordingly, CRCN was attempting to interplead into court the $35 million and asked the court to assess the competing claims of vendors to such funds. CRCN further requested that Pioneer be ordered to pay vendors amounts owed for transactions between CRCN (as Pioneer's agent) and vendors, and that such contracts are to be specifically enforced. Finally, CRCN was attempting to be indemnified against the future claims of vendors.

State of Washington Business and Occupation Tax

The State of Washington's Business and Occupation Tax applies to gross revenue from business activities. For most types of business, the tax applies to the gross sales price received for goods or services. For certain types of financial trading activities, including the sale of stocks, bonds and other securities, the tax applies to the realized gain from the sale of the financial asset. On an audit for the period from 1997 through June 2000, the Department of Revenue (DOR) took the position that approximately 20 percent of the forward energy trades of Avista Energy should not be treated as securities trades, but rather as energy deliveries. As a result, the DOR applied tax against the gross sales price of the energy contracts at issue. Avista Energy subsequently received an assessment of $14.5 million for tax and interest related to the disputed issue. It is the position of Avista Energy that all of its forward contract trading activities are substantively the same and there is no proper basis for the distinction made by the DOR. An administrative appeal was filed with the DOR and a hearing was held on September 25, 2001. The DOR issued a Proposed Determination on December 4, 2002, which reiterated the original $14.5 million assessment. At the present time Avista Energy is still in active negotiations with the DOR with respect to a Final Determination in this matter and believes that a satisfactory settlement can be reached. However, if a satisfactory settlement can not be reached, Avista Energy will have to record a charge and attempt to resolve the issue in court.

Sale of Pentzer Corporation Subsidiary

On February 26, 2001, IDX Corporation, formerly known as Store Fixtures Group, Inc., filed a complaint against Pentzer in the United States District Court for the District of Massachusetts, alleging breach of contract and negligent misrepresentation relating to a stock purchase agreement. Pursuant to this agreement, Pentzer sold the capital stock of a group of companies on August 31, 1999. Plaintiff alleges that Pentzer breached various representations and warranties concerning financial statements and inventory, contending that reliance on such representations and warranties caused them to pay more for the group of companies than they were worth. In total, plaintiff claims damages in the approximate amount of $7.8 million plus interest and attorney's fees. The Court approved the parties' joint motion to extend the discovery dates. The discovery process continues, as mediation that commenced during June 2002 has not been successful to date.

Montana Hydroelectric Security Act Initiative

In the November 5, 2002 General Election, Montana voters rejected an initiative that would have created a public agency to study whether it would benefit the people of Montana to have the state own and operate certain hydroelectric generating facilities located within the state. The initiative would have authorized the new public agency to acquire, through a negotiated purchase or an acquisition at fair market value through a condemnation proceeding, any or all hydroelectric facilities larger than 5 MW within the state. The Company's largest generation plant, the Noxon Rapids Hydroelectric Generating Station (Noxon Rapids) (527 MW), is located in Montana on the Clark Fork River.

Hamilton Street Bridge Site

A portion of the Hamilton Street Bridge Site in Spokane, Washington (including a former coal gasification plant site that operated for approximately 60 years until 1948) was acquired by the Company through a merger in 1958. The Company no longer owns the property. Initial core samples taken from the site indicated environmental contamination at the site. On January 15, 1999, the Company received notice from the State of Washington's Department of Ecology (DOE) that it had been designated as a potentially liable party (PLP) with respect to any hazardous substances located on this site, stemming from the Company's past ownership of the former gas plant site. In its notice, the DOE stated that it intended to complete an on-going remedial investigation of this site, complete a feasibility study to determine the most effective means of halting or controlling future releases of substances from the site, and to implement appropriate remedial measures. The Company responded to the DOE acknowledging its listing as a PLP, but requested that additional parties also be listed as PLPs. In the spring of 1999, the DOE named two other parties as additional PLPs.

An Agreed Order was signed by the DOE, the Company and another PLP, Burlington Northern & Santa Fe Railway Co. (BNSF) on March 13, 2000 that provided for the completion of a remedial investigation and a feasibility study. The work to be performed under the Agreed Order includes three major technical parts: completion of the remedial investigation; performance of a focused feasibility study; and implementation of an interim groundwater monitoring plan. During the second quarter of 2000, the Company received comments from the DOE on its initial remedial investigation, then submitted another draft of the remedial investigation, which was accepted as final by the DOE. After responding to comments from the DOE, the feasibility study was accepted by the DOE during the fourth quarter of 2000. After receiving input from the Company and the other PLPs, the final Cleanup Action Plan (CAP) was issued by the DOE on August 10, 2001. On September 10, 2001, the DOE issued an initial draft Consent Decree for the PLPs to review. During the first quarter of 2002, the Company and BNSF signed a cost sharing agreement. On September 11, 2002, the Company, BNSF and the DOE finalized the Consent Decree to implement the CAP. The third PLP has indicated it will not sign the Consent Decree. It is currently estimated that the Company's share of the costs will be less than $1.0 million. The Engineering and Design Report for the CAP was submitted to the DOE in January 2003. If approved by the DOE, it is anticipated that the CAP will be implemented in mid-2003. Negotiations are continuing with the third PLP with respect to the logistics of the CAP.

Spokane River

In March 2001, the DOE informed Avista Development, a subsidiary of Avista Capital, of a health advisory concerning PCBs found in fish caught in a portion of the Spokane River. In June 2001, Avista Development received official notice that it had been designated as a PLP with respect to contaminated sites on the Spokane River. The DOE discovered PCBs in fish and sediments in the Spokane River in the 1970s and 1980s. In the 1990s, the DOE performed subsequent sampling of the river and identified potential sources of the PCBs, including the Spokane Industrial Park (SIP) and a number of other entities in the area. The SIP, renamed Pentzer Development Corporation (Pentzer Development) in 1990, operated a wastewater treatment plant at the site until it was closed in December 1993. The SIP's treatment plant discharged to the Spokane River under the terms of a National Pollutant Discharge Elimination System permit issued by the DOE. Pentzer Development sold the property in 1996 and merged with Avista Development in 1998. Avista Development filed a response to this notice in August 2001. In December 2001, the DOE confirmed Avista Development's status as a PLP and named at least two other PLPs in this matter. During the first half of 2002, Avista and one other PLP met with the DOE to begin discussions and provide comments to the DOE on a draft Consent Decree and Scope of Work for a focused remedial investigation and feasibility study of the site. One other PLP has not been participating in negotiations. The Consent Decree and Scope of Work for the remedial investigation and feasibility study of the site were finalized during the fourth quarter of 2002. The other PLP that has been participating in the negotiations has filed for bankruptcy; however, the bankruptcy court has permitted the disbursement of funds related this environmental matter. It is currently expected that the actual cleanup of PCB sediments in the Spokane River will be coordinated to the extent possible with the EPA's separate plan to remove heavy metals from the Spokane River, contamination that resulted from decades of mining upstream at locations in Idaho and is not related to the activities of Avista Development.

Lake Coeur d'Alene

In July 1998, the United States District Court for the District of Idaho issued its finding that the Coeur d'Alene Tribe of Idaho owns portions of the bed and banks of Lake Coeur d'Alene and the St. Joe River lying within the current boundaries of the Coeur d'Alene Reservation. This action was brought by the United States on behalf of the Tribe against the State of Idaho. While the Company is not a party to this action, the Company is continuing to evaluate the potential impact of this decision on the operation of its hydroelectric facilities on the Spokane River, downstream of Lake Coeur d'Alene. The United States District Court decision was affirmed by the United States Court of Appeals for the Ninth Circuit. The United States Supreme Court affirmed this decision in June 2001. This will result in the Company being liable to the Coeur d'Alene Tribe of Idaho for payments for use of reservation lands under Section 10(e) of the Federal Power Act.

Spokane River Relicensing

The Company operates six hydroelectric plants on the Spokane River, and five of these (Long Lake, Nine Mile, Upper Falls, Monroe Street and Post Falls) are under one FERC license and referred to herein as the Spokane River Project. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. The license for the Spokane River Project expires in August 2007; the Company filed a Notice of Intent to Relicense on July 29, 2002. The formal consultation process involving planning and information gathering with stakeholder groups is underway. The Company's goal is to develop with the stakeholders a comprehensive and cost-effective settlement agreement to be filed as part of the Company's license application to the FERC in July 2005.

Clark Fork Settlement Agreement

The issue of high levels of dissolved gas which exceed Idaho and federal water quality standards downstream of the Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) during spill periods continues to be studied, as agreed to in the Clark Fork Settlement Agreement and incorporated into the renewed FERC license. To date, intensive biological studies in the lower Clark Fork River and Lake Pend Oreille have documented minimal biological effects of high dissolved gas levels on free ranging fish. Under the terms of the Clark Fork Settlement Agreement, the Company developed an abatement and mitigation strategy during 2002 with the other signatories to the agreement. In December 2002, the Company submitted its plan for review and approval by the other signatories as well as the FERC. The structural alternative proposed in the plan provides for the modification of the two existing diversion tunnels built when Cabinet Gorge was originally constructed. The costs of modifications to the first tunnel are currently estimated to be $37 million (including AFUDC and inflation) and would be incurred between 2004 and 2009. The second tunnel would be modified only after evaluation of the performance of the first tunnel and such modifications would commence no later than 10 years following the completion of the first tunnel. It is currently estimated that the costs to modify the second tunnel would be $23 million (including AFUDC and inflation). As part of the plan, the Company will also provide $0.5 million annually commencing as early as 2004, as mitigation for aquatic resources that might be adversely affected by high dissolved gas levels. Mitigation funds will continue until the modification of the second tunnel commences or if the second tunnel is not modified to an agreed upon point in time commensurate with the biological effects of high dissolved gas levels. The Company will seek regulatory recovery of the costs for the modification of Cabinet Gorge and the mitigation payments.

The operating license for the Clark Fork Projects describes the approach to restore bull trout populations in the project areas. Using the concept of adaptive management, the Company is evaluating the feasibility of fish passage and, depending upon the results of these experimental studies, determining the applications of funds toward continuing fish passage efforts or other population enhancement measures.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes that any ultimate liability arising from these actions will not have a material adverse impact on the Company’s financial condition, results of operations or cash flows.

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 potential liabilities under the Federal Endangered Species Act (ESA) for species of fish that have either already been added to the endangered species list, been listed as “threatened” or been petitioned for listing. Thus far, measures adopted and implemented have had minimal impact on the Company.

Under the federal licenses for its hydroelectric projects, the Company is obligated to protect its property rights, including water rights. The State of Montana is examining the status of all water right claims within state boundaries, which could potentially adversely affect the energy production of the Company’s Cabinet Gorge and Noxon Rapids hydroelectric facilities. The Company is participating in this extended process, which is unlikely to be concluded in the foreseeable future.

The Company must be in compliance with requirements under the Clean Air Act Amendments (CAAA) at the Colstrip thermal generating plant, in which the Company maintains an ownership interest. The anticipated share of costs at Colstrip is not expected to have a major economic impact on the Company.

As of December 31, 2002, the Company’s collective bargaining agreement with the International Brotherhood of Electrical Workers represented approximately 48 percent of all Avista Utilities employees. The current agreement with the local union representing the majority of the bargaining unit employees expires on March 25, 2005. A local agreement in the South Lake Tahoe area, which represents 5 employees, also expires on March 25, 2005. Three other labor agreements in Oregon, which cover approximately 55 employees, expire on March 31, 2003. Negotiations are currently ongoing with respect to the agreements that expire on March 31, 2003.

NOTE 29. DISPOSITION OF POWER PLANT

In May 2000, the owners of Centralia sold the plant to TransAlta. Avista Utilities recorded an after-tax gain totaling $37.2 million from the sale of its 17.5 percent ownership interest in the plant. Of the total after-tax gain, $9.0 million was recorded in the Consolidated Statements of Income and Comprehensive Income for the year ended December 31, 2000 and $28.2 million was deferred and returned to Avista Utilities’ customers through rates over established periods of time. Washington customers received $20.7 million of the after-tax gain through pre-tax credits to their electric bills over the two-month period of December 2000 and January 2001. Idaho customers are receiving the remaining $7.5 million of the after-tax gain, which is a rate reduction of 1.8 percent, over an eight-year period.

AVISTA CORPORATION

NOTE 30. SELECTED QUARTERLY FINANCIAL DATA (Unaudited)

The Company's energy 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, except per share amounts) for 2002 and 2001 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2002				
Operating revenues	$306,979	$218,362	$189,830	$265,275
Operating expenses	260,471	180,627	169,453	225,208
Income from operations	46,508	37,735	20,377	40,067
Income (loss) from continuing operations	15,520	9,331	(1,082)	10,541
Income (loss) from discontinued operations	(272)	1,014	(533)	936
Net income before cumulative effect of accounting change	15,248	10,345	(1,615)	11,477
Cumulative effect of accounting change	(4,148)	—	—	—
Net income (loss)	11,100	10,345	(1,615)	11,477
Income (loss) available for common stock	$ 10,492	$ 9,737	$ (2,223)	$ 10,899
Outstanding common stock:				
Weighted average	47,671	47,774	47,866	47,978
End of period	47,737	47,830	47,930	48,044
Earnings (loss) per share, basic and diluted:				
Earnings (loss) per share from continuing operations	$ 0.32	$ 0.18	$ (0.04)	$ 0.21
Earnings (loss) per share from discontinued operations	(0.01)	0.02	(0.01)	0.02
Earnings (loss per share before cumulative effect of accounting change	0.31	0.20	(0.05)	0.23
Cumulative effect of accounting change	(0.09)	—	—	—
Total earnings (loss) per share, basic	$ 0.22	$ 0.20	$ (0.05)	$ 0.23
Dividends paid per common share	$ 0.12	$ 0.12	$ 0.12	$ 0.12
Trading price range per common share:				
High	$ 16.47	$ 16.60	$ 13.89	$ 12.10
Low	$ 13.00	$ 11.00	$ 10.16	$ 8.75
2001				
Operating revenues	$473,855	$371,135	$232,113	$318,210
Operating expenses	408,408	314,585	198,494	304,534
Income from operations	65,447	56,550	33,619	13,676
Income (loss) from continuing operations	32,121	25,980	6,111	(4,607)
Loss from discontinued operations	(2,718)	(3,255)	(38,421)	(3,055)
Net income (loss)	29,403	22,725	(32,310)	(7,662)
Income (loss) available for common stock	$ 28,795	$ 22,117	$ (32,918)	$ (8,270)
Outstanding common stock:				
Weighted average	47,237	47,372	47,486	47,569
End of period	47,266	47,465	47,537	47,633
Earnings (loss) per share, basic and diluted:				
Earnings (loss) per share from continuing operations	$ 0.67	$ 0.54	$ 0.12	$ (0.11)
Loss per share from discontinued operations	(0.06)	(0.07)	(0.81)	(0.06)
Total earnings (loss) per share, basic	$ 0.61	$ 0.47	$ (0.69)	$ (0.17)
Dividends paid per common share	$ 0.12	$ 0.12	$ 0.12	$ 0.12
Trading price range per common share:				
High	$ 20.63	$ 23.97	$ 19.98	$ 14.60
Low	$ 15.60	$ 16.27	$ 13.40	$ 10.60

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 8, 2003.

Executive Officers of the Registrant Name	Age	Business Experience During the Past 5 Years
Gary G. Ely	55	Director and Chairman of the Board since May 2001. President and Chief Executive Officer since October 2000; Executive Vice President February 1999 - October 2000; Senior Vice President and General Manager August 1996 - February 1999.
Malyn K. Malquist	50	Senior Vice President and Chief Financial Officer since November 2002; Senior Vice President September 2002 – November 2002; General Manager of Truckee Meadows Water Authority June 2001 – September 2002; President of Malyn Malquist Consulting January 2001 – June 2001; Chief Executive Officer of Data Engines, Inc. June 2000 – October 2000; Various positions at Sierra Pacific Resources April 1994 – April 2000, positions included Chairman of the Board, Chief Executive Officer, President, Senior Vice President, Chief Financial Officer and Principal Operations Officer.
Jon E. Eliassen	56	Senior Vice President; Senior Vice President and Chief Financial Officer November 1998 – November 2002; Senior Vice President, Chief Financial Officer and Treasurer December 1997 - November 1998; Senior Vice President and Chief Financial Officer August 1996 - December 1997.
David J. Meyer	49	Senior Vice President and General Counsel since September 1998; prior to employment with the Company: Attorney - Paine Hamblen Coffin Brooke & Miller 1974 - September 1998.
Scott L. Morris	45	Senior Vice President since February 2002; Vice President November 2000 – February 2002; President - Avista Utilities since August 2000; General Manager - Avista Utilities October 1991 - - August 2000.
David A. Brukardt	48	Vice President and Treasurer since March 2003; Chief Communication Officer and Vice President of Corporate Relations and Strategic Planning September 2001 – March 2003; Chief Communication Officer and Vice President of Investor and Corporate Relations August 2000 – September 2001; Vice President of Investor Relations August 1999 - August 2000; prior to employment with the Registrant: Director - Investor and Corporate Relations - Harnischfeger Industries, Inc. and Vice President - Harnischfeger Foundation July 1995 - - July 1999.
Christy M. Burmeister-Smith	46	Vice President and Controller since June 1999; Controller - Energy Delivery and various other positions with the Company since 1980.
Karen S. Feltes	47	Vice President of Human Resources and Corporate Secretary since March 2003; Vice President of Human Resources and Corporate Services February 2002 – March 2003; Various Human Resources positions with the Company April 1998 – February 2002. Adjunct Instructor-City University and Director of Human Resources-Spokane Club 1996-1998.
Lloyd Meyers	60	Vice President of Power Supply – Avista Utilities since September 2001; President – Avista Power since January 1999; President Avista Energy 1997 – January 1999.

Kelly O. Norwood	44	Vice President since November 2000; Vice President of Rates and Regulation – Avista Utilities since March 2002; Vice President and General Manager of Energy Resources - Avista Utilities August 2000 – March 2002; various other staff and management positions with the Company since 1981.
Ronald R. Peterson	50	Vice President of Energy Resources and Optimization since March 2003; Vice President and Treasurer since November 1998 – March 2003; Vice President Finance - Avista Utilities since September 2001; Vice President and Controller February 1998 - November 1998; Controller August 1996 - February 1998.
Terry L. Syms	54	Vice President and Assistant to the Chairman since March 2003; Vice President and Corporate Secretary February 1998 – March 2003; Corporate Secretary March 1988 - February 1998.
Roger D. Woodworth	46	Vice President since November 1998; Vice President of Utility Operations of Avista Utilities since September 2001; Vice President – Corporate Development November 1998 – September 2001; Director of Corporate Development and various other positions with the Company since 1979.

All of the Company's executive officers, with the exception of Malyn K. Malquist, Kelly O. Norwood, Christy M. Burmeister-Smith and Karen S. Feltes, were officers or directors of one or more of the Company's subsidiaries in 2002. 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 8, 2003.

Item 12. Security Ownership of Certain Beneficial Owners and Management

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

Information regarding security ownership of certain beneficial owners (owning 5 percent or more of Registrant's voting securities) 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 8, 2003.

(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 8, 2003.

(c) Changes in control:

None.

AVISTA CORPORATION

(d) Securities authorized for issuance under equity compensation plans:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders (1)	1,815,600	$16.26	722,612 (3)
Equity compensation plans not approved by security holders (2)	868,750	$14.52	1,631,250
Total	2,684,350	$15.69	2,353,862

(1) Includes the Long-Term Incentive Plan approved by shareholders in 1998 and the Non-Employee Director Stock Plan approved by shareholders in 1996.

(2) Represents stock options outstanding and stock available for future issuance under the Non-Officer Employee Long-Term Incentive Plan, which was adopted by the Company in 2000. Under this plan, employees (excluding directors and executive officers) of the Company and its subsidiaries may be granted stock options, stock appreciation rights, stock awards, performance awards, other stock-based awards and dividend equivalent rights. Stock options granted under this plan are equal to the market price of the Company's common stock on the date of grant. Stock options granted under this plan have terms of up to 10 years and generally vest at a rate of 25 percent per year over a four-year period.

(3) Includes 85,937 of shares available for future compensation to non-employee directors under the Non-Employee Director Stock Plan.

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 8, 2003.

Item 14. Controls and Procedures

The Company has disclosure controls and procedures (as defined in Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934, as amended) to ensure that material information contained in its filings with the Securities and Exchange Commission is recorded, processed, summarized and reported on a timely and accurate basis. The Company’s principal executive officer and principal financial officer have reviewed and evaluated the Company’s disclosure controls and procedures within 90 days prior to the filing date of this report. Based on such evaluation, the Company’s principal executive officer and principal financial officer have concluded that the Company’s disclosure controls and procedures are effective at ensuring that material information is recorded, processed, summarized and reported on a timely and accurate basis in the Company’s filings with the Securities and Exchange Commission. Since such evaluation there have not been any significant changes in the Company’s internal controls, or in other factors that could significantly affect these controls.

PART IV

Item 15. 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 Comprehensive Income for the Years Ended December 31, 2002, 2001 and 2000

Consolidated Balance Sheets, December 31, 2002 and 2001

Consolidated Statements of Capitalization, December 31, 2002 and 2001

Consolidated Statements of Cash Flows for the Years Ended December 31, 2002, 2001 and 2000

Consolidated Statements of Stockholders' Equity for the Years Ended December 31, 2002, 2001 and 2000

Schedule of Information by Business Segments for the Years Ended December 31, 2002, 2001 and 2000

Notes to Consolidated Financial Statements

(a) 2. Financial Statement Schedules:

None

(a) 3. Exhibits:

Reference is made to the Exhibit Index commencing on page 107. 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 December 9, 2002 with respect to agreement in principle between Avista Corp., Avista Energy and the FERC staff.

AVISTA CORPORATION

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.

AVISTA CORPORATION

March 14, 2003	By	/s/ Gary G. Ely
Date		Gary G. Ely 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/ Gary G. Ely Gary G. Ely Chairman of the Board, President and Chief Executive Officer	Principal Executive Officer	March 14, 2003
/s/ Malyn K. Malquist Malyn K. Malquist (Senior Vice President and Chief Financial Officer)	Principal Financial and Accounting Officer	March 14, 2003
/s/ Erik J. Anderson Erik J. Anderson	Director	March 14, 2003
/s/ Kristianne Blake Kristianne Blake	Director	March 14, 2003
/s/ David A. Clack David A. Clack	Director	March 14, 2003
/s/ Roy L. Eiguren Roy L. Eiguren	Director	March 14, 2003
/s/ Sarah M. R. Jewell Sarah M. R. Jewell	Director	March 14, 2003
/s/ John F. Kelly John F. Kelly	Director	March 14, 2003
/s/ Jessie J. Knight, Jr. Jessie J. Knight, Jr.	Director	March 14, 2003
/s/ Lura J. Powell Lura J. Powell	Director	March 14, 2003
/s/ R. John Taylor R. John Taylor	Director	March 14, 2003

AVISTA CORPORATION

CERTIFICATIONS

I, Gary G. Ely, certify that:

1. I have reviewed this annual report on Form 10-K of Avista Corporation:

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this annual report;

4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the Company and we have:

   a. designed such disclosure controls and procedures to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b. evaluated the effectiveness of the Company's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c. presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation, to the Company's auditors and to the audit committee of the Company's board of directors:

   a. all significant deficiencies in the design or operation of internal controls which could adversely affect the Company's ability to record, process, summarize and report financial data and have identified for the Company's auditors any material weaknesses in internal controls; and

   b. any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal controls; and

6. The Company's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 14, 2003

/s/ Gary G. Ely

Gary G. Ely
Chairman of the Board, President and
Chief Executive Officer
(Principal Executive Officer)

AVISTA CORPORATION

I, Malyn K. Malquist, certify that:

1. I have reviewed this annual report on Form 10-K of Avista Corporation:

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this annual report;

4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the Company and we have:

    a. designed such disclosure controls and procedures to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

    b. evaluated the effectiveness of the Company's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

    c. presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation, to the Company's auditors and to the audit committee of the Company's board of directors:

    a. all significant deficiencies in the design or operation of internal controls which could adversely affect the Company's ability to record, process, summarize and report financial data and have identified for the Company's auditors any material weaknesses in internal controls; and

    b. any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal controls; and

6. The Company's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 14, 2003

/s/ Malyn K. Malquist

Malyn K. Malquist
Senior Vice President and
Chief Financial Officer
(Principal Financial Officer)

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Registration Statement Nos. 2-81697, 2-94816, 33-54791, 333-03601, 333-22373, 333-58197, 33-32148, 333-33790, and 333-47290 on Form S-8, in Registration Statement Nos. 33-53655, 333-39551, 333-82165, 333-63243, 333-16353, 333-16353-01, 333-16353-02, 333-16353-03, 033-60-136, and 333-64652 on Form S-3, and in Registration Statement Nos. 333-62232, and 333-82502 on Form S-4 of our report dated February 7, 2003 (March 3, 2003, as to Note 28), which includes an explanatory paragraph for changes in accounting for goodwill and the presentation of energy trading activities, appearing in this Annual Report on Form 10-K of Avista Corporation for the year ended December 31, 2002.

/s/ Deloitte & Touche LLP

DELOITTE & TOUCHE LLP

Seattle, Washington
March 13, 2003

Table of Contents

AVISTA CORPORATION

EXHIBIT INDEX

	Previously Filed*		
Exhibit	With Registration Number	As Exhibit	
3(a)	1-3701 (with 2001 Form 10-K)		Restated Articles of Incorporation of Avista Corporation as amended November 1, 1999.
3(b)	**		Bylaws of Avista Corporation, as amended November 8, 2002.
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.
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.

* Incorporated herein by reference.

** Filed herewith.

AVISTA CORPORATION

EXHIBIT INDEX (continued)

	Previously Filed*		
Exhibit	With Registration Number	As Exhibit	
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(a)-29	1-3701 (with 2001 Form 10-K)	4(a)-29	Twenty-Eighth Supplemental Indenture, dated as of September 1, 2001
4(a)-30	333-82502	4(b)	Twenty-Ninth Supplemental Indenture, dated as of December 1, 2001
4(a)-31	1-3701 (with June 30, 2002 10-Q)	4(f)	Thirtieth Supplemental Indenture, dated as of May 1, 2002
4(a)-32	333-82165	4(a)	Indenture dated as of April 1, 1998 between Avista Corp. Corporation and The Chase Manhattan Bank, as Trustee.
4(a)-33	1-3701 (with March 31, 2001 Form 10-Q)	4(f)	Indenture dated as of April 3, 2001, by and among the Company and Chase Manhattan Bank and Trust Company, National Association, as Trustee
4(b)-1	1-3701 (with 1999 Form 10-K)		Loan Agreement between City of Forsyth, Montana, and the Company, dated as of September 1, 1999 (Series 1999A).
4(b)-2	1-3701 (with 1999 Form 10-K)		Indenture of Trust, Pollution Control Revenue Refunding Bonds (Series 1999A) between City of Forsyth, Montana, and Chase Manhattan Bank and Trust Company, N.A., dated as of September 1, 1999.
4(b)-3	1-3701 (with 1999 Form 10-K)		Loan Agreement between City of Forsyth, Montana, and the Company, dated as of September 1, 1999 (Series 1999B).

* Incorporated herein by reference.

** Filed herewith.

EXHIBIT INDEX (continued)

Exhibit	Previously Filed* With Registration Number	As Exhibit	
4(b)-4	1-3701 (with 1999 Form 10-K)		Indenture of Trust, Pollution Control Revenue Refunding Bonds (Series 1999B) between City of Forsyth, Montana, and Chase Manhattan Bank and Trust Company, N.A., dated as of September 1, 1999.
4(c)	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).
4(d)	1-3701 (with June 30, 2002 Form 10-Q)	4(d)	Credit Agreement, dated as of May 21, 2002, among Avista Corporation, The Banks Party Hereto, Keybank and Washington Mutual Bank, as Co-Agents, U.S. Bank, National Association, as Managing Agent, Fleet National Bank and Wells Fargo Bank, as Documentation Agents, Union Bank of California, N.A., as Syndication Agent and The Bank of New York, as Administrative Agent and Issuing Bank.
4(e)	1-3701 (with June 30, 2002 Form 10-Q)	4(e)	Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corp., as Seller, Avista Corporation, as initial Servicer and Eaglefunding Capital Corporation, as Conduit Purchaser and Fleet National Bank, as Committed Purchaser and Fleet Securities, Inc. as Administrator.
4(f)	1-3701 (with Form 8-K dated November 15, 1999)	4	Rights Agreement, dated as of November 15, 1999, between the Company and the Bank of New York as successor Rights Agent.
4(g)	333-82502	4(c)	Exchange and Registration Rights Agreement, dated December 19, 2001 among the Company and Goldman, Sach & Co., BNY Capital Markets, Inc., Fleet Securities, Inc. and TD Securities (USA), Inc.
10(a)-l	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.
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 (effective until November 1, 2005.
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 (effective until November 1, 2005).

* Incorporated herein by reference.

** Filed herewith.

EXHIBIT INDEX (continued)

	Previously Filed*		
Exhibit	With Registration Number	As Exhibit	
10(b)-3	**		Priest Rapids Project Product Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10(b)-4	**		Priest Rapids Project Reasonable Portion Power Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10(b)-5	**		Additional Product Sales Agreement (Priest Rapids Project) executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
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 (effective until November 1, 2009).
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 (effective until November 1, 2009).
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.

* Incorporated herein by reference.

** Filed herewith.

AVISTA CORPORATION

EXHIBIT INDEX (continued)

	Previously Filed*		
Exhibit	**With Registration Number**	**As Exhibit**	
10(f)	2-60728	5(j)	Pacific Northwest Coordination Agreement, dated as of September 15, 1964.
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 1986 Form 10-K)	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 September 30, 1985 Form 10-Q)	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 September 30, 1985 Form 10-Q)	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 September 30, 1985 Form 10-Q)	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.
10(j)-1	2-66184	5(r)	Service Agreement (Natural Gas Storage Service), dated as of August 27, 1979, between the Company and Northwest Pipeline Corporation.
10(j)-2	2-60728	5(s)	Service Agreement (Liquefaction-Storage Natural Gas Service), dated as of December 7, 1977, between the Company and Northwest Pipeline Corporation.

* Incorporated herein by reference.

** Filed herewith.

EXHIBIT INDEX (continued)

	Previously Filed*		
Exhibit	**With Registration Number**	**As Exhibit**	
10(j)-3	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)-4	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)-5	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(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(l)-1	1-3701 (with 1986 Form 10-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(s)-1	Agreements for Purchase and Sale of Firm Capacity between the Company and Portland General Electric Company dated March and June 1992.

* Incorporated herein by reference.

** Filed herewith.

AVISTA CORPORATION

EXHIBIT INDEX (continued)

	Previously Filed*		
Exhibit	With Registration Number	As Exhibit	
10(q)-1	1-3701 (with 1992 Form 10-K)	10(t)-8	Executive Deferral Plan of the Company. (***)
10(q)-2	1-3701 (with 1992 Form 10-K)	10(t)-10	The Company's Unfunded Supplemental Executive Retirement Plan. (***)
10(q)-3	1-3701 (with 1992 Form 10-K)	10(t)-11	The Company's Unfunded Supplemental Executive Disability Plan. (***)
10(q)-4	1-3701 (with 1992 Form 10-K)	10(t)-12	Income Continuation Plan of the Company. (***)
10(q)-5	333-03601	10	Non-Employee Director Stock Plan. (***)
10(q)-6	1-3701 (with 1998 Form 10-K)	10(q)-5	Long-Term Incentive Plan. (***)
10(q)-7	1-3701 (with 1999 Form 10-K)	10(q)-7	Employment Agreement between the Company and David J. Meyer. (***)
10(q)-8	**		Employment Agreement between the Company and Malyn K. Malquist. (***)
10(q)-9	333-47290	99.1	Non-Officer Employee Long-Term Incentive Plan
10(q)-10	**		Form of Change of Control Agreement between the Company and its Executive Officers. (***) (1)
10(q)-11	**		Form of Change of Control Agreement between the Company and its Executive Officers. (***) (2)
10(q)-12	**		Form of Change of Control Agreement between the Company and its Executive Officers. (***) (3)
12	**		Statement re computation of ratio of earnings to fixed charges and preferred dividend requirements.
21	**		Subsidiaries of Registrant.
99(a)	**		Certification of Corporate Officers (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)

* 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.

(1) Applies for Karen S. Feltes and Kelly O. Norwood.

(2) Applies for Malyn K. Malquist and, Scott L. Morris.

(3) Applies for Gary G. Ely, David J. Meyer, David A. Brukardt, Christy M. Burmeister-Smith, Ronald R. Peterson, Terry L. Syms and Roger D. Woodworth. New agreements will be entered into during 2004 for these officers consistent with the Change of Control Agreements listed in exhibits 10(q)-10 and 10(q)-11.

Exhibit 3(b)

BYLAWS

OF

AVISTA CORPORATION

As Amended November 8, 2002

BYLAWS
OF
AVISTA CORPORATION

* * * * *

ARTICLE I.
OFFICES

The principal office of the Corporation shall be in the City of Spokane, Washington. The Corporation may have such other offices, either within or without the State of Washington, as the Board of Directors may designate from time to time.

ARTICLE II.
SHAREHOLDERS

SECTION 1. ANNUAL MEETING. The Annual Meeting of Shareholders shall be held on such date in the month of May in each year as determined by the Board of Directors for the purpose of electing directors and for the transaction of such other business as may come before the meeting. If the day fixed for the Annual Meeting shall be a legal holiday, such meeting shall be held on the next succeeding business day.

SECTION 2. SPECIAL MEETINGS. Special meetings of the shareholders may be called by the President, the Chairman of the Board, the majority of the Board of Directors, the Executive Committee of the Board, and shall be called by the President at the request of the holders of not less than two-thirds (2/3) of the voting power of all shares of the voting stock voting together as a single class. Only those matters that are specified in the call of or request for a special meeting may be considered or voted at such meeting.

SECTION 3. PLACE OF MEETING. Meetings of the shareholders, whether they be annual or special, shall be held at the principal office of the Corporation, unless a place, either within or without the state, is otherwise designated by the Board of Directors in the notice provided to shareholders of such meetings.

SECTION 4. NOTICE OF MEETING. Written or printed notice of every meeting of shareholders shall be mailed by the Corporate Secretary or any Assistant Corporate Secretary, not less than ten (10) nor more than fifty (50) days before the date of the meeting, to each holder of record of stock entitled to vote at the meeting. The notice shall be mailed to each shareholder at his last known post office address, provided, however, that if a shareholder is present at a meeting, or waives notice thereof in writing before or after the meeting, the notice of the meeting to such shareholders shall be unnecessary.

SECTION 5. VOTING OF SHARES. At every meeting of shareholders each holder of stock entitled to vote thereat shall be entitled to one vote for each share of such stock held in his name on the books of the Corporation, subject to the provisions of applicable law and the Articles of Incorporation, and may vote and otherwise act in person or by proxy; provided, however, that in elections of directors there shall be cumulative voting as provided by law and by the Articles of Incorporation.

SECTION 6. QUORUM. The holders of a majority of the number of outstanding shares of stock of the Corporation entitled to vote thereat, present in person or by proxy at any meeting, shall constitute a quorum, but less than a quorum shall have power to adjourn any meeting from time to time without notice. No change shall be made in this Section 6 without the affirmative vote of the holders of at least a majority of the outstanding shares of stock entitled to vote.

SECTION 7. CLOSING OF TRANSFER BOOKS OR FIXING OF RECORD DATE. For the purposes of determining shareholders entitled to notice of or to vote at any meeting of shareholders or any adjournment thereof, or shareholders entitled to receive payment of any dividend, or in order to make a determination of shareholders for any other proper purpose, the Board of Directors of the Corporation may provide that the stock transfer books shall be closed for a stated period but not to exceed, in any case, fifty (50) days. If the stock transfer books shall be closed for the purpose of determining shareholders entitled to notice of or to vote at a meeting of shareholders, such books shall be closed for at least ten (10) days immediately preceding such meeting. In lieu of closing the stock transfer books, the Board of Directors may fix in advance a date as the record date for any such determination of shareholders, such date in any case to be not more than seventy (70) days and, in case of a meeting of shareholders, not less than ten (10) days prior to the date on which the particular action, requiring such determination of shareholders, is to be taken. When a determination of shareholders entitled to vote at any meeting of shareholders has been made as provided in this section, such determination shall apply to any adjournment thereof.

SECTION 8. VOTING RECORD. The officer or agent having charge of the stock transfer books for shares of the Corporation shall make, at least ten (10) days before each meeting of shareholders, a complete record of the shareholders entitled to vote at such meeting or any adjournment thereof, arranged in alphabetical order, with the address of and the number of shares held by each, which record, for a period of ten (10) days prior to such meeting, shall be kept on file at the registered office of the Corporation. Such record shall be produced and kept open at the time and place of the meeting and shall be subject to the inspection of any shareholder during the whole time of the meeting for the purposes thereof.

SECTION 9. CONDUCT OF PROCEEDINGS. The Chairman of the Board shall preside at all meetings of the shareholders. In the absence of the Chairman, the President shall preside and in the absence of both, the Executive Vice President shall preside. The members of the Board of Directors present at the meeting may appoint any officer of the Corporation or member of the Board to act as Chairman of any meeting in the absence of the Chairman, the President, or Executive Vice President. The Corporate Secretary of the Corporation, or in his absence, an Assistant Corporate Secretary, shall act as Secretary at all meetings of the shareholders. In the absence of the Corporate Secretary or Assistant Corporate Secretary at any meeting of the shareholders, the presiding officer may appoint any person to act as Secretary of the meeting.

SECTION 10. PROXIES. At all meetings of shareholders, a shareholder may vote in person or by proxy. A shareholder or the shareholder's duly authorized agent or attorney-in-fact may appoint a proxy by (i) executing a proxy in writing or (ii) transmitting or authorizing the transmission of an electronic proxy in any manner permitted by law. Such proxy shall be filed with the Corporate Secretary of the Corporation before or at the time of the meeting.

ARTICLE III.

BOARD OF DIRECTORS

SECTION 1. GENERAL POWERS. The powers of the Corporation shall be exercised by or under the authority of the Board of Directors, except as otherwise provided by the laws of the State of Washington and the Articles of Incorporation.

SECTION 2. NUMBER AND TENURE. The number of Directors of the Corporation shall be nine (9); provided, however, that if the right to elect a majority of the Board of Directors shall have accrued to the holders of the Preferred Stock as provided in paragraph (1) of subdivision (j) of Article THIRD of the Articles of Incorporation, then, during such period as such holders shall have such right, the number of directors may exceed nine (9). Directors shall be divided into three classes, as nearly equal in number as possible. At each Annual Meeting of Shareholders, directors elected to succeed those directors whose terms expire shall be elected for a term of office to expire at the third succeeding Annual Meeting of Shareholders after their election. Notwithstanding the foregoing, directors elected by the holders of the Preferred Stock in accordance with paragraph (1) of subdivision (j) of Article THIRD of the Articles of Incorporation shall be elected for a term which shall expire not later than the next Annual Meeting of Shareholders. All directors shall hold office until the expiration of their respective terms of office and until their successors shall have been elected and qualified.

SECTION 3. REGULAR MEETINGS. The regular annual meeting of the Board of Directors shall be held immediately following the adjournment of the annual meeting of the shareholders or as soon as practicable after said annual meeting of shareholders. But, in any event, said regular annual meeting of the Board of Directors must be held on either the same day as the annual meeting of shareholders or the next business day following said annual meeting of shareholders. At such meeting the Board of Directors, including directors newly elected, shall organize itself for the coming year, shall elect officers of the Corporation for the ensuing year, and shall transact all such further business as may be necessary or appropriate. The Board shall hold regular quarterly meetings, without call or notice, on such dates as determined by the Board of Directors. At such quarterly meetings the Board of Directors shall transact all business properly brought before the Board.

SECTION 4. SPECIAL MEETINGS. Special meetings of the Board of Directors may be called by or at the request of the Chairman of the Board, the President, the Executive Vice President or any three (3) directors. Notice of any special meeting shall be given to each director at least two (2) days in advance of the meeting.

SECTION 5. EMERGENCY MEETINGS. In the event of a catastrophe or a disaster causing the injury or death to members of the Board of Directors and the principal officers of the Corporation, any director or officer may call an emergency meeting of the Board of Directors. Notice of the time and place of the emergency meeting shall be given not less than two (2) days prior to the meeting and may be given by any available means of communication. The director or directors present at the meeting shall constitute a quorum for the purpose of filling vacancies determined to exist. The directors present at the emergency meeting may appoint such officers as necessary to fill any vacancies determined to exist. All appointments under this section shall be temporary until a special meeting of the shareholders and directors is held as provided in these Bylaws.

SECTION 6. CONFERENCE BY TELEPHONE. The members of the Board of Directors, or of any committee created by the Board, may participate in a meeting of the Board or of the committee by means of a conference telephone or similar communication equipment by means of which all persons participating in the meeting can hear each other at the same time. Participation in a meeting by such means shall constitute presence in person at a meeting.

SECTION 7. QUORUM. A majority of the number of directors shall constitute a quorum for the transaction of business at any meeting of the Board of Directors. The action of a majority of the directors present at a meeting at which a quorum is present shall be the action of the Board.

SECTION 8. ACTION WITHOUT A MEETING. Any action required by law to be taken at a meeting of the directors of the Corporation, or any action which may be taken at a meeting of the directors or of a committee, may be taken without a meeting if a consent in writing, setting forth the action so taken, shall be signed by all of the directors, or all of the members of the committee, as the case may be. Such consent shall have the same effect as a unanimous vote.

SECTION 9. VACANCIES. Subject to the provisions of paragraph (1) of subdivision (j) of Article THIRD of the Articles of Incorporation, (a) any vacancy occurring in the Board of Directors may be filled by the affirmative vote of a majority of the remaining directors though less than a quorum of the Board of Directors and any director so elected to fill a vacancy shall be elected for the unexpired term of his or her predecessor in office and (b) any directorship to be filled by reason of an increase in the number of directors may be filled by the Board of Directors for a term of office continuing only until the next election of directors by the shareholders.

SECTION 10. RESIGNATION OF DIRECTOR. Any director or member of any committee may resign at any time. Such resignation shall be made in writing and shall take effect at the time specified therein. If no time is specified, it shall take effect from the time of its receipt by the Corporate Secretary, who shall record such resignation, noting the day, hour and minute of its reception. The acceptance of a resignation shall not be necessary to make it effective.

SECTION 11. REMOVAL. Subject to the provisions of paragraph (1) of subdivision (j) of Article THIRD of the Articles of Incorporation, any director may be removed from office at any time, but only for cause and only by the affirmative vote of the holders of at least a majority of the voting power of all of the shares of capital stock of the Corporation entitled generally to vote in the election of directors voting together as a single class, at a meeting of shareholders called expressly for that purpose; provided, however, that if less than the entire Board of Directors is to be removed, no one of the directors may be removed if the votes cast against the removal of such director would be sufficient to elect such director if then cumulatively voted at an election of the class of directors of which such director is a part. No decrease in the number of directors constituting the Board of Directors shall shorten the term of any incumbent director.

SECTION 12. ORDER OF BUSINESS. The Chairman of the Board shall preside at all meetings of the directors. In the absence of the Chairman, the officer or member of the Board designated by the Board of Directors shall preside. At meetings of the Board of Directors, business shall be transacted in such order as the Board may determine. Minutes of all proceedings of the Board of Directors, or committees appointed by it, shall be prepared and maintained by the Corporate Secretary or an Assistant Corporate Secretary and the original shall be maintained in the principal office of the Corporation.

SECTION 13. NOMINATION OF DIRECTORS. Subject to the provisions of paragraph (1) of subdivision (j) of Article THIRD of the Articles of Incorporation, nominations for the election of directors may be made by the Board of Directors, or a nominating committee appointed by the Board of Directors, or by any holder of shares of the capital stock of the Corporation entitled generally to vote in the election of directors (such stock being hereinafter in this Section called "Voting Stock"). However, any holder of shares of the Voting Stock may nominate one or more persons for election as directors at a meeting only if written notice of such shareholder's intent to make such nomination or nominations has been given, either by personal delivery or by United States mail, postage prepaid, to the Corporate Secretary not later than (i) with respect to an election to be held at an annual meeting of shareholders, ninety (90) days in advance of such meeting and (ii) with respect to an election to be held at a special meeting of shareholders for the election of directors, the close of business on the seventh day following the date on which notice of such meeting is first given to shareholders. Each such notice shall set forth: (a) the name and address of the shareholder who intends to make the nomination and of the person or persons to be nominated; (b) a representation that such shareholder is a holder of record of shares of the Voting Stock of the Corporation and intends to appear in person or by proxy at the meeting to nominate the person or persons identified in the notice; (c) a description of all arrangements or understandings between such shareholder and each nominee and any other person or persons (naming such person or persons) pursuant to which the nomination or nominations are to be made by such shareholder; (d) such other information regarding each nominee proposed by such shareholder as would be required to be included in a proxy statement under the Securities Exchange Act of 1934, as amended, and the rules and regulations thereunder (or any subsequent revisions replacing such Act, rules or regulations) if the nominee(s) had been nominated, or were intended to be nominated, by the Board of Directors; and (e) the consent of each nominee to serve as a Director of the Corporation if so elected. The Chairman of the meeting may refuse to acknowledge the nomination of any person not made in compliance with the foregoing procedure.

SECTION 14. PRESUMPTION OF ASSENT. A director of the Corporation who is present at a meeting of the Board of Directors, or of a committee thereof, at which action on any corporate matter is taken, shall be presumed to have assented to the action unless his dissent shall be entered in the minutes of the meeting or unless he shall file his written dissent to such action with the person acting as the Secretary of the meeting before the adjournment thereof or shall forward such dissent by registered mail to the Corporate Secretary of the Corporation immediately after the adjournment of the meeting. Such right to dissent shall not apply to a director who voted in favor of such action.

SECTION 15. RETIREMENT OF DIRECTORS. Directors who are seventy (70) years of age or more shall retire from the Board effective at the conclusion of the Annual Meeting of Shareholders held in the year in which their term expires, and any such Director shall not be nominated for election at such Annual Meeting. The foregoing shall be effective in 1988 and thereafter as to any Director who is seventy (70) years of age or more during the year in which his or her term expires.

ARTICLE IV.
EXECUTIVE COMMITTEE
AND
ADDITIONAL COMMITTEES

SECTION 1. APPOINTMENT. The Board of Directors, by resolution adopted by a majority of the Board, may designate three or more of its members to constitute an Executive Committee. The designation of such committee and the delegation thereto of authority shall not operate to relieve the Board of Directors, or any member thereof, of any responsibility imposed by law.

SECTION 2. AUTHORITY. The Executive Committee, when the Board of Directors is not in session, shall have and may exercise all of the authority of the Board of Directors including authority to authorize distributions or the issuance of shares of stock, except to the extent, if any, that such authority shall be limited by the resolution appointing the Executive Committee or by law.

SECTION 3. TENURE. Each member of the Executive Committee shall hold office until the next regular annual meeting of the Board of Directors following his designation and until his successor is designated as a member of the Executive Committee.

SECTION 4. MEETINGS. Regular meetings of the Executive Committee may be held without notice at such times and places as the Executive Committee may fix from time to time by resolution. Special meetings of the Executive Committee may be called by any member thereof upon not less than two (2) days notice stating the place, date and hour of the meeting, which notice may be written or oral. Any member of the Executive Committee may waive notice of any meeting and no notice of any meeting need be given to any member thereof who attends in person.

SECTION 5. QUORUM. A majority of the members of the Executive Committee shall constitute a quorum for the transaction of business at any meeting thereof. Actions by the Executive Committee must be authorized by the affirmative vote of a majority of the appointed members of the Executive Committee.

SECTION 6. ACTION WITHOUT A MEETING. Any action required or permitted to be taken by the Executive Committee at a meeting may be taken without a meeting if a consent in writing, setting forth the action so taken, shall be signed by all of the members of the Executive Committee.

SECTION 7. PROCEDURE. The Executive Committee shall select a presiding officer from its members and may fix its own rules of procedure which shall not be inconsistent with these Bylaws. It shall keep regular minutes of its proceedings and report the same to the Board of Directors for its information at a meeting thereof held next after the proceedings shall have been taken.

SECTION 8. COMMITTEES ADDITIONAL TO EXECUTIVE COMMITTEE. The Board of Directors may, by resolution, designate one or more other committees, each such committee to consist of two (2) or more of the directors of the Corporation. A majority of the members of any such committee may determine its action and fix the time and place of its meetings unless the Board of Directors shall otherwise provide.

ARTICLE V.
OFFICERS

SECTION 1. NUMBER. The Board of Directors shall elect one of its members Chairman of the Board. The Board of Directors shall elect a President, who may also serve as Chairman, one or more Vice Presidents, a Corporate Secretary, a Treasurer, and may from time to time elect such other officers as the Board deems appropriate. The same person may be appointed to more than one office, except that the offices of President and Corporate Secretary may not be held by the same person. The Board of Directors has granted authority to the Chief Executive Officer to appoint such assistant officers as might be deemed appropriate.

SECTION 2. ELECTION AND TERM OF OFFICE. The officers of the Corporation shall be elected by the Board of Directors at the annual meeting of the Board. Each officer shall hold office until his successor shall have been duly elected and qualified.

SECTION 3. REMOVAL. Any officer or agent may be removed by the Board of Directors whenever in its judgment the best interests of the Corporation will be served thereby, but such removal shall be without prejudice to contract rights, if any, of the person so removed. Election or appointment of an officer or agent shall not of itself create contract rights.

SECTION 4. VACANCIES. A vacancy in any office because of death, resignation, removal, disqualification or otherwise may be filled by the Board of Directors for the unexpired portion of the term.

SECTION 5. POWERS AND DUTIES. The officers shall have such powers and duties as usually pertain to their offices, except as modified by the Board of Directors, and shall have such other powers and duties as may from time to time be conferred upon them by the Board of Directors.

ARTICLE VI.
CONTRACTS, CHECKS AND DEPOSITS

SECTION 1. CONTRACTS. The Board of Directors may authorize any officer or officers or agents, to enter into any contract or to execute and deliver any instrument in the name of and on behalf of the Corporation, and such authority may be general or confined to specific instances.

SECTION 2. CHECKS/DRAFTS/NOTES. All checks, drafts or other orders for the payment of money, notes or other evidences of indebtedness issued in the name of the Corporation shall be signed by such officer or officers, agent or agents of the Corporation and in such manner as shall from time to time be determined by resolution of the Board of Directors.

SECTION 3. DEPOSITS. All funds of the Corporation not otherwise employed shall be deposited from time to time to the credit of the Corporation in such banks, trust companies or other depositories as the Board of Directors by resolution may select.

ARTICLE VII.
CERTIFICATES FOR SHARES AND THEIR TRANSFER

SECTION 1. CERTIFICATES FOR SHARES. Certificates representing shares of the Corporation shall be in such form as shall be determined by the Board of Directors and shall contain such information as prescribed by law. Such certificates shall be signed by the President or a Vice President and by either the Corporate Secretary or an Assistant Corporate Secretary, and sealed with the corporate seal or a facsimile thereof. The signatures of such officers upon a certificate may be facsimiles. The name and address of the person to whom the shares represented thereby are issued, with the number of shares and date of issue, shall be entered on the stock transfer books of the Corporation. All certificates surrendered to the Corporation for transfer shall be cancelled and no new certificate shall be issued until the former certificate for a like number of shares shall have been surrendered and cancelled, except that in case of a lost, destroyed or mutilated certificate a new one may be issued therefor upon such terms and indemnity to the Corporation as the Board of Directors may prescribe.

SECTION 2. TRANSFER OF SHARES. Transfer of shares of the Corporation shall be made only on the stock transfer books of the Corporation by the holder of record thereof or by his legal representative, who shall furnish proper evidence of authority to transfer, or by his attorney thereunto authorized by power of attorney duly executed and filed with the Corporate Secretary of the Corporation, and on surrender for cancellation of the certificate for such shares. The person in whose name shares stand on the books of the Corporation shall be deemed by the Corporation to be the owner thereof for all purposes. The Board of Directors shall have power to appoint one or more transfer agents and registrars for transfer and registration of certificates of stock.

ARTICLE VIII.
CORPORATE SEAL

The seal of the Corporation shall be in such form as the Board of Directors shall prescribe.

ARTICLE IX.
INDEMNIFICATION

SECTION 1. INDEMNIFICATION OF DIRECTORS AND OFFICERS. The Corporation shall indemnify and reimburse the expenses of any person who is or was a director, officer, agent or employee of the Corporation or is or was serving at the request of the Corporation as a director, officer, partner, trustee, employee, or agent of another enterprise or employee benefit plan to the extent permitted by and in accordance with Article SEVENTH of the Company's Articles of Incorporation and as permitted by law.

SECTION 2. LIABILITY INSURANCE. The Corporation shall have the power to purchase and maintain insurance on behalf of any person who is or was a director, officer, employee, or agent of the Corporation or is or was serving at the request of the Corporation as a director, officer, employee or agent of another corporation, partnership, joint venture, trust, other enterprise, or employee benefit plan against any liability asserted against him and incurred by him in any such capacity or arising out of his status as such, whether or not the Corporation would have the power to indemnify him against such liability under the laws of the State of Washington.

SECTION 3. RATIFICATION OF ACTS OF DIRECTOR, OFFICER OR SHAREHOLDER. Any transaction questioned in any shareholders' derivative suit on the ground of lack of authority, defective or irregular execution, adverse interest of director, officer or shareholder, nondisclosure, miscomputation, or the application of improper principles or practices of accounting may be ratified before or after judgment, by the Board of Directors or by the shareholders in case less than a quorum of directors are qualified; and, if so ratified, shall have the same force and effect as if the questioned transaction had been originally duly authorized, and said ratification shall be binding upon the Corporation and its shareholders and shall constitute a bar to any claim or execution of any judgment in respect of such questioned transaction.

ARTICLE X.
AMENDMENTS

Except as to Section 6 of Article II of these Bylaws, the Board of Directors may alter or amend these Bylaws at any meeting duly held, the notice of which includes notice of the proposed amendment. Bylaws adopted by the Board of Directors shall be subject to change or repeal by the shareholders; provided, however, that Section 2 of the Article II, Section 2 (other than the provision thereof specifying the number of Directors of the Corporation), and Sections 9, 11 and 13 of Article III and this proviso shall not be altered, amended or repealed, and no provision inconsistent therewith or herewith shall be included in these Bylaws, without the affirmative votes of the holders of at least eighty percent (80%) of the voting power of all the shares of the Voting Stock voting together as a single class.

PRIEST RAPIDS PROJECT

PRODUCT SALES CONTRACT

INDEX TO SECTIONS

Exhibits

PRIEST RAPIDS PROJECT PRODUCT SALES CONTRACT

Executed by
PUBLIC UTILITY DISTRICT NO. 2
OF GRANT COUNTY
And
AVISTA CORPORATION

This contract is entered into as of December 12, 2001 between Public Utility District No. 2 of Grant County, Washington (the "District"), a municipal corporation of the State of Washington, and Avista Corporation (the "Purchaser"), a corporation organized and existing under the laws of the State of Washington. The District and the Purchaser are referred to as a "Party" and collectively as "Parties."

SECTION 1. TERM OF CONTRACT

(a) Except as otherwise provided herein, this contract shall be in full force and effect from and after it has been executed by the District and the Purchaser. Unless sooner terminated pursuant to other provisions, this contract shall remain in effect until the earlier of expiration or termination of the New FERC License or such time that the District no longer has authority to market Priest Rapids Project Products. Except as otherwise provided herein, all obligations accruing under this contract are preserved until satisfied.

(b) By executing this contract, the Purchaser has exercised all of the Purchaser's rights, and the District has fulfilled and satisfied all of the District's obligations, under Section(1)(b) of the 1956 and 1959 Contracts. Upon execution of this contract by the District and the Purchaser, Section 1(b) of the 1956 and 1959 Contracts shall have no further force or effect; provided, however, by executing this contract the Parties intend to preserve the right of Purchaser to exercise the first right of refusal under Section 1(b) of the 1956 and 1959 Contracts against a successor licensee other than the District.

(c) Notwithstanding Section 1(a), the affirmative obligations of the Parties in Sections 3(a), (b) and (c), 4 through 7, 9 through 14, 16, 17 and 28 (a) and (b)(1-4) shall take effect on November 1, 2005.

(d) Parties to the 1956 Contract and the Idaho Cooperatives shall have until October 31, 2005 to execute this contract. Parties to the 1959 Contract shall have until October 31, 2009 to execute this contract.

SECTION 2. DEFINITIONS.

As used in this contract, the following terms when initially capitalized shall have the following meanings:

"1956 Contract" shall mean the contract entered into by the District and various parties during May 1956 for the sale of capacity and energy from the Priest Rapids Development as supplemental and amended from time to time.

"1959 Contract" shall mean the contract entered into by the District and various parties during June 1959 for the sale of capacity and energy from the Wanapum Development as supplemented and amended from time to time.

"Annual FERC License" shall mean a license for the Priest Rapids Project issued by FERC to the District for an interim period before a New FERC License.

"Bond Resolution" shall mean each and all of the resolutions adopted by the District authorizing the issuance of outstanding Debt for the Priest Rapids Project.

"Contract Year" shall mean the 12 month period commencing at 12:01 a.m. on January 1 of each year and ending at 12:01 a.m. on the following January 1; provided, however, that the first Contract Year shall commence on November 1, 2005, and end the following January 1, 2006, and that the last Contract Year shall end on the last day of the New FERC License, or such time that the District no longer has authority to market Priest Rapids Project Products.

"Contract(s)" shall mean this contract and similar contracts between the District and other Purchasers.

"Debt" shall mean any bonds, notes, or other debt obligations of the District, including, but not limited to all bonds outstanding at the effective date of this contract, a line of credit, installment purchase agreement, financing lease, interfund loan, derivative securities or payment obligations and any other obligation for borrowed money, the proceeds of which will be used for the benefit of the Priest Rapids Project, including to finance betterments, renewals, replacements and additions to the Priest Rapids Project, to refund other debt, or any other lawful purpose related to the Priest Rapids Project. Debt does not include the Columbia River-Priest Rapids Hydro-Electric Production System Revenue Bonds, Series 1956, which have been paid, or the Wanapum Hydroelectric Refunding Revenue Bonds, Series 1963, which are scheduled to be repaid on or prior to January 1, 2004.

"Displacement Resource" means the monthly amounts of capacity and energy set forth in Exhibit A to this contract. If the District obtains a Replacement Contract, or if the District and the Purchaser mutually agree in writing to use some other resource as a Displacement Resource, the District and the Purchaser will revise Exhibit A to reflect the capacity and energy of such Replacement Contract or resource.

"Electric System" shall mean the separate electric utility system of the District, including all associated generation, transmission and distribution facilities and any betterments, renewals, replacements and additions of such system, but does not include the Priest Rapids Project or any other utility properties designated as a separate utility system of the District.

"Eligible Purchasers" means the parties to the 1956 and 1959 Contracts, and the Kootenai Electric Cooperative, Inc., Clearwater Power Company, Idaho County Light and Power Cooperative Association, Inc., Northern Lights, Inc. and the electric cooperative members of the

Snake River Power Association, Inc. (collectively, the "Idaho Cooperatives") as of October 31, 2000.

"FERC" shall mean the Federal Energy Regulatory Commission or its successor.

"FERC License" shall mean any license for the Priest Rapids Project issued by FERC to the District.

"Market Price" shall mean the price (in dollars per megawatt-hour) on the wholesale power market for firm power in amounts equal to the Surplus Product and Displacement Product, respectively, forecast to be available to Purchaser during the next Contract Year pursuant to Sections 5(d) and 5(h), multiplied by such amounts of Surplus Product and Displacement Product.

"Marketing Plan" shall mean the plan for making available in a fair, equitable, and non-discriminatory manner pursuant to market-based principles and procedures the Reasonable Portion as required by applicable law or PL 83-544 Orders.

"New FERC License" shall mean the license issued by FERC to the District following the expiration of the Original FERC License for operation of the Priest Rapids Project for a duration of 30 years or longer, not including any subsequent annual or other license.

"Operating Agreements" shall mean any agreements to which the District is or may become a party, which provide for operation of the Priest Rapids Project, including but not limited to, the Pacific Northwest Coordination Agreement, the Agreement for the Hourly Coordination of Projects on the Mid-Columbia River, the Western Systems Coordinating Council Agreement, the Agreement Relating to Wanapum Development Encroachment on the Rock Island Project and the Northwest Power Pool, which is the voluntary association of utilities formed in the Pacific Northwest for the purpose of ensuring the adequacy and reliability of the electric power systems in the Pacific Northwest.

"Original FERC License" shall mean the Federal Power Commission License for the Priest Rapids Project issued to the District on November 4, 1955, together with amendments thereto.

"Pacific Northwest" shall have the meaning ascribed thereto in Section 3(14) of the Regional Act.

"Priest Rapids Development" shall mean the separate utility system of the District, including a dam at the Priest Rapids Development, all generation and transmission facilities associated therewith, and all betterments, renewals, replacements, and additions to such system, as further described in Section 2(f) of Exhibit 1 of District Resolution No. 390 which is attached as Exhibit B, but shall not include any additional generation, transmission and distribution facilities hereafter constructed or acquired by the District as a part of the Electric System or the Wanapum Development or any other utility properties of the District acquired or constructed as a separate utility system.

"Priest Rapids Project" shall mean the hydroelectric project on the Columbia River in the State of Washington designated by the Federal Power Commission as Project No. 2114. The Priest Rapids Project consists of the Priest Rapids Development and the Wanapum Development.

"Priest Rapids Project Output" shall mean the amount of capacity, energy (both firm and non-firm), pondage, reactive power, ancillary services and any other product from the Priest Rapids Development from November 1, 2005 to November 1, 2009 and from the Priest Rapids Project from November 1, 2009 through the term of this contract under the operating conditions which exist during the term, including periods when the Priest Rapid Project may be wholly or partially inoperable for any reason, after correction for encroachment, Canadian entitlement, station and project use, and depletions required by the FERC License or other regulatory requirements.

"Priest Rapids Project Products" means those products that the District agrees to sell to the Purchaser, and the Purchaser agrees to purchase as more particularly described in Sections 3 and 5 hereof, and is limited to the Surplus Product and the Displacement Product.

"Prudent Utility Practice" means those practices, methods and acts which: (i) when engaged in are commonly used in prudent engineering and operations to operate electric equipment and associated mechanical and civil facilities lawfully and with safety, reliability, efficiency and expedition or (ii) in the exercise of reasonable judgment considering the facts known when engaged in, could have been reasonably expected to achieve the desired result consistent with applicable law, safety, reliability, efficiency and expedition. "Prudent Utility Practice" is not intended to be the optimum practice, method or act, to the exclusion of all others, but rather to be a spectrum of commonly used practices, methods or acts.

"Public Law 83-544" (or "PL 83-544") shall mean the legislation passed by the 83rd Congress authorizing the District to develop the Priest Rapids Project.

"Purchasers" shall mean the Purchaser and each person or entity that has entered into a contract with the District substantially similar to this contract.

"Purchaser Product Percentage" shall mean the fixed percentage (stated to the second decimal point, e.g., 0.01%) as set forth in Section 3 for each of the individual Priest Rapids Project Products made available under this contract. For parties to the 1956 and 1959 Contracts, Purchaser Product Percentage for any one Priest Rapids Project Product in this contract may not exceed twice the average of their participation in the 1956 and 1959 Contracts except that for those Purchasers that were parties to the 1956 Contracts but were not parties to the 1959 Contracts their Purchaser Product Percentage for the period November 1, 2005 to October 31, 2009 may not exceed twice their participation in the 1956 Contract. For any individual Idaho Cooperative, Purchaser Product Percentage shall not exceed the Purchaser Product Percentage of any individual party to the 1956 or 1959 Contract that is one of the Purchasers except when the provisions of Section 3(c) are applied. Each of such fixed percentages is subject to revision pursuant to Sections 3(c), (d), (e), (f), and 5(j).

"Reasonable Portion" shall mean that 30% portion of the Priest Rapids Project Output required by FERC pursuant to Public Law 83-544 to be offered for sale by the District.

"Regional Act" shall mean Public Law 96-501, the Pacific Northwest Electric Power Planning and Conservation Act.

"Risk Premium" shall mean the sum of the following: (i) for the Surplus Product, the positive difference for a year determined by subtracting from the Market Price of the Surplus Product the cost to the Purchaser of the Surplus Product during each year pursuant to Section 7(a)(3); and (ii) for the Displacement Product, the positive difference for a year determined by subtracting from the Market Price of the Displacement Product the cost to the Purchaser of the Displacement Product during each year pursuant to Section 7(a)(4).

"Risk Premium Revenues" shall mean the payments received by the District from all Purchasers pursuant to Section 7(a)(5).

"Uncontrollable Forces" shall mean any cause reasonably beyond the control of the Party and which the Party subject thereto has made reasonable efforts to avoid, remove or mitigate, including but not limited to acts of God, fire, flood, explosion, strike, sabotage, act of the public enemy, civil or military authority, including court orders, injunctions, and orders of government agencies with proper jurisdiction, insurrection or riot, an act of the elements, failure of equipment or contractors, or inability to obtain or ship materials or equipment because of the affect of similar causes on suppliers or carriers; provided, however, that in no event shall an Uncontrollable Force excuse the Purchaser from the obligation to pay any amount when due and owing under this contract.

"Wanapum Development" shall mean the second stage of the Priest Rapids Project as more fully described in Section 2.2 of District Resolution No. 474, which is attached as Exhibit B, but shall not include any generation, transmission and distribution facilities hereafter constructed or acquired by the District as a part of the Electric System or the Priest Rapids Development, or any other utility properties of the District acquired or constructed as a separate utility system.

The following terms are defined in the cited sections of this contract:

"Act of Default" at Section 22(a).
"Annual Power Costs" at Section 6(a).
"Committee" at Section 28.
"Coverage Requirement" at Section 6(a)(9).
"Displacement Product" at Section 3(b).
"District Reserved Share" at Section 5(b)(3).
"Estimated District Loads" at Section 5(b)(1).
"Estimated Unmet District Loads" at Section 5(f).
"Excess Costs" at Section 7(g).
"Financing Costs" at Section 6(a)(3).
"Idaho Cooperatives" at "Eligible Purchasers."
"Improvements" at Section 5(j)(4).
"New FERC License Costs" at Section 6(a)(6).
"Party" and "Parties" at the Preamble.
"PL 83-544 Orders" at Section 3(f).
"Purchaser Actual Cost" at Section 7(g).
"Purchaser Allocation of Pondage" at Section 9(d)(5).
"Purchaser Estimated Cost" at Section 7(a)(8).

"Purchaser Power Allocation" at Section 5(b)(4).
"Purchaser Product Percentage of Displacement Product" at Section 3(b).
"Purchaser Product Percentage of Surplus Product" at Section 3(a).
"Purchaser Risk Premium" at Section 7(a)(5).
"Refund Costs" at Section 7(g).
"Replacement Contract" at Section 3(b).
"Rock Island Hydroelectric Project" at Section 16(b).
"Supplemental Displacement Product Agreement" at Section 3(b).
"Surplus Product" at Section 3(a).

SECTION 3. PRIEST RAPIDS PROJECT PRODUCTS AND PURCHASER PRODUCT PERCENTAGES; REGULATORY APPROVALS.

Upon execution of this contract, Purchaser shall select a Purchaser Product Percentage for each of the Priest Rapids Project Products described below; provided, however, that Purchaser must select a Purchaser Product Percentage of Surplus Product other than zero in order to select Purchaser Product Percentage for Displacement Product. Each of the Purchaser Product Percentages selected may be a difference percentage, and the Purchaser Product Percentages for Displacement Product may be zero.

(a) SURPLUS PRODUCT. The District desires to market Priest Rapids Project Output that is surplus to its needs. To minimize the volatility of such marketing and in order to achieve stable retail rates, the District desires to market this surplus in a manner that the Purchaser assumes the uncertainty of future Priest Rapids Project Output, costs and market prices. To accomplish these objectives the District believes that the price for the Surplus Product should be at cost.

The District shall sell to the Purchaser and the Purchaser shall purchase 25 percent of Surplus Product ("Purchaser Product Percentage of Surplus Product"). The amount and cost of the Surplus Product is defined in Sections 5 and 6, respectively.

(b) DISPLACEMENT PRODUCT. The District desires to enhance its success in obtaining a New FERC License by making available to other electric utilities in the Pacific Northwest benefits that would not otherwise be possible but for the Priest Rapids Project. For this purpose, the District may, pursuant to this contract, offer the Purchaser Priest Rapids Project Output that otherwise would be used by the District to meet Estimated District Loads but for capacity and energy acquired by the District from Displacement Resources.

The District shall sell to the Purchaser and the Purchaser shall purchase 25 percent of Displacement Product ("Purchaser Product Percentage of Displacement Product"). The amount and cost of Displacement Product is defined in Sections 5 and 6, respectively. The Displacement Product does not entail the resale of federal power available to the District.

By notification to the District by October 1, 2005, the Purchaser may elect to have the District market the Purchaser Product Percentage of the Displacement Product pursuant to a supplementary agreement between the Purchaser and the District. The District will assign to the Purchaser the cost incurred by the District in marketing such Displacement Product.

The District may at its discretion seek a resource to extend the availability of the capacity and energy identified in Exhibit A beyond 2011 ("Replacement Contract"). If the District has determined to not seek a Replacement Contract, nevertheless upon the request of the Purchaser and after execution of an agreement or agreements ("Supplemental Displacement Product Agreement") by the District and all requesting Purchasers setting forth the term of the Replacement Contract, the product to be purchased, and the obligation of requesting Purchasers to pay the District an amount equal to any and all costs, charges, surcharges and penalties payable under such Replacement Contract, the District will use reasonable efforts to obtain a Replacement Contract. If such a Replacement Contract is obtained, an amount equal to the capacity and energy available thereunder will be offered to the Purchaser pursuant to the terms of this contract as the Displacement Product, subject to the terms of any Supplemental Displacement Product Agreement.

(c) REALLOCATION. If collectively Purchasers subscribe to Purchaser Product Percentages for any Priest Rapids Project Product that total more than 100%, either initially or at any time before the time limits set forth in Section 1(d), then Purchaser Product Percentages for such Priest Rapids Project Product will be determined as follows; provided, however, that the application of the following formula shall not result in the Purchaser being assigned a Purchaser Product Percentage larger than that included in this contract on the date of execution:

(1) Step 1. Each such Priest Rapids Project Product will be divided between parties to the 1956 and 1959 Contracts, as a group, and the Idaho Cooperatives, as a group, in proportion to the number of retail electric customers located in the Pacific Northwest (determined by the number of retail meters) served by each group as of October 31, 2000.

(2) Step 2. Each Purchaser Product Percentage of such Priest Rapids Project Product will be determined as follows:

(A) For parties to the 1956 and 1959 Contracts, the proportion of such Priest Rapids Project Product from Step 1 above will be distributed to individual Purchasers as follows:

(i) For November 1, 2005 through October 31, 2009 the Surplus Product shall be distributed in proportion to participation in the 1956 Contract and the Displacement Product shall be distributed in proportion to participation in the 1956 Contract and 1959 Contract weighted 25% and 75%, respectively.

(ii) For the period after November 1, 2009 the Surplus Product and Displacement Product shall be distributed in proportion to the sum of participation in the 1956 Contract and 1959 Contract divided by two.

(iii) Notwithstanding any other provision of this contract, for those Eligible Purchasers that sign this contract after December 31, 2001, the Purchaser Product Percentage for the Surplus Product and the Displacement Product may not exceed the average of the Purchaser's Power Allocations, as those terms are defined in the 1956 and 1959 Contracts, divided by 63.5 percent.

(iv) Notwithstanding any other provision of this contract, for those Eligible Purchasers that sign this contract after October 31, 2005, their participation in the Priest Rapids Development shall be deemed to be zero for purposes of determining their Purchaser Product Percentage for the Surplus Product and the Displacement Product under this contract.

(B) For the Idaho Cooperatives, the proportion of such Priest Rapids Project Product from Step 1 will be distributed to individual cooperatives in proportion to the number of retail electric customers located in the Pacific Northwest (determined by number of retail meters) each cooperative served as of October 31, 2000.

(d) If the reallocation procedure of Section 3(c) is implemented, then for the period November 1, 2005 through October 31, 2009, the following shall apply to those Purchasers who were parties to the 1956 Contracts but were not parties to the 1959 Contracts:

(1) The Purchaser Product Percentage of Displacement Product shall be adjusted to be in proportion to participation in the 1956 Contract (the Purchaser's percent participation in the 1956 Contract divided by 63.5%).
(2) The District shall be obligated to provide the Displacement Product pursuant to Section 5 using the Purchaser Product Percentage of Displacement Product as calculated pursuant to Section 3(d)(1), and the Purchaser shall be obligated to make payments for the Displacement Product pursuant to Sections 6 and 7 using such Purchaser Product Percentage of Displacement Product.

The adjustments to Purchaser Product Percentage of Displacement Product will have no effect on the Purchaser Product Percentage of any other Product hereunder, nor on the Purchaser Product Percentage of any other Purchaser.

(e) If a Contract with one of the Purchasers is terminated pursuant to Section 22 as a result of such Purchaser's Act of Default, the District shall give the non-defaulting Purchasers notice of such default. Beginning with the first month that is at least 30 days following such notice, the Purchaser Product Percentages of Surplus and Displacement Products (other than zero) of non-defaulting Purchasers shall be increased pro rata until either: (i) the Purchaser Product Percentages of Surplus and Displacement Products of the defaulting Purchaser have been fully allocated or (ii) a further pro rata increase to the Purchaser Product Percentages of Surplus and Displacement Products of the non-defaulting Purchasers would adversely affect the tax-exempt status of any outstanding Debt. In the event of (ii), the portion of the Purchaser Product Percentages of Surplus and Displacement Products of the defaulting Purchaser not yet allocated will be offered to all Purchasers that can accept such allocation without adversely affecting the tax-exempt status of any outstanding Debt. If after such offer there remains some portion of the Purchaser Product Percentages of Surplus and Displacement Products of the defaulting Purchaser not yet allocated, the District, at its discretion may elect to accept such unallocated portion. If after all of the foregoing there remains unallocated Purchaser Product Percentages of Surplus and Displacement Products of the defaulting Purchaser, the Purchaser Product Percentages of Surplus and Displacement Products (other than zero) of non-defaulting Purchasers shall be increased pro rata based on each such non-defaulting Purchaser's Purchaser Product Percentages of Surplus and Displacement Products before any allocation under this Section 3(c). In the event that the allocation described in the immediately preceding sentence adversely affects the tax-exempt status of Debt, any increased costs resulting therefrom will be included in Annual Power Costs. Nothing in this subsection is intended to limit any claims the non-defaulting Purchasers may assert against the defaulting Purchaser.

(1) REGULATORY APPROVALS. The District and the Purchaser believe that this contract fully complies with the requirements of Public Law 83-544. FERC has ordered that a Reasonable Portion of the Priest Rapids Project Output be offered for sale based on market principles and that Eligible Purchasers are to receive a meaningful priority. Additionally, FERC has stated that the District may negotiate power contracts as part of the license application process provided that implementation of such contracts is contingent on receipt of license authority. The District and the Purchaser agree that nothing in this contract limits in any way the District's ability to conform to these FERC requirements. Nothing in this contract, other than Section 8, limits the ability of the Purchaser from participating in any FERC or court proceedings that may address Public Law 83-544.

The Parties understand that FERC's orders of February 11, 1998 and June 12, 1998 in Docket No. EL95-35 (the "PL 83-544 Orders") require the District, as part of its application for a New FERC License, to file the Marketing Plan for making available the Reasonable Portion in a fair, equitable and non-discriminatory manner pursuant to market-based principles and procedures. The Parties further understand and agree that nothing in this contract is intended to affect or limit in anyway the right of the District to develop and file the Marketing Plan which it determines is consistent with the PL 85-544 Orders.

In the event that FERC or a court of competent jurisdiction shall by order determine that any provision of this contract violates a requirement of either PL 83-544 or of any of the PL 83-544 Orders, the Parties shall, within 30 days of the entry of such an order, commence negotiations for the purpose of reaching agreement on such amendments to this contract, if any, as may be needed for the purpose of complying with that order and for the purpose of preserving the basic benefits and obligations of the Parties. If, within 90 days of commencement of negotiations, the Parties are not able to resolve their differences and to agree upon any necessary amendments, either Party may, after notice to the other Party, cause the matter to be submitted to binding arbitration as provided in Section 28.

If following the issuance of the arbitration decision, a Party reasonably determines that acceptance of such amendments will result in materially decreased benefits or materially increased obligations when compared to this contract, the Party may by notice to the other Party explain its reasons for the determination and, if given within 10 days of the arbitration decision, terminate this contract.

SECTION 4. TREATMENT OF THE SALE OF THE REASONABLE PORTION.

Pursuant to the PL 83-544 Orders, the Reasonable Portion must be offered for sale. Purchaser has no claim or right under this contract to receive any of the Reasonable Portion, or any proceeds from the sale thereof; provided, however, that nothing in this contract shall be interpreted as prohibiting the District and the Purchaser from entering one or more separate agreements regarding the Reasonable Portion and the disposition of the proceeds of the sale of the Reasonable Portion.

SECTION 5. DETERMINATION OF PRODUCT AVAILABILITY, DISTRICT RESERVED \ SHARE AND RISK PREMIUM.

(a) The Priest Rapids Project Products available to Purchaser during each Contract Year will be determined by the sequential application of the following provisions of this Section 5 (i.e., Section 5(b), then Section 5(c), then Section 5(d), etc.).

(b) For the purpose of determining the estimated amount of Surplus Product to be made available to the Purchaser, on or before 30 days prior to the beginning of each Contract Year, the District shall prepare and mail to the Purchaser a pro forma statement showing for the next Contract Year:

(1) "Estimated District Loads," which shall mean all projected retail electric energy loads for the next Contract Year based on average weather conditions, plus aggregated losses, projected to be used at locations served by the District during the next Contract Year with the exception of (i) locations outside of the geographic boundaries shown on Exhibit C and (ii) that portion of loads of individual retail customers that during a consecutive 12 month period after 2000 exceed by ten average megawatts or more the energy load of such customer for the immediately preceding consecutive 12 month period. Once load at a location is included in Estimated District Loads, loads at such location shall continue to be included in full in future Contract Years without regard to the source of supply for such load. For example, if a load is expected to be served in all or part by an entity other than the District during the next Contract Year, the entire load shall continue to be included in Estimated District Loads. If a new load or increased load of one average megawatt or more at a single retail customer has been included in Estimated District Loads in the current Contract Year, and less than 90% of such new or increased load was actually measured in the current year, then Estimated District Loads shall be reduced for the next Contract Year by the difference between the amount included in the current Contract Year and the amount measured. If there are more than one such new or increased loads for the current Contract Year, they shall be combined for determining both the 90% and the amount of any reduction. If in the current Contract Year a load of one average megawatt or more is placed on the District which was not included in the current Contract Year's Estimated District Loads, then the next Contract Year's Estimated District Loads shall be increased by the amount of such load measured in the current Contract Year. Except for such load correction calculations, Estimated District Loads for the next Contract Year shall be not less than the current Contract Year's Estimated District Loads.

(2) Estimated amount of firm energy from the Priest Rapids Project for the next Contract Year based on critical water planning using the procedures of Operating Agreements in effect on October 31, 2000, unless the District and Purchasers whose Purchaser Product Percentages of Surplus Product total 66% or more mutually agree to use procedures from a subsequent Operating Agreement.

(3) The "District Reserved Share" for the next Contract Year shall be; (A) prior to November 1, 2009, the smaller of; (i) the ratio of Estimated District Loads from

Section 5(b)(1) less the District's 36.5% of the estimated firm energy output of the Wanapum Development, to the estimated firm energy output of the Priest Rapids Development from Section 5(b)(2), expressed as a percentage or (ii) 100% minus the Reasonable Portion; and (b) on and after November 1, 2009, the smaller of: (i) the ratio of Estimated District Loads from Section 5(b)(1) to the estimated firm energy output of the Priest Rapids Project from Section 5(b)(2), expressed as a percentage or (ii) 100% minus the Reasonable Portion.

(4) The "Purchaser Power Allocation" shall be the product of: (i) 100% minus the sum of the District Reserved Share as determined in Section 5(b)(3) and the Reasonable Portion and (ii) the Purchaser Product Percentage of the Surplus Product.

(c) During each Contract Year, the District shall have available for its use and shall take the District Reserved Share multiplied by the actual Priest Rapids Project Output. The District shall have the unilateral right, without obligation to the Purchaser, to use Priest Rapids Project Output resulting from the District Reserved Share for any purpose. In no event shall the Purchaser have any right under this contract to any portion of the District Reserved Share of Priest Rapids Project Output or the associated revenues. The District may use the District Reserved Share of the non-firm portion of the actual output of the Priest Rapids Project in any manner the District deems appropriate, and shall have no obligation to use such non-firm portion to serve the District's retail loads during any Contract Year.

(d) The Surplus Product available to the Purchaser in each Contract Year shall be the actual Priest Rapids Project Output multiplied by the Purchaser Power Allocation from Section 5(b)(4).

(e) For the purpose of determining the estimated amount of Displacement Product to be made available to the Purchaser, on or before 30 days prior to the beginning of each Contract Year, the District shall prepare and mail the Purchaser a pro forma statement showing for the next Contract Year the estimated amount of capacity and energy from Displacement Product.

(f) The monthly amount of "Estimated Unmet District Load" shall be determined as the Estimated District Load as calculated in Section 5(b)(1), less the estimated firm Priest Rapids Project Output from Section 5(b)(2). The difference so determined will be shaped on a monthly basis using the District's historic load patterns.

(g) In those Contract Years when there is Estimated Unmet District Load forecasted pursuant to Section 5(f), the District shall be entitled to take and shall take from the Displacement Product that is not subject to a Supplemental Displacement Product Agreement pursuant to Section 3(b) an amount equal to the Estimated Unmet District Load from Section 5(f).

(h) The Purchaser shall have available for its use and shall take Displacement Product equal to the actual Displacement Resource available during the Contract Year minus the amount of Displacement Resource used by the District in such Contract Year as determined in Section 5(g), multiplied by the Purchaser Product Percentage of Displacement Product; provided, however, if the Purchaser has elected to have the District make sales pursuant to

Section 3(b), then Purchaser will receive proceeds from such sales as set forth in Section 10 in lieu of the amounts of capacity and energy described in this Section 5(h).

(i) On or before 30 days prior to the beginning of each Contract Year, the District shall prepare and mail the Purchaser a pro forma statement showing for the next Contract Year an estimate of the Purchaser Risk Premium to be paid by the Purchaser, using a Risk Premium calculated with a Market Price determined by the District not more than 60 days prior to the start of the next Contract Year by reference to published future price data for the next Contract Year, and the applicable percentage from Section 7(a)(5).

(j) Deliveries of Priest Rapids Project Products may be reduced if the District does not obtain an Annual FERC License or New FERC License, or under any of the following conditions as determined by the District:

(1) Pursuant to Sections 5 or 9.

(2) If the District is unable to deliver Priest Rapids Project Products to the Purchaser due to Uncontrollable Forces.

(3) If failure to reduce deliveries, together with deliveries to all other Purchasers and deliveries to the District, would result in exceeding the capability of the Priest Rapids Project or subject it or its operation to undue hazard or violate the FERC License, any applicable law, regulation, or Operating Agreement.

(4) In case of emergencies or in order to install equipment in, make repairs to, make betterments, renewals, replacements, and additions to ("Improvements"), investigations and inspections of, or perform other maintenance work on the Priest Rapids Project.

The District will use its reasonable efforts to give advance notice to the Purchaser regarding any planned interruption or reduction, giving the reason therefor and stating the probable duration thereof.

(k) Notwithstanding any other Section of this contract, if the Priest Rapids Project is capable of producing Priest Rapids Project Output, but the amount of each Priest Rapids Project Product to be made available to the Purchaser is projected to be zero for a Contract Year, the Purchaser may give the District written notice, no later than 100 days after the start of the Contract Year, that the Purchaser elects to terminate this contract. In such event, this contract shall terminate effective upon receipt of such written notice by the District.

SECTION 6. ANNUAL POWER COSTS.

(a) "Annual Power Costs" as used in this contract shall include, for the Priest Rapids Development beginning November 1, 2005 and for the Priest Rapids Project beginning November 1, 2009, all of the District's costs and expenses of every type, both direct and indirect, resulting from the ownership, operation, maintenance of and Improvements that are incurred or paid by the District during each Contract Year and that are incurred consistent with Prudent Utility Practice. Such costs and expenses shall for any Contract Year include, but not be limited to the following, in each case without duplication:

(1) All operations, costs, maintenance costs, administrative costs, taxes, in lieu of tax payments relating to production and delivery of Priest Rapids Project Output (excluding depreciation) including, but not limited to, those specified in the Uniform System of Accounts as prescribed by the FERC for electric utilities and licensees.

(2) Amounts that the District determines are needed to pay for the prevention or correction of any loss or damage and for Improvements to keep the Priest Rapids Project in good operating condition. Subject to Section 28, the Purchaser agrees that the District shall have the sole right to determine what costs and expenses shall be incurred in connection with the ownership, operation, and maintenance of and Improvements to the Priest Rapids Project.

(3) Subject to Section 6(c), interest that accrues and is payable into the debt service fund with respect to outstanding Debt; principal that accrues and is payable into the debt service fund with respect to outstanding Debt, whether at maturity or by reason of redemption (including premiums for redeeming Debt prior to its scheduled maturity), amounts required to restore any reserve accounts maintained to secure Debt to the level required by the resolution authorizing the Debt and Financing Costs. "Financing Costs" include, but are not limited to, discounts, insurance premiums, letter of credit fees, costs of hedging interest rates, costs of compliance with disclosure requirements, legal and bond counsel fees, independent auditors, printing, financial advisor, bond registrar and trustee costs.

(4) Subject to Section 6(c), costs of creating and replenishing any reserve or contingency fund required to be maintained by any Bond Resolutions and working capital funds.

(5) Any liability or cost, including settlements and judgments, incurred as a result of or related to the ownership, operation or maintenance of the Priest Rapids Project and not covered by insurance.

(6) Costs incurred by the District in applying for a New FERC License as recorded on the District's books of account for the Priest Rapids Project (account number 183090), including but not limited to those costs and interest expenses incurred before November 1, 2005 ("New FERC License Costs"). New FERC License Costs incurred prior to November 1, 2005 will be recovered uniformly over a 15-year amortization period commencing with the Contract Year starting on January 1, 2006. The estimated New FERC License Costs incurred by the District after November 1, 2005 will be included in Annual Power Costs. In the event of termination of this contract for any reason subsequent to the effective date of the New FERC License, the Purchaser shall pay the District an amount equal to the unrecovered New FERC License Costs multiplied by the Purchaser Power Allocation at the time of termination. In the event of termination of this contract for any reason prior to the effective date of the New FERC License, Purchaser shall have no liability for unrecovered New FERC License Costs.

(7) Obligations entered into by the District as part of its effort to obtain a New FERC License, including but not limited to the cost of replacing Priest Rapids Project Products that may be committed in such obligations.

(8) Cost incurred by the District to fulfill obligations, if any, to parties to the 1956 and 1959 Contracts who do not sign this contract, as such costs are required or approved by a court, or reasonably approved by the District after notice to the Purchaser.

(9) An amount equal to 15% of debt service in that Contract Year or such higher amount as may be required by a Bond Resolution ("Coverage Requirement").

(b) The District shall credit against Annual Power Costs the following:

(1) Any insurance or other proceeds received by the District as reimbursement for damages, losses, costs or expenses included in the Annual Power Costs, and any insurance or other proceeds received as a result of the interruption or reduction of Priest Rapids Project Output.

(2) Revenue, if any, received from obligations entered into by the District as part of its effort to obtain a New FERC License.

(3) Revenue, if any, received as a result of the District fulfilling obligations to parties to the 1956 or 1959 Contracts that do not sign this contract, pursuant to Section (I)(b) of those contracts, excluding revenue required to be paid pursuant to the 1959 Contract.

(4) The Coverage Requirement, to the extent that it is not expended during a Contract Year for capital or other costs of the Priest Rapids Project (the amount not spent shall be credited against Annual Power Costs for the following Contract Year).

(5) Interest earnings on funds of the Priest Rapids Project that are not required to be retained by such fund by a Bond Resolution.

(6) An estimate of the cost of the Reasonable Portion, which shall be an amount equal to the product of the Reasonable Portion and the Annual Power Costs.

(c) Costs directly or indirectly associated with the District's Electric System or any other separate system of the District shall not be part of Annual Power Costs other than the payment of Debt held by the Electric System.

(d) Any payment received by the District as a result of the taking of the whole or any portion of the Priest Rapids Project Output by any state or federal government agency shall be used by the District to credit Annual Power Costs or to retire, at or prior to maturity, Debt, whichever shall be proper under the circumstances existing at the time of the taking.

(c) The Purchaser agrees that the District shall have the sole discretion to determine what portion, if any, of the Priest Rapid Project financing will be accomplished by issuance of Debt and the terms and covenants of any Debt.

(1) To the extent that the District makes Improvements to the Priest Rapids Project that are not financed by Debt proceeds, Annual Power Costs will include a cost as determined by the following: the District shall determine all of the Improvements anticipated for the Priest Rapids Project for the Contract Year and the District shall estimate the weighted average economic service life of the Improvements, and shall calculate a weighted average market interest rate assuming the District were to issue Debt to finance such Improvements, both as reasonably determined by the District. Based on such calculations the District shall include in Annual Power Costs an amount sufficient to amortize the costs (including both interest and principal pursuant to this Section 6(e)(1)) of such Improvements on a level basis over a period equal to the estimated weighted average economic service life of the Improvements. The amortization period for any Improvements shall not exceed 30 years and land shall be deemed to have a service life of 30 years. The District may adjust prospectively the amortization of any Improvements to reflect the actual costs of such Improvements, to correct any error in computation or to reflect a material change in the District's estimate of the average economic life of the Improvements. The District shall not be required to amortize capital expenditures that are estimated to cost below the amount that in accordance with the District's capitalization policy are not required to be capitalized and may include such costs in Annual Power Costs.

(2) To the extent that the District issues Debt (i) with a final maturity that is not earlier than the expiration of the estimated weighted average service life of the Improvements, to be financed with the Debt and (ii) the total annual amounts required for the payment of interest, principal and sinking fund requirements of such Debt when due in a Contract Year do not vary by more than 10% from those required in any other Contract Year, then Annual Power Costs shall include the actual principal and sinking fund requirements that accrues and is payable into the debt service fund for that Debt for the Contract Year. To the extent that the District issues Debt that does not meet the requirements of (i) and (ii) in the prior sentence, then Annual Power Costs will include, with respect to such Debt, an amount as determined by the District as of the date of issuance of the Debt, sufficient to amortize the original principal amount of such Debt on a level debt service basis over a period equal to the estimated weighted average economic service life of the Improvements financed or refinanced by such Debt, commencing on the later of (a) the date of issuance of the Debt or (b) the in service date of such Improvements, and based on an interest rate equal to, at the election of the District, either (i) the weighted average interest rate of the Debt or (ii) the weighted average market rate at the time of issuance of the Debt for debt with similar terms and borrowers similar to the District, as reasonably determined by the District. The amortization period for any Debt shall not exceed 30 years, land shall be deemed to have an economic useful life of 30 years, and any Debt proceeds deposited into a reserve account shall be credited against Annual Power Cost in the final year of the Debt. The District may adjust prospectively the amortization of the principal amount of any Debt to correct any error in computation or to reflect a material

change in the District's reasonable estimate of the in service date or the average economic life of the Improvements.

(3) To the extent that the District creates or replenishes reserve and contingency funds required by Bond Resolutions or working capital funds that are not financed by Debt proceeds, Annual Power Costs will include a cost determined in a manner analogous to the calculation in Section 6(e)(2) with such amounts amortized over 15 years. Upon termination of this contract, any such funds will belong to the District.

(f) On or prior to July 31st of each year, for budgetary purposes only and not for determining Priest Rapids Project Products or Purchaser's payment obligations under this contract, the District shall provide the Purchaser a pro forma budget showing an estimate of Annual Power Costs, Priest Rapids Project Output, and Estimated District Loads for the following Contract Year.

SECTION 7. PAYMENT FOR PRIEST RAPIDS PROJECT PRODUCTS AND RISK PREMIUM.

(a) On or before 30 days prior to the beginning of each Contract Year beginning in 2005, the District shall prepare and mail the Purchaser a pro forma statement for the next Contract Year showing:

(1) An estimate of Annual Power Costs specifically assigned to the Purchaser. Specific assignment shall occur whenever a Purchaser or a group of Purchasers cause identifiable costs to be placed on the Priest Rapids Project, including but not limited to increased interest costs of Debt that can not be issued as tax-exempt because of the Purchaser's expected use of any Priest Rapids Project Product or violation of Section 24(b).

(2) A detailed estimate of the Annual Power Costs, less those costs specifically assigned in section 7(a)(1), for the Contract Year.

(3) An estimate of the cost to the Purchaser of the Surplus Product, which shall be an amount obtained by multiplying the estimated Annual Power Costs from section 7(a)(2) by the Purchaser Power Allocation calculated in section 5(b)(4).

(4) An estimate of the cost to the Purchaser of the Displacement Product, which shall be the cost, including the costs of transmission and necessary services, to the District of acquiring Displacement Resources multiplied by the ratio of the Displacement Product available to Purchaser determined pursuant to Section 5(h) and the total Displacement Resource determined pursuant to Section 5(h).

(5) An estimate of the "Purchaser Risk Premium" to be paid by Purchaser equal to the product of the Risk Premium determined pursuant to Section 5(i) and the applicable percentage determined as follows:

(A) The applicable percentage is zero if the Purchaser has executed this contract on or before December 31, 2001 or, in the case of the City of Forest Grove, McMinnville, Milton-Freewater or Seattle City Light, has provided to the District written assurances on or before December 31, 2001 that the superintendent or city manager supports this contract and will so recommend to its respective city council and this contract is executed on or before March 31, 2002 in the case of Seattle City Light, and on or before February 1, 2002, in the case of Forest Grove, McMinnville or Milton-Freewater.

(B) If Purchaser executed this contract after December 31, 2001, but on or before December 31, 2002, the applicable percentage is 25 percent.

(C) If Purchaser executed this contract after December 31, 2002, but on or before December 31, 2003, the applicable percentage is 50 percent.

(D) If Purchaser executed this contract after December 31, 2003, but on or before December 31, 2004, the applicable percentage is 75 percent.

(E) If Purchaser executed this contract after December 31, 2004, but on or before December 31, 2009, the applicable percentage is 100 percent.

(F) If Purchaser has violated any provision of Section 8, the applicable percentage is 100 percent.

(6) If the percentage of Risk Premium applicable to Purchaser, pursuant to Section 7(a)(5), is zero, Purchaser shall be entitled to a credit against Purchaser Estimated Cost equal to the sum of:

(A) The product of the Purchaser Product Percentage of Surplus Product as set forth in Section 3(a) (or as reallocated pursuant to Section 3(c) or (d) among Purchasers with a Risk Premium percentage of zero) and the Risk Premium Revenues from the Surplus Product.

(B) The product of the Purchaser Product Percentage of the Displacement Product as set forth in Section 3(b) (or as reallocated pursuant to Section 3(c) or (d) among Purchasers with a Risk Premium percentage of zero) and the Risk Premium Revenues from the Displacement Product.

The District shall retain for its own use any Risk Premium Revenues that are not allocated pursuant to Section 7(a)(6).

(7) An estimate of the cost to the District of selling capacity and energy using the Displacement Product, as elected by the Purchaser pursuant to Section 3(b).

(8) The sum of amounts (expressed in dollars) calculated pursuant to Sections 7(a)(1), (3), (4), (5) and (6), hereinafter referred to as the "Purchaser Estimated Cost."

(9) The amount of the monthly payments to be made by the Purchaser to pay the Purchaser Estimated Cost during the next Contract Year.

(b) The pro forma statement provided pursuant to Section 7(a) shall be in lieu of the issuance of monthly bills to the Purchaser by the District, and the Purchaser shall be obligated to pay the monthly amounts contained therein in accordance with this Section 7.

(c) In the event of receipts or payments substantially affecting the Annual Power Costs during any Contract Year, the District shall prepare and mail to the Purchaser a revised statement of estimated Annual Power Costs and Purchaser Estimated Cost, which revised statement shall supersede any previous statement or revised statement, and the Purchaser shall be obligated to make monthly payments set forth on such revised statement for the balance of the Contract Year.

(d) Purchaser Estimated Cost shall continue to accrue and the Purchaser shall make payment for the same up to the time of termination of this contract for whatever reason, irrespective of the condition of the Priest Rapids Project and whether or not it is capable of producing Priest Rapids Project Products. If the Priest Rapids Project is not capable of producing Priest Rapids Project Products, then the Purchaser Estimated Cost will be based on Priest Rapids Project Output in the last full year of operation. In this event, at the request of the Purchaser, the District will make its reasonable best efforts to acquire replacement Priest Rapids Products the cost of which will be added to the Purchaser Estimated Cost.

(e) The monthly payments of Purchaser Estimated Costs set forth in the statement or revised statement shall be due and payable by electronic funds transfer to the District's account, designated in writing by the District, on the 20th calendar day of each month.

(f) If payment in full of any monthly payment amount set forth on a statement or revised statement is not received by the District on or before the close of business on the 20th day of the month, a delayed payment charge of 2% of the unpaid amount due will be made. Any bill which remains unpaid for more than 30 days after the due date shall, in addition to the delayed payment charge, accrue interest at the lesser of 1.5% per month or the maximum rate allowed by law. If the 20th calendar day of the month is a Saturday, Sunday or a District recognized holiday, the next following business day shall be the last day on which payment may be received without the addition of the delayed-payment charge. Additionally, if payment due to the District under this Section 7 remains unpaid 30 days after the due date, the District may thereafter suspend delivery of Priest Rapids Project Products to the Purchaser which would otherwise occur until payment in full of all amounts due and owing (including any interest and delay charges) is received by the District.

(g) On or before 150 days after the end of each Contract Year, the District will submit to the Purchaser a detailed statement of the Purchaser Estimated Cost and the Purchaser Actual Cost for the Contract Year. "Purchaser Actual Cost" on such statement shall be calculated in the same manner as Purchaser Estimated Cost as set forth in Sections 7(a)(1)-(7) but using the actual costs incurred by the District in the preceding Contract Year; provided, however, that the estimated values calculated pursuant to Sections 5(b)(1)-(2) shall not be modified. If the Purchaser Actual Costs exceed the Purchaser Estimated Costs on such statement ("Excess Costs"), the District shall bill the Purchaser for an amount equal to such Excess Costs, and the Purchaser shall pay such bill within 30 days or be subject to the delayed-payment and interest charges as provided in Section 7(f). If the Purchaser Actual Costs are less than the Purchaser Estimated Costs, or if credits are due pursuant to Section 6(b)(1)-(5) or both ("Refund Costs"), the District shall give credit to the Purchaser against the Purchaser Estimated Costs for the current Contract Year in an amount equal to such Refund Costs;

provided, that if Refund Costs are due to Purchaser following the expiration of this contract, the District shall make a cash refund of such amount to the Purchaser.

(h) The District may use any payments received from the Purchaser under this contract in any manner that the District, in its sole discretion, shall determine. The District agrees to pay or cause to be paid for the Priest Rapids Project from lawfully available money of the District, including payments from the Purchaser and other Purchasers, all the operating costs, taxes and assessments, capital expenditures, payments required for Debt and other costs of the Priest Rapids Project. If the District issues tax-exempt Debt based on the governmental use of the Priest Rapids Project Output by the Purchaser, the Purchaser covenants that it shall not use any Priest Rapids Project Output in a manner, or take any other action, that will or is likely to adversely affect the tax-exempt status of any Debt.

SECTION 8. SUPPORT AND COOPERATION.

(a) The District shall make application and use reasonable efforts to obtain a New FERC License and obtain FERC approval of this contract, if required. The District reserves the right to determine when such applications should be made.

(b) In accordance with FERC direction contained in the PL 83-544 Orders, the District commits to providing the Eligible Purchasers with a meaningful priority in the sale of the Reasonable Portion.

(c) Purchasers may also participate in the development by the District of a proposed Marketing Plan. This Marketing Plan will be submitted to FERC for approval as part of the relicensing process application; provided, however, that nothing in this Section shall be construed as compelling the Purchaser to comment on or refrain from commenting on the Marketing Plan.

(d) Purchaser covenants that it shall provide reasonable support, cooperation and assistance to the District in the District's acquisition of a New and Annual FERC License, any necessary federal, state or local permits relating to the Priest Rapids Project, FERC approval of this contract, if FERC approval is requested by the District; provided, however, that nothing in this contract shall preclude the Purchaser from filing comments with FERC to protect the Purchaser's economic benefits provided by this contract.

(e) In the event that the District believes that the Purchaser has violated any of the above covenants of Section 8(d), the District may by written notice to the Purchaser describe the alleged violation in reasonable detail and give the Purchaser no less than 10 business days within which to cease the activity in question or to provide to the District a written explanation as to why the Purchaser believes the activity does not constitute a violation of any of the aforementioned covenants. If the Purchaser does not cure the alleged default and the District continues to consider the action to be in breach of the covenants, the matter shall be resolved pursuant to arbitration conducted under Section 28. If the Purchaser is determined to be in breach of the covenants, the District shall have the right to terminate this contract effective immediately upon written notice to the Purchaser, without any liability or further obligation on the part of the District. In the event of such termination, the District shall have the right to use or sell, in any manner the District determines, any Priest Rapids Project Product the Purchaser would have been otherwise entitled to under this contract.

(f) Purchaser covenants that it shall refrain from filing or supporting any FERC license application for the Priest Rapids Project other than that filed by the District and refrain from filing or supporting any effort that would lead to modification of the FERC decisions on Public Law 83-544 contained in the PL 83-544 Orders, unless such a request or petition is filed by the District and the Purchaser agrees with that request or petition. For purposes of this Section 8(f), "refrain from supporting" means prepare no documents, sign no other agreement or contract other than this contract for Priest Rapids Project Output or for other products or that is contingent upon an entity other than the District receiving a license from FERC to operate the Priest Rapids Project, submit no testimony, engage in no lobbying and provide no funding.

(g) The Purchaser covenants that it will not take any action which, in the opinion of a neutral third party, would likely be construed as: (i) having a material adverse effect on the District's ability to obtain an Annual FERC License or a New FERC License or the anticipated economic benefits of this contract or (ii) constituting a judicial challenge to the authority of the District or the Purchaser to enter into and implement the provisions of this contract. This covenant does not apply to anticipated economic benefits under other agreements between the District and third parties, such as with the Bonneville Power Administration.

(h) In the event that the District believes that the Purchaser has violated any of the above covenants of Section 8(f) or (g), the District may by written notice to the Purchaser describe the alleged violation in reasonable detail and give the Purchaser no less than 4 business days after receipt of such written notice by Purchaser within which to cease the activity in question or to provide to the District a written explanation as to why the Purchaser believes the activity does not constitute a violation of any of the aforementioned covenants. If the Purchaser does not cure the alleged default and the District continues to reasonably consider the action to be in breach of the covenants, the District shall have the right to terminate this contract and the 1956 and 1959 Contracts, effective immediately upon written notice to the Purchaser, without any liability or further obligation on the part of the District. In the event of such termination, the District shall have the right to use or sell, in any manner the District determines, any Priest Rapids Project Product the Purchaser would have been otherwise entitled to under this contract and any output from the Priest Rapids Project under the 1956 or 1959 Contracts.

SECTION 9. SCHEDULING OF DELIVERIES OF SURPLUS AND DISPLACEMENT PRODUCTS.

(a) This Section 9 shall apply only to the scheduling of the Surplus and Displacement Products.

(b) It is the intent of the Parties that Priest Rapids Project Output shall be fully coordinated with other resources available to the Purchaser and with the resources of other Purchasers and that the operation of the Priest Rapids Project shall be consistent with existing Operating Agreements unless mutually agreed to by the Parties. If provisions of this Section 9 conflict with the provisions of any Operating Agreement to which both the District and the Purchaser are parties, the conflicting provisions of such Operating Agreement shall prevail. Scheduling of Priest Rapids Project Output shall be as requested by the Purchaser, acting singly or as a member of a group of Purchasers, subject to the limitations set forth in this contract.

(c) The Purchaser, acting singly or as a member of a group of Purchasers, shall make available to the District each normal working day, in conformance with then prevailing scheduling procedures for scheduling Pacific Northwest generating resources, hourly schedules of desired Surplus Product deliveries for the following day or days. The schedules will be completed in a time frame consistent with standard industry practices in the Pacific Northwest. Such schedule shall be based upon the probable water supply to the Priest Rapids Project (inflows) and the resulting probable output. Revisions in the schedule may be made at any time upon the request of the Purchaser if required by changes in estimated river flows or system loads. Deviations from schedules shall be held to a minimum by the District and corrected for as promptly as practicable on an hourly basis under conditions as nearly equivalent as practicable to those occurring when the deviations occurred. Alternatively, the Purchaser may provide scheduling information via a dynamic electronic signal.

(d) The schedules for Surplus Product requested by the Purchaser shall be in accordance with the following:

(1) The net hourly schedule for delivery or spill shall be within the limitations of the Purchaser Power Allocation and the Purchaser Power Allocation of the minimum discharge as determined by the District.

(2) The District shall make all determinations concerning the Priest Rapids Project maximum output and minimum discharge; the District shall have the unilateral right to determine the maximum allowable amount of change in Priest Rapids Project Output during any time period and the maximum number of unit starts and stops allowable during any time period. Such operating guidelines will be reviewed annually with the Purchaser. The District will consider suggestions by the Purchaser, then make its final determination consistent with Prudent Utility Practice. The Purchaser shall schedule Priest Rapids Project Output requests within such guidelines.

(3) Each Purchaser's schedule shall not be less than the Purchaser Power Allocation of the minimum operating capability of the Priest Rapids Project; provided, however, that if at times one or more Purchasers schedule more than their Purchaser Power Allocation of the minimum operating capability of the Priest Rapids Project, the Purchasers that have scheduled their Purchaser Power Allocation of such minimum operating capability may reduce their schedules during such times subject to meeting the minimum operating requirements of the Priest Rapids Project.

(4) Subject to Section 5(j), the Purchaser shall be entitled to a share of the Priest Rapids Project Output each hour, determined by multiplying the total Priest Rapids Project inflows by the Purchaser Power Allocation.

(5) In addition to Priest Rapids Project Output available under Section 9(d)(4), the Purchaser shall be entitled to a share of the pondage available at the Priest Rapids Project (the "Purchaser Allocation of Pondage"), determined by multiplying the total of the pondage available by the Purchaser Power Allocation. The pondage available at the Priest Rapids Project shall be determined by the District as the volume of water that can be stored between the then current maximum forebay elevation and the then current minimum forebay elevation.

(6) The District will establish and maintain for Purchaser a pondage account that will reflect the use of pondage by the Purchaser. The Purchaser may schedule more or less than its share of the Priest Rapids Project inflows determined in accordance with Section 9(c) by scheduling from or to such pondage account. The aggregate amount of the energy scheduled from the pondage account shall not exceed the Purchaser Allocation of Pondage determined in accordance with Section 9(d)(5) and scheduling by the Purchaser to its pondage account shall be only against its prior accumulated pondage draft.

(7) During any hour that spill is occurring at the Priest Rapids Project in order to control the forebay elevation, the spill shall first reduce the inflow of each of the Purchasers whose pondage account is overfull proportionate to the amount of the overfill, but not exceeding the amount of the overfill. If unallocated spill remains, it shall next be allocated to reduce the inflow of each of the Purchasers whose request for generation is less than its entitlement during the hour, in proportion to the amount by which its request is less that its entitlement. Any remaining unallocated spill shall be allocated to reduce the inflow of all Purchasers in proportion to each Purchaser Power Allocation.

(8) During any hour that spill is occurring at the Priest Rapids Project for fish or any other non-power purpose determined necessary or desirable by the District, the spill shall be allocated to reduce the inflow of all Purchasers in proportion to each Purchaser Power Allocation.

(9) The District has the right to operate the Priest Rapids Project in such manner as it deems to be in its best interests so long as the same is consistent with the FERC License, applicable laws and regulations, Prudent Utility Practice and this contract.

(10) The District shall have the unilateral right to restrict deliveries hereunder as may be necessary to fulfill any non-power regulatory or other legal requirements and shall have the unilateral right to determine the amounts of spill required at the Priest Rapids Project.

(c) The Displacement Project shall be scheduled to the Purchaser by the District from the Priest Rapids Project on the same basis that the capacity and energy from the Displacement Resource is scheduled to the District. The Purchaser may request an alternative schedule for the delivery of the Displacement Product, and the District will agree to such request if the District reasonably determines that doing so will not result in financial loss or operational harm to the District.

SECTION 10. PAYMENT OF PROCEEDS FROM THE SALE OF DISPLACEMENT PRODUCT.

If the Purchaser has elected to have the District market Purchaser Percentage of Displacement Product, then the proceeds from the sale of such portion of the Displacement Product, less any costs incurred by the District in making such sale, will be paid monthly to the Purchaser, in the month following receipt of such proceeds by the District.

SECTION 11. POINT OF DELIVERY.

(a) Priest Rapids Project Output supplied hereunder shall be approximately 230 kV, three-phase, alternating current, at approximately 60 hertz.

(b) The Surplus Product and the Displacement Product to be delivered hereunder shall be made available to the Purchaser, at its option, exercisable from time to time, at any one or more of the following points:

(1) The 230 kV bus of the Bonneville Power Administration's Midway Substation;

(2) The 230 kV bus of the switchyard of the Wanapum Development;

(3) The 230 kV bus of the Vantage Substation; or

(4) At any other location mutually agreed to by the District and Purchaser.

SECTION 12. METERING AND TRANSMISSION LOSSES.

(a) The District shall provide and maintain suitable meters in the generator leads of the Priest Rapids Project to indicate and record the Priest Rapids Project Output. The actual Priest Rapids Project Output shall be determined from totaled readings from the meters. The District shall also arrange for suitable metering at the point of delivery specified in Section 11 or at other points as agreed upon. The District or an agent of the District shall read meters and records thereof shall be made available to the Purchaser as may be reasonably requested.

(b) All losses of Purchaser Percentage of Surplus and Displacement Products purchased hereunder resulting from transformation and transmission shall be borne by the Purchaser.

SECTION 13. INFORMATION TO BE MADE AVAILABLE TO THE PURCHASER.

(a) The District agrees to keep records of the Priest Rapids Project in accordance with the Uniform System of Accounts as prescribed by FERC for electric utilities and licensees; provided, if there are inconsistencies between the Uniform System of Accounts and this contract, this contract shall control. The Purchaser, upon at least 30 days advance written notice to the District, shall have the right to audit or examine operating and financial records relating to the Priest Rapids Project during the District's normal business hours. To the extent practicable, the Purchasers shall conduct any such audit or examination jointly to minimize the disruption to the District's business operations. All costs incurred by the District associated with such audit, including, but not limited to, District labor, materials and reproduction services shall be billed to the Purchaser, and shall be promptly reimbursed by the Purchaser in accordance with Section 7(c).

(b) Upon request, any audit reports of the Priest Rapids Project by a firm of certified public accountants employed by the District or by the State Auditor's Office of the State of Washington will be provided to the Purchaser.

(c) Policies of insurance carried by the District pursuant to Section 14 shall be available at the office of the District for inspection by the Purchaser.

(d) The Purchaser's representatives shall at all times be given reasonable access to the Priest Rapids Project, subject to the District's applicable safety rules and regulations.

(e) Upon request, the Purchaser may obtain information to document the capability of the Priest Rapids Project to produce Priest Rapids Project Output.

SECTION 14. INSURANCE.

The District shall have the right to self-insure and/or obtain and maintain insurance with policies payable to the District for the following coverage:

(a) Obligations of the District under any state or federal Workmen's Compensation laws or other employer's liability;

(b) Public liability for bodily injury and property damage;

(c) Physical loss or damage to the Priest Rapids Project on a replacement cost basis; and

(d) Any other insurance determined to be necessary.

SECTION 15. ADDITIONAL FACILITIES AND PRODUCTS.

(a) From time to time during the term of this contract the District may decide in its sole discretion, and in the absence of any requirement by FERC or any state or federal agency, to take actions to increase the Priest Rapids Project Output, including but not limited to installation of additional generating facilities or raising the forebay elevation. Whenever the District proposes to so increase the Priest Rapids Project Output, it shall give notice in writing of such intent to the Purchaser stating:

(1) The estimated additional Priest Rapids Project Output that is expected to be available as a result of the installation of the proposed changes;

(2) The estimated incremental cost (i.e. the costs which will be incurred as a result of installing the proposed changes which costs would not be incurred were such proposed additional facilities not installed) of the additional Priest Rapids Project Output on an annual basis;

(3) The estimated construction period for the installation of the proposed changes; and

(4) Other available pertinent information.

(b) Following the issuance of notice of a proposal as provided in Section 15(a), the Purchaser shall have the following options: (i) Purchaser may terminate this contract effective one year after the date of the issuance of a FERC order approving the changes to the Priest Rapids Project; or (ii) Purchaser may elect not to participate in the proposed increase in the Priest Rapids Project Output and to retain this contract, in which case the Parties shall attempt in good faith to negotiate a mutually acceptable agreement setting out, among other matters, any adjustments to Purchaser Product Percentages of Priest Rapids Project Products and Purchaser's responsibility for the Annual Power Costs. Such options shall be exercised by giving written notice to the District of Purchaser's election on or before the expiration of 90 days from the date of receipt of the written notice issued pursuant to Section 15(a). In the event that Purchaser has elected option (ii) above and the Parties fail to negotiate a mutually acceptable agreement, Purchaser may elect to terminate this contract pursuant to option (i) so long as the written notice of termination is received by the District on or before the expiration of 180 days from the date of receipt of the written notice issued pursuant to Section 15(a). If the Purchaser does not exercise either of its options pursuant to this Section 15(b) or if the Parties fail to negotiate a mutually acceptable agreement and the Purchaser does not timely provide the District with a notice of termination, then the Purchaser shall be obligated to pay its proportionate share of the costs and expenses related to the additional generating capability as provided in Sections 6 and 7, and shall be entitled to receive a percentage of such additional Priest Rapids Project Output determined on the basis of the Purchaser Power Allocation.

(c) If at any time the District determines that it is not desirable for it to proceed with the changes as proposed pursuant to Section 15(a), the District shall be under no obligation to proceed with such changes and shall so notify the Purchaser in writing of such determination not to proceed. If the Purchaser has exercised its option to terminate this contract pursuant to Section 15(b), such termination shall be cancelled upon the issuance of the written notification by the District pursuant to this Section 15(c), but only if such written notification by the District is issued within one year of the date of the issuance of a FERC order approving the changes.

(d) All costs of studies, engineering, and administrative activities necessary to apply for and receive FERC approval of the proposed changes to the Priest Rapids Project shall be included as Annual Power Costs and the Purchaser shall pay its share of such costs pursuant to Section 7; provided, however, if the Purchaser has given notice of termination of this contract in accordance with Section 15(b) and such termination has not been cancelled pursuant to Section 15(c), then the Purchaser shall not be liable for any such costs.

(e) Notwithstanding any other provisions of this Section 15, whenever the District determines that it is necessary or in its best interest to modify the Priest Rapids Project in any way or to install additional facilities at or in the Priest Rapids Project to comply with any law, rule, regulation, or order of FERC or any state or federal agency with authority to issue or make and enforce such an order, rule, regulation or decision, the Purchaser shall share the benefits and costs resulting from the modification or installation of the additional facilities in the same manner and to the same extent as provided above, except that the Purchaser shall not have the option to terminate or adjust its interest and participation in this contract as provided in Section 15(b).

(l) At any time a Purchaser may request the District to modify the Priest Rapids Project or propose conservation projects within Grant County. The District commits to consider such requests in good faith; however, the District is under no obligation to agree to implement such requests.

SECTION 16. PROJECT INTEGRATION.

(a) It is the intention of the Parties hereto that the operation of the Priest Rapids Project shall be integrated and that all benefits accruing as a result of such integration shall be shared equally by the Priest Rapids and Wanapum Developments. It is also agreed that before November 1, 2009 and after such date if required by any Bond Resolution, all joint costs of the Priest Rapids and Wanapum Developments shall be equitably allocated between them as determined by the District.

(b) The Parties agree that any compensation (whether energy or money) due or which may become due the owner of the Rock Island Hydroelectric Project because of encroachment by the Priest Rapids Project after November 1, 2009 on the Rock Island Hydroelectric Project will either proportionately reduce the amount of Priest Rapids Project Output or be included in Annual Power Costs, as appropriate, but shall not reduce the amount required to be paid by the Purchaser under Sections 6 and 7. "Rock Island Hydroelectric Project" shall mean the FERC Hydroelectric Project No. 943 currently operated by Public Utility District No. 1 of Chelan County, Washington.

SECTION 17. LIABILITY OF PARTIES.

(a) Except as otherwise provided in this contract, each Party hereby releases the other Party and its commissioners, officers, directors, agents and employees from any claim for loss or damage arising out of the ownership, operation, and maintenance of the Priest Rapids Project including any loss of profits or revenues, loss of use of power system, cost of capital, cost of purchased or replacement power, other substantially similar liability or other direct or indirect consequential loss or damage, except as provided in the Agreement Limiting Liability Among Western Interconnected Systems for parties to that agreement. This release shall not include any claim by the Purchaser for refunds for over-payments made to the District nor any claim for specific performance of the District's obligation to deliver to the Purchaser during the term of this contract the Priest Rapids Project Products to which the Purchaser is entitled under this contract.

(b) The Purchaser shall have no claim of any type or right of action against the District: (i) as a result of a FERC or court order or amendment described in Section 3(f); (ii) as a result of the failure to receive an Annual FERC License or a New FERC license or the adjustment of delivery of Priest Rapids Products pursuant to Section 5(j) whether arising under the terms of this contract or otherwise; or (iii) as a result of the District's purchasing or selling power or energy on behalf of the Purchaser pursuant to Section 3(b), and the Purchaser hereby releases the District and its commissioners, officers, agents and employees from any claim for loss or damage arising out of the events described in this paragraph.

SECTION 18. NOTICES AND COMPUTATION OF TIME.
Any notice or demand, except those provided for in Section 7, by the Purchaser under this contract to the District shall be deemed properly given if mailed postage prepaid and addressed to Manager, Public Utility District No. 2 of Grant County, Box 878, Ephrata Washington 98823; any notice or demand by the District to the Purchaser under this contract shall be deemed properly given if mailed postage prepaid and addressed to Vice President, Energy Resources, Avista Corporation, P.O. Box 3727, Spokane, Washington 99220.

In computing any period of time from such notice, such period shall commence at 12:00 A.M. (midnight) on the date mailed. The designations of the name and address to which any such notice or demand is directed may be changed at any time by either Party giving notice as provided above.

SECTION 19. DISTRICT'S BOND RESOLUTIONS AND LICENSE.
It is recognized by the Parties that the District, in its operation of the Priest Rapids Project, must comply with the requirements of the Bond Resolution and with the FERC License together with amendments thereof from time to time made, and the District is hereby authorized to take such actions as the District determines are necessary and appropriate to comply with such Bond Resolution and FERC License.

SECTION 20. GOVERNING LAW.
The Parties agree that the laws of the State of Washington shall govern this contract.

SECTION 21. ASSIGNMENT OF CONTRACT.
Neither the Purchaser nor the District shall by contract, operation of law or otherwise, assign this contract or any right or interest in this contract without the prior written consent of the other Party, which shall not be unreasonably withheld; provided, however, a Party may, without the consent of the other Party (and without relieving itself from liability hereunder): (i) transfer or assign this contract to an affiliate of the Party provided that the affiliate's creditworthiness is equal or higher than that of the Party; or (ii) transfer or assign this contract to any person or entity succeeding to all or substantially all of the distribution and generating facilities of the Party whose creditworthiness is equal or higher than that of the Party; provided, however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions in this contract and the transferring Party shall deliver such tax and enforceability assurance as the other Party may reasonably request.

SECTION 22. REMEDIES ON DEFAULT.
(a) "Act of Default" shall mean:

(1) The failure of a Party to make, when due, any payment required under this contract if such failure is not remedied within three days after written notice, provided that the payment is not the subject of a good faith dispute pursuant to Section 28. If requested by the District, the Purchaser shall deposit the disputed amount in escrow with a bank acceptable to the Parties.

(2) Any representation or warranty in this contract is false or misleading in any material respect when made or ceases to remain true during the term of this contract.

(3) The failure of the Purchaser, after Section 8 or any provision thereof has been found by a court to be void, unlawful or unenforceable, to perform in accordance with the provisions of Section 8, including without limitation any provision or provisions found to be void, unlawful or unenforceable.

(4) A Party shall make an assignment or any general arrangement for the benefit of creditors; file a petition or otherwise commence or acquiesce in the commencement of a proceeding under any bankruptcy or similar law for the protection of creditors; or otherwise becomes bankrupt or insolvent or unable to pay its debts as they fall due.

(b) If a Party commits an Act of Default during the term of this contract, the non-defaulting Party may take any one or more of the following remedial steps:

(1) Take any action or exercise any remedy provided to the Party under the provisions of Sections 7 or 8.

(2) Except where a different time period is set forth herein, if the defaulting Party fails to remedy an Act of Default within ten days after receiving written notification of the default, then the non-defaulting Party may give a written notice of termination of this contract on a date specified in such notice, which date shall be not less than 30 days after the date of such notice. If the Purchaser is given written notice as provided herein, this contract shall terminate upon the date specified in such notice, the Purchaser thereafter shall have no right, title, or interest in, to, or with respect to the Priest Rapids Project, or any Priest Rapids Project Product, or any Priest Rapids Project Output, but the Purchaser shall remain liable for all amounts due the District which have accrued prior to the date of termination.

(3) The District may, prior to the termination of this contract pursuant to Section 22(b)(2), at any time suspend any and all rights of the Purchaser to the Priest Rapids Project Products upon not less than five days' notice to the Purchaser. The District may, without further notice to the Purchaser, grant any or all of such suspended rights to any person or entity for the duration of the suspension. In such event, the Purchaser shall, in addition to its other obligations under this contract, upon demand, pay to the District all expenses and any losses incurred in connection with such suspension and any grant of the suspended rights to another person or entity. No suspension of any or all of the rights of the Purchaser to Priest Rapids Project Products shall be construed as an election to terminate the interests of the Purchaser in, to, and under this contract unless a written notice of termination is given to the Purchaser pursuant to this contract or unless such termination be decreed by a court of competent jurisdiction.

(4) The non-defaulting Party may begin and maintain successive proceedings against the defaulting Party for the recovery of damages or for a sum equal to any and all payments required to be made pursuant to this contract.

(5) A Party may take whatever action at law or in equity as may appear necessary or desirable to collect the amounts payable by the defaulting Party under this contract then due and thereafter to become due, or to enforce performance and observation of any obligation, agreement or covenant of the defaulting Party under this contract.

(6) No right or remedy conferred upon or reserved to a Party is intended to be exclusive of any other right or remedy, and each and every right and remedy shall be cumulative and in addition to any other right or remedy given hereunder, or now or hereafter legally existing, upon the occurrence of any Act of Default. Failure of the District to insist at any time on the strict observance or performance by the Purchaser of any of the provisions of this contract, or to exercise any right or remedy provided for in this contract shall not impair any such right or remedy nor be construed as a waiver or relinquishment thereof for the future. Receipt by the District of any payment required to be made hereunder with knowledge of the breach of any provisions of this contract shall not be deemed a waiver of such breach. In addition to all other remedies provided in this contract, the District shall be entitled, to the extent permitted by applicable law, to injunctive relief in case of the violation, or attempted or threatened violation, of any of the provisions of this contract, or to a decree requiring performance of any of the provisions of this contract or to any other remedy legally allowed to the District.

(7) The District shall not have the right to accelerate future payment obligations of the Purchaser in the event of default under this contract.

SECTION 23. VENUE AND ATTORNEY FEES.
Venue of any action filed to enforce or interpret the provisions of this contract shall be exclusively in the United States District Court for the Eastern District of Washington or the Superior Court of the State of Washington for Grant County and the Parties irrevocably submit to the jurisdiction of any such court. In the event of litigation to enforce the provisions of this contract, the prevailing Party shall be entitled to reasonable attorney's fees in addition to any other relief allowed.

SECTION 24. COMPLIANCE WITH LAW.

(a) The Parties shall conform to and comply with all laws, rules, regulations, license conditions or restrictions promulgated by the FERC or any other governmental agency or entity having jurisdiction over the Priest Rapids Project. The Purchaser shall cooperate and take whatever action is necessary to cooperate fully with the District in meeting such requirements. Obligations of the District contained in this contract are hereby expressly made subordinate and subject to such compliance.

(b) The Purchaser shall ensure that Priest Rapids Project Products available to Purchaser under this contract are not sold, resold, distributed for use or used outside the Pacific Northwest in violation of the Bonneville Project Act, Public Law 75-329, the Pacific Northwest Consumer Power Preference Act, Public Law 88-552, the Regional Act or in contravention of any applicable state or federal law, order, regulation, or policy. If such sales occur in violation of the foregoing, the Purchaser shall reimburse the District for any penalties imposed on and costs incurred by the District as a consequence of such violation.

SECTION 25. HEADINGS.
The headings of sections and paragraphs of this contract are for convenience of reference only and are not intended to restrict, affect or be of any weight in the interpretation or construction of the provisions of such sections and paragraphs.

SECTION 26. ENTIRE AGREEMENT; MODIFICATION; CONFLICT IN PRECEDENCE.
This contract does not modify the terms and conditions contained in the 1956 and 1959 Contracts except as provided in Sections 1(b) and 8. This contract constitutes the entire agreement between the Parties with respect to the subject matter of this contract, and supersedes all previous communications between the Parties, either verbal or written, with respect to such subject matter. No modifications of this contract shall be binding upon the Parties unless such modifications are in writing signed by each Party. To the extent there are any conflicting provisions between this contract and the 1956 Contract, or this contract and the 1959 Contract after November 1, 2009, the terms and conditions in this contract shall take precedence and be controlling and the 1956 and 1959 Contracts are hereby amended accordingly.

SECTION 27. NO PARTNERSHIP OR THIRD PARTY RIGHTS.
(a) This contract shall not be interpreted or construed to create an association, joint venture, or partnership between the Parties, or to impose any partnership obligations or liability upon any Party. Without limiting the foregoing, Purchaser shall not be liable for, and the District hereby releases the Purchaser from, the payment of Debt except as provided in Sections 6 and 7.

(b) This contract shall not be construed to create rights in or grant remedies to any third party as a beneficiary of this contract.

SECTION 28. PURCHASERS' COMMITTEE; ARBITRATION.
(a) There is hereby established a Purchasers' committee (the "Committee"). Each Purchaser may appoint one representative (and one alternate) as a Committee member to attend Committee meetings. The members of the Committee shall elect a chair, and may adopt such rules for the conduct of business as it deems appropriate. Meetings between the District and Purchasers shall be held routinely, but not more frequently than once a quarter, provided, however, that such meetings may be held more frequently than once each quarter at the request of the District or upon the request of members of the Committee whose Purchaser Product Percentage of Surplus Product totals 66% or more. All meetings between the District and Purchaser will be held in Grant County, Washington, unless the District and the Purchaser agree to another location.

(b) In addition to other matters subject to arbitration pursuant to other provisions of this contract, if approved by members of the Committee whose Purchaser Product Percentage of Surplus Product totals 66% or more, the Committee may submit to binding arbitration the following issues:

    (1) Have the Estimated District Loads been forecast in accordance with Prudent Utility Practice and, if not, what is the appropriate Estimated District Loads in accordance with Prudent Utility Practice for the Contract Year?

(2) Have the Annual Power Costs been determined by the District in accordance with Prudent Utility Practice and have such costs been incurred for the benefit of Priest Rapids Project Output and, if not, what are the appropriate Annual Power Costs in accordance with Prudent Utility Practice for the Contract Year; provided that nothing in this Section shall be interpreted to limit the ability of the District to meet its payment obligations under a Bond Resolution?

(3) Are discretionary outages that would reduce Priest Rapids Project Output by more than 25% scheduled so as to be fair to both the District and Purchases given that the benefit of the Priest Rapids Project to the Purchasers declines over time and, if not, what should be the appropriate schedule for outages? Current or future market conditions for electricity will not be a factor in arbitrating this issue. If failure to perform the proposed outage would reasonably reduce Priest Rapids Project Output or conflict with Section 18, the outage will not be subject to arbitration.

(4) What modifications to this contract, pursuant to Section 3(f), are necessary to comply with FERC or court orders and to preserve the basic benefits and obligations of the Parties?

(5) Has the Purchaser violated the covenants in Section 8(e)?

(b) The board of arbitrators shall be composed of three persons, one of whom shall be appointed by the District, one of whom shall be appointed by majority vote of the Committee, and the third person to be appointed by the two persons so appointed. The District and the Committee shall appoint their arbitrator within 15 days after notification of the Committee's vote to submit a matter to binding arbitration. In the event the two members cannot agree upon the appointment of a third person within 10 days, then such third person shall be appointed by the presiding judge of the Superior Court of Kittitas County, Washington. The arbitration shall be conducted jointly by the participating Purchasers, and under rules as may be determined by the arbitrators; provided, however, that all parties shall be afforded discovery consistent with the Federal Rules of Civil Procedure; and, provided further, if the arbitrators do not unanimously agree on the rules governing the arbitration, the arbitration shall be conducted in accordance with the Commercial Arbitration Rules of the American Arbitration Association. The board so designated shall conduct a hearing within 30 days of completion of their selection, and within 15 days after the hearing (unless such time is extended by agreement of the Parties) shall notify the Parties of their decision in writing, stating the reasons therefore and separately listing their findings of fact, conclusions of law and order. Insofar as the Parties hereto may legally do so, they agree to abide by the decision of the board. All factual determinations made by the board shall be conclusive and binding on the Parties and not subject to judicial review. Any conclusions of law made by the board shall be subject to review by a court specified in Section 23; provided, that the order issued by the board shall be effective unless and until a stay is issued by the board or such court suspends the effectiveness of the order.

SECTION 29. REPRESENTATION AND WARRANTIES.
Each Party represents and warrants to the other Party that:

(a) It is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation.

(b) The execution, delivery and performance of this contract are within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, or order applicable to it.

(c) This contract constitutes a legally valid and binding obligation enforceable against it in accordance with its terms, subject to equitable defenses and applicable bankruptcy, insolvency and similar laws affecting creditors' rights generally.

The District hereby represents and warrants to the Purchaser that during the term of this contract, the District will not waive, reduce or otherwise forego the collection of the Risk Premium pursuant to Section 7 of this and all other Contracts.

SECTION 30. COUNTERPARTS.
This contract may be executed in counterparts, each of which shall be an original and all of which shall constitute the same contract.

PUBLIC UTILITY DISTRICT NO. 2
OF GRANT COUNTY, WASHINGTON

By: /s/ Mike Conley
(SEAL) ------------------------
President

ATTEST:

/s/ Thomas W. Flint

Secretary

AVISTA CORPORATION

By: /s/ Gary G. Ely

Gary G. Ely
(SEAL) Title: Chairman of the Board,
President and CEO

EXHIBIT A

MONTHLY AMOUNTS OF DISPLACEMENT RESOURCE

A. For the period November 1, 2005 through September 30, 2006:

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FEB MAR
APR MAY
JUN JUL
AUG SEP
OCT NOV
DEC - -
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Capacity
  (MW)
123 123
121 197
249 252
219 151
138 n/a
123 124
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 Energy
 (MWh)
 91,512
 82,656
 90,024
141,643
185,256
181,440
162,936
112,344
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99,360
n/a
88,560
92,256
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B. For the period October 1, 2006 through September 30, 2011:

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- JAN
FEB(1)
MAR APR
MAY JUN
JUL AUG
SEP OCT
NOV DEC
- -----

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Capacity
(MW)
148 149
150 222
270 268
234 167
161 159
163 163
- -----

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Energy
(MWh)
110,112
100,128
111,600
159,618
200,880
192,960
174,096
124,248
115,920
118,455
117,360
121,272
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(1) MWh in February 2008 are 103,704

EXHIBIT B
DEFINITIONS OF PRIEST RAPIDS DEVELOPMENT
AND WANAPUM DEVELOPMENT

RESOLUTION NO. 390 -- DEFINITION OF PRIEST RAPIDS DEVELOPMENT

Section 2(f) of Exhibit 1. "Priest Rapids Development" shall mean those properties and facilities consisting of the Priest Rapids dam, site, reservoir, switchyard and power plant, including all generating facilities associated therewith up to and including the first ten (10) main turbine generator units each with a nameplate rating of approximately 78,850 kilowatts and any additional generating facilities which may be installed as provided for in Section 19 of the Original Power Sales Contract, together with the associated transmission facilities consisting of two 230 KV transmission lines and terminal facilities interconnecting the Priest Rapids switchyard and the Bonneville Power Administration's Midway Substation and an undivided one-half (1/2) interest in the interconnecting facilities' between the Priest Rapids switchyard and the Wanapum switchyard.

RESOLUTION NO. 474 -- DEFINITION OF WANAPUM DEVELOPMENT

Section 2.2. The District specifies and adopts the plan and system hereinafter set forth for the acquisition, by purchase or condemnation, and construction of the following generation and transmission facilities as a separate utility system of the District constituting the Wanapum Development of the District, to wit:

A. The District shall construct an electric generating plant and associated facilities on the Columbia River at approximately river mile 415 from the mouth of said river at the Wanapum site on said river, in Grant and Kittitas Counties, Washington, as authorized by the Federal Power Commission License for Project No. 2114, originally issued November 4, 1955, and all amendments thereto; said generating plant to have an installed nameplate rating of approximately 831,250 kilowatts, and said generating plant and associated facilities to include, but not limited to, a concrete gravity dam, a fully enclosed reinforced concrete powerhouse containing ten (10) turbo-generating units with provisions in the intake structure for the installation of six (6) additional turbo-generating units, a reservoir, waterways, fish ladders and other fish protective devices; provisions for future installation of navigation locks; transforming facilities; a switchyard; transmission facilities necessary to connect the powerhouse to the existing transmission facilities of the Priest Rapids Development and to the transmission facilities of the Bonneville Power Administration in the vicinity of said Project; railroad siding, shops, warehouses, construction camp, offices, and dwellings; and all other structures, fixtures, equipment or facilities used or useful in the construction, maintenance and operation of the Wanapum Development; and all necessary water rights, development rights, permits and licenses, casements, rights-of-way, flowage rights and rights permitting the storage of water, riparian rights and shore rights.

AMENDMENT NO. 1 TO THE PRIEST RAPIDS PROJECT PRODUCT SALES CONTRACT

The Public Utility District No. 2 of Grant County, Washington, ("District"), and Avista Corporation ("Purchaser"), hereby agree to this Amendment No. 1 to the Priest Rapids Project Product Sales Contract dated December 12, 2001 (the "Product Contract"). Unless otherwise defined herein, all capitalized terms defined in the Product Contract shall have the meanings set forth therein when used in this Amendment.

1. Term of Amendment No. 1

This Amendment No. 1 shall take effect on upon the execution by the District and Purchaser, and shall expire on the earlier of the expiration or termination date of the Product Contract.

2. Amendments to Provisions of the Product Contract

Purchaser and the District agree that the Product Contract is hereby amended as follows:

2.1 The definition of the term Priest Rapids Project Output set forth in Section 2 is deleted in its entirety and replace with the following:

"Priest Rapids Project Output" shall mean the amount of capacity, energy (both firm and non-firm), pondage, reactive power, ancillary services (including dynamic load following services) and any other product from the Priest Rapids Development from November 1, 2005 to November 1, 2009 and from the Priest Rapids Project from November 1, 2009 through the term of this contract under the operating conditions which exist during the term, including periods when the Priest Rapid Project may be wholly or partially inoperable for any reason, after correction for encroachment, Canadian entitlement, station and project use, and depletions required by the FERC License or other regulatory requirements.

2.2 Section 6(b)(6) is deleted in its entirety.

2.3 Section 7(a)(4) is deleted in its entirety and replaced with the following:

An estimate of the cost to the Purchaser of the Displacement Product, which shall be the Purchaser Product Percentage of (i) the cost, including the costs of transmission and necessary services, to the District of acquiring Displacement Resources, (ii) less the cost, including the costs of transmission and necessary services, of that portion of the total Displacement Resources reserved by the District pursuant to Section 5(b).

2.4 Section 8(h) is deleted in its entirety and replaced with the following:

In the event that the District believes that the Purchaser has violated any of the above covenants of Section 8(f) or (g), the District may by written notice to the Purchaser describe the alleged violation in reasonable detail and give the Purchaser no less than 4 business days after receipt of such written notice by Purchaser within which to cease the activity in question or to provide to the District a written explanation as to why the Purchaser believes the activity does not constitute a violation of any of the aforementioned covenants. If the Purchaser does not cure the alleged default and the District continues to reasonably consider the action to be in breach of the covenants, the District shall have the right to terminate this contract, effective immediately upon written notice to the Purchaser, without any liability or further obligation on the part of the District. In the event of such termination, the District shall have the right to use or sell, in any manner the District determines, any Priest Rapids Project Product the Purchaser would have been otherwise entitled to under this contract.

2.5 Section 9(d)(8) of the Product Contract is amended by adding at the end of such Section 9(d)(8) the following sentence:

For purposes of Section 9(d)(7) and (8), spill shall mean the product of the spill occurring at the Priest Rapids Project during any hour and the sum of the Purchaser Power Allocations of all Purchasers. Any actual spill that is not allocated to Purchasers pursuant to such sections shall be allocated to the District.

2.6 The Product Contract is amended by adding a new Exhibit D, Purchasers Product Percentage Allocations, which is attached hereto.

In Witness Whereof, Purchaser and the District have caused this Amendment No. 1 to be executed in their respective names by their duly authorized officers.

AVISTA CORPORATION	PUBLIC UTILITY DISTRICT NO. 2 OF GRANT COUNTY, WASHINGTON
By: /s/ Gary G. Ely	By: /s/ Mike Conley
Title: Chairman, President & CEO	Title: President, Board of Commissioners
Date Signed: Feb. 6, 2002	Date Signed: Feb. 11, 2002
	/s/ Thomas W. Flint Secretary, Board of Commissioners

EXHIBIT A. AMENDMENT 1

Purchasers Product Percentage Allocations

Purchaser Name	Historical Shares 1956	1959	Requested Purchaser Product%	Number of Customers 2000	Section 3c/e Step 1 Allocation	Section 3c/e Step 2 Allocation(1) Surplus	Displace
A. 1956/1959 PURCHASERS							
Pacific Corp	13.9%	18.7%	32.6%	768,446		25.03%	25.03%
Portland General	13.9%	18.7%	32.6%	726,039		25.03%	25.03%
Puget Sound Energy	8.0%	10.8%	18.8%	915,851		14.43%	14.43%
Avista Utilities	6.1%	8.2%	25.0%	309,986		10.98%	10.98%
Cowlitz PUD	2.0%	2.7%	4.7%	44,361		3.61%	3.61%
Eugene Water & Elec	1.7%	2.3%	4.0%	80,097		3.07%	3.07%
City of Forest Grove	0.5%	0.7%	(5)	8,592		0.92%	0.92%
City of McMinnville	0.5%	0.7%	(5)	13,973		0.92%	0.92%
City of Milton-Freewater	0.5%	0.7%	(5)	4,581		0.92%	0.92%
B. 1956 ONLY PURCHASERS(2)							
Seattle City Light	8.0%	n/a	(5)	349,557		6.14%	6.14%
Tacoma Power	8.0%	n/a	16.0%	147,819		6.14%	6.14%
Kittitas PUD	0.4%	n/a		3,078		0.31%	0.31%
Total A + B				3,392,380	97.51%	97.51%	97.51%
C. NO. IDAHO PURCHASERS							
Clearwater	n/a	n/a	10.43%	9,314		0.27%	0.27%
Idaho Co. Light & Power	n/a	n/a	2.41%	3,007		0.09%	0.09%
Kootenai	n/a	n/a	16.28%	16,244		0.47%	0.47%
Northern Lights	n/a	n/a	12.30%	14,541		0.42%	0.42%
D. SNAKE RIVER PURCHASERS							
Fall River Rural Elec	n/a	n/a	(6)	10,992		0.32%	0.32%
Lost River Electric	n/a	n/a	(6)	2,327		0.07%	0.07%
Lower Valley Electric	n/a	n/a	(6)	19,182		0.55%	0.55%
Ralt River Rural Elec	n/a	n/a	(6)	2,927		0.08%	0.08%
Salmon River Electric	n/a	n/a	(6)	2,570		0.07%	0.07%
United Electric	n/a	n/a	(6)	5,515		0.16%	0.16%
Association Total			1.24%	43,513		1.25%	1.25%
Total C & D				86,619	2.49%	2.49%	2.49%
Total	63.5%	63.5%			100.00%	100.00%	100.00%

Purchaser Name	Section 3c/e Step 2 Allocation (1) Reasonable Portion	Added Products(7)	Surplus(2)	Adjustment for 2005-2009 Displace(3)	Reasonable Portion(4)	Added Products(7)
A. 1956/1959 PURCHASERS						
Pacific Corp	25.03%	25.67%	21.34%	26.87%	23.19%	21.89%
Portland General	25.03%	25.67%	21.43%	26.87%	23.19%	21.89%
Puget Sound Energy	14.43%	14.80%	12.28%	15.51%	13.36%	12.60%
Avista Utilities	10.98%	11.26%	9.37%	11.79%	10.17%	9.61%
Cowlitz PUD	3.61%	3.70%	3.07%	3.88%	3.34%	3.15%
Eugene Water & Elec	3.07%	3.15%	2.61%	3.39%	2.84%	2.68%
City of Forest Grove	0.92%	0.94%	0.77%	1.00%	0.84%	0.79%
City of McMinnville	0.92%	0.94%	0.77%	1.00%	0.84%	0.79%
City of Milton-Freewater	0.92%	0.94%	0.77%	1.00%	0.84%	0.79%
B. 1956 ONLY PURCHASE(2)						
Seattle City Light	6.14%	6.30%	12.28%	12.28%	12.28%	12.60%
Tacoma Power	6.14%	6.30%	12.28%	12.28%	12.28%	12.60%
Kittitas PUD	0.31%	0.31%	0.61%	0.61%	0.61%	0.63%
Total A + B	97.51%	100.00%	97.51%	116.40%	103.81%	100.00%
C. NO. IDAHO PURCHASERS						
Clearwater	0.27%	n/a	0.27%	0.27%	0.27%	n/a
Idaho Co. Light & Power	0.09%	n/a	0.09%	0.09%	0.09%	n/a
Kootenai	0.47%	n/a	0.47%	0.47%	0.47%	n/a
Northern Lights	0.42%	n/a	0.42%	0.42%	0.42%	n/a
D. SNAKE RIVER PURCHASERS						
Fall River Rural Elec	0.32%	n/a	0.32%	0.32%	0.32%	n/a
Lost River Electric	0.07%	n/a	0.07%	0.07%	0.07%	n/a
Lower Valley Electric	0.55%	n/a	0.55%	0.55%	0.55%	n/a
Ralt River Rural Elec	0.08%	n/a	0.08%	0.08%	0.08%	n/a
Salmon River Electric	0.07%	n/a	0.07%	0.07%	0.07%	n/a
United Electric	0.16%	n/a	0.16%	0.16%	0.16%	n/a
Association Total						
Total C & D	1.25%	n/a	1.25%	1.25%	1.25%	n/a
Total						
	2.49%	n/a	2.49%	2.49%	2.49%	n/a

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100.00%	100.00%	100.00%	118.89%	106.30%	100.00%

NOTES: (1) Allocated per average of 1956 and 1956 Shares or, for Idaho Purchasers, per number of customers.
(2) Allocated per 1956 Shares Surplus Product and, for Idaho Purchasers, per number of customers.
(3) Allocated per 75% of 1956 Shares and 25% of 1959 Shares for 1956/1959 Purchaser, per 1956 Shares for the Only 1955 Purchaser, and number of customers for No. Idaho and Snake River Purchasers.
(3) Allocated per 75% of 1956 Shares and 25% of 1959 Shares for 1955/1959 Purchasers, per 1956 Shares for the Only 1956 Purchaser, and number of customers for No. Idaho and Snake River Purchasers.
(5) Have Intent to Sign Contract Letter without Requested Purchaser Product Percent.
(6) Snake River Purchaser's Contract with the Association.
(7) Allocated only to the 1956/1959 and Only 1956 Purchasers per 1956 Shares for 2005-2009, then average of 1956 and 1959 Shares post-2009.

PRIEST RAPIDS PROJECT

REASONABLE PORTION

POWER SALES CONTRACT

INDEX TO SECTIONS

PRIEST RAPIDS PROJECT REASONABLE PORTION POWER SALES CONTRACT

Executed by
PUBLIC UTILITY DISTRICT NO. 2
OF GRANT COUNTY
And
AVISTA CORPORATION

This contract is entered into as of December 12, 2001 between Public Utility District No. 2 of Grant County, Washington (the "District"), a municipal corporation of the State of Washington, and Avista Corporation (the "Purchaser"), a corporation organized and existing under the laws of the State of Washington. The District and the Purchaser are referred to as a "Party" and collectively as "Parties."

SECTION 1. TERM OF CONTRACT.

(a) Except as otherwise provided herein, this contract shall be in full force and effect from and after it has been executed by the District and the Purchaser. Unless sooner terminated pursuant to other provisions, this contract shall remain in effect until the earlier of expiration or termination of the New FERC License or such time that the District no longer has authority to market Priest Rapids Project Output. Except as otherwise provided herein, all obligations accruing under this contract are preserved until satisfied.

(b) Notwithstanding Section 1(a), the affirmative obligations of the Parties in Sections 3(a), (b), (c), (d) and (g), 4 through 6, 8 through 12 and 23 (a) and (b) (1-2, and 5) shall take effect on November 1, 2005.

(c) Except as provided in Section 1(d), all Eligible Purchasers shall have until December 31, 2001 to execute this contract.

(d) If the City of Forest Grove, McMinnville, Milton-Freewater or Seattle City Light provides the District written assurance on or before December 31, 2001, that its superintendent or its city manager supports the execution of this contract and will so recommend to its city council, then if Seattle City Light provides such written assurance it shall have until March 31, 2002, to execute this contract, and if Forest Grove, McMinnville or Milton Freewater provides the District such written assurance, the city providing such written assurance shall have until February 1, 2002, to execute this contract.

SECTION 2. DEFINITIONS.

As used in this contract, the following terms when initially capitalized shall have the following meanings:

"1956 Contract" shall mean the contract entered into by the District and various parties during May 1956 for the sale of capacity and energy from the Priest Rapids Development as supplemented and amended from time to time.

"1959 Contract" shall mean the contract entered into by the District and various parties during June 1959 for the sale of capacity and energy from the Wanapum Development as supplemented and amended from time to time.

"Annual FERC License" shall mean a license for the Priest Rapids Project issued by FERC to the District for an interim period before a New FERC License.

"Bond Resolution" shall mean each and all of the resolutions adopted by the District authorizing the issuance of outstanding Debt for the Priest Rapids Project.

"Contract Year" shall mean the 12 month period commencing at 12:01 a.m. on January 1 of each year and ending at 12:01 a.m. on the following January 1; provided, however, that the first Contract Year shall commence on November 1, 2005, and end the following January 1, 2006, and that the last Contract Year shall end on the last day of the New FERC License, or such time that the District no longer has authority to market Priest Rapids Project Output.

"Contract(s)" shall mean this contract and similar contracts between the District and other Purchasers.

"Debt" shall mean any bonds, notes, or other debt obligations of the District, including, but not limited to all bonds outstanding at the effective date of this contract, a line of credit, installment purchase agreement, financing lease, interfund loan, derivative securities or payment obligations and any other obligation for borrowed money, the proceeds of which will be used for the benefit of the Priest Rapids Project, including to finance betterments, renewals, replacements and additions to the Priest Rapids Project, to refund other debt, or any other lawful purpose related to the Priest Rapids Project. Debt does not include the Columbia River-Priest Rapids Hydro-Electric Production System Revenue Bonds, Series 1956, which have been paid, or the Wanapum Hydroelectric Refunding Revenue Bonds, Series 1963, which are scheduled to be repaid on or prior to January 1, 2004.

"Electric System" shall mean the separate electric utility system of the District, including all associated generation, transmission and distribution facilities and any betterments, renewals, replacements and additions of such system, but does not include the Priest Rapids Project or any other utility properties designated as a separate utility system of the District.

"Eligible Purchasers" means the Purchasers who are parties to the 1956 and 1959 Contracts, and the Kootenai Electric Cooperative, Inc., Clearwater Power Company, Idaho County Light and Power Cooperative Association, Inc., Northern Lights, Inc. and the electric cooperative members of the Snake River Power Association, Inc. (collectively, the "Idaho Cooperatives") as of October 31, 2000.

"FERC" shall mean the Federal Energy Regulatory Commission or its successor.

"FERC License" shall mean any license for the Priest Rapids Project issued by FERC to the District.

"Marketing Plan" shall mean the plan for making available in a fair, equitable, and non-discriminatory manner pursuant to market-based principles and procedures the Reasonable Portion as required by applicable law or PL 83-544 Orders.

"New FERC License" shall mean the license issued by FERC to the District following the expiration of the Original FERC License for operation of the Priest Rapids Project for a duration of 30 years or longer, not including any subsequent annual or other license.

"Operating Agreements" shall mean any agreements to which the District is or may become a party, which provide for operation of the Priest Rapids Project, including but not limited to, the Pacific Northwest Coordination Agreement, the Agreement for the Hourly Coordination of Projects on the Mid-Columbia River, the Western Systems Coordinating Council Agreement, the Agreement Relating to Wanapum Development Encroachment on the Rock Island Project and the Northwest Power Pool, which is the voluntary association of utilities formed in the Pacific Northwest for the purpose of ensuring the adequacy and reliability of the electric power systems in the Pacific Northwest.

"Original FERC License" shall mean the Federal Power Commission License for the Priest Rapids Project issued to the District on November 4, 1955, together with amendments thereto.

"Pacific Northwest" shall have the meaning ascribed thereto in Section 3(14) of the Regional Act.

"Priest Rapids Development" shall mean the separate utility system of the District, including a dam at the Priest Rapids Development, all generation and transmission facilities associated therewith, and all betterments, renewals, replacements, and additions to such system, as further described in Section 2(f) of Exhibit 1 of District Resolution No. 390 which is attached as Exhibit A, but shall not include any additional generation, transmission and distribution facilities hereafter constructed or acquired by the District as a part of the Electric System or the Wanapum Development or any other utility properties of the District acquired or constructed as a separate utility system.

"Priest Rapids Project" shall mean the hydroelectric project on the Columbia River in the State of Washington designated by the Federal Power Commission as Project No. 2114. The Priest Rapids Project consists of the Priest Rapids Development and the Wanapum Development.

"Priest Rapids Project Output" shall mean the amount of capacity, energy (both firm and non-firm), pondage, reactive power, ancillary services and any other product from the Priest Rapids Development from November 1, 2005 to November 1, 2009, and from the Priest Rapids Project from November 1, 2009 through the term of this contract under the operating conditions which exist during the term, including periods when the Priest Rapid Project may be wholly or partially inoperable for any reason, after correction for encroachment, Canadian entitlement, station and project use, and depletions required by the FERC License or other regulatory requirements.

"Prudent Utility Practice" means those practices, methods and acts which: (i) when engaged in are commonly used in prudent engineering and operations to operate electric equipment and associated mechanical and civil facilities lawfully and with safety, reliability, efficiency and expedition or (ii) in the exercise of reasonable judgment considering the facts known when engaged in, could have been reasonably expected to achieve the desired result consistent with applicable law, safety, reliability, efficiency and expedition. Prudent Utility Practice is not intended to be the optimum practice, method or act, to the exclusion of all others, but rather to be a spectrum of commonly used practices, methods or acts.

"Public Law 83-544" (or "PL 83-544") shall mean the legislation passed by the 83rd Congress authorizing the District to develop the Priest Rapids Project.

"Purchasers" shall mean the Purchaser and each person or entity that has entered into a contract with the District substantially similar to this contract.

"Purchaser Revenue Allocation" shall mean the fixed percentage (stated to the second decimal point, e.g., 0.01%) as set forth in Section 3(b) of the proceeds from and the costs of the sale of the Reasonable Portion made available under this contract. For parties to the 1956 and 1959 Contracts, Purchaser Revenue Allocation may not exceed twice the average of their participation in the 1956 and 1959 Contracts except that for those Purchasers that were parties to the 1956 Contracts but were not parties to the 1959 Contracts their Purchaser Revenue Allocation for the period November 1, 2005 to October 31, 2009 may not exceed twice their participation in the 1956 Contract. For any individual Idaho Cooperative, Purchaser Revenue Allocation shall not exceed the Purchaser Product Percentage of any individual party to the 1956 or 1959 Contract that is one of the Purchasers except when the provisions of Section 3(e) are applied. The Purchaser Revenue Allocation set forth in Section 3(b) is subject to revision pursuant to Sections 3(e), 3(f), 3(g), 3(h) and 4(f).

"Reasonable Portion" shall mean that 30% portion of the Priest Rapids Project Output required by FERC pursuant to Public Law 83-544 to be offered for sale by the District.

"Reasonable Portion Proceeds" shall mean the proceeds derived from the sale of the Reasonable Portion pursuant to the Marketing Plan.

"Regional Act" shall mean Public Law 96-501, the Pacific Northwest Electric Power Planning and Conservation Act.

"Uncontrollable Forces" shall mean any cause reasonably beyond the control of the Party and which the Party subject thereto has made reasonable efforts to avoid, remove or mitigate, including but not limited to acts of God, fire, flood, explosion, strike, sabotage, act of the public enemy, civil or military authority, including court orders, injunctions, and orders of government agencies with proper jurisdiction, insurrection or riot, an act of the elements, failure of equipment or contractors, or inability to obtain or ship materials or equipment because of the affect of similar causes on suppliers or carriers; provided, however, that in no event shall an Uncontrollable Force excuse the Purchaser from the obligation to pay any amount when due and owing under this contract.

"Wanapum Development" shall mean the second stage of the Priest Rapids Project as more fully described in Section 2.2 of District Resolution No. 474, which is attached as Exhibit A, but shall not include any generation, transmission and distribution facilities hereafter constructed or acquired by the District as a part of the Electric System or the Priest Rapids Development, or any other utility properties of the District acquired or constructed as a separate utility system.

The following terms are defined in the cited sections of this contract:

"Act of Default" at Section 17(a).
"Annual Power Costs" at Section 5(a).
"Committee" at Section 23.
"Coverage Requirement" at Section 5(a)(9).
"Estimated District Loads" at Section 4(c)(1).
"Estimated District Power Costs" at Section 4(c)(4).
"Estimated Power Cost Shortfall" at Section 8(a)(4).
"Estimated Unmet District Load" at Section 4(c)(3).
"Excess Costs" at Section 6(g).
"Financing Costs" at Section 5(a)(3).
"Idaho Cooperatives" at "Eligible Purchasers."
"Improvements" at Section 4(f)(4).
"Multi-Year Contracts" at Section 8(a)(3).
"New FERC License Costs" at Section 5(a)(6).
"Party" and "Parties" at the Preamble.
"PL 83-544 Orders" at Section 3(h).
"Purchaser Estimated Costs" at Section 6(a)(5).
"Refund Costs" at Section 6(g).
"Rock Island Hydroelectric Project" at Section 11(b).
"Zero Year" at Section 8(a)(3).

SECTION 3. PROCEEDS FROM THE SALE OF THE REASONABLE PORTION.

(a) Pursuant to the PL 83-544 Orders, the Reasonable Portion must be offered for sale. The District, therefore, desires to mitigate the risk associated with generating the Reasonable Portion including, but not limited to, the uncertainty of future Priest Rapids Project Output, costs and market prices. The District believes that this can be best accomplished by allocating to Purchasers the costs and proceeds from the sale of the Reasonable Portion.

(b) Upon execution of this contract, Purchaser shall select a percentage allocation of the costs and proceeds from the sale of the Reasonable Portion as described below. The percentage allocation of the costs and proceeds from the sale of the Reasonable Portion ("Purchaser Revenue Allocation") shall be 25 percent. The amount of the proceeds and the costs from the sale of the Reasonable Portion are defined in Sections 4 and 6, respectively.

(c) The District will use the Purchaser Revenue Allocation of the Reasonable Portion Proceeds to purchase capacity and energy for the Purchaser pursuant to a supplementary agreement between the Purchaser and the District. The District will directly assign to the Purchaser the cost incurred by the District in using the Purchaser Revenue Allocation to purchase such capacity and energy.

(d) By notification to the District pursuant to Section 4(b), the Purchaser may elect to receive its Purchaser Revenue Allocation of Reasonable Portion Proceeds in cash rather than receiving energy and capacity.

(e) REALLOCATION. If collectively Purchasers subscribe to Purchaser Revenue Allocations that total more than 100%, then Purchaser Revenue Allocations will be determined as follows; provided, however, that the application of the following formula shall not result in the Purchasers being assigned a Purchaser Revenue Allocation larger than that included in this contract on the date of execution:

(1) Step 1. One-hundred percent of the Purchaser Revenue Allocation will be divided between the Purchasers who are parties to the 1956 and 1959 Contracts, as a group, and the Purchasers who are included in the Idaho Cooperatives, as a group, in proportion to the number of retail electric customers located in the Pacific Northwest (determined by the number of retail meters) served by each group as of October 31, 2000.

(2) Step 2. Each Purchaser's Revenue Allocation will be determined as follows:

(A) For Purchasers who are parties to the 1956 and 1959 Contracts, the proportion of such Purchaser Revenue Allocations from Step 1 above will be distributed to individual Purchasers as follows:

(i) For November 1, 2005 through October 31, 2009 the Purchaser Revenue Allocations shall be distributed in proportion to participation in the 1956 Contract and 1959 Contract weighted 75% and 25%, respectively.

(ii) For the period after November 1, 2009 the Purchaser Revenue Allocations shall be distributed in proportion to the sum of participation in the 1956 Contract and 1959 Contract divided by two.

(B) For the Purchasers who are included in the Idaho Cooperatives, the proportion of such Purchaser Revenue Allocations from Step 1 will be distributed to such individual cooperatives in proportion to the number of retail electric customers located in the Pacific Northwest (determined by number of retail meters) each cooperative served as of October 31, 2000.

(f) If the reallocation procedure of Section 3(e) is implemented, then for the period November 1, 2005 through October 31, 2009, the following shall apply to Purchasers who were parties to the 1956 Contracts but were not parties to the 1959 Contracts:

(1) The Purchaser Revenue Allocation shall be adjusted to be in proportion to participation in the 1956 Contract (the Purchaser's percent participation in the 1956 Contract divided by 63.5%),

(2) The District shall be obligated to provide the Reasonable Portion Proceeds pursuant to Section 5 using the Purchaser Revenue Allocation, calculated pursuant to Section 3(f)(1), and the Purchaser shall be obligated to make payments pursuant to Sections 5 and 6 using such Purchaser Revenue Allocation.

The adjustments to Purchaser Revenue Allocation pursuant to this Section 3(f) will have no effect on the Purchaser Revenue Allocation of any other Purchaser.

(g) If a Contract with one of the Purchasers is terminated pursuant to Section 17 as a result of such Purchaser's Act of Default, the District shall give the non-defaulting Purchasers notice of such default. Beginning with the first month that is at least 30 days following such notice, the Revenue Allocations (other than zero) of non-defaulting Purchasers shall be increased pro rata until either: (i) the Purchaser Revenue Allocation of the defaulting Purchaser have been fully allocated or (ii) a further pro rata increase to the Purchaser Revenue Allocations of the non-defaulting Purchasers would adversely affect the tax-exempt status of any outstanding Debt. In the event of (ii), the portion of the Purchaser Revenue Allocation of the defaulting Purchaser not yet allocated will be offered to all Purchasers that can accept such allocation without adversely affecting the tax-exempt status of any outstanding Debt. If after such offer there remains some portion of the Purchaser Revenue Allocation of the defaulting Purchaser not yet allocated, the District at its discretion may elect to accept such unallocated portion. If after all of the foregoing there remains unallocated Purchaser Revenue Allocation of the defaulting Purchaser, the Purchaser Revenue Allocations (other than zero) of non-defaulting Purchasers shall be increased pro rata based on each such non-defaulting Purchaser's Purchaser Revenue Allocation before any allocation under this Section 3(g). In the event that the allocation described in the immediately preceding sentence adversely affects the tax-exempt status of Debt, any increased costs resulting therefrom will be included in Annual Power Costs. Nothing in this subsection is intended to limit any claims the non-defaulting Purchasers may assert against the defaulting Purchaser.

(h) REGULATORY APPROVALS. The District and the Purchaser believe that this contract fully complies with the requirements of Public Law 83-544. FERC has ordered that a Reasonable Portion of the Priest Rapids Project Output be offered for sale based on market principles and that Eligible Purchasers are to receive a meaningful priority. Additionally, FERC has stated that the District may negotiate power contracts as part of the license application process provided that implementation of such contracts is contingent on receipt of license authority. The District and the Purchaser agree that nothing in this contract limits in any way the District's ability to conform to these FERC requirements. Nothing in this contract, other than Section 7, limits the ability of the Purchaser from participating in any FERC or court proceedings that may address Public Law 83-544.

The Parties understand that FERC's orders of February 11, 1998 and June 12, 1998 in Docket No. EL95-35 (the "PL 83-544 Orders") require the District, as part of its application for a New FERC License, to file the Marketing Plan for making available the Reasonable Portion in a fair, equitable and non-discriminatory manner pursuant to market-based principles and procedures. The Parties further understand and agree that nothing in this contract is intended to affect or limit in any way the right of the District to develop and file the Marketing Plan which it determines is consistent with the PL 83-544 Orders.

In the event that FERC or a court of competent jurisdiction shall by order determine that any provision of this contract violates a requirement of either PL 83-544 or of any of the PL 83-

544 Orders, the Parties shall, within 30 days of the entry of such an order, commence negotiations for the purpose of reaching agreement on such amendments to this contract, if any, as may be needed for the purpose of complying with that order and for the purpose of preserving the basic benefits and obligations of the Parties. If, within 90 days of commencement of negotiations, the Parties are not able to resolve their differences and to agree upon any necessary amendments, either Party may, after notice to the other Party, cause the matter to be submitted to binding arbitration as provided in Section 23.

If following the issuance of the arbitration decision, a Party reasonably determines that acceptance of such amendments will result in materially decreased benefits or materially increased obligations when compared to this contract, the Party may by notice to the other Party explain its reasons for the determination and, if given within 10 days of the arbitration decision, terminate this contract.

SECTION 4. DETERMINATION OF ESTIMATED PURCHASER REVENUE ALLOCATION OF REASONABLE PORTION PROCEEDS.

(a) The estimated Purchaser Revenue Allocation of the Reasonable Portion Proceeds expected to be available to Purchaser during each Contract Year will be determined by application of the following provisions of this Section 4.

(b) On or before 60 days prior to the beginning of each Contract Year, Purchaser shall provide the District with written notification if it wishes to elect, pursuant to Section 3(d), to receive its Purchaser Revenue Allocation of Reasonable Portion Proceeds in cash instead of the District purchasing energy and capacity therewith. In the event that Purchaser fails to make such annual election pursuant to this section, the District will provide Purchaser with energy and capacity pursuant to Section 3(c).

(c) For the purpose of determining the estimated Purchaser Revenue Allocation of the Reasonable Portion Proceeds for the next Contract Year, on or before 30 days prior to the beginning of each Contract Year, the District shall prepare and mail to the Purchaser a pro forma statement showing for the next Contract Year:

   (1) "Estimated District Loads," which shall mean all projected retail electric energy loads for the next Contract Year based on average weather conditions, plus aggregated losses, projected to be used at locations served by the District during the next Contract Year with the exception of (i) locations outside of the geographic boundaries shown on Exhibit B and (ii) that portion of loads of individual retail customers that during a consecutive 12 month period after 2000 exceed by ten average megawatts or more the energy load of such customer for the immediately preceding consecutive 12 month period. Once load at a location is included in Estimated District Loads, loads at such location shall continue to be included in full in future Contract Years without regard to the source of supply for such load. For example, if a load is expected to be served in all or part by an entity other than the District during the next Contract Year, the entire load shall continue to be included in Estimated District Loads. If a new load or increased load of one average megawatt or more at a single retail customer has been included in Estimated District Loads in the current Contract Year, and less than 90% of such new or increased load was actually measured in

the current year, then Estimated District Loads shall be reduced for the next Contract Year by the difference between the amount included in the current Contract Year and the amount measured. If there are more than one such new or increased loads for the current Contract Year, they shall be combined for determining both the 90% and the amount of any reduction. If in the current Contract Year a load of one average megawatt or more is placed on the District which was not included in the current Contract Year's Estimated District Loads, then the next Contract Year's Estimated District Loads shall be increased by the amount of such load measured in the current Contract Year. Except for such load correction calculations, Estimated District Loads for the next Contract Year shall be not less than the current Contract Year's Estimated District Loads.

(2) The estimated amount of firm energy from the Priest Rapids Project for the next Contract Year based on critical water planning using the procedures of Operating Agreements in effect on October 31, 2000, unless the District and Purchasers whose Purchaser Revenue Allocation total 66% or more mutually agree to use procedures from a subsequent Operating Agreement.

(3) The monthly amount of "Estimated Unmet District Load" determined as follows:

(A) Prior to November 1, 2009, the Estimated District Load as calculated in Section 4(c)(1) less 70% of the estimated firm energy output of the Priest Rapids Development less 36.5% of the estimated firm energy output of the Wanapum Development both as calculated in Section 4(c)(2).

(B) On or after November 1, 2009, the Estimated District Loads as calculated in Section 4(c)(1) less 70% of the estimated firm energy output of the Priest Rapids Project as calculated in Section 4(c)(2).

(C) In the event that the calculation in Section 4(c)(3)(A) or (B) above is less than zero the Estimated Unmet District Load will be zero.

(D) The difference so determined will be shaped on a monthly basis using the District's historic load patterns.

(4) The "Estimated District Power Costs" which shall equal the estimated cost, including the costs of transmission and other necessary services, of acquiring the monthly amount of capacity and energy identified in Section 4(c)(3) determined by references to published futures price data and firm power supply contracts entered into by the District, and rates for transmission and other necessary services. Prior to the start of the next Contract Year, any Purchaser may provide the District with a written firm and irrevocable bid(s) for all or part of the capacity and energy needed to serve the Estimated Unmet district Load from Section 4(c)(3) for the next Contract Year, and for which the District has not procured a firm power supply. If such bid(s), or in the case of a partial supply bid the combination of the bid and the Estimated Power Cost for the remaining Estimated Unmet District Load, is less costly than the Estimated District Power Cost set forth in the pro forma statement as determined by the District, the District may either: (i) acquire from the Purchaser the

capacity and energy offered, and use the bid price in the calculation of the Estimated District Power Costs for the Estimated Unmet District load so served; or (ii) substitute the bid price for the portion of the Estimated Unmet District Load that could have been served with the capacity and energy so bid in the calculation of Estimated District Power Costs.

(5) The estimated Reasonable Portion Proceeds.

(d) Subject to Section 8, in those Contract Years when the District has Estimated District Power Costs as determined pursuant to Section 4(c)(4), the District shall be entitled to and shall take from the actual Reasonable Portion Proceeds the Estimated District Power Costs calculated pursuant to Section 4(c)(4).

(e) Subject to Section 8, the Purchaser shall have available the capacity and energy purchased pursuant to Section 3(c) with an amount equal to the actual Reasonable Portion Proceeds received by the District, minus the Estimated District Power Costs as calculated in Section 4(c)(4), multiplied by the Purchaser Revenue Allocation; provided, however, if the Purchaser has elected to receive cash rather than capacity and energy, Purchaser shall be entitled to receive in cash an amount equal to the actual Reasonable Portion Proceeds received by the District, minus the Estimated District Power Costs as calculated in Section 4(c)(4), multiplied by the Purchaser Revenue Allocation.

(f) The Purchaser Revenue Allocation of the Reasonable Portion Proceeds available to Purchaser may be reduced if the District does not obtain an Annual FERC License or New FERC License, and under any of the following conditions as determined by the District:

(1) Pursuant to Section 4.

(2) If the district is unable to produce the Reasonable Portion due to Uncontrollable Forces.

(3) If failure to reduce deliveries of the Reasonable Portion would result in exceeding the capability of the Priest Rapids Project or subject it or its operation to undue hazard or violate the FERC License, any applicable law, regulation, or Operating Agreement.

(4) In case of emergencies or in order to install equipment in, make repairs to, make betterments, renewals, replacements, and additions to ("Improvements"), investigations and inspections of, or perform other maintenance work on the Priest Rapids Project.

The District will use its reasonable efforts to give advance notice to the Purchaser regarding any planned interruption or reduction, giving the reason therefor and stating the probable duration thereof.

(g) Notwithstanding any other Section of this contract, if the Priest Rapids Project is capable of producing Priest Rapids Project Output, but the Purchaser Revenue Allocation of the Reasonable Portion Proceeds to be made available to the Purchaser is projected to be zero for a Contract Year, the Purchaser may give the District written notice, no later than 100 days after the start of the Contract Year, that the Purchaser elects to terminate this contract. In such event, this contract shall terminate effective upon receipt of such written notice by the District.

SECTION 5. ANNUAL POWER COSTS.

(a) "Annual Power Costs" as used in this contract shall include, for the Priest Rapids Development beginning November 1, 2005 and for the Priest Rapids Project beginning November 1, 2009, all of the District's costs and expenses of every type, both direct and indirect, resulting from the ownership, operation, maintenance of and Improvements that are incurred or paid by the District during each Contract Year and that are incurred consistent with Prudent Utility Practice. Such costs and expenses shall for any Contract Year include, but not be limited to the following, in each case without duplication:

(1) All operations costs, maintenance costs, administrative costs, taxes, in lieu of tax payments relating to production and delivery of Priest Rapids Project Output (excluding depreciation) including, but not limited to, those specified in the Uniform System of Accounts as prescribed by the FERC for electric utilities and licensees.

(2) Amounts that the District determines are needed to pay for the prevention or correction of any loss or damage and for Improvements to keep the Priest Rapids Project in good operating condition. Subject to Section 23, the Purchaser agrees that the District shall have the sole right to determine what costs and expenses shall be incurred in connection with the ownership, operation, and maintenance of and Improvements to the Priest Rapids Project.

(3) Subject to Section 5(e), interest that accrues and is payable into the debt service fund with respect to outstanding Debt; principal that accrues and is payable into the debt service fund with respect to outstanding Debt, whether at maturity or by reason of redemption (including premiums for redeeming Debt prior to its scheduled maturity), amounts required to restore any reserve accounts maintained to secure Debt to the level required by the resolution authorizing the Debt and Financing Costs. "Financing Costs" include, but are not limited to, discounts, insurance premiums, letter of credit fees, costs of hedging interest rates, costs of compliance with disclosure requirements, legal and bond counsel fees, independent auditors, printing, financial advisor, bond registrar and trustee costs.

(4) Subject to Section 5(e), costs of creating and replenishing any reserve or contingency fund required to be maintained by any Bond Resolutions and working capital funds.

(5) Any liability or cost, including settlements and judgments, incurred as a result of or related to the ownership, operation or maintenance of the Priest Rapids Project and not covered by insurance.

(6) Costs incurred by the District in applying for a New FERC License as recorded on the District's books of account for the Priest Rapids Project (account number 183090), including but not limited to those costs and interest expenses incurred before November 1, 2005 ("New FERC License Costs"). New FERC License Costs incurred prior to November 1, 2005 will be recovered uniformly over a 15-year amortization period.

commencing with the Contract Year starting on January 1, 2006. The estimated New FERC License Costs incurred by the District after November 1, 2005 will be included in Annual Power Costs. In the event of termination of this contract for any reason subsequent to the effective date of the New FERC License, the Purchaser shall pay the District an amount equal to the unrecovered New FERC License Costs multiplied by the Purchaser Power Allocation at the time of termination. In the event of termination of this contract for any reason prior to the effective date of the New FERC License, Purchaser shall have no liability for unrecovered New FERC License Costs.

(7) Obligations entered into by the District as part of its effort to obtain a New FERC License, including but not limited to the cost or replacing Priest Rapids Project Products that may be committed in such obligations.

(8) Costs incurred by the District to fulfill obligations, if any, to the parties to the 1956 and 1959 Contracts who do not sign this contract, as such costs are required or approved by a court, or reasonably approved by the District after notice to the Purchaser.

(9) An amount equal to 15% of debt service in that Contract Year or such higher amount as may be required by a Bond Resolution ("Coverage Requirement").

(b) The District shall credit against Annual Power Costs the following:

(1) Any insurance or other proceeds received by the District as reimbursement for damages, losses, costs or expenses included in the Annual Power Costs, and any insurance or other proceeds received as a result of the interruption or reduction of Priest Rapids Project Output.

(2) Revenue, if any, received from obligations entered into by the District as part of its effort to obtain a New FERC License.

(3) Revenue, if any, received as a result of the District fulfilling obligations to parties to the 1956 or 1959 Contract that do not sign this contract, pursuant to Section (1)(b) of those contracts, excluding revenue required to be paid pursuant to the 1959 Contract.

(4) The Coverage Requirement, to the extent that it is not expended during a Contact Year for capital or other costs of the Priest Rapids Project (the amount not spent shall be credited against Annual Power Costs for the following Contract Year).

(5) Interest earnings on funds of the Priest Rapids Project that are not required to be retained by such fund by a Bond Resolution.

(c) Costs directly or indirectly associated with the District's Electric System or any other separate system of the District shall not be part of Annual Power Costs other than the payment of Debt held by the Electric System.

(d) Any payment received by the District as a result of the taking of the whole or any portion of the Priest Rapids Project Output by any state or federal government agency shall be used by the District to credit Annual Power Costs or to retire, at or prior to maturity, Debt, whichever shall be proper under the circumstances existing at the time of the taking.

(e) The Purchaser agrees that the District shall have the sole discretion to determine what portion, if any, of the Priest Rapid Project financing will be accomplished by issuance of Debt and the terms and covenants of any Debt.

(1) To the extent that the District makes Improvements to the Priest Rapids Project that are not financed by Debt proceeds, Annual Power Costs will include a cost as determined by the following: the District shall determine all of the Improvements anticipated for the Priest Rapids Project for the Contract Year and the District shall estimate the weighted average economic service life of the Improvements, and shall calculate a weighted average market interest rate assuming the District were to issue Debt to finance such Improvements, both as reasonably determined by the District. Based on such calculations the District shall include in Annual Power Costs an amount sufficient to amortize the costs (including both interest and principal pursuant to this Section 5(e)(1)) of such Improvements on a level basis over a period equal to the estimated weighted average economic service life of the Improvements. The amortization period for any Improvements shall not exceed 30 years and land shall be deemed to have a service life of 30 years. The District may adjust prospectively the amortization of any Improvements to reflect the actual costs of such Improvements, to correct any error in computation or to reflect a material change in the District's estimate of the average economic life of the Improvements. The District shall not be required to amortize capital expenditures that are estimated to cost below the amount that in accordance with the District's capitalization policy are not required to be capitalized and may include such costs in Annual Power Costs.

(2) To the extent that the District issues Debt (i) with a final maturity that is not earlier than the expiration of the estimated weighted average service life of the Improvements, to be financed with the Debt and (ii) the total annual amounts required for the payment of interest, principal and sinking fund requirements of such Debt when due in a Contract Year do not vary by more than 10% from those required in any other Contract Year, then Annual Power Costs shall include the actual principal and sinking fund requirements that accrues and is payable into the debt service fund for that Debt for the Contract Year. To the extent that the District issues Debt that does not meet the requirements of (i) and (ii) in the prior sentence, then Annual Power Costs will include, with respect to such Debt, an amount as determined by the District as of the date of issuance of the Debt, sufficient to amortize the original principal amount of such Debt on a level debt service basis over a period equal to the estimated weighted average economic service life of the Improvements financed or refinanced by such Debt, commencing on the later of (a) the date of issuance of the Debt or (b) the in service date of such Improvements, and based on an interest rate equal to, at the election of the District, either (i) the weighted average interest rate of the Debt or (ii) the weighted average market rate at the time of issuance of the Debt for debt with similar terms and borrowers similar to the District, as reasonably

determined by the District. The amortization period for any Debt shall not exceed 30 years, land shall be deemed to have an economic useful life of 30 years, and any Debt proceeds deposited into a reserve account shall be credited against Annual Power Cost in the final year of the Debt. The District may adjust prospectively the amortization of the principal amount of any Debt to correct any error in computation or to reflect a material change in the District's reasonable estimate of the in service date or the average economic life of the Improvements.

(3) To the extent that the District creates or replenishes reserve and contingency funds required by Bond Resolutions or working capital funds that are not financed by Debt proceeds, Annual Power Costs will include a cost determined in a manner analogous to the calculation in Section 5(c)(2) with such amounts amortized over 15 years. Upon termination of this contract, any such funds will belong to the District.

(f) On or prior to July 31st of each year, for budgetary purposes only and not for determining Priest Rapids Project Products or Purchaser's payment obligations under this contract, the District shall provide the Purchaser a pro forma budget showing an estimate of Annual Power Costs, Priest Rapids Project Output, Purchaser Revenue Allocation and Estimated District Loads for the following Contract Year.

SECTION 6. PAYMENT FOR PRIEST RAPIDS PROJECT PURCHASER REVENUE ALLOCATION.

(a) On or before 30 days prior to the beginning of each Contract Year beginning in 2005, the District shall prepare and mail the Purchaser a pro forma statement for the next Contract Year showing:

(1) An estimate of Annual Power Costs specifically assigned to the Purchaser. Specific assignment shall occur whenever a Purchaser or a group of Purchasers cause identifiable costs to be placed on the Priest Rapids Project.

(2) A detailed estimate of the Annual Power Costs, less those costs specifically assigned in Section 6(a)(1), for the Contract Year.

(3) An estimate of the cost to the Purchaser attributable to the Purchaser Revenue Allocation of the costs of the Reasonable Portion, which shall be an amount equal to the product of the Reasonable Portion and the Annual Power Costs from Section 6(a)(2) multiplied by the ratio of the estimated Reasonable Portion Proceeds to be received by the Purchaser calculated pursuant to Section 4(c) to the estimated total Reasonable Portion Proceeds from Section 4(c)(5).

(4) An estimate of the cost of purchasing capacity and energy with the Purchaser Revenue Allocation of the Reasonable Portion Proceeds pursuant to Section 3(c).

(5) The sum of amounts (expressed in dollars) calculated pursuant to Sections 6(a)(1),(3), and (4), hereinafter referred to as the "Purchaser Estimated Cost."

(6) The amount of the monthly payments to be made by the Purchaser to pay the Purchaser Estimated Cost during the next Contract Year.

(b) The pro forma statement provided pursuant to Section 6(a) shall be in lieu of the issuance of monthly bills to the Purchaser by the District, and the Purchaser shall be obligated to pay the monthly amounts contained therein in accordance with this Section 6.

(c) In the event of receipts or payments substantially affecting the Annual Power Costs during any Contract Year, the District shall prepare and mail to the Purchaser a revised statement of estimated Annual Power Costs and Purchaser Estimated Cost, which revised statement shall supersede any previous statement or revised statement, and the Purchaser shall be obligated to make monthly payments set forth on such revised statement for the balance of the Contract Year.

(d) Purchaser Estimated Cost shall continue to accrue and the Purchaser shall make payment for the same up to the time of termination of this contract for whatever reason, irrespective of the condition of the Priest Rapids Project and whether or not it is capable of producing Priest Rapids Project Output, the Reasonable Portion or the Purchaser Revenue Allocation of the Reasonable Portion Proceeds. If the Priest Rapids Project is not capable of producing Priest Rapids Project Output then the Purchaser Estimated Cost will be based on Priest Rapids Project Output in the last full year of operation. In this event, at the request of the Purchaser, the District will make its reasonable best efforts to acquire replacement Priest Rapids Products the cost of which will be added to the Purchaser Estimated Cost.

(e) The monthly payments of Purchaser Estimated Costs set forth in the statement or revised statement shall be due and payable by electronic funds transfer to the District's account, designated in writing by the District, on the 20th calendar day of each month.

(f) If payment in full of any monthly payment amount set forth on a statement or revised statement is not received by the District on or before the close of business on the 20th day of the month, a delayed payment charge of 2% of the unpaid amount due will be made. Any bill which remains unpaid for more than 30 days after the due date shall, in addition to the delayed payment charge, accrue interest at the lesser of 1.5% per month or the maximum rate allowed by law. If the 20th calendar day of the month is a Saturday, Sunday or a District recognized holiday, the next following business day shall be the last day on which payment may be received without the addition of the delayed-payment charge. Additionally, if payment due to the District under this Section 6 remains unpaid 30 days after the due date, the District may thereafter suspend payment of the Purchaser Revenue Allocation to the Purchaser which would otherwise occur until payment in full of all amounts due and owing (including any interest and delay charges) is received by the District.

(g) On or before 150 days after the end of each Contract Year, the District will submit to the Purchaser a detailed statement of the Purchaser Estimated Cost and the Purchaser Actual Cost for the Contract Year. Purchaser Actual Cost on such statement shall be calculated in the same manner as Purchaser Estimated Cost as set forth in Sections 6(a)(1)-(5) but using the actual costs incurred by the District in the preceding Contract Year; provided, however, that the estimated values calculated pursuant to Sections 4(c)(1)-(2) and 4(c)(5) shall not be modified. If the Purchaser Actual Costs exceed the Purchaser Estimated Costs on such statement ("Excess Costs"), the District shall bill the Purchaser for an amount equal to such Excess Costs, and the Purchaser shall pay such bill within 30 days or be subject to the delayed-payment and interest charges as provided in Section 6(f). If the Purchaser Actual Costs are less than the Purchaser Estimated Costs, or if credits are due pursuant to Section 5(b) or both ("Refund Costs"), the District shall give credit to the Purchaser against the Purchaser Estimated Costs for the current Contract Year in an amount equal to such Refund Costs; provided, that if Refund Costs are due to Purchaser following the expiration of this contract, the District shall make a cash refund of such amount to the Purchaser.

(h) The District may use any payments received from the Purchaser under this contract in any manner that the District, in its sole discretion, shall determine. The District agrees to pay or cause to be paid for the Priest Rapids Project from lawfully available money of the District, including payments from the Purchaser and other Purchasers, all the operating costs, taxes and assessments, capital expenditures, payments required for Debt and other costs of the Priest Rapids Project. If the District issues tax-exempt Debt based on the governmental use of the Priest Rapids Project Output by the Purchaser, the Purchaser covenants that it shall not use any Priest Rapids Project Output in a manner, or take any other action, that will or is likely to adversely affect the tax-exempt status of any Debt.

SECTION 7. SUPPORT AND COOPERATION.

(a) The District shall make application and use reasonable efforts to obtain a New FERC License and obtain FERC approval of this contract, if required. The District reserves the right to determine when such applications should be made.

(b) In accordance with FERC direction contained in the PL 83-544 Orders, the District commits to providing the Eligible Purchasers with a meaningful priority in the sale of the Reasonable Portion.

(c) Purchasers may also participate in the development by the District of a proposed Marketing Plan. This Marketing Plan will be submitted to FERC for approval as part of the relicensing process application; provided, however, that nothing in this Section shall be construed as compelling the Purchaser to comment on or refrain from commenting on the Marketing Plan.

(d) Purchaser covenants that it shall provide reasonable support, cooperation and assistance to the District in the District's acquisition of a New and Annual FERC License, any necessary federal, state or local permits relating to the Priest Rapids Project, FERC approval of this contract, if FERC approval is requested by the District; provided, however, that nothing in this contract shall preclude the Purchaser from filing comments with FERC to protect the Purchaser's economic benefits provided by this contract.

(e) In the event that the District believes that the Purchaser has violated any of the above covenants of Section 7(d), the District may by written notice to the Purchaser describe the alleged violation in reasonable detail and give the Purchaser no less than 10 business days within which to cease the activity in question or to provide to the District a written explanation as to why the Purchaser believes the activity does not constitute a violation of any of the aforementioned covenants. If the Purchaser does not cure the alleged default and the District continues to consider the action to be in breach of the covenants, the matter shall be resolved pursuant to arbitration conducted under Section 23. If the Purchaser is determined to be in breach of the covenants, the District shall have the right to terminate this contract effective immediately upon written notice to the Purchaser, without any liability or further obligation on the part of the District. In the event of such termination, the District shall have the right to use or sell, in any manner the District determines, the Purchaser Revenue Allocation the Purchaser would have been otherwise entitled to under this contract.

(f) Purchaser covenants that it shall refrain from filing or supporting any FERC license application for the Priest Rapids Project other than that filed by the District and refrain from filing or supporting any effort that would lead to modification of the FERC decisions on Public Law 83-544 contained in the PL 83-544 Orders, unless such a request or petition is filed by the District and the Purchaser agrees with that request or petition. For purposes of this Section 7(f), "refrain from supporting" means prepare no documents, submit no testimony, sign no other agreement or contract other than this contract for Priest Rapids Project Output or for other products or that is contingent upon a party other than the District receiving a license from FERC to operate the Priest Project, engage in no lobbying and provide no funding.

(g) The Purchaser covenants that it will not take any action which, in the opinion of a neutral third party, would likely be construed as: (i) having a material adverse effect on the District's ability to obtain an Annual FERC License or a New FERC License or on the anticipated economic benefits of this contract or (ii) constituting a judicial challenge to the authority of the District or the Purchaser to enter into and implement the provisions of this contract. This covenant does not apply to anticipated economic benefits under other agreements between the District and third parties, such as with the Bonneville Power Administration.

(h) In the event that the District believes that the Purchaser has violated any of the above covenants of Section 7(f) or (g), the District may by written notice to the Purchaser describe the alleged violation in reasonable detail and give the Purchaser no less than 4 business days after receipt of such written notice by Purchaser within which to cease the activity in question or to provide to the District a written explanation as to why the Purchaser believes the activity does not constitute a violation of any of the aforementioned covenants. If the Purchaser does not cure the alleged default and the District continues to reasonably consider the action to be in breach of the covenants, the District shall have the right to terminate this contract and the 1956 and 1959 Contracts, effective immediately upon written notice to the Purchaser, without any liability or further obligation on the part of the District. In the event of such termination, the District shall have the right to use or sell, in any manner the District determines, the Purchaser Revenue Allocation the Purchaser would have been otherwise entitled to under this contract and any output from the Priest Rapids Project under the 1956 or 1959 Contracts.

SECTION 8. PAYMENT OF THE REASONABLE PORTION PROCEEDS.

(a) The Purchaser Revenue Allocation of the Reasonable Portion Proceeds shall be paid to the Purchaser monthly, as follows:

(1) The monthly payment to the Purchaser shall be the product of the Purchaser Revenue Allocation and the difference between the actual monthly payments of the Reasonable Portion Proceeds received by the District and the monthly Estimated District Power Costs pursuant to Section 4(c)(4); provided, however, if the Purchaser has elected to have the District make purchases of capacity and energy under a supplementary agreement pursuant to Section 3(c), then Purchaser will receive such capacity and energy in lieu of the proceeds described in this Section 8(a)(1). Nothing in this Section 8(a)(1) will result in a negative payment or a bill to the Purchaser when such Estimated District Power Costs exceed the actual monthly Reasonable Portion Proceeds received by the District.

(2) Payments due from the District to Purchaser pursuant to Section 8(a)(1) shall be made in accordance with the provisions of Section 6, and such payment shall be due not later than the 20th calendar day of each month.

(3) During the term of this contract, the District may be entitled to take during a Contract Year all of the Reasonable Portion Proceeds pursuant to Section 4(d) resulting in a zero payment to purchaser ("Zero Year"). If in any Zero Year the District has in place one or more multiple year contracts, the terms of which include or span the Zero Year ("Multi-Year Contracts"), then the payments to the Purchaser from such Multi-Year Contracts included in the calculations performed pursuant to Section 4(c) shall be proportional to the annual market price of power as forecast at the time the Multi-Year Contracts were agreed to by the District.

(4) If in any month the Estimated District Power Costs from Section 4(c)(4) exceed the actual Reasonable Portion Proceeds received in such month ("Estimated Power Cost Shortfall"), the Estimated Power Cost Shortfall shall be carried forward to the next month or months remaining in the Contract Year in which such Estimated Power Cost Shortfall occurred until paid in full from the Reasonable Portion Proceeds received by the District.

SECTION 9. INFORMATION TO BE MADE AVAILABLE TO THE PURCHASER.

(a) The District agrees to keep records of the Priest Rapids Project in accordance with the Uniform System of Accounts as prescribed by FERC for electric utilities and licensees; provided, if there are inconsistencies between the Uniform System of Accounts and this contract, this contract shall control. The Purchaser, upon at least 30 days advance written notice to the District, shall have the right to audit or examine operating and financial records relating to the Priest Rapids Project during the District's normal business hours. To the extent practicable, the Purchasers shall conduct any such audit or examination jointly to minimize the disruption to the District's business operations. All costs incurred by the District associated with such audit, including, but not limited to, District labor, materials and reproduction services shall be billed to the Purchaser, and shall be promptly reimbursed by the Purchaser in accordance with Section 6(c).

(b) Upon request, any audit reports of the Priest Rapids Project by a firm of certified public accountants employed by the District or by the State Auditor's Office of the State of Washington will be provided to the Purchaser.

(c) Policies of insurance carried by the District pursuant to Section 10 shall be available at the office of the District for inspection by the Purchaser.

(d) The Purchaser's representatives shall at all times be given reasonable access to the Priest Rapids Project, subject to the District's applicable safety rules and regulations.

(e) Upon request, the Purchaser may obtain information to document the capability of the Priest Rapids Project to produce Priest Rapids Project Output.

SECTION 10. INSURANCE.

The District shall have the right to self-insure and/or obtain and maintain insurance with policies payable to the District for the following coverage:

(a) Obligations of the District under any state or federal Workmen's Compensation laws or other employer's liability;

(b) Public liability for bodily injury and property damage;

(c) Physical loss or damage to the Priest Rapids Project on a replacement cost basis; and

(d) Any other insurance determined to be necessary.

SECTION 11. PROJECT INTEGRATION.

(a) It is the intention of the Parties hereto that the operation of the Priest Rapids Project shall be integrated and that all benefits accruing as a result of such integration shall be shared equally by the Priest Rapids and Wanapum Developments. It is also agreed that before November 1, 2009 and after such date if required by any Bond Resolution, all joint costs of the Priest Rapids and Wanapum Developments shall be equitably allocated between them as determined by the District.

(b) The Parties agree that any compensation (whether energy or money) due or which become due the owner of the Rock Island Hydroelectric Project because of encroachment by the Priest Rapids Project after November 1, 2009 on the Rock Island Hydroelectric Project will either proportionately reduce the amount of Priest Rapids Project Output or be included in Annual Power Costs, as appropriate, but shall not reduce the amount required to be paid by the Purchaser under Sections 5 and 6. "Rock Island Hydroelectric Project" shall mean the FERC Hydroelectric Project No. 943 currently operated by Public Utility District No. 1 of Chelan County, Washington.

SECTION 12. LIABILITY OF PARTIES.

(a) Except as otherwise provided in this contract, each Party hereby releases the other Party and its commissioners, officers, directors, agents and employees from any claim for loss or damage arising out of the ownership, operation, and maintenance of the Priest Rapids Project including any loss of profits or revenues, loss of use of power system, cost of capital, cost of purchased or replacement power, other substantially similar liability or other direct or indirect consequential loss or damage, except as provided in the Agreement Limiting Liability Among Western Interconnected Systems for parties to that agreement. This release shall not include any claim by the Purchaser for refunds for over-payments made to the District nor any claim for specific performance of the District's obligation to deliver to the Purchaser during the term of this contract the Purchaser Revenue Allocation to which the Purchaser is entitled under this contract.

(b) The Purchaser shall have no claim of any type or right of action against the District: (i) as a result of a FERC or court order or amendment described in Section 3(h); (ii) as a result of the failure to receive an Annual FERC License or a New FERC license or the adjustment of delivery of Priest Rapids Products pursuant to Section 4(f) whether arising under the terms of this contract or otherwise; or (iii) as a result of the District's purchasing power or energy on behalf of the Purchaser pursuant to Sections 3(c), and the Purchaser hereby releases the District and its commissioners, officers, agents and employees from any claim for loss or damage arising out of the events described in this paragraph.

SECTION 13. NOTICES AND COMPUTATION OF TIME.
Any notice or demand, except those provided for in Section 6, by the Purchaser under this contract to the District shall be deemed property given if mailed postage prepaid and addressed to Manager, Public Utility District No. 2 of Grant County, Box 878, Ephrata Washington 98823; any notice or demand by the District to the Purchaser under this contract shall be deemed properly given if mailed postage prepaid and addressed to the Vice President, Energy Resources, Avista Corporation, P.O. Box 3727, Spokane, Washington 99220.

In computing any period of time from such notice, such period shall commence at 12:00 A.M. (midnight) on the date mailed. The designations of the name and address to which any such notice or demand is directed may be changed at any time by either Party giving notice as provided above.

SECTION 14. DISTRICT'S BOND RESOLUTIONS AND LICENSE.
It is recognized by the Parties that the District, in its operation of the Priest Rapids Project, must comply with the requirements of the Bond Resolution and with the FERC License together with amendments thereof from time to time made, and the District is hereby authorized to take such actions as the District determines are necessary and appropriate to comply with such Bond Resolution and FERC License.

SECTION 15. GOVERNING LAW.
The Parties agree that the laws of the State of Washington shall govern this contract.

SECTION 16. ASSIGNMENT OF CONTRACT.
Neither the Purchaser nor the District shall by contract, operation of law or otherwise, assign this contract or any right or interest in this contract without the prior written consent of the other Party, which shall not be unreasonably withheld; provided, however, a Party may, without the consent of the other Party (and without relieving itself from liability hereunder): (i) transfer or

assign this contract to an affiliate of the Party provided that the affiliate's creditworthiness is equal or higher than that of the Party; or (ii) transfer or assign this contract to any person or entity succeeding to all or substantially all of the distribution and generating facilities of the Party whose creditworthiness is equal or higher than that of the Party; provided, however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions in this contract and the transferring Party shall deliver such tax and enforceability assurance as the other Party may reasonably request.

SECTION 17. REMEDIES ON DEFAULT.

(a) "Act of Default" shall mean:

(1) The failure of a Party to make, when due, any payment required under this contract if such failure is not remedied within three days after written notice, provided that the payment is not the subject of a good faith dispute pursuant to Section 23. If requested by the District, the Purchaser shall deposit the disputed amount in escrow with a bank acceptable to the Parties.

(2) Any representation or warranty in this contract is false or misleading in any material respect when made or ceases to remain true during the term of this contract.

(3) The failure of the Purchaser, after Section 7 or any provision thereof has been found by a court to be void, unlawful or unenforceable, to perform in accordance with the provisions of Section 7, including without limitation any provision or provisions found to be void, unlawful or unenforceable.

(4) A Party shall make an assignment or any general arrangement for the benefit of creditors; file a petition or otherwise commence or acquiesce in the commencement of a proceeding under any bankruptcy or similar law for the protection of creditors; or otherwise becomes bankrupt or insolvent or unable to pay its debts as they fall due.

(b) If a Party commits an Act of Default during the term of this contract, the non-defaulting Party may take any one or more of the following remedial steps:

(1) Take any action or exercise any remedy provided to the Party under the provisions of Sections 6 or 7.

(2) Except where a different time period is set forth herein, if the defaulting Party fails to remedy an Act of Default within ten days after receiving written notification of the default, then the non-defaulting Party may give a written notice of termination of this contract on a date specified in such notice, which date shall be not less than 30 days after the date of such notice. If the Purchaser is given written notice as provided herein, this contract shall terminate upon the date specified in such notice, the Purchaser thereafter shall have no right, title, or interest in, to, or with respect to the Priest Rapids Project, or any Purchaser Revenue Allocation, or any Priest Rapids Project Output, but the Purchaser shall remain liable for all amounts due the District which have accrued prior to the date of termination.

(3) The District may, prior to the termination of this contract pursuant to Section 17(b)(2), at any time suspend any and all rights of the Purchaser to the Purchaser Revenue Allocation upon not less than five days' notice to the Purchaser. The District may, without further notice to the Purchaser, grant any or all of such suspended rights to any person or entity for the duration of the suspension. In such event, the Purchaser shall, in addition to its other obligations under this contract, upon demand, pay to the District all expenses and any losses incurred in connection with such suspension and any grant of the suspended rights to another person or entity. No suspension of any or all of the rights of the Purchaser Revenue Allocation shall be construed as an election to terminate the interests of the Purchaser in, to, and under this contract unless a written notice of termination is given to the Purchaser pursuant to this contract or unless such termination be decreed by a court of competent jurisdiction.

(4) The non-defaulting Party may begin and maintain successive proceedings against the defaulting Party for the recovery of damages or for a sum equal to any and all payments required to be made pursuant to this contract.

(5) A Party may take whatever action at law or in equity as may appear necessary or desirable to collect the amounts payable by the defaulting Party under this contract then due and thereafter to become due, or to enforce performance and observation of any obligation, agreement or covenant of the defaulting Party under this contract.

(6) No right or remedy conferred upon or reserved to a Party is intended to be exclusive of any other right or remedy, and each and every right and remedy shall be cumulative and in addition to any other right or remedy given hereunder, or now or hereafter legally existing, upon the occurrence of any Act of Default. Failure of the District to insist at any time on the strict observance or performance by the Purchaser of any of the provisions of this contract, or to exercise any right or remedy provided for in this contract shall not impair any such right or remedy nor be construed as a waiver or relinquishment thereof for the future. Receipt by the District of any payment required to be made hereunder with knowledge of the breach of any provisions of this contract shall not be deemed a waiver of such breach. In addition to all other remedies provided in this contract, the District shall be entitled, to the extent permitted by applicable law, to injunctive relief in case of the violation, or attempted or threatened violation, of any of the provisions of this contract, or to a decree requiring performance of any of the provisions of this contract or to any other remedy legally allowed to the District.

(7) The District shall not have the right to accelerate future payment obligations of the Purchaser in the event of default under this contract.

SECTION 18. VENUE AND ATTORNEY FEES.

Venue of any action filed to enforce or interpret the provisions of this contract shall be exclusively in the United States District Court for the Eastern District of Washington or the Superior Court of the State of Washington for Grant County and the Parties irrevocably submit to the jurisdiction of any such court. In the event of litigation to enforce the provisions of this contract, the prevailing Party shall be entitled to reasonable attorney's fees in addition to any other relief allowed.

SECTION 19. COMPLIANCE WITH LAW.
The Parties shall conform to and comply with all laws, rules, regulations, license conditions or restrictions promulgated by the FERC or any other governmental agency or entity having jurisdiction over the Priest Rapids Project. The Purchaser shall cooperate and take whatever action is necessary to cooperate fully with the District in meeting such requirements. Obligations of the District contained in this contract are hereby expressly made subordinate and subject to such compliance.

SECTION 20. HEADINGS.
The headings of sections and paragraphs of this contract are for convenience of reference only and are not intended to restrict, affect or be of any weight in the interpretation or construction of the provisions of such sections and paragraphs.

SECTION 21. ENTIRE AGREEMENT; MODIFICATION; CONFLICT IN PRECEDENCE.
This contract does not modify the terms and conditions contained in the 1956 and 1959 Contracts except as provided in Sections 1(b) and 7. This contract constitutes the entire agreement between the Parties with respect to the subject matter of this contract, and supersedes all previous communications between the Parties, either verbal or written, with respect to such subject matter. No modifications of this contract shall be binding upon the Parties unless such modifications are in writing signed by each Party. To the extent there are any conflicting provisions between this contract and the 1956 Contract, or this contract and the 1959 Contract after November 1, 2009, the terms and conditions in this contract shall take precedence and be controlling and the 1956 and 1959 Contracts are hereby amended accordingly.

SECTION 22. NO PARTNERSHIP OR THIRD PARTY RIGHTS.
(a) This contract shall not be interpreted or construed to create an association, joint venture or partnership between the Parties, or to impose any partnership obligations or liability upon any Party. Without limiting the foregoing, the Purchaser shall not be liable for, and the District hereby releases the Purchaser from, the payment of Debt except as provided in Sections 5 and 6.

(b) This contract shall not be construed to create rights in or grant remedies to any third party as a beneficiary of this contract.

SECTION 23. PURCHASERS' COMMITTEE; ARBITRATION.
(a) There is hereby established a Purchasers' committee (the "Committee"). Each Purchaser may appoint one representative (and one alternate) as a Committee member to attend Committee meetings. The members of the Committee shall elect a chair, and may adopt such rules for the conduct of business as it deems appropriate. Meetings between the District and Purchasers shall be held routinely, but not more frequently than once a quarter, provided, however, that such meetings may be held more frequently than once each quarter at the request of the District or upon the request of members of the Committee whose Purchaser Revenue Allocations total 66% or more. All meetings between the District and Purchaser will be held in Grant County, Washington, unless the District and the Purchasers agree to another location.

(b) In addition to other matters subject to arbitration pursuant to other provisions of this contract, if approved by members of the Committee whose Purchaser Revenue Allocations total 66% or more, the Committee may submit to binding arbitration the following issues:

(1) Have the Estimated District Loads been forecast in accordance with Prudent Utility Practice and, if not, what is the appropriate Estimated District Loads in accordance with Prudent Utility Practice for the Contract Year?

(2) Have the Annual Power Costs been determined by the District in accordance with Prudent Utility Practice and have such costs been incurred for the benefit of Priest Rapids Project Output and, if not, what are the appropriate Annual Power Costs in accordance with Prudent Utility Practice for the Contract Year; provided that nothing in this Section shall be interpreted to limit the ability of the District to meet its payment obligations under a Bond Resolution?

(3) What modifications to this contract, pursuant to Section 3(h), are necessary to comply with FERC or court orders and to preserve the basic benefits and obligations of the Parties?

(4) Has the Purchaser violated the covenants in Section 7(e)?

(5) Are the annual proceeds from the sales of the Reasonable Portion pursuant to Multi-Year Contracts proportional to the annual market price of power, as forecast at the time the Multi-Year Contracts were agreed to by the District, and if not, what adjustments are necessary to the payments to Purchaser pursuant to Section 4(e) to reflect such forecast annual market price of power for sales made pursuant to such Multi-Year Contracts?

(c) The board of arbitrators shall be composed of three persons, one of whom shall be appointed by the District, one of whom shall be appointed by majority vote of the Committee, and the third person to be appointed by the two persons so appointed. The District and the Committee shall appoint their arbitrator within 15 days after notification of the Committee's vote to submit a matter to binding arbitration. In the event the two members cannot agree upon the appointment of a third person within 10 days, then such third person shall be appointed by the presiding judge of the Superior Court of Kittitas County, Washington. The arbitration shall be conducted jointly by the participating Purchasers, and under rules as may be determined by the arbitrators; provided, however, that all parties shall be afforded discovery consistent with the Federal Rules of Civil Procedure; and, provided further, if the arbitrators do not unanimously agree on the rules governing the arbitration, the arbitration shall be conducted in accordance with the Commercial Arbitration Rules of the American Arbitration Association. The board so designated shall conduct a hearing within 30 days of completion of their selection, and within 15 days after the hearing (unless such time is extended by agreement of the Parties) shall notify the Parties of their decision in writing, stating the reasons therefore and separately listing their findings of fact, conclusions of law and order. Insofar as the Parties hereto may legally do so, they agree to abide by the decision of the board. All factual determinations made by the board shall be conclusive and binding on the

Parties and not subject to judicial review. Any conclusions of law made by the board shall be subject to review by a court specified in Section 23; provided, that the order issued by the board shall be effective unless and until a stay is issued by the board or such court suspends the effectiveness of the order.

SECTION 24. REPRESENTATIONS AND WARRANTIES.

Each party represents and warrants to the other Party that:

(a) It is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation.

(b) The execution, delivery and performance of this contract are within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, or order applicable to it.

(c) This contract constitutes a legally valid and binding obligation enforceable against it in accordance with its terms, subject to equitable defenses and applicable bankruptcy, insolvency and similar laws affecting creditors' rights generally.

SECTION 25. COUNTERPARTS.

This contract may be executed in counterparts, each of which shall be an original and all of which shall constitute the same contract.

PUBLIC UTILITY DISTRICT NO. 2
OF GRANT COUNTY, WASHINGTON

By /s/ Mike Conley

President

(SEAL)

ATTEST:
/s/ Thomas W. Flint

Secretary

AVISTA CORPORATION

By: /s/ Gary G. Ely

Gary G. Ely
Title: Chairman of the Board,
President and CEO

(SEAL)

EXHIBIT A

DEFINITIONS OF PRIEST RAPIDS DEVELOPMENT
AND WANAPUM DEVELOPMENT

RESOLUTION NO. 390 -- DEFINITION OF PRIEST RAPIDS DEVELOPMENT

Section 2(f) of Exhibit 1. "Priest Rapids Development" shall mean those properties and facilities consisting of the Priest Rapids dam, site, reservoir, switchyard and power plant, including all generating facilities associated therewith up to and including the first ten (10) main turbine generator units each with a nameplate rating of approximately 78,850 kilowatts and any additional generating facilities which may be installed as provided for in Section 19 of the Original Power Sales Contract, together with the associated transmission facilities consisting of two 230 KV transmission lines and terminal facilities interconnecting the Priest Rapids switchyard and the Bonneville Power Administration's Midway Substation and an undivided one-half (1/2) interest in the interconnecting facilities between the Priest Rapids switchyard and the Wanapum switchyard.

RESOLUTION NO. 474 -- DEFINITION OF WANAPUM DEVELOPMENT

Section 2.2. The District specifies and adopts the plan and system hereinafter set forth for the acquisition, by purchase or condemnation, and construction of the following generation and transmission facilities as a separate utility system of the District constituting the Wanapum Development of the District, to wit:

A. The District shall construct an electric generating plant and associated facilities on the Columbia River at approximately river mile 415 from the mouth of said river at the Wanapum site on said river, in Grant and Kittitas Counties, Washington, as authorized by the Federal Power Commission License from Project No. 2114, originally issued November 4, 1955, and all amendments thereto; said generating plant to have an installed nameplate rating of approximately 831,250 kilowatts, and said generating plant and associated facilities to include, but not limited to, a concrete gravity dam, a fully enclosed reinforced concrete powerhouse containing ten (10) turbo-generating units with provisions in the intake structure for the installation of six (6) additional turbo-generating units, a reservoir, waterways, fish ladders and other fish protective devices; provisions for future installation of navigation locks; transforming facilities; a switchyard; transmission facilities necessary to connect the powerhouse to the existing transmission facilities of the Priest Rapids Development and to the transmission facilities of the Bonneville Power Administration in the vicinity of said Project; railroad siding, shops, warehouses, construction camp, offices, and dwellings; and all other structures, fixtures, equipment or facilities used or useful in the construction, maintenance and operation of the Wanapum Development; and all necessary water rights, development rights, permits and licenses, casements, rights-of-way, flowage rights and rights permitting the storage of water, riparian rights and shore rights.

AMENDMENT NO. 1 TO THE
PRIEST RAPIDS PROJECT REASONABLE PORTION
POWER SALES CONTRACT

The Public Utility District No. 2 of Grant County, Washington, ("District"), and Avista Corporation ("Purchaser"), hereby agree to this Amendment No. 1 to the Priest Rapids Project Reasonable Portion Power Sales Contract dated December 12, 2001 (the "Reasonable Portion Contract"). Unless otherwise defined herein, all capitalized terms defined in the Reasonable Portion Contract shall have the meanings set forth therein when used in this Amendment.

1. Term of Amendment No. 1
This Amendment No. 1 shall take effect on upon the execution by the District and Purchaser, and shall expire on the earlier of the expiration or termination date of the Reasonable Portion Contract.

2. Amendments to Provisions of the Reasonable Portion Contract
Purchaser and the District agree that the Reasonable Portion Contract is hereby amended as follows:

2.1 The definition of the term Priest Rapids Project Output set forth in Section 2 is deleted in its entirety and replaced with the following:

"Priest Rapids Project Output" shall mean the amount of capacity, energy (both firm and non-firm), pondage, reactive power, ancillary services (including dynamic load following services) and any other product from the Priest Rapids Development from November 1, 2005 to November 1, 2009 and from the Priest Rapids Project from November 1, 2009 through the term of this contract under the operating conditions which exist during the term, including periods when the Priest Rapid Project may be wholly or partially inoperable for any reason, after correction for encroachment, Canadian entitlement, station and project use, and depletions required by the FERC License or other regulatory requirements.

2.2 Section 4(c)(4) is amended by adding the following sentence after the last sentence thereof:

After the District has acquired capacity and energy as needed to serve its Estimated Unmet District Load, the District shall not subsequently substitute therefore more costly capacity and energy, in order to provide the less costly capacity and energy to other wholesale or retail power customers of the District.

2.3 Section 7(h) is deleted in its entirety and is replaced with the following:

> In the event that the District believes that the Purchaser has violated any of the above covenants of Section 7(f) or (g), the District may by written notice to the Purchaser describe the alleged violation in reasonable detail and give the Purchaser no less than 4 business days after receipt of such written notice by Purchaser within which to cease the activity in question or to provide to the District a written explanation as to why the Purchaser believes the activity does not constitute a violation of any of the aforementioned covenants. If the Purchaser does not cure the alleged default and the District continues to reasonably consider the action to be in breach of the covenants, the District shall have the right to terminate this contract, effective immediately upon written notice to the Purchaser, without any liability or further obligation on the part of the District. In the event of such termination, the District shall have the right to use or sell, in any manner the District determines, the Purchaser Revenue Allocation the Purchaser would have been otherwise entitled to under this contract.

2.4 The Reasonable Portion Contract is amended by adding a new Exhibit C, Purchasers Product Percentage Allocations, which is attached hereto.

In Witness Whereof, Purchaser and the District have caused this Amendment No. 1 to be executed in their respective names by their duly authorized officers.

AVISTA CORPORATION	PUBLIC UTILITY DISTRICT NO. 2 OF GRANT COUNTY, WASHINGTON
By: /s/ Gary G. Ely	By: /s/ Mike Conley
Title: Chairman, President & CEO	Title: President, Board of Commissioners
Date Signed: Feb. 6, 2002	Date Signed: 2/11/02
	/s/ Thomas W. Flint Secretary, Board of Commissioners

EXHIBIT A. AMENDMENT 1

Purchasers Product Percentage Allocations

Purchaser Name	Historical Shares 1956	1959	Requested Purchaser Product%	Number of Customers 2000	Section 3c/e Step 1 Allocation	Section 3c/e Step 2 Allocation(1) Surplus	Displace
A. 1956/1959 PURCHASERS							
Pacific Corp	13.9%	18.7%	32.6%	768,446		25.03%	25.03%
Portland General	13.9%	18.7%	32.6%	726,039		25.03%	25.03%
Puget Sound Energy	8.0%	10.8%	18.8%	915,851		14.43%	14.43%
Avista Utilities	6.1%	8.2%	25.0%	309,986		10.98%	10.98%
Cowlitz PUD	2.0%	2.7%	4.7%	44,361		3.61%	3.61%
Eugene Water & Elec	1.7%	2.3%	4.0%	80,097		3.07%	3.07%
City of Forest Grove	0.5%	0.7%	(5)	8,592		0.92%	0.92%
City of McMinnville	0.5%	0.7%	(5)	13,973		0.92%	0.92%
City of Milton-Freewater	0.5%	0.7%	(5)	4,581		0.92%	0.92%
B. 1956 ONLY PURCHASERS(2)							
Seattle City Light	8.0%	n/a	(5)	349,557		6.14%	6.14%
Tacoma Power	8.0%	n/a	16.0%	147,819		6.14%	6.14%
Kittitas PUD	0.4%	n/a		3,078		0.31%	0.31%
Total A + B				3,392,380	97.51%	97.51%	97.51%
C. NO. IDAHO PURCHASERS							
Clearwater	n/a	n/a	10.43%	9,314		0.27%	0.27%
Idaho Co. Light & Power	n/a	n/a	2.41%	3,007		0.09%	0.09%
Kootenai	n/a	n/a	16.28%	16,244		0.47%	0.47%
Northern Lights	n/a	n/a	12.30%	14,541		0.42%	0.42%
D. SNAKE RIVER PURCHASERS							
Fall River Rural Elec	n/a	n/a	(6)	10,992		0.32%	0.32%
Lost River Electric	n/a	n/a	(6)	2,327		0.07%	0.07%
Lower Valley Electric	n/a	n/a	(6)	19,182		0.55%	0.55%
Ralt River Rural Elec	n/a	n/a	(6)	2,927		0.08%	0.08%
Salmon River Electric	n/a	n/a	(6)	2,570		0.07%	0.07%
United Electric	n/a	n/a	(6)	5,515		0.16%	0.16%
Association Total			1.24%	43,513		1.25%	1.25%
Total C & D				86,619	2.49%	2.49%	2.49%
Total	63.5%	63.5%			100.00%	100.00%	100.00%

Purchaser Name	Section 3c/e Step 2 Allocation (1) Reasonable Portion	Added Products(7)	Surplus(2)	Adjustment for 2005-2009 Displace(3)	Reasonable Portion(4)	Added Products(7)
A. 1956/1959 PURCHASERS						
Pacific Corp	25.03%	25.67%	21.34%	26.87%	23.19%	21.89%
Portland General	25.03%	25.67%	21.43%	26.87%	23.19%	21.89%
Puget Sound Energy	14.43%	14.80%	12.28%	15.51%	13.36%	12.60%
Avista Utilities	10.98%	11.26%	9.37%	11.79%	10.17%	9.61%
Cowlitz PUD	3.61%	3.70%	3.07%	3.88%	3.34%	3.15%
Eugene Water & Elec	3.07%	3.15%	2.61%	3.39%	2.84%	2.68%
City of Forest Grove	0.92%	0.94%	0.77%	1.00%	0.84%	0.79%
City of McMinnville	0.92%	0.94%	0.77%	1.00%	0.84%	0.79%
City of Milton-Freewater	0.92%	0.94%	0.77%	1.00%	0.84%	0.79%
B. 1956 ONLY PURCHASE(2)						
Seattle City Light	6.14%	6.30%	12.28%	12.28%	12.28%	12.60%
Tacoma Power	6.14%	6.30%	12.28%	12.28%	12.28%	12.60%
Kittitas PUD	0.31%	0.31%	0.61%	0.61%	0.61%	0.63%
Total A + B	97.51%	100.00%	97.51%	116.40%	103.81%	100.00%
C. NO. IDAHO PURCHASERS						
Clearwater	0.27%	n/a	0.27%	0.27%	0.27%	n/a
Idaho Co. Light & Power	0.09%	n/a	0.09%	0.09%	0.09%	n/a
Kootenai	0.47%	n/a	0.47%	0.47%	0.47%	n/a
Northern Lights	0.42%	n/a	0.42%	0.42%	0.42%	n/a
D. SNAKE RIVER PURCHASERS						
Fall River Rural Elec	0.32%	n/a	0.32%	0.32%	0.32%	n/a
Lost River Electric	0.07%	n/a	0.07%	0.07%	0.07%	n/a
Lower Valley Electric	0.55%	n/a	0.55%	0.55%	0.55%	n/a
Ralt River Rural Elec	0.08%	n/a	0.08%	0.08%	0.08%	n/a
Salmon River Electric	0.07%	n/a	0.07%	0.07%	0.07%	n/a
United Electric	0.16%	n/a	0.16%	0.16%	0.16%	n/a
Association Total						
Total C & D	1.25%	n/a	1.25%	1.25%	1.25%	n/a
Total						
	2.49%	n/a	2.49%	2.49%	2.49%	n/a

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100.00%	100.00%	100.00%	118.89%	106.30%	100.00%

NOTES: (1) Allocated per average of 1956 and 1956 Shares or, for Idaho Purchasers, per number of customers.
(2) Allocated per 1956 Shares Surplus Product and, for Idaho Purchasers, per number of customers.
(3) Allocated per 75% of 1956 Shares and 25% of 1959 Shares for 1956/1959 Purchaser, per 1956 Shares for the Only 1955 Purchaser, and number of customers for No. Idaho and Snake River Purchasers.
(3) Allocated per 75% of 1956 Shares and 25% of 1959 Shares for 1955/1959 Purchasers, per 1956 Shares for the Only 1956 Purchaser, and number of customers for No. Idaho and Snake River Purchasers.
(5) Have Intent to Sign Contract Letter without Requested Purchaser Product Percent.
(6) Snake River Purchaser's Contract with the Association.
(7) Allocated only to the 1956/1959 and Only 1956 Purchasers per 1956 Shares for 2005-2009, then average of 1956 and 1959 Shares post-2009.

Exhibit 10(b)-5

ADDITIONAL PRODUCTS SALES AGREEMENT

INDEX TO SECTIONS

ADDITIONAL PRODUCTS SALES AGREEMENT

Executed by
PUBLIC UTILITY DISTRICT NO. 2
OF GRANT COUNTY
And
AVISTA CORPORATION

This Additional Products Sales Agreement ("Agreement") is entered into as of December 12, 2001 between Public Utility District No. 2 of Grant County, Washington (the "District"), a municipal corporation of the State of Washington, and Avista Corporation (the "Purchaser"), a corporation of the State of Washington. The District and the Purchaser are referred to as a "Party" and collectively as "Parties."

SECTION 1. TERM OF AGREEMENT.
Except as otherwise provided herein, this Agreement shall be in full force and effect from and after it has been executed by the District and the Purchaser. Unless sooner terminated pursuant to other provisions, this Agreement shall remain in effect until the earlier of expiration or termination of the New FERC License or such time that the District no longer has authority to market Priest Rapids Project Products. Except as otherwise provided herein, all obligations accruing under this Agreement are preserved until satisfied.

SECTION 2. DEFINITIONS.
As used in this Agreement, the following terms when initial capitalization herein shall have the meaning ascribed to them in the Priest Rapids Project Product Sales Contract, or as set forth below:

"Agreements" shall mean this Agreement and similar agreements between the District and other Purchasers.

"Heavy Load Hours" shall mean those hours, as defined by then current industry standards, that constitute the higher value, or higher demand hours in the week. Currently, these hours are defined as hour ending 0600 through hour ending 2200, Monday through Saturday excluding holidays defined by the National Electric Reliability Council.

"Interest Rate" shall mean the Prime Rate for Large Banks as reported in the Wall Street Journal, as reported on the first day of the month in which payment was received by the District.

"Light Load Hours" shall mean those hours, as defined by then current industry standards, that constitute the lower value, or lower demand hours in the week. Currently, these hours are defined as all hours that are not Heavy Load Hours.

"Products" means those products that the District agrees to sell to the Purchaser, and the Purchaser agrees to purchase as more particularly described in Sections 3 and 5 hereof.

"Purchasers" shall mean the Purchaser and each person or entity that has entered into an agreement with the District substantially similar to this Agreement.

SECTION 3. PURCHASER'S PRODUCTS.
Subject to the terms and conditions of this Agreement, Purchaser hereby agrees to purchase and the District hereby agrees to make available and sell to the Purchaser the Product set below.

Non-Firm Generation Product

SECTION 4. TREATMENT OF THE SALE OF THE REASONABLE PORTION.
Pursuant to the PL 83-544 Orders, the Reasonable Portion must be offered for sale. Purchaser has no claim or right under this Agreement to receive any of the Reasonable Portion, or any proceeds from the sale thereof; provided, however, that nothing in this Agreement shall be interpreted as prohibiting the District and the Purchaser from entering one or more separate agreements regarding the Reasonable Portion and the disposition of the proceeds of the sale of the Reasonable Portion.

SECTION 5. DETERMINATION OF PRODUCT AVAILABILITY AND PRODUCT COSTS.
(a) The amount of each Product that the District will make available to Purchaser during each Contract Year, and the cost of each Product that will be charged to the Purchaser, will be determined by the terms of the exhibit listed below:

Non-firm Generation Product -- Exhibit 1.

(b) Purchaser agrees to pay to the District, in accordance with Section 7, the costs of the Product listed in Section 5(a).

(c) Deliveries of Product pursuant to this Agreement will be terminated if the District does not obtain an Annual FERC License or New FERC License, and may be reduced under any of the following conditions as determined by the District:

(1) Pursuant to Section 5.
(2) If the District is unable to deliver the Product to the Purchaser due to Uncontrollable Forces.
(3) If failure to reduce deliveries, together with deliveries to all other Purchasers and deliveries to the District, would result in exceeding Priest Rapids Project Output or subject it or its operation to undue hazard or violate the FERC License, any applicable law, regulation, or Operating Agreement.
(4) In case of emergencies or in order to install equipment in, make repairs to, make betterments, renewals, replacements, and additions to ("Improvements"), investigations and inspections of, or perform other maintenance work on the Priest Rapids Project.

The District will use its reasonable efforts to give advance notice to the Purchaser regarding any planned interruption or reduction, giving the reason therefor and stating the probable duration thereof.

SECTION 6. SCHEDULING OF PRODUCT DELIVERIES; METERING, TRANSMISSION LOSSES, POINTS OF DELIVERY AND RISK OF LOSS.

(a) The scheduling of deliveries of the Product provided hereunder shall be governed by the provisions of Exhibit 1.

(b) The treatment of metering, transmission losses and Points of Delivery of the Product provided hereunder shall be governed by the provisions of Exhibit 1.

(c) Unless otherwise provided in Exhibit 1, title to and risk of loss for the Product provided hereunder shall reside with the District until such Product reaches the Point of Delivery, at which time risk of loss and title to such Product shall reside with the Purchaser.

SECTION 7. PAYMENT FOR PRODUCT.

(a) The District shall provide to Purchaser for each Product provided hereunder as specified in Exhibit 1, either a pro forma annual statement of estimated Product costs, or a monthly invoice for the costs of the Product made available to the Purchaser in the preceding month.

(b) The monthly payments set forth in the pro forma annual statement of estimated Product costs shall be due and payable by Purchaser by electronic funds transfer to the District's account, designated in writing by the District, on the 20th calendar day of each month. The payment of monthly invoices by Purchaser shall be due and payable by electronic funds transfer to the District's account, designated in writing by the District, on the 20th calendar day after the date of issuance of the monthly invoice.

(c) If payment in full of any monthly payment amount set forth on a pro forma annual statement or a monthly invoice is not received by the District on or before the due date as set forth in Subsection 7(b), a delayed payment charge of 2% of the unpaid amount due will be made. Any bill which remains unpaid for more than 30 days after the due date shall, in addition to the delayed payment charge, accrue interest at the lesser of 1.5% per month or the maximum rate allowed by law. If the due date as set forth in Subsection 7(b) is a Saturday, Sunday or a District recognized holiday, the next following business day shall be the last day on which payment may be received without the addition of the delayed-payment charge. Additionally, if payment due to the District under this Section 7 remains unpaid 30 days after the due date, the District may thereafter suspend delivery of Products to the Purchaser which would otherwise occur until payment in full of all amounts due and owing (including any interest and delay charges) is received by the District.

(d) For Products that are billed on a pro forma annual statement of estimated Product costs, on or before 180 days after the end of each Contract Year, the District will either credit against estimated Product costs due from Purchaser in the then current Contract Year, or bill to Purchaser, the true-up amount, if any, as determined pursuant to the provisions of Exhibit 1;

provided, that if a refund of costs are due to Purchaser following the expiration of this Agreement, the District shall make a cash refund of such amount to the Purchaser.

(e) In the event that the Purchaser in good faith disputes a monthly invoice, Purchaser shall pay the amount of the monthly invoice in full and designate in writing to the District on or before the due date the portion of the monthly invoice that is subject to the dispute. The Parties shall in good faith attempt to resolve such dispute. If upon the final resolution of such dispute, whether by agreement of the Parties or otherwise, payment of all or any portion of the disputed amount is due to the Purchaser, such payment amount shall include interest on the amount to be paid to the Purchaser, calculated from the date of payment by Purchaser to the date of payment to Purchaser, using the Interest Rate.

(f) If a payment due from Purchaser to the District pursuant to this Section 7 is due and unpaid for a period of sixty (60) days or more, the District may terminate this Agreement by providing to the Purchaser written notice of such termination not less than ten (10) days prior to the date of termination.

SECTION 8. LIABILITY OF PARTIES.

(a) Except as otherwise provided in this Agreement, each Party hereby releases the other Party and its commissioners, officers, directors, agents and employees from any claim for loss or damage arising out of the ownership, operation, and maintenance of the Priest Rapids Project including any loss of profits or revenues, loss of use of power system, cost of capital, cost of purchased or replacement power, other substantially similar liability or other direct or indirect consequential loss or damage, except as provided in the Agreement Limiting Liability Among Western Interconnected Systems for parties to that agreement. This release shall not include any claim by the Purchaser for refunds for over-payments made to the District nor any claim for specific performance of the District's obligation to deliver to the Purchaser during the term of this Agreement the Products to which the Purchaser is entitled under this Agreement.

(b) The Purchaser shall have no claim of any type or right of action against the District: (i) as a result of a FERC or court order or amendment; (ii) as a result of the failure to receive an Annual FERC License or a New FERC license or the adjustment of delivery of Priest Rapids Products pursuant to Section 5(c) whether arising under the terms of this Agreement or otherwise; and the Purchaser hereby releases the District and its commissioners, officers, agents and employees from any claim for loss or damage arising out of the events described in this paragraph.

SECTION 9. NOTICES AND COMPUTATION OF TIME.

Any notice or demand, except those provided for in Section 7, under this Agreement shall be deemed properly given if such notice is given pursuant to Section 18 of the Purchaser's Product Sales Contract. In computing any period of time from such notice, such period shall commence at 12:00 a.m. (midnight) on the date mailed. The designations of the name and address to which any such notice or demand is directed may be changed at any time by either Party giving notice as provided above.

SECTION 10. GOVERNING LAW.

The Parties agree that the laws of the State of Washington shall govern this Agreement.

SECTION 11. ASSIGNMENT OF AGREEMENT.

Neither the Purchaser nor the District shall by contract, operation of law or otherwise, assign this Agreement or any right or interest in this Agreement without the prior written consent of the other Party, which shall not be unreasonably withheld; provided, however, a Party may, without the consent of the other Party (and without relieving itself from liability hereunder) (i) transfer or assign this Agreement to an affiliate of the Party provided that the affiliate's creditworthiness is equal or higher than that of the Party or (ii) transfer or assign this Agreement to any person or entity succeeding to all or substantially all of the distribution and generating facilities of the Party whose creditworthiness is equal or higher than that of the Party; provided, however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions in this Agreement and the transferring Party shall deliver such tax and enforceability assurance as the other Party may reasonably request.

SECTION 12. REMEDIES.

(a) A Party may take whatever action at law or in equity as may appear necessary or desirable to collect the amounts payable by the defaulting Party under this Agreement then due and thereafter to become due, or to enforce performance and observation of any obligation, agreement or covenant of the defaulting Party under this Agreement.

(b) No right or remedy conferred upon or reserved to a Party is intended to be exclusive of any other right or remedy, and each and every right and remedy shall be cumulative and in addition to any other right or remedy given hereunder, or now or hereafter legally existing, upon the occurrence of any default. Failure of the Party to insist at any time on the strict observance or performance by the other Party of any of the provisions of this Agreement, or to exercise any right or remedy provided for in this Agreement shall not impair any such right or remedy nor be construed as a waiver or relinquishment thereof for the future. Receipt by the District of any payment required to be made hereunder with knowledge of the breach of any provisions of this Agreement shall not be deemed a waiver of such breach.

SECTION 13. VENUE AND ATTORNEY FEES.

Venue of any action filed to enforce or interpret the provisions of this Agreement shall be exclusively in the United States District Court for the Eastern District of Washington or the Superior Court of the State of Washington for Grant County and the Parties irrevocably submit to the jurisdiction of any such court. In the event of litigation to enforce the provisions of this Agreement, the prevailing Party shall be entitled to reasonable attorney's fees in addition to any other relief allowed.

SECTION 14. COMPLIANCE WITH LAW.

(a) The Parties shall conform to and comply with all laws, rules, regulations, license conditions or restrictions promulgated by the FERC or any other governmental agency or entity having jurisdiction over the Priest Rapids Project. The Purchaser shall cooperate and take whatever action is necessary to cooperate fully with the District in meeting such requirements.

Obligations of the District contained in this Agreement are hereby expressly made subordinate and subject to such compliance.

(b) The Purchaser shall ensure that Products available to Purchaser under this Agreement are not sold, resold, distributed for use or used outside the Pacific Northwest in violation of the Bonneville Project Act, Public Law 75-329, the Pacific Northwest Consumer Power Preference Act, Public Law 88-552, the Regional Act or in contravention of any applicable state or federal law, order, regulation, or policy. If such sales occur in violation of the foregoing, the Purchaser shall reimburse the District for any penalties imposed on and costs incurred by the District as a consequence of such violation.

SECTION 15. HEADINGS.

The headings of sections and paragraphs of this Agreement are for convenience of reference only and are not intended to restrict, affect or be of any weight in the interpretation or construction of the provisions of such sections and paragraphs.

SECTION 16. ENTIRE AGREEMENT; MODIFICATION.

This Agreement constitutes the entire agreement between the Parties with respect to the subject matter of this Agreement, and supersedes all previous communications between the Parties, either verbal or written, with respect to such subject matter. No modifications of this Agreement shall be binding upon the Parties unless such modifications are in writing signed by each Party.

SECTION 17. NO PARTNERSHIP OR THIRD PARTY RIGHTS.

(a) This Agreement shall not be interpreted or construed to create an association, joint venture or partnership between the Parties, or to impose any partnership obligations or liability upon any Party.

(b) This Agreement shall not be construed to create rights in or grant remedies to any third party as a beneficiary of this Agreement.

SECTION 18. REPRESENTATIONS AND WARRANTIES.

Each Party represents and warrants to the other Party that:

(a) It is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation.

(b) The execution, delivery and performance of this Agreement are within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, or order applicable to it.

(c) This Agreement constitutes a legally valid and binding obligation enforceable against it in accordance with its terms, subject to equitable defenses and applicable bankruptcy, insolvency and similar laws affecting creditors' rights generally.

SECTION 19. CONFLICTS.

In the event of a conflict between any provision of this Agreement and those contained in the Priest Rapids Project Product Sales Contract, the provisions of the Priest Rapids Project Product Sales Contract shall prevail.

SECTION 20. COUNTERPARTS.

This Agreement may be executed in the counterparts, each of which shall be an original and all of which shall constitute the same Agreement.

PUBLIC UTILITY DISTRICT NO. 2
OF GRANT COUNTY, WASHINGTON

By /s/ Mike Conley

President

(SEAL)

ATTEST;

/s/ Thomas W. Flint

Secretary

AVISTA CORPORATION

By: /s/ Gary G. Ely

Gary G. Ely
Title: Chairman of the Board,
President and CEO

(SEAL)

EXHIBIT 1

NON-FIRM GENERATION PRODUCT
(AND EXCHANGE FOR LOAD FOLLOWING PRODUCT)

Except as otherwise provided in this Exhibit 1 or in the Agreement, terms used herein with initial capitalization shall have the meanings set forth in Section 2 of the Priest Rapids Project Product Sales Contract.

1. NON-FIRM GENERATION PRODUCT DESCRIPTION

The Non-Firm Generation Product is a portion of the non-firm energy available to the District from the Priest Rapids Project as and when such energy is available, as determined by the District.

2. PURCHASERS SHARE OF NON-FIRM GENERATION PRODUCT

The District will make available Purchaser's Share (defined below) of the Non-Firm Generation Product that the District determines is available each day during the term of this Agreement in accordance with this Exhibit 1. The Purchaser's Share shall be the Purchaser's percent participation in the 1956 Contract divided by 63.5% from November 1, 2005 through October 31, 2009 after which it shall be the average of the Purchaser's participation in the 1956 and 1959 Contracts divided by 63.5%.

As part of the pro forma statement provided to Purchaser pursuant to Section 5(b) of the Priest Rapids Project Product Sales Contract, the District shall provide to Purchaser an estimate for the next Contract Year of the amount of Priest Rapids Project Non-Firm Generation by month that the Priest Rapids Project is expected to produce based on information available at the time such estimate is prepared.

3. AVAILABILITY OF NON-FIRM GENERATION PRODUCT

The Non-Firm Generation Product will be available commencing November 1, 2005.

The amount of Non-Firm Generation Product for each day is the Project Non-Firm Generation for such day multiplied by a percentage equal to 100% less the sum of all Purchaser Power Allocations from all of the Priest Rapids Project Product Sales Contracts, less the Reasonable Portion and less 36.5%. For purposes of such calculation, Project Non-Firm Generation is the actual energy generation (in mwhrs) of the Priest Rapids Project Output less the product of firm energy calculated pursuant to Section 5(b)(2) of the Priest Rapids Project Product Sales Contract, distributed on a shaped basis over each day, and a factor of 1.08 for Monday through Friday, and a factor of 0.8 for Saturdays and Sundays. In the event that the calculation of Project Non-Firm Generation is less than zero, the actual Non-Firm Generation will be zero.

For example: If firm energy is 250 mw and actual generation is 300 mw, then Project Non-Firm

Generation on Monday through Friday would be 300-(250*1.08)=30 mw. Project Non-Firm Generation on Saturday and Sunday would be 300-(250*0.8)=100 mw.

The District will estimate the Purchaser's Non-firm Generation Product on a daily preschedule basis according to available data ("Estimated Purchaser's Non-firm"). On Monday through Saturday, such schedule shall be delivered with the same amount of megawatt-hours delivered in Heavy Load Hours as in Light Load Hours. On Sundays, such schedule shall be delivered in equal hourly amounts over all 24 hours. On an after-the-fact basis, the District will compute the amount of Purchaser's Non-firm and will maintain a deviation account to track the difference in the daily Estimated Purchaser's Non-firm and the actual Purchaser's Non-firm. Positive and negative balances in the deviation account will be used to adjust the daily Estimated Purchaser's Non-firm that is delivered on a preschedule basis. Positive and negative balances will carry through from month to month.

Preschedule deliveries to Purchasers will be reduced or eliminated in realtime in the event of a contingency that reduces or eliminates the District's ability to generate the daily Estimated Purchaser's Non-firm at the Priest Rapids Project.

4. PRICING AND PAYMENT

For each Contract Year during the term of this Agreement, the Purchaser shall pay the District in twelve equal monthly installments the product of the estimated Annual Power Cost contained in the pro forma statement prepared pursuant to Section 7(a) of the Priest Rapids Project Product Sales Contract and the ratio of Purchaser Estimated Non-Firm to the average total generation of the Priest Rapids Project estimated pursuant to the Operating Agreements. The pro forma statement provided to purchaser pursuant to Section 7(a) of the Priest Rapids Project Product Sales Contract shall separately set forth the Purchaser's estimated monthly payment obligation for Non-Firm Generation Product for the next Contract Year.

The payments made by Purchaser for the Non-Firm Generation Product on an estimated basis will be trued up to actual values not later than 150 days after end of each Contract Year using actual Annual Power Costs prepared pursuant to Section 7(g) of the Priest Rapids Project Product Sales Contract, and actual metered amounts of Non-Firm Generation Product. Any amounts due to Purchaser will be credited against Purchaser's payment obligation in the then current Contract Year, and any amounts due from Purchaser to the District will be invoiced to Purchaser, all in accordance with such Section 7(g).

5. EXCHANGE OF NON-FIRM GENERATION PRODUCT FOR LOAD FOLLOWING PRODUCT

(a) EXCHANGE DEFINED - The Load Following Product provides capacity and associated energy for short periods of time. The Purchaser then returns the same amount of energy within 168 hours.

Upon notice to the District by January 1, 2003, the Purchaser may make a one-time irrevocable exchange of their entire share of Non-Firm Generation Product for Load

Following Product on the basis of 1.5 megawatts of Load Following Product for each megawatt of Non-Firm Generation Product. For the purpose of this calculation of this exchange the Project Non-firm Generation shall be calculated pursuant to Operating Agreements based on the average historical river flows.

The total amount exchanged by all Purchasers shall not exceed the Monthly Maximum Load Following Product defined below which shall be allocated on a first come first served basis. The Purchaser's Share of Load Following Product will be the ratio of the number of megawatts of Non-firm Generation Product exchanged by an individual Purchaser to the total exchanged by all Purchasers.

(b) AVAILABILITY - The Load Following Product will be available commencing November 1, 2005. Load Following Product will be available only after all other obligations of the Priest Rapids Project, including but not limited to, meeting and following the District's loads, meeting commercial arrangements entered into prior to this Agreement, requirements of Operating Agreements, meeting regulatory requirements, and after accounting for water conditions and the status of the Priest Rapids Project. Notwithstanding the table below the amount of Load Following Product will be reduced if the District is unable to meet these obligations or if it would otherwise be forced to the market to buy Load Following Product.

The monthly Maximum Load Following Product will be 50 megawatts from November 2005 through October 31, 2009 or 100 megawatts after October 31, 2009 and associated energy.

On or before the tenth day preceding each month the District will identify to the Purchaser the estimated Monthly Minimum Load Following Product (in megawatts) that the District expects to be available during the next month, but will not be less than the firm amounts shown below.

2005-
2009
Nov.
Dec.
Jan.
Feb.
Mar.
Apr.
May
Jun.
Jul.
Aug.
Sep.
Oct.

--- -
--- -
--- -
--- -
--- -
--- 0
50 50
50 50
0 25
25 50
50 50
0

2009
forward
Nov.
Dec.
Jan.
Feb.
Mar.
Apr.
May
Jun.
Jul.
Aug.
Sep.
Oct. -
--- --
-- ---
- ----
---- -
--- --
- ----
---- -
--- --
-- ---
- 100

100
100
100
100 50
100
100
100
100
100
100

Each day, the District shall provide the Purchaser with the Daily Load Following Product (in megawatts) that the District determines will be available for the subsequent preschedule day or days. The actual Daily Load Following Product shall be between the Monthly Minimum Load following Product and the Monthly Maximum Load Following product.

The Purchaser's Load Following Product shall be the lesser of the amount of Load Following Product exchanged pursuant to Section 5a of this Exhibit 1 or the Daily Load

Following Product times the Purchaser's Share.

(c) RETURN OF ENERGY - Energy associated with the Load Following Product used by Purchaser shall be returned to the District in like quantities (hour for hour) on like days 168 hours after the delivery by the District to the Purchaser. Energy returned to the District shall be delivered at the District's Point of Delivery as specified in Section 7 of this Exhibit 1.

If, in real-time, the District determines that Purchaser's schedule of return energy to the District is in excess of the estimated Purchaser's Load Following Product in future hours, and that such excess will cause spill, then District may, at its option, require the Purchaser to reduce its schedule. Purchaser shall reduce its schedule by such excess amount. Purchaser shall schedule the remaining energy to the District at the earliest time possible for both District and Purchaser.

District shall meter the actual Load Following Product used to meet Purchasers load signal in each hour.

(d) CHARGE FOR SPILL - The District will charge the Purchaser for any spill allocated to the District if it is determined by the District that such spill was directly attributable to the actions of the Purchaser under this Agreement. Such charge will equal the product of such spill (in megawatt-hours) and the Market Energy Rate for the daily diurnal period in which such spill occurred.

Market Energy Rate shall mean the rate (in $/mwhr) at which firm energy is available on the wholesale power market, for quantities comparable to the spill caused by the actions of Purchaser, during the diurnal period that the spill occurred, as determined by the District.

(e) EXCESS LOAD FOLLOWING PRODUCT AND ENERGY NOT RETURNED - In the event that Purchaser takes in any hour Load Following Product in excess of its Purchaser's Share, Purchaser shall be subject to a charge equal to 150% of the Mid-C Market Capacity Rate for the daily diurnal period in which the Load Following Product was taken times the amount of Load Following Product (in megawatts) taken in excess of Purchaser's Share.

Market Capacity Rate shall mean the rate (in $/mw-mo.) as quoted by the Bonneville Power Administration, for quantities comparable to the Load Following Product made available to Purchasers, during the diurnal period that Purchaser took Load Following Product in excess of its Purchaser's Share.

In the event that Purchaser does not return energy associated with Load Following Product delivered by Purchaser, then Purchaser shall be considered in Default pursuant to Section 22 of the Priest Rapids Project Product Sales Contract.

6. BILLING

Purchaser shall pay the amounts set forth in the pro forma statement provided to Purchaser pursuant to section 7(a) of the Priest Rapids Project Product Sales Contract.

Not later than ten (10) days after the end of each month during the term, the District will prepare and provide to the Purchaser an invoice setting forth the payment due from Purchaser to the District for the Load Following Product made available for the preceding month.

7. POINTS OF DELIVERY

The District shall make available to the Purchaser the Non-Firm Generation Product at the Points of Delivery specified in Section 11 of the Priest Rapids Project Product Sales Contract.

The District shall make available to the Purchaser the Load Following Product and associated energy, and Purchaser shall return energy to the District, at the Points of Delivery specified in Section 11 of the Priest Rapids Project Product Sales Contract.

8. METERING, TRANSMISSION AND LOSSES

Metering, transmission and losses will be in accordance with Section 12 of the Priest Rapids Project Product Sales Contract.

9. INFORMATION AND COMMUNICATIONS

Purchaser shall be responsible for the costs of installing and maintaining any communications equipment necessary to effectuate the delivery of the Non-Firm Generation Product or Load Following Product between the District and the Purchaser.

10. SCHEDULING AND ACCOUNTING

Scheduling and accounting shall be performed according to then current industry standards.

AMENDMENT NO. 1 TO THE ADDITIONAL PRODUCTS SALES AGREEMENT

The Public Utility District No. 2 of Grant County, Washington, ("District"), and Avista Corporation ("Purchaser"), hereby agree to this Amendment No. 1 to the Additional Products Sales Agreement dated December 12, 2001 (the "Product Agreement"). Unless otherwise defined herein, all capitalized terms defined in the Product Agreement shall have the meanings set forth therein when used in this Amendment.

1. Term of Amendment No. 1

This Amendment No. 1 shall take effect on upon the execution by the District and Purchaser, and shall expire on the earlier of the expiration or termination date of the Product Agreement.

2. Amendments to Provisions of the Product Agreement

Purchaser and the District agree that the Product Agreement is hereby amended as follows:

2.1 The first paragraph of Section 2 of Exhibit 1 is amended by adding after the last sentence thereof the following:

The amount of Non-Firm Generation Product available to Purchaser shall equal the product of Purchaser's Share and the Non-Firm Generation Product.

2.2 The second paragraph of Section 3 of Exhibit 1 is deleted in its entirety and is replaced with the following:

The amount of Non-Firm Generation Product for each day is the Project Non-Firm Generation for such day multiplied by a percentage equal to 100% less the sum of all Purchaser Power Allocations from all of the Priest Rapids Project Product Sales Contracts, less the Reasonable Portion and less 36.5%. For purposes of such calculation, Project Non-Firm Generation shall be the actual energy generation (in mwhrs) of the Priest Rapids Project Output less the firm energy calculated pursuant to Section 5(b)(2) of the Priest Rapids Project Product Sales Contract, times the shaping factors described below. For example, based on current operating requirements of the Priest Rapids Project, the Project Firm Generation is distributed on a shaped basis over the week, using a factor of 1.08 for Monday through Friday, and a factor of 0.8 for Saturdays and Sundays. These factors will be changed by the District to reflect changes in operating constraints applicable to the Priest Rapids Project. In the event that the calculation of Project Non-firm Generation is less than zero, there will be no obligation on the part of the Purchaser to schedule Non-Firm Generation Product back to the District, but such negative amount will be included in the deviation account.

2.3 The third paragraph of Section 3 of Exhibit 1 is deleted in its entirety and is replaced with the following:

For example: Assume that flows during the week are 324 MW and that flows during the weekend are 240 MW. If firm energy (critical generation) is 250 MW then Project Non-Firm Generation on Monday through Friday would be 324-(250*1.08)=54 MW times 24 hours =1,296 MWh for each weekday. The amount of power scheduled during the weekend would be 240-(250*0.8)=40 MW times 24 hours = 960 MWh for each weekend day.

2.4 The fourth and fifth sentences of the fourth paragraph of Section 3 of Exhibit 1 are revised as follows:

Whenever they appear in such sentences, the phrase "Estimated Purchaser's Non-Firm" is revised to read "Estimated Purchaser's Non-Firm Generation Product", and the phrase "Purchaser's Non-Firm" is revised to read "Purchaser's Non-Firm Generation Product".

2.5 The second paragraph of Section 5(a) of Exhibit 1 is deleted in its entirety and is replaced with the following:

Upon notice to the District by January 1, 2003, the Purchaser may make a one-time irrevocable exchange of their entire share of Non-Firm Generation Product for Load Following Product on the basis of 1.5 megawatts of Load Following Product for each average annual megawatt of Non-Firm Generation Product. For the purpose of the calculation of this exchange, the Project Non-firm Generation shall be calculated pursuant to Operating Agreements based on the average historical river flows.

For purposes of determining Purchaser's entitlement to Load Following Product, the exchange ratio set forth above shall be applied to the amount of Non-Firm Generation Product initially available to Purchaser hereunder, but such ratio shall be applied in subsequent years to any increased amount of Non-Firm Generation Product to which the Purchaser would have been entitled absent its election hereunder.

2.6 Section 5 of Exhibit 1 is amended by adding a new subsection 5(f) as follows:

> If the one-time exchange has been made as provided in this section 5, Purchaser's compensation to the District for the Load Following Product shall be limited to the return of energy and the charges set forth in Sections 5(c), (d) and (e). Purchaser shall not be required to pay to the District as compensation for the Load Following Product any portion of the Annual Power Costs of the Priest Rapids Project pursuant to section 4 of this Exhibit 1.

2.7 The Product Agreement is amended by adding a new Exhibit 2, Purchasers Product Percentage Allocations, which is attached hereto.

In Witness Whereof, Purchaser and the District have caused this Amendment No. 1 to be executed in their respective names by their duly authorized officers.

AVISTA CORPORATION

By: /s/ Gary G. Ely

Title: CHAIRMAN, PRESIDENT & CEO

Date Signed: FEB. 6, 2002

PUBLIC UTILITY DISTRICT NO. 2 OF GRANT COUNTY, WASHINGTON

By: /s/ Mike Conley

Title: PRESIDENT, BOARD OF COMMISSIONERS

Date Signed: 2/11/02

/s/ Thomas W. Flint

Secretary, Board of Commissioners

EXHIBIT 10(q)-8

September 9, 2002

Malyn Malquist
3321 Corey Drive
Reno, NV 89509

Dear Malyn:

This letter will confirm our recent discussions regarding my offer to you for the position of Senior Vice President and CFO of Avista Corporation. We have agreed that your starting date will be effective sometime in late September 2002 or early October 2002 based upon our mutual agreement. Your annual salary in your position as Senior Vice President and CFO will be $245,000 paid in 26 biweekly increments in accordance with Avista Corporation's normal payroll procedures. You will be eligible to participate in Avista Corporation's Executive annual incentive plan. For year 2002, the incentive bonus potential for the CFO position is 60% of base salary. Actual incentive bonus payout for officers is determined based on successfully reaching the objectives identified in each annual plan. You will be granted 50,000 non-qualified stock options upon your hire date. This initial employment grant will vest in 25% increments annually over a four-year period. You will also be provided with a Change in Control Contract upon your hire date that provides you with benefit protection as outlined in the contract in the event of a change in control.

As an Avista Corporation employee, you and your eligible family members will be entitled to participate in the normal benefits package offered to all employees, including medical, vision, and dental coverage. You will also be eligible to participate in the 401(k) plan on the enrollment date that coincides with or immediately follows your employment date (20th of each month, effective the first pay close in the following month).

As an executive of the Company, you will be enrolled in the Executive Income Continuation Plan and the Supplemental Executive Long Term Disability Plan upon completion of your signature for these plans. You will also be eligible to participate in the Supplemental Executive Retirement Plan, hereafter referred to as the Plan, according to the eligibility set forth in the Plan document. Once you have reached 5 years of service and at least age 55, you will be eligible for the benefit under Section 4.1b of the Plan. After 5 years of service and having reached at least age 55, you will be credited with 3 years Vesting Service and 2 years Benefit Service for each completed year of employment (meeting a minimum of 1000 hours of service and credited with 1/12th of a year for every 173 1/3 hours worked up to a maximum of 12 months credited per year). The Early Retirement Reduction Factors (ERRF) for retirement from active service as described in the Retirement Plan for Employees of Avista Corporation will be utilized in determining the benefit payable from the Plan. No benefits will be payable from the Plan if you terminate with fewer than 5 years of service. You will become eligible to participate in the Retiree Medical Plan after five years of service, as defined above, and having reached at least age 55. Upon meeting eligibility, you will participate at the 15-year employment level to determine the appropriate Company contribution and premium caps.

To assist with your move to Spokane, Avista will provide you with a relocation coordinator and cover the reimbursable amounts of the actual costs of your relocation up to a mutually agreed upon level. The Company will pay for reasonable expenses for one round trip between Reno and Spokane, including airfare, lodging, and meals in connection with a house-hunting trip of up to seven days in duration for you and your spouse. The Company will also pay for reasonable temporary living expenses for a period of up to 90 days for food, lodging, and rental car, if necessary, upon arrival in Spokane. To facilitate an earlier start date, the company will reimburse you for the cost of your weekend travel between Reno and Spokane for up to three months until your family can be moved.

You will receive 33 days of one leave (crediting you for 24 years of service) immediately upon employment, which can be used in accordance with Avista Corporation policy guidelines. After your one-year anniversary, your one leave will be accumulated on an accrual basis each pay period based upon 25 years of service. For the purpose of calculating your one leave accrual, you will be granted an additional year of service for each year worked with Avista Corporation.

Please note that acceptance of this offer does not create a contract of continuing employment at Avista Corporation. Your employment with Avista Corporation is on an at-will basis; either you or Avista Corporation may terminate the employment relationship at any time for any reason not expressly prohibited by law. Notwithstanding the foregoing, in the event that, at any time prior to your completing 5 years of full employment with Avista Corporation, the Company chooses to relieve you from your position, other than for cause or an actual Change in Control event, you will be entitled to receive severance benefits as described herein. This provision becomes null and void upon your fifth year employment anniversary. For purposes of this offer letter, Cause shall mean (i) any act of personal dishonesty taken by you in connection with your responsibilities as an employee which is intended to result in your personal enrichment, (ii) your conviction of a felony, (iii) any act by you that constitutes material misconduct and is injurious to Avista Corporation, or (iv) continued violations by you of your obligations to Avista Corporation. In the event of a Change in Control, your Change of Control contract takes precedent and this severance benefit is not payable.

Based upon the circumstances outlined in the preceding paragraph occurring, you would be entitled to receive continuing severance payments (less applicable withholding taxes) at a rate equal to your current base salary as then in effect, for a period of one year from the date of such termination, to be paid periodically in accordance with Avista Corporation's normal payroll policies. The company will also continue to provide you with regular company medical health benefits for the period of the first three months of your severance. After three months, you could elect to participate in COBRA coverage at which time you would be responsible for paying the full monthly premium associated with the coverage you elected.

As a condition of employment, you will be required to sign a Confidentiality, Non-Solicitation, Invention and Non-Compete Agreement. This letter and the Confidentiality, Non-Solicitation, Invention and Non-Compete Agreement set forth the terms of your employment with Avista Corporation and supersede any prior representations or agreements whether written or oral. This letter may not be modified or amended except by a written agreement signed by the CEO and Chairman of Avista Corporation and you.

In the event of any dispute or claim relating to or arising out of our employment relationship, you and Avista Corporation agree that (i) any and all such disputes will be fully and finally resolved by binding arbitration conducted by the American Arbitration Association in Spokane County, Washington, (ii) you are waiving any and all rights to a jury trial, but all court remedies will be available in arbitration, (iii) all disputes will be resolved by a neutral arbitrator who will issue a written opinion, (iv) the arbitration will provide for adequate discovery, and (v) each of you and Avista Corporation will pay one half of the costs and expenses of such arbitration and each of you and Avista Corporation will separately pay your respective counsel fees and expenses. However, we agree that this arbitration provision will not apply to any disputes or claims relating to or arising out of the misuse or misappropriation of Avista Corporation's proprietary information.

I am looking forward to you joining Avista Corporation, and I have full confidence that your background and experience will assist you in making a significant contribution to the financial and strategic direction of our Company. If you are in agreement with the general terms outlined in this letter, I ask that you sign and return the original letter to me as soon as possible.

Sincerely,

/s/ Gary G. Ely

Gary G. Ely
CEO and Chairman of the Board of Directors
Avista Corporation

Accepted by: /s/ Malyn Malquist

Malyn Malquist

Dated: September 10, 2002

CHANGE OF CONTROL AGREEMENT

AGREEMENT by and between Avista Corporation, a Washington corporation (the "Company") and ______________________________________, (the "Executive"), dated as of the ____ day of ________________________, 20__.

The Board of Directors of the Company (the "Board"), has determined that it is in the best interests of the Company and its shareholders to assure that the Company will have the continued dedication of the Executive, notwithstanding the possibility, threat or occurrence of a Change of Control (as defined below) of the Company. The Board believes it is imperative to diminish the inevitable distraction of the Executive by virtue of the personal uncertainties and risks created by a pending or threatened Change of Control and to encourage the Executive's full attention and dedication to the Company currently and in the event of any threatened or pending Change of Control, and to provide the Executive with compensation and benefits arrangements upon a Change of Control which ensure that the compensation and benefits expectations of the Executive will be satisfied and which are competitive with those of other corporations. Therefore, in order to accomplish these objectives, the Board has caused the Company to enter into this Agreement.

NOW, THEREFORE, IT IS HEREBY AGREED AS FOLLOWS:

1. Certain Definitions. (a) The "Effective Date" shall mean the first date during the Change of Control Period (as defined in Section 1(b)) on which a Change of Control (as defined in Section 2) occurs. Anything in this Agreement to the contrary notwithstanding, if a Change of Control occurs and if the Executive's employment with the Company is terminated prior to the date on which the Change of Control occurs, and if it is reasonably demonstrated by the Executive that such termination of employment (i) was at the request of a third party who has taken steps reasonably calculated to effect a Change of Control or (ii) otherwise arose in connection with or anticipation of a Change of Control, then for all purposes of this Agreement the "Effective date" shall mean the date immediately prior to the date of such termination of employment.

(b) The "Change of Control Period" shall mean the period commencing on the date hereof and ending on the third anniversary of the date hereof; provided, however, that commencing on the date one year after the date hereof, and on each annual anniversary of such date (such date and each annual anniversary thereof shall be hereinafter referred to as the "Renewal Date"), unless previously terminated, the Change of Control Period shall be automatically extended so as to terminate three (3) years from such Renewal Date, unless at least sixty (60) days prior to the Renewal Date the Company shall give notice to the Executive that the Change of Control Period shall not be so extended.

2. Change of Control. For the purpose of this Agreement, a "Change of Control" shall mean:

(a) The acquisition by any individual, entity or group (within the meaning of Section 13(d)(3) or 14(d)(2) of the Securities Exchange Act of 1934, as amended (the "Exchange

Act")) (a "Person") of beneficial ownership (within the meaning of Rule 13d-3 promulgated under the Exchange Act) of twenty percent (20%) or more of either (i) the then outstanding shares of common stock of the Company (the "Outstanding Company Common Stock") or (ii) the combined voting power of the then outstanding voting securities of the Company entitled to vote generally in the election of directors (the "Outstanding Company Voting Securities"); provided, however, that for purposes of this subsection (a), the following acquisitions shall not constitute a Change of Control: (i) any acquisition directly from the Company, (ii) any acquisition by the Company, (iii) any acquisition by any employee benefit plan (or related trust) sponsored or maintained by the Company or any corporation controlled by the Company or (iv) any acquisition by any corporation pursuant to a transaction which complies with clauses (i), (ii) and (iii) of subsection (c) of this Section 2; or

(b) Individuals who, as of the date hereof, constitute the Board (the "Incumbent Board") cease for any reason to constitute at least a majority of the Board; provided, however, that any individual becoming a director subsequent to the date hereof whose election, or nomination for election by the Company's shareholders, was approved by a vote of at least a majority of the directors then comprising the Incumbent Board shall be considered as though such individual were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as a result of an actual or threatened election contest with respect to the election or removal of directors, or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board; or

(c) Consummation of a reorganization, merger or consolidation or sale or other disposition of all or substantially all of the assets of the Company (a "Business Combination"), in each case, unless, following such Business Combination, (i) all or substantially all of the individuals and entities who were the beneficial owners, respectively, of the Outstanding Company Common Stock and Outstanding Company Voting Securities immediately prior to such Business Combination beneficially own, directly or indirectly, more than fifty percent (50%) of, respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation resulting from such Business Combination (including, without limitation, a corporation which as a result of such transaction owns the Company or all or substantially all of the Company's assets either directly or through one or more subsidiaries) in substantially the same proportions as their ownership, immediately prior to such Business Combination of the Outstanding Company Common Stock and Outstanding Company Voting Securities, as the case may be, (ii) no Person (excluding any corporation resulting from such Business Combination or employee benefit plan (or related trust) of the Company or such corporation resulting from such Business Combination) beneficially owns, directly or indirectly, twenty percent (20%) or more of, respectively, the then outstanding shares of common stock of the corporation resulting from such Business Combination or the combined voting power of the then outstanding voting securities of such corporation except to the extent that such ownership existed prior to the Business Combination and (iii) at least a majority of the members of the board of directors of the corporation resulting from such Business Combination were members of the Incumbent Board at the time of the execution of the initial agreement, or of the action of the Board, providing for such Business Combination; or

(d) Approval by the shareholders of the Company of a complete liquidation or dissolution of the Company.

3. Employment Period. The Company hereby agrees to continue the Executive in its employ, and the Executive hereby agrees to remain in the employ of the Company subject to the terms and conditions of this Agreement, for the period commencing on the Effective Date and ending on the third anniversary of such date (the "Employment Period").

4. Terms of Employment. (a) Position and Duties. (i) During the Employment Period, (A) the Executive's position (including status, offices, titles and reporting requirements), authority, duties and responsibilities shall be at least commensurate in all material respects with the most significant of those held, exercised and assigned at any time during the one hundred twenty (120) day period immediately preceding the Effective Date and (B) the Executive's services shall be performed at the location where the Executive was employed immediately preceding the Effective Date or any office or location less than 35 miles from such location.

(ii) During the Employment Period, and excluding any periods of vacation and sick leave to which the Executive is entitled, the Executive agrees to devote reasonable attention and time during normal business hours to the business and affairs of the Company and, to the extent necessary to discharge the responsibilities assigned to the Executive hereunder, to use the Executive's reasonable best efforts to perform faithfully and efficiently such responsibilities. During the Employment Period it shall not be a violation of this Agreement for the Executive to (A) serve on corporate, civic or charitable boards or committees, (B) deliver lectures, fulfill speaking engagements or teach at educational institutions and (C) manage personal investments, so long as such activities do not significantly interfere with the performance of the Executive's responsibilities as an employee of the Company in accordance with this Agreement. It is expressly understood and agreed that to the extent that any such activities have been conducted by the Executive prior to the Effective Date, the continued conduct of such activities (or the conduct of activities similar in nature and scope thereto) subsequent to the Effective Date shall not thereafter be deemed to interfere with the performance of the Executive's responsibilities to the Company.

(b) Compensation. (i) Base Salary. During the Employment Period, the Executive shall receive an annual base salary ("Annual Base Salary"), which shall be paid at a monthly rate, at least equal to twelve times the highest monthly base salary paid or payable, including any base salary which has been earned but deferred, to the Executive by the Company and its affiliated companies in respect of the twelve month period immediately preceding the month in which the Effective Date occurs. During the Employment Period, the Annual Base Salary shall be reviewed no more than 12 months after the last salary increase awarded to the Executive prior to the Effective Date and thereafter at least annually. Any increase in Annual Base Salary shall not serve to limit or reduce any other obligation to the Executive under this Agreement. Annual Base Salary shall not be reduced after any such increase and the term Annual Base Salary as utilized in this Agreement shall refer to Annual Base Salary as so increased. As used in this Agreement, the term "affiliated companies" shall include any company controlled by, controlling or under common control with the Company.

(ii) Annual Bonus. In addition to Annual Base Salary, the Executive shall be awarded, for each fiscal year ending during the Employment Period, an annual bonus (the "Annual Bonus") in cash at least equal to the Executive's highest bonus under the Company's Annual Incentive Plans, or any comparable bonus under any predecessor or successor plan, for the last three (3) full fiscal years prior to the Effective Date (annualized in the event that the Executive was not employed by the Company for the whole of such fiscal year) (the "Recent Annual Bonus"). Each such Annual bonus shall be paid no later than the end of the third month of the fiscal year next following the fiscal year for which the Annual Bonus is awarded, unless the Executive shall elect to defer the receipt of such Annual Bonus.

(iii) Incentive, Savings and Retirement Plans. During the Employment Period, the Executive shall be entitled to participate in all incentive, savings and retirement plans, practices, policies and programs applicable generally to other peer executives of the Company and its affiliated companies, but in no event shall such plans, practices, policies and programs provide the Executive with incentive opportunities (measured with respect to both regular and special incentive opportunities, to the extent, if any, that such distinction is applicable), savings opportunities and retirement benefit opportunities, in each case, less favorable, in the aggregate, than the most favorable of those provided by the Company and its affiliated companies for the Executive under such plans, practices, policies and programs as in effect at any time during the 120-day period immediately preceding the Effective Date or if more favorable to the Executive, those provided generally at any time after the Effective Date to other peer executives of the Company and its affiliated companies.

(iv) Welfare Benefit Plans. During the Employment Period, the Executive and/or the Executive's family, as the case may be, shall be eligible for participation in and shall receive all benefits under welfare benefit plans, practices, policies and programs provided by the Company and its affiliated companies (including, without limitation, medical, prescription, dental, disability, employee life, group life, accidental death and travel accident insurance plans and programs) to the extent applicable generally to other peer executives of the Company and its affiliated companies, but in no event shall such plans, practices, policies and programs provide the Executive with benefits which are less favorable, in the aggregate, than the most favorable of such plans, practices, policies and programs in effect for the Executive at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive, those provided generally at any time after the Effective Date to other peer executives of the Company and its affiliated companies.

(v) Expenses. During the Employment Period, the Executive shall be entitled to receive prompt reimbursement for all reasonable expenses incurred by the Executive in accordance with the most favorable policies, practices and procedures of the Company and its affiliated companies in effect for the Executive at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive, as in effect generally at any time thereafter with respect to other peer executives of the Company and its affiliated companies.

(vi) Fringe Benefits. During the Employment Period, the Executive shall be entitled to fringe benefits, including, without limitation, tax and financial planning services, payment of club dues, and, if applicable, use of an automobile and payment of related expenses, in accordance with the most favorable plans, practices, programs and policies of the Company and its affiliated companies in effect for the Executive at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive, as in effect generally at any time thereafter with respect to other peer executives of the Company and its affiliated companies.

(vii) Office and Support Staff. During the Employment Period, the Executive shall be entitled to an office or offices of a size and with furnishings and other appointments, and to exclusive personal secretarial and other assistance, at least equal to the most favorable of the foregoing provided to the Executive by the Company and its affiliated companies at any time during the 120-period immediately preceding the Effective date or, if more favorable to the Executive, as provided generally at any time thereafter with respect to other peer executives of the Company and its affiliated companies.

(viii) Vacation. During the Employment Period, the Executive shall be entitled to paid vacation in accordance with the most favorable plans, policies, programs and practices of the Company and its affiliated companies as in effect for the Executive at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive, as in effect generally at any time thereafter with respect to other peer executives of the Company and its affiliated companies.

5. Termination of Employment. (a) Death or Disability. The Executive's employment shall terminate automatically upon the Executive's death during the Employment Period. If the Company determines in good faith that the Disability of the Executive has occurred during the Employment Period (pursuant to the definition of Disability set forth below), it may give to the Executive written notice in accordance with Section 12(b) of this Agreement of its intention to terminate the Executive's employment. In such event, the Executive's employment with the Company shall terminate effective on the 30th day after receipt of such notice by the Executive (the "Disability Effective Date), provided that, within the thirty (30) days after such receipt, the Executive shall not have returned to full-time performance of the Executive's duties. For purposes of this Agreement, "Disability" shall mean the absence of the Executive from the Executive's duties with the Company on a full-time basis for one hundred eighty (180) consecutive business days as a result of incapacity due to mental or physical illness which is determined to be total and permanent by a physician selected by the Company or its insurers and acceptable to the Executive or the Executive's legal representative.

(b) Cause. The Company may terminate the Executive's employment during the Employment Period for Cause. For purposes of this Agreement, "Cause" shall mean:

(i) the willful and continued failure of the Executive to perform substantially the Executive's duties with the Company or one of its affiliates (other than any such failure resulting from incapacity due to physical or mental illness), after a written demand for substantial performance is delivered to the Executive by the Board or the Chief Executive Officer of the Company which specifically identifies the manner in which the Board or Chief

Executive Officer believes that the Executive has not substantially performed the Executive's duties, or

(ii) the willful engaging by the Executive in illegal conduct or gross misconduct which is materially and demonstrably injurious to the Company.

For purposes of this provision, no act or failure to act, on the part of the Executive, shall be considered "willful" unless it is done, or omitted to be done, by the Executive in bad faith or without reasonable belief that the Executive's action or omission was in the best interests of the Company. Any act, or failure to act, based upon authority given pursuant to a resolution duly adopted by the Board or upon the instructions of the Chief Executive Officer or a senior officer of the Company or based upon the advice of counsel for the Company shall be conclusively presumed to be done, or omitted to be done, by the Executive in good faith and in the best interests of the Company. The cessation of employment of the Executive shall not be deemed to be for Cause unless and until there shall have been delivered to the Executive a copy of a resolution duly adopted by the affirmative vote of not less than three-quarters of the entire membership of the Board at a meeting of the Board called and held for such purpose (after reasonable notice is provided to the Executive and the Executive is given an opportunity, together with counsel, to be heard before the Board), finding that, in the good faith opinion of the Board, the Executive is guilty of the conduct described in subparagraph (i) or (ii) above, and specifying the particulars thereof in detail.

(c) Good Reason. The Executive's employment may be terminated by the Executive for Good Reason. For purposes of this Agreement, "Good Reason" shall mean:

(i) the assignment to the Executive of any duties inconsistent in any respect with the Executive's position (including status, offices, titles and reporting requirements), authority, duties or responsibilities as contemplated by Section 4(a) of this Agreement, or any other action by the Company which results in a diminution in such position, authority, duties or responsibilities, excluding for this purpose an isolated, insubstantial and inadvertent action not taken in bad faith and which is remedied by the Company promptly after receipt of notice thereof given by the Executive;

(ii) any failure by the Company to comply with any of the provisions of Section 4(b) of this Agreement, other than an isolated, insubstantial and inadvertent failure not occurring in bad faith and which is remedied by the Company promptly after receipt of notice thereof given by the Executive;

(iii) the Company's requiring the Executive to be based at any office or location other than as provided in Section 4(a)(i)(B) hereof or the Company's requiring the Executive to travel on Company business to a substantially greater extent than required immediately prior to the Effective Date;

(iv) any purported termination by the Company of the Executive's employment otherwise than as expressly permitted by this Agreement; or

(v) any failure by the Company to comply with and satisfy Section 11(c) of this Agreement.

For purposes of this Section 5(c), a determination of "Good Reason" made by the Executive with which the Company does not agree shall be resolved pursuant to the following dispute resolution procedure. First, the parties shall in good faith attempt to resolve any dispute arising hereunder. Second, if such efforts are unsuccessful, the parties shall submit to binding arbitration with such arbitration to be conducted in Spokane, Washington, by the American Arbitration Association under its National Rules for the Resolution of Employment Disputes.

(d) Notice of Termination. Any termination by the Company for Cause, or by the Executive for Good Reason, shall be communicated by Notice of Termination to the other party hereto given in accordance with Section 12(b) of this Agreement. For purposes of this Agreement, a "Notice of Termination" means a written notice which (i) indicates the specific termination provision in this Agreement relied upon, (ii) to the extent applicable, sets forth in reasonable detail the facts and circumstances claimed to provide a basis for termination of the Executive's employment under the provision so indicated and (iii) if the Date of Termination (as defined below) is other than the date of receipt of such notice, specifies the termination date (which date shall be not more than thirty days after the giving of such notice). The failure by the Executive or the Company to set forth in the Notice of Termination any fact or circumstance which contributes to a showing of Good Reason or Cause shall not waive any right of the Executive or the Company, respectively, hereunder or preclude the Executive or the Company, respectively, from asserting such fact or circumstance in enforcing the Executive's or the Company's rights hereunder.

(e) Date of Termination. "Date of Termination" means (i) if the Executive's employment is terminated by the Company for Cause, or by the Executive for Good Reason, the date of receipt of the Notice of Termination or any later date specified therein, as the case may be, (ii) if the Executive's employment is terminated by the Company other than for Cause or Disability, the Date of Termination shall be the date on which the Company notifies the Executive of such termination and (iii) if the Executive's employment is terminated by reason of death or Disability, the Date of Termination shall be the date of death of the Executive or the Disability Effective Date, as the case may be.

6. Obligations of the Company upon Termination. (a) Good Reason; Other Than for Cause, Death or Disability. If, during the Employment Period, the Company shall terminate the Executive's employment other than for Cause or Disability or the Executive shall terminate employment for Good Reason:

(i) the Company shall pay to the Executive in a lump sum in cash within thirty (30) days after the Date of Termination the aggregate of the following amounts:

(A) the sum of (1) the Executive's Annual Base Salary through the Date of Termination to the extent not theretofore paid, (2) the product of (x) the higher of (I) the Recent Annual Bonus and (II) the Annual Bonus paid or payable, including any bonus or portion thereof which has been earned but deferred (and annualized for any fiscal year consisting of less than twelve (12) full months or during which the Executive was employed for less than twelve (12) full months), for the most recently completed fiscal year during the Employment Period, if any (such higher amount being referred to as the "Highest Annual Bonus" and (y) a fraction, the numerator of which is the number of days in the current fiscal year through the Date of Termination, and the denominator of which is 365 and (3) any compensation previously deferred by the Executive (together with any accrued interest or earnings thereon) and any accrued vacation pay, in each case to the extent not theretofore paid (the sum of the amounts described in clauses (1), (2), and (3) shall be hereinafter referred to as the "Accrued Obligations"); and

(B) the amount equal to the product of (1) two and (2) the sum of (x) the Executive's Annual Base Salary and (y) the Highest Annual Bonus; and

(C) an amount equal to the excess of (a) the actuarial equivalent of the benefit under the Company's qualified defined benefit retirement plan (the "Retirement Plan") (utilizing actuarial assumptions no less favorable to the Executive than those in effect under the Company's Retirement Plan immediately prior to the Effective Date), and any excess or supplemental retirement plan in which the Executive participates (together, the "SERP") which the Executive would receive if the Executive's employment continued for two years after the Date of Termination assuming for this purpose that all accrued benefits are fully vested, and, assuming that the Executive's compensation in each of the two years is that required by Section 4(b)(i) and Section 4(b)(ii), over (b) the actuarial equivalent of the Executive's actual benefit (paid or payable), if any, under the Retirement Plan and the SERP as of the Date of Termination;

(ii) for two years after the Executive's Date of Termination, or such longer period as may be provided by the terms of the appropriate plan, program, practice or policy, the Company shall continue benefits to the Executive and/or the Executive's family at least equal to those which would have been provided to them in accordance with the plans, programs, practices and policies described in Section 4(b) (iv) of this Agreement if the Executive's employment had not been terminated or, if more favorable to the Executive, as in effect generally at any time thereafter with respect to other peer executives of the Company and its affiliated companies and their families, provided, however, that if the Executive becomes re-employed with another employer and is eligible to receive medical or other welfare benefits under another employer provided plan, the medical and other welfare benefits described herein shall be secondary to those provided under such other plan during such applicable period of eligibility. For purposes of determining eligibility (but not the time of commencement of benefits) of the Executive for retiree benefits pursuant to such plans, practices, programs and policies, the Executive shall be considered to have remained employed until two years after the Date of Termination and to have retired on the last day of such period;

(iii) the Company shall, at its sole expense as incurred, with payment made directly to the provider of services, provide the Executive with outplacement services the scope and provider of which shall be selected by the Executive with the Company having payment approval, in its sole discretion, for reasonable services for a period of two (2) years at a cost of not greater than thirty-thousand dollars ($30,000); and

(iv) to the extent not theretofore paid or provided, the Company shall timely pay or provide to the Executive any other amounts or benefits required to be paid or provided or which the Executive is eligible to receive under any plan, program, policy or practice or contract or agreement of the Company and its affiliated companies (such other amounts and benefits shall be hereinafter referred to as the "Other Benefits").

(b) Death. If the Executive's employment is terminated by reason of the Executive's death during the Employment Period, this Agreement shall terminate without further obligations to the Executive's legal representatives under this Agreement, other than for payment of Accrued Obligations and the timely payment or provision of Other Benefits. Accrued Obligations shall be paid to the Executive's estate or beneficiary, as applicable, in a lump sum in cash within 30 days of the Date of Termination. With respect to the provision of Other Benefits, the term Other Benefits as utilized in this Section 6(b) shall include, without limitation, and the Executive's estate and/or beneficiaries shall be entitled to receive, benefits at least equal to the most favorable benefits provided by the Company and affiliated companies to the estates and beneficiaries of peer executives of the Company and such affiliated companies under such plans, programs, practices arid policies relating to death benefits, if any, as in effect with respect to other peer executives and their beneficiaries at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive's estate and/or the Executive's beneficiaries, as in effect on the date of the Executive's death with respect to other peer executives of the Company and its affiliated companies and their beneficiaries.

(c) Disability. If the Executive's employment is terminated by reason of the Executive's Disability during the Employment Period, this Agreement shall terminate without further obligations to the Executive, other than for payment of Accrued Obligations and the timely payment or provision of Other Benefits. Accrued Obligations shall be paid to the Executive in a lump sum in cash within 30 days of the Date of Termination. With respect to the provision of Other Benefits, the term Other Benefits as utilized in this Section 6(c) shall include, and the Executive shall be entitled after the Disability Effective Date to receive, disability and other benefits at least equal to the most favorable of those generally provided by the Company and its affiliated companies to disabled executives and/or their families in accordance with such plans, programs, practices and policies relating to disability, if any, as in effect generally with respect to other peer executives and their families at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive and/or the Executive's family, as in effect at any time thereafter generally with respect to other peer executives of the Company and its affiliated companies and their families.

(d) Cause; Other than for Good Reason. If the Executive's employment shall be terminated for Cause during the Employment Period, this Agreement shall terminate without further obligations to the Executive other than the obligation to pay to the Executive (x) his Annual Base Salary through the Date of Termination, (y) the amount of any compensation previously deferred by the Executive, and (z) Other Benefits, in each case to the extent theretofore unpaid. If the Executive voluntarily terminates employment during the Employment Period, excluding a termination for Good Reason, this Agreement shall terminate without further obligations to the Executive, other than for Accrued Obligations and the timely payment or provision of Other Benefits. In such case, all Accrued Obligations shall be paid to the Executive in a lump sum in cash within 30 days of the Date of Termination.

7. Non-Exclusivity of Rights. Nothing in this Agreement shall prevent or limit the Executive's continuing or future participation in any plan, program, policy or practice provided by the Company or any of its affiliated companies and for which the Executive may qualify, nor, subject to Section 12(f), shall anything herein limit or otherwise affect such rights as the Executive may have under any contract or agreement with the Company or any of its affiliated companies. Amounts which are vested benefits or which the Executive is otherwise entitled to receive under any plan, policy, practice or program of or any contract or agreement with the Company or any of its affiliated companies at or subsequent to the Date of Termination shall be payable in accordance with such plan, policy, practice or program or contract or agreement except as explicitly modified by this Agreement.

8. Full Settlement. The Company's obligation to make the payments provided for in this Agreement and otherwise to perform its obligations hereunder shall not be affected by any set-off, counterclaim, recoupment, defense or other claim, right or action which the Company may have against the Executive or others. In no event shall the Executive be obligated to seek other employment or take any other action by way of mitigation of the amounts payable to the Executive under any of the provisions of this Agreement and such amounts shall not be reduced whether or not the Executive obtains other employment. The Company agrees to pay interest on any delayed payment at the applicable Federal rate provided for in Section 7872(f) (2) (A) of the Internal Revenue Code of 1986, as amended (the "Code"). In any suit, proceeding, dispute or action (including arbitration) to enforce or interpret any of the terms of this Agreement, the prevailing party shall be entitled to recover expenses, including reasonable attorneys' fees, in connection with such suit, proceeding, dispute or action, including appeal.

9. Certain Additional Payments by the Company.

(a) Anything in this Agreement to the contrary notwithstanding and except as Set forth below, in the event it shall be determined that any payment or distribution by the Company to or for the benefit of the Executive (whether paid or payable or distributed or distributable pursuant to the terms of this Agreement or otherwise, but determined without regard to any additional payments required under this Section 9) (a "Payment") would be subject to the excise tax imposed by Section 4999 of the Code or any interest or penalties are incurred by the Executive with respect to such excise tax (such excise tax, together with any such interest and penalties, are hereinafter collectively referred to as the "Excise Tax"), then the Executive shall be entitled to receive an additional payment (a "Gross-Up Payment") in an amount such that after payment by the Executive of all taxes (including any interest or penalties imposed with respect to such taxes), including, without limitation, any income taxes (and any interest and penalties imposed with respect thereto) and Excise Tax imposed upon the Gross-Up Payment, the Executive retains an amount of the Gross-Up Payment equal to the Excise Tax imposed upon the Payments. Notwithstanding the foregoing provisions of this Section 9 (a), if it shall be determined that the Executive is entitled to a Gross-Up Payment, but that the Payments do not exceed 110% of the greatest amount (the "Reduced Amount") that could be paid to the Executive such that the receipt of Payments would not give rise to any Excise Tax, then no Gross-Up

Payment shall be made to the Executive and the Payments, in the aggregate, shall be reduced to the Reduced amount.

(b) Subject to the provisions of Section 9(c), all determinations required to be made under this Section 9, including whether and when a Gross-Up Payment is required and the amount of such Gross-Up Payment and the assumptions to be utilized in arriving at such determination, shall be made by Deloitte and Touche or such other certified public accounting firm as may be designated by the Executive (the "Accounting Firm") which shall provide detailed supporting calculations both to the Company and the Executive within fifteen (15) business days of the receipt of notice from the Executive that there has been a Payment, or such earlier time as is requested by the Company. In the event that the Accounting Firm is serving as accountant or auditor for the individual, entity or group effecting the Change of Control, the Executive shall appoint another nationally recognized accounting firm to make the determinations required hereunder (which accounting firm shall then be referred to as the Accounting Firm hereunder). All fees and expenses of the Accounting Firm shall be borne solely by the Company. Any Gross-Up Payment, as determined pursuant to this Section 9, shall be paid by the Company to the Executive within five days of the receipt of the Accounting Firm's determination. Any determination by the Accounting Firm shall be binding upon the Company and the Executive. As a result of the uncertainty in the application of Section 4999 of the Code at the time of the initial determination by the Accounting Firm hereunder, it is possible that Gross-Up Payments which will not have been made by the Company should have been made ("Underpayment"), consistent with the calculations required to be made hereunder. In the event that the Company exhausts its remedies pursuant to Section 9(c) and the Executive thereafter is required to make a payment of any Excise Tax, the Accounting Firm shall determine the amount of the Underpayment that has occurred and any such Underpayment shall be promptly paid by the Company to or for the benefit of the Executive.

(c) The Executive shall notify the Company in writing of any claim by the Internal Revenue Service that, if successful, would require the payment by the Company of the Gross-Up Payment. Such notification shall be given as soon as practicable but no later than ten business days after the Executive is informed in writing of such claim and shall apprise the Company of the nature of such claim and the date on which such claim is requested to be paid. The Executive shall not pay such claim prior to the expiration of the 30-day period following the date on which it gives such notice to the Company (or such shorter period ending on the date that any payment of taxes with respect to such claim is due). If the Company notifies the Executive in writing prior to the expiration of such period that it desires to contest such claim, the Executive shall:

(i) give the Company any information reasonably requested by the Company relating to such claim;

(ii) take such action in connection with contesting such claim as the Company shall reasonably request in writing from time to time, including, without limitation, accepting legal representation with respect to such claim by an attorney reasonably selected by the Company;

(iii) cooperate with the Company in good faith in order effectively to contest such claim, and

(iv) permit the Company to participate in any proceedings relating to such claim;

provided, however, that the Company shall bear and pay directly all costs and expenses (including additional interest and penalties) incurred in connection with such contest and shall indemnify and hold the Executive harmless, on an after-tax basis, for any Excise Tax or income tax (including interest and penalties with respect thereto) imposed as a result of such representation and payment of costs and expenses. Without limitation on the foregoing provisions of this Section 9(c), the Company shall control all proceedings taken in connection with such contest and, at its sole option, may pursue or forgo any and all administrative appeals, proceedings, hearings and conferences with the taxing authority in respect of such claim and may, at its sole option, either direct the Executive to pay the tax claimed and sue for a refund or contest the claim in any permissible manner, and the Executive agrees to prosecute such contest to a determination before any administrative tribunal, in a court of initial jurisdiction and in one or more appellate courts, as the Company shall determine; provided, however, that if the Company directs the Executive to pay such, claim and sue for a refund, the Company shall advance the amount of such payment to the Executive, on an interest-free basis and shall indemnify and hold the Executive harmless, on an after-tax basis, from any Excise Tax or income tax (including interest or penalties with respect thereto) imposed with respect to such advance or with respect to any imputed income with respect to such advance; and further provided that any extension of the statute of limitations relating to payment of taxes for the taxable year of the Executive with respect to which such contested amount is claimed to be due is limited solely to such contested amount. Furthermore, the Company's control of the contest shall be limited to issues with respect to which a Gross-Up Payment would be payable hereunder and the Executive shall be entitled to settle or contest, as the case may be, any other issue raised by the Internal Revenue Service or any other taxing authority.

(d) If, after the receipt by the Executive of an amount advanced by the Company pursuant to Section 9(c), the Executive becomes entitled to receive any refund with respect to such claim, the Executive shall (subject to the Company's complying with the requirements of Section 9(c)) promptly pay to the Company the amount of such refund (together with any interest paid or credited thereon after taxes applicable thereto). If, after the receipt by the Executive of an amount advanced by the Company pursuant to Section 9 (c), a determination is made that the Executive shall not be entitled to any refund with respect to such claim and the Company does not notify the Executive in writing of its intent to contest such denial of refund prior to the expiration of 30 days after such determination, then such advance shall be forgiven and shall not be required to be repaid and the amount of such advance shall offset, to the extent thereof, the amount of Gross-Up Payment required to be paid.

10. Confidential Information. The Executive shall hold in a fiduciary capacity for the benefit of the Company all secret or confidential information, knowledge or data relating to the Company or any of its affiliated companies, and their respective businesses, which shall have been obtained by the Executive during the Executive's employment by the Company or any of its

affiliated companies and which shall not be or become public knowledge (other than by acts by the Executive or representatives of the Executive in violation of this Agreement). After termination of the Executive's employment with the Company, the Executive shall not, without the prior written consent of the Company or as may otherwise be required by law or legal process, communicate or divulge any such information, knowledge or data to anyone other than the Company and those designated by it. In no event shall an asserted violation of the provisions of this Section 10 constitute a basis for deferring or withholding any amounts otherwise payable to the Executive under this Agreement. Any Avista Corporation Employee Confidentiality, Non-Solicitation and Invention Agreement signed by Executive is incorporated herein by reference as if set forth in full.

11. Successors. (a) This Agreement is personal to the Executive and without the prior written consent of the Company shall not be assignable by the Executive otherwise than by will or the laws of descent and distribution. This Agreement shall inure to the benefit of and be enforceable by the Executive's legal representatives.

(b) This Agreement shall inure to the benefit of and be binding upon the Company and its successors and assigns.

(c) The Company will require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business and/or assets of the Company to assume expressly and agree to perform this Agreement in the same manner and to the same extent that the Company would be required to perform it if no such succession has taken place. As used in this Agreement, "Company" shall mean the Company as herein before defined and any successor to its business and/or assets as aforesaid which assumes and agrees to perform this Agreement by operation of law, or otherwise.

12. Miscellaneous. (a) This Agreement shall be governed by and construed in accordance with the laws of the State of Washington, without reference to principles of conflict of laws. Venue for any suit, action or proceeding concerning this agreement is to be in the Superior Court of the State of Washington for Spokane County. By this Agreement, the parties confer jurisdiction over the subject matter of and parties to this Agreement to the Superior Court of the State of Washington for Spokane County. The captions of this Agreement are not part of the provisions hereof and shall have no force or effect. This Agreement may not be amended or modified otherwise than by a written agreement executed by the parties hereto or their respective successors and legal representatives.

(b) All notices and other communications hereunder shall be in writing and shall be given by hand delivery to the other party or by registered or certified mail, return receipt requested, postage prepaid, addressed as follows:

If to the Executive:

If to the Company:

Attention: General Counsel

or to such other address as either party shall have furnished to the other in writing in accordance herewith. Notice and communications shall be effective when actually received by the addressee.

(c) The invalidity or unenforceability of any provision of this Agreement shall not affect the validity or enforceability of any other provision of this Agreement.

(d) The Company may withhold from amounts payable under this Agreement such Federal, state, local or foreign taxes as shall be required to be withheld pursuant to any applicable law or regulation.

(e) The Executive's or the Company's failure to insist upon strict compliance with any provision of this Agreement or the failure to assert any right the Executive or the Company may have hereunder, including, without limitation, the right of the Executive to terminate employment for Good Reason pursuant to Section 5(c)(i)-(v) of this Agreement, shall not be deemed to be a waiver of such provision or right or any other provision or right of this Agreement.

(f) The Executive and the Company acknowledge that, except as may otherwise be provided under any other written agreement between the Executive and the Company, the employment of the Executive by the Company is "at will" and, subject to Section 1(a) hereof, prior to the Effective Date, the Executive's employment and/or this Agreement may be terminated by either the Executive or the Company at any time prior to the Effective date, in which case the Executive shall have no further rights under this Agreement. From and after the Effective date this Agreement shall supersede any other agreement between the parties with respect to the subject matter hereof.

IN WITNESS WHEREOF, the Executive has hereunto set the Executive's hand and, pursuant to the authorization from its Board of Directors, the Company has caused these presents to be executed in its name on its behalf, all as of the day and year first above written.

____
[Executive]

AVISTA CORPORATION

By: _______________________________

EXHIBIT 10(q)-11

CHANGE OF CONTROL AGREEMENT

AGREEMENT by and between Avista Corporation, a Washington corporation (the "Company") and ______________________________________, (the "Executive"), dated as of the ____ day of ________________________, 20__.

The Board of Directors of the Company (the "Board"), has determined that it is in the best interests of the Company and its shareholders to assure that the Company will have the continued dedication of the Executive, notwithstanding the possibility, threat or occurrence of a Change of Control (as defined below) of the Company. The Board believes it is imperative to diminish the inevitable distraction of the Executive by virtue of the personal uncertainties and risks created by a pending or threatened Change of Control and to encourage the Executive's full attention and dedication to the Company currently and in the event of any threatened or pending Change of Control, and to provide the Executive with compensation and benefits arrangements upon a Change of Control which ensure that the compensation and benefits expectations of the Executive will be satisfied and which are competitive with those of other corporations. Therefore, in order to accomplish these objectives, the Board has caused the Company to enter into this Agreement.

NOW, THEREFORE, IT IS HEREBY AGREED AS FOLLOWS:

1. Certain Definitions. (a) The "Effective Date" shall mean the first date during the Change of Control Period (as defined in Section 1(b)) on which a Change of Control (as defined in Section 2) occurs. Anything in this Agreement to the contrary notwithstanding, if a Change of Control occurs and if the Executive's employment with the Company is terminated prior to the date on which the Change of Control occurs, and if it is reasonably demonstrated by the Executive that such termination of employment (i) was at the request of a third party who has taken steps reasonably calculated to effect a Change of Control or (ii) otherwise arose in connection with or anticipation of a Change of Control, then for all purposes of this Agreement the "Effective date" shall mean the date immediately prior to the date of such termination of employment.

(b) The "Change of Control Period" shall mean the period commencing on the date hereof and ending on the third anniversary of the date hereof; provided, however, that commencing on the date one year after the date hereof, and on each annual anniversary of such date (such date and each annual anniversary thereof shall be hereinafter referred to as the "Renewal Date"), unless previously terminated, the Change of Control Period shall be automatically extended so as to terminate three (3) years from such Renewal Date, unless at least sixty (60) days prior to the Renewal Date the Company shall give notice to the Executive that the Change of Control Period shall not be so extended.

2. Change of Control. For the purpose of this Agreement, a "Change of Control" shall mean:

(a) The acquisition by any individual, entity or group (within the meaning of Section 13(d)(3) or 14(d)(2) of the Securities Exchange Act of 1934, as amended (the "Exchange

Act")) (a "Person") of beneficial ownership (within the meaning of Rule 13d-3 promulgated under the Exchange Act) of twenty percent (20%) or more of either (i) the then outstanding shares of common stock of the Company (the "Outstanding Company Common Stock") or (ii) the combined voting power of the then outstanding voting securities of the Company entitled to vote generally in the election of directors (the "Outstanding Company Voting Securities"); provided, however, that for purposes of this subsection (a), the following acquisitions shall not constitute a Change of Control: (i) any acquisition directly from the Company, (ii) any acquisition by the Company, (iii) any acquisition by any employee benefit plan (or related trust) sponsored or maintained by the Company or any corporation controlled by the Company or (iv) any acquisition by any corporation pursuant to a transaction which complies with clauses (i), (ii) and (iii) of subsection (c) of this Section 2; or

(b) Individuals who, as of the date hereof, constitute the Board (the "Incumbent Board") cease for any reason to constitute at least a majority of the Board; provided, however, that any individual becoming a director subsequent to the date hereof whose election, or nomination for election by the Company's shareholders, was approved by a vote of at least a majority of the directors then comprising the Incumbent Board shall be considered as though such individual were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as a result of an actual or threatened election contest with respect to the election or removal of directors, or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board; or

(c) Consummation of a reorganization, merger or consolidation or sale or other disposition of all or substantially all of the assets of the Company (a "Business Combination"), in each case, unless, following such Business Combination, (i) all or substantially all of the individuals and entities who were the beneficial owners, respectively, of the Outstanding Company Common Stock and Outstanding Company Voting Securities immediately prior to such Business Combination beneficially own, directly or indirectly, more than fifty percent (50%) of, respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation resulting from such Business Combination (including, without limitation, a corporation which as a result of such transaction owns the Company or all or substantially all of the Company's assets either directly or through one or more subsidiaries) in substantially the same proportions as their ownership, immediately prior to such Business Combination of the Outstanding Company Common Stock and Outstanding Company Voting Securities, as the case may be, (ii) no Person (excluding any corporation resulting from such Business Combination or employee benefit plan (or related trust) of the Company or such corporation resulting from such Business Combination) beneficially owns, directly or indirectly, twenty percent (20%) or more of, respectively, the then outstanding shares of common stock of the corporation resulting from such Business Combination or the combined voting power of the then outstanding voting securities of such corporation except to the extent that such ownership existed prior to the Business Combination and (iii) at least a majority of the members of the board of directors of the corporation resulting from such Business Combination were members of the Incumbent Board at the time of the execution of the initial agreement, or of the action of the Board, providing for such Business Combination; or

(d) Approval by the shareholders of the Company of a complete liquidation or dissolution of the Company.

3. Employment Period. The Company hereby agrees to continue the Executive in its employ, and the Executive hereby agrees to remain in the employ of the Company subject to the terms and conditions of this Agreement, for the period commencing on the Effective Date and ending on the third anniversary of such date (the "Employment Period").

4. Terms of Employment. (a) Position and Duties. (i) During the Employment Period, (A) the Executive's position (including status, offices, titles and reporting requirements), authority, duties and responsibilities shall be at least commensurate in all material respects with the most significant of those held, exercised and assigned at any time during the one hundred twenty (120) day period immediately preceding the Effective Date and (B) the Executive's services shall be performed at the location where the Executive was employed immediately preceding the Effective Date or any office or location less than 35 miles from such location.

(ii) During the Employment Period, and excluding any periods of vacation and sick leave to which the Executive is entitled, the Executive agrees to devote reasonable attention and time during normal business hours to the business and affairs of the Company and, to the extent necessary to discharge the responsibilities assigned to the Executive hereunder, to use the Executive's reasonable best efforts to perform faithfully and efficiently such responsibilities. During the Employment Period it shall not be a violation of this Agreement for the Executive to (A) serve on corporate, civic or charitable boards or committees, (B) deliver lectures, fulfill speaking engagements or teach at educational institutions and (C) manage personal investments, so long as such activities do not significantly interfere with the performance of the Executive's responsibilities as an employee of the Company in accordance with this Agreement. It is expressly understood and agreed that to the extent that any such activities have been conducted by the Executive prior to the Effective Date, the continued conduct of such activities (or the conduct of activities similar in nature and scope thereto) subsequent to the Effective Date shall not thereafter be deemed to interfere with the performance of the Executive's responsibilities to the Company.

(b) Compensation. (i) Base Salary. During the Employment Period, the Executive shall receive an annual base salary ("Annual Base Salary"), which shall be paid at a monthly rate, at least equal to twelve times the highest monthly base salary paid or payable, including any base salary which has been earned but deferred, to the Executive by the Company and its affiliated companies in respect of the twelve month period immediately preceding the month in which the Effective Date occurs. During the Employment Period, the Annual Base Salary shall be reviewed no more than 12 months after the last salary increase awarded to the Executive prior to the Effective Date and thereafter at least annually. Any increase in Annual Base Salary shall not serve to limit or reduce any other obligation to the Executive under this Agreement. Annual Base Salary shall not be reduced after any such increase and the term Annual Base Salary as utilized in this Agreement shall refer to Annual Base Salary as so increased. As used in this Agreement, the term "affiliated companies" shall include any company controlled by, controlling or under common control with the Company.

(ii) Annual Bonus. In addition to Annual Base Salary, the Executive shall be awarded, for each fiscal year ending during the Employment Period, an annual bonus (the "Annual Bonus") in cash at least equal to the Executive's highest bonus under the Company's Annual Incentive Plans, or any comparable bonus under any predecessor or successor plan, for the last three (3) full fiscal years prior to the Effective Date (annualized in the event that the Executive was not employed by the Company for the whole of such fiscal year) (the "Recent Annual Bonus"). Each such Annual bonus shall be paid no later than the end of the third month of the fiscal year next following the fiscal year for which the Annual Bonus is awarded, unless the Executive shall elect to defer the receipt of such Annual Bonus.

(iii) Incentive, Savings and Retirement Plans. During the Employment Period, the Executive shall be entitled to participate in all incentive, savings and retirement plans, practices, policies and programs applicable generally to other peer executives of the Company and its affiliated companies, but in no event shall such plans, practices, policies and programs provide the Executive with incentive opportunities (measured with respect to both regular and special incentive opportunities, to the extent, if any, that such distinction is applicable), savings opportunities and retirement benefit opportunities, in each case, less favorable, in the aggregate, than the most favorable of those provided by the Company and its affiliated companies for the Executive under such plans, practices, policies and programs as in effect at any time during the 120-day period immediately preceding the Effective Date or if more favorable to the Executive, those provided generally at any time after the Effective Date to other peer executives of the Company and its affiliated companies.

(iv) Welfare Benefit Plans. During the Employment Period, the Executive and/or the Executive's family, as the case may be, shall be eligible for participation in and shall receive all benefits under welfare benefit plans, practices, policies and programs provided by the Company and its affiliated companies (including, without limitation, medical, prescription, dental, disability, employee life, group life, accidental death and travel accident insurance plans and programs) to the extent applicable generally to other peer executives of the Company and its affiliated companies, but in no event shall such plans, practices, policies and programs provide the Executive with benefits which are less favorable, in the aggregate, than the most favorable of such plans, practices, policies and programs in effect for the Executive at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive, those provided generally at any time after the Effective Date to other peer executives of the Company and its affiliated companies.

(v) Expenses. During the Employment Period, the Executive shall be entitled to receive prompt reimbursement for all reasonable expenses incurred by the Executive in accordance with the most favorable policies, practices and procedures of the Company and its affiliated companies in effect for the Executive at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive, as in effect generally at any time thereafter with respect to other peer executives of the Company and its affiliated companies.

(vi) Fringe Benefits. During the Employment Period, the Executive shall be entitled to fringe benefits, including, without limitation, tax and financial planning services, payment of club dues, and, if applicable, use of an automobile and payment of related expenses, in accordance with the most favorable plans, practices, programs and policies of the Company and its affiliated companies in effect for the Executive at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive, as in effect generally at any time thereafter with respect to other peer executives of the Company and its affiliated companies.

(vii) Office and Support Staff. During the Employment Period, the Executive shall be entitled to an office or offices of a size and with furnishings and other appointments, and to exclusive personal secretarial and other assistance, at least equal to the most favorable of the foregoing provided to the Executive by the Company and its affiliated companies at any time during the 120-period immediately preceding the Effective date or, if more favorable to the Executive, as provided generally at any time thereafter with respect to other peer executives of the Company and its affiliated companies.

(viii) Vacation. During the Employment Period, the Executive shall be entitled to paid vacation in accordance with the most favorable plans, policies, programs and practices of the Company and its affiliated companies as in effect for the Executive at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive, as in effect generally at any time thereafter with respect to other peer executives of the Company and its affiliated companies.

5. Termination of Employment. (a) Death or Disability. The Executive's employment shall terminate automatically upon the Executive's death during the Employment Period. If the Company determines in good faith that the Disability of the Executive has occurred during the Employment Period (pursuant to the definition of Disability set forth below), it may give to the Executive written notice in accordance with Section 12(b) of this Agreement of its intention to terminate the Executive's employment. In such event, the Executive's employment with the Company shall terminate effective on the 30th day after receipt of such notice by the Executive (the "Disability Effective Date), provided that, within the thirty (30) days after such receipt, the Executive shall not have returned to full-time performance of the Executive's duties. For purposes of this Agreement, "Disability" shall mean the absence of the Executive from the Executive's duties with the Company on a full-time basis for one hundred eighty (180) consecutive business days as a result of incapacity due to mental or physical illness which is determined to be total and permanent by a physician selected by the Company or its insurers and acceptable to the Executive or the Executive's legal representative.

(b) Cause. The Company may terminate the Executive's employment during the Employment Period for Cause. For purposes of this Agreement, "Cause" shall mean:

(i) the willful and continued failure of the Executive to perform substantially the Executive's duties with the Company or one of its affiliates (other than any such failure resulting from incapacity due to physical or mental illness), after a written demand for substantial performance is delivered to the Executive by the Board or the Chief Executive Officer of the Company which specifically identifies the manner in which the Board or Chief

Executive Officer believes that the Executive has not substantially performed the Executive's duties, or

(ii) the willful engaging by the Executive in illegal conduct or gross misconduct which is materially and demonstrably injurious to the Company.

For purposes of this provision, no act or failure to act, on the part of the Executive, shall be considered "willful" unless it is done, or omitted to be done, by the Executive in bad faith or without reasonable belief that the Executive's action or omission was in the best interests of the Company. Any act, or failure to act, based upon authority given pursuant to a resolution duly adopted by the Board or upon the instructions of the Chief Executive Officer or a senior officer of the Company or based upon the advice of counsel for the Company shall be conclusively presumed to be done, or omitted to be done, by the Executive in good faith and in the best interests of the Company. The cessation of employment of the Executive shall not be deemed to be for Cause unless and until there shall have been delivered to the Executive a copy of a resolution duly adopted by the affirmative vote of not less than three-quarters of the entire membership of the Board at a meeting of the Board called and held for such purpose (after reasonable notice is provided to the Executive and the Executive is given an opportunity, together with counsel, to be heard before the Board), finding that, in the good faith opinion of the Board, the Executive is guilty of the conduct described in subparagraph (i) or (ii) above, and specifying the particulars thereof in detail.

(c) Good Reason. The Executive's employment may be terminated by the Executive for Good Reason. For purposes of this Agreement, "Good Reason" shall mean:

(i) the assignment to the Executive of any duties inconsistent in any respect with the Executive's position (including status, offices, titles and reporting requirements), authority, duties or responsibilities as contemplated by Section 4(a) of this Agreement, or any other action by the Company which results in a diminution in such position, authority, duties or responsibilities, excluding for this purpose an isolated, insubstantial and inadvertent action not taken in bad faith and which is remedied by the Company promptly after receipt of notice thereof given by the Executive;

(ii) any failure by the Company to comply with any of the provisions of Section 4(b) of this Agreement, other than an isolated, insubstantial and inadvertent failure not occurring in bad faith and which is remedied by the Company promptly after receipt of notice thereof given by the Executive;

(iii) the Company's requiring the Executive to be based at any office or location other than as provided in Section 4(a)(i)(B) hereof or the Company's requiring the Executive to travel on Company business to a substantially greater extent than required immediately prior to the Effective Date;

(iv) any purported termination by the Company of the Executive's employment otherwise than as expressly permitted by this Agreement; or

(v) any failure by the Company to comply with and satisfy Section 11(c) of this Agreement.

For purposes of this Section 5(c), a determination of "Good Reason" made by the Executive with which the Company does not agree shall be resolved pursuant to the following dispute resolution procedure. First, the parties shall in good faith attempt to resolve any dispute arising hereunder. Second, if such efforts are unsuccessful, the parties shall submit to binding arbitration with such arbitration to be conducted in Spokane, Washington, by the American Arbitration Association under its National Rules for the Resolution of Employment Disputes.

(d) Notice of Termination. Any termination by the Company for Cause, or by the Executive for Good Reason, shall be communicated by Notice of Termination to the other party hereto given in accordance with Section 12(b) of this Agreement. For purposes of this Agreement, a "Notice of Termination" means a written notice which (i) indicates the specific termination provision in this Agreement relied upon, (ii) to the extent applicable, sets forth in reasonable detail the facts and circumstances claimed to provide a basis for termination of the Executive's employment under the provision so indicated and (iii) if the Date of Termination (as defined below) is other than the date of receipt of such notice, specifies the termination date (which date shall be not more than thirty days after the giving of such notice). The failure by the Executive or the Company to set forth in the Notice of Termination any fact or circumstance which contributes to a showing of Good Reason or Cause shall not waive any right of the Executive or the Company, respectively, hereunder or preclude the Executive or the Company, respectively, from asserting such fact or circumstance in enforcing the Executive's or the Company's rights hereunder.

(e) Date of Termination. "Date of Termination" means (i) if the Executive's employment is terminated by the Company for Cause, or by the Executive for Good Reason, the date of receipt of the Notice of Termination or any later date specified therein, as the case may be, (ii) if the Executive's employment is terminated by the Company other than for Cause or Disability, the Date of Termination shall be the date on which the Company notifies the Executive of such termination and (iii) if the Executive's employment is terminated by reason of death or Disability, the Date of Termination shall be the date of death of the Executive or the Disability Effective Date, as the case may be.

6. Obligations of the Company upon Termination. (a) Good Reason; Other Than for Cause, Death or Disability. If, during the Employment Period, the Company shall terminate the Executive's employment other than for Cause or Disability or the Executive shall terminate employment for Good Reason:

(i) the Company shall pay to the Executive in a lump sum in cash within thirty (30) days after the Date of Termination the aggregate of the following amounts:

(A) the sum of (1) the Executive's Annual Base Salary through the Date of Termination to the extent not theretofore paid, (2) the product of (x) the higher of (I) the Recent Annual Bonus and (II) the Annual Bonus paid or payable, including any bonus or portion thereof which has been earned but deferred (and annualized for any fiscal year consisting of less than twelve (12) full months or during which the Executive was employed for less than twelve (12) full months), for the most recently completed fiscal year during the Employment Period, if any (such higher amount being referred to as the "Highest Annual Bonus" and (y) a fraction, the numerator of which is the number of days in the current fiscal year through the Date of Termination, and the denominator of which is 365 and (3) any compensation previously deferred by the Executive (together with any accrued interest or earnings thereon) and any accrued vacation pay, in each case to the extent not theretofore paid (the sum of the amounts described in clauses (1), (2), and (3) shall be hereinafter referred to as the "Accrued Obligations"); and

(B) the amount equal to the product of (1) three and (2) the sum of (x) the Executive's Annual Base Salary and (y) the Highest Annual Bonus; and

(C) an amount equal to the excess of (a) the actuarial equivalent of the benefit under the Company's qualified defined benefit retirement plan (the "Retirement Plan") (utilizing actuarial assumptions no less favorable to the Executive than those in effect under the Company's Retirement Plan immediately prior to the Effective Date), and any excess or supplemental retirement plan in which the Executive participates (together, the "SERP") which the Executive would receive if the Executive's employment continued for three years after the Date of Termination assuming for this purpose that all accrued benefits are fully vested, and, assuming that the Executive's compensation in each of the three years is that required by Section 4(b)(i) and Section 4(b)(ii), over (b) the actuarial equivalent of the Executive's actual benefit (paid or payable), if any, under the Retirement Plan and the SERP as of the Date of Termination;

(ii) for three years after the Executive's Date of Termination, or such longer period as may be provided by the terms of the appropriate plan, program, practice or policy, the Company shall continue benefits to the Executive and/or the Executive's family at least equal to those which would have been provided to them in accordance with the plans, programs, practices and policies described in Section 4(b) (iv) of this Agreement if the Executive's employment had not been terminated or, if more favorable to the Executive, as in effect generally at any time thereafter with respect to other peer executives of the Company and its affiliated companies and their families, provided, however, that if the Executive becomes re-employed with another employer and is eligible to receive medical or other welfare benefits under another employer provided plan, the medical and other welfare benefits described herein shall be secondary to those provided under such other plan during such applicable period of eligibility. For purposes of determining eligibility (but not the time of commencement of benefits) of the Executive for retiree benefits pursuant to such plans, practices, programs and policies, the Executive shall be considered to have remained employed until three years after the Date of Termination and to have retired on the last day of such period;

(iii) the Company shall, at its sole expense as incurred, with payment made directly to the provider of services, provide the Executive with outplacement services the scope and provider of which shall be selected by the Executive with the Company having payment approval, in its sole discretion, for reasonable services for a period of two (2) years at a cost of not greater than thirty-thousand dollars ($30,000); and

(iv) to the extent not theretofore paid or provided, the Company shall timely pay or provide to the Executive any other amounts or benefits required to be paid or provided or which the Executive is eligible to receive under any plan, program, policy or practice or contract or agreement of the Company and its affiliated companies (such other amounts and benefits shall be hereinafter referred to as the "Other Benefits").

(b) Death. If the Executive's employment is terminated by reason of the Executive's death during the Employment Period, this Agreement shall terminate without further obligations to the Executive's legal representatives under this Agreement, other than for payment of Accrued Obligations and the timely payment or provision of Other Benefits. Accrued Obligations shall be paid to the Executive's estate or beneficiary, as applicable, in a lump sum in cash within 30 days of the Date of Termination. With respect to the provision of Other Benefits, the term Other Benefits as utilized in this Section 6(b) shall include, without limitation, and the Executive's estate and/or beneficiaries shall be entitled to receive, benefits at least equal to the most favorable benefits provided by the Company and affiliated companies to the estates and beneficiaries of peer executives of the Company and such affiliated companies under such plans, programs, practices arid policies relating to death benefits, if any, as in effect with respect to other peer executives and their beneficiaries at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive's estate and/or the Executive's beneficiaries, as in effect on the date of the Executive's death with respect to other peer executives of the Company and its affiliated companies and their beneficiaries.

(c) Disability. If the Executive's employment is terminated by reason of the Executive's Disability during the Employment Period, this Agreement shall terminate without further obligations to the Executive, other than for payment of Accrued Obligations and the timely payment or provision of Other Benefits. Accrued Obligations shall be paid to the Executive in a lump sum in cash within 30 days of the Date of Termination. With respect to the provision of Other Benefits, the term Other Benefits as utilized in this Section 6(c) shall include, and the Executive shall be entitled after the Disability Effective Date to receive, disability and other benefits at least equal to the most favorable of those generally provided by the Company and its affiliated companies to disabled executives and/or their families in accordance with such plans, programs, practices and policies relating to disability, if any, as in effect generally with respect to other peer executives and their families at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive and/or the Executive's family, as in effect at any time thereafter generally with respect to other peer executives of the Company and its affiliated companies and their families.

(d) Cause; Other than for Good Reason. If the Executive's employment shall be terminated for Cause during the Employment Period, this Agreement shall terminate without further obligations to the Executive other than the obligation to pay to the Executive (x) his Annual Base Salary through the Date of Termination, (y) the amount of any compensation previously deferred by the Executive, and (z) Other Benefits, in each case to the extent theretofore unpaid. If the Executive voluntarily terminates employment during the Employment Period, excluding a termination for Good Reason, this Agreement shall terminate without further obligations to the Executive, other than for Accrued Obligations and the timely payment or provision of Other Benefits. In such case, all Accrued Obligations shall be paid to the Executive in a lump sum in cash within 30 days of the Date of Termination.

7. Non-Exclusivity of Rights. Nothing in this Agreement shall prevent or limit the Executive's continuing or future participation in any plan, program, policy or practice provided by the Company or any of its affiliated companies and for which the Executive may qualify, nor, subject to Section 12(f), shall anything herein limit or otherwise affect such rights as the Executive may have under any contract or agreement with the Company or any of its affiliated companies. Amounts which are vested benefits or which the Executive is otherwise entitled to receive under any plan, policy, practice or program of or any contract or agreement with the Company or any of its affiliated companies at or subsequent to the Date of Termination shall be payable in accordance with such plan, policy, practice or program or contract or agreement except as explicitly modified by this Agreement.

8. Full Settlement. The Company's obligation to make the payments provided for in this Agreement and otherwise to perform its obligations hereunder shall not be affected by any set-off, counterclaim, recoupment, defense or other claim, right or action which the Company may have against the Executive or others. In no event shall the Executive be obligated to seek other employment or take any other action by way of mitigation of the amounts payable to the Executive under any of the provisions of this Agreement and such amounts shall not be reduced whether or not the Executive obtains other employment. The Company agrees to pay interest on any delayed payment at the applicable Federal rate provided for in Section 7872(f) (2) (A) of the Internal Revenue Code of 1986, as amended (the "Code"). In any suit, proceeding, dispute or action (including arbitration) to enforce or interpret any of the terms of this Agreement, the prevailing party shall be entitled to recover expenses, including reasonable attorneys' fees, in connection with such suit, proceeding, dispute or action, including appeal.

9. Certain Additional Payments by the Company.

(a) Anything in this Agreement to the contrary notwithstanding and except as Set forth below, in the event it shall be determined that any payment or distribution by the Company to or for the benefit of the Executive (whether paid or payable or distributed or distributable pursuant to the terms of this Agreement or otherwise, but determined without regard to any additional payments required under this Section 9) (a "Payment") would be subject to the excise tax imposed by Section 4999 of the Code or any interest or penalties are incurred by the Executive with respect to such excise tax (such excise tax, together with any such interest and penalties, are hereinafter collectively referred to as the "Excise Tax"), then the Executive shall be entitled to receive an additional payment (a "Gross-Up Payment") in an amount such that after payment by the Executive of all taxes (including any interest or penalties imposed with respect to such taxes), including, without limitation, any income taxes (and any interest and penalties imposed with respect thereto) and Excise Tax imposed upon the Gross-Up Payment, the Executive retains an amount of the Gross-Up Payment equal to the Excise Tax imposed upon the Payments. Notwithstanding the foregoing provisions of this Section 9 (a), if it shall be determined that the Executive is entitled to a Gross-Up Payment, but that the Payments do not exceed 110% of the greatest amount (the "Reduced Amount") that could be paid to the Executive such that the receipt of Payments would not give rise to any Excise Tax, then no Gross-Up

Payment shall be made to the Executive and the Payments, in the aggregate, shall be reduced to the Reduced amount.

(b) Subject to the provisions of Section 9(c), all determinations required to be made under this Section 9, including whether and when a Gross-Up Payment is required and the amount of such Gross-Up Payment and the assumptions to be utilized in arriving at such determination, shall be made by Deloitte and Touche or such other certified public accounting firm as may be designated by the Executive (the "Accounting Firm") which shall provide detailed supporting calculations both to the Company and the Executive within fifteen (15) business days of the receipt of notice from the Executive that there has been a Payment, or such earlier time as is requested by the Company. In the event that the Accounting Firm is serving as accountant or auditor for the individual, entity or group effecting the Change of Control, the Executive shall appoint another nationally recognized accounting firm to make the determinations required hereunder (which accounting firm shall then be referred to as the Accounting Firm hereunder). All fees and expenses of the Accounting Firm shall be borne solely by the Company. Any Gross-Up Payment, as determined pursuant to this Section 9, shall be paid by the Company to the Executive within five days of the receipt of the Accounting Firm's determination. Any determination by the Accounting Firm shall be binding upon the Company and the Executive. As a result of the uncertainty in the application of Section 4999 of the Code at the time of the initial determination by the Accounting Firm hereunder, it is possible that Gross-Up Payments which will not have been made by the Company should have been made ("Underpayment"), consistent with the calculations required to be made hereunder. In the event that the Company exhausts its remedies pursuant to Section 9(c) and the Executive thereafter is required to make a payment of any Excise Tax, the Accounting Firm shall determine the amount of the Underpayment that has occurred and any such Underpayment shall be promptly paid by the Company to or for the benefit of the Executive.

(c) The Executive shall notify the Company in writing of any claim by the Internal Revenue Service that, if successful, would require the payment by the Company of the Gross-Up Payment. Such notification shall be given as soon as practicable but no later than ten business days after the Executive is informed in writing of such claim and shall apprise the Company of the nature of such claim and the date on which such claim is requested to be paid. The Executive shall not pay such claim prior to the expiration of the 30-day period following the date on which it gives such notice to the Company (or such shorter period ending on the date that any payment of taxes with respect to such claim is due). If the Company notifies the Executive in writing prior to the expiration of such period that it desires to contest such claim, the Executive shall:

(i) give the Company any information reasonably requested by the Company relating to such claim;

(ii) take such action in connection with contesting such claim as the Company shall reasonably request in writing from time to time, including, without limitation, accepting legal representation with respect to such claim by an attorney reasonably selected by the Company;

(iii) cooperate with the Company in good faith in order effectively to contest such claim, and

(iv) permit the Company to participate in any proceedings relating to such claim;

provided, however, that the Company shall bear and pay directly all costs and expenses (including additional interest and penalties) incurred in connection with such contest and shall indemnify and hold the Executive harmless, on an after-tax basis, for any Excise Tax or income tax (including interest and penalties with respect thereto) imposed as a result of such representation and payment of costs and expenses. Without limitation on the foregoing provisions of this Section 9(c), the Company shall control all proceedings taken in connection with such contest and, at its sole option, may pursue or forgo any and all administrative appeals, proceedings, hearings and conferences with the taxing authority in respect of such claim and may, at its sole option, either direct the Executive to pay the tax claimed and sue for a refund or contest the claim in any permissible manner, and the Executive agrees to prosecute such contest to a determination before any administrative tribunal, in a court of initial jurisdiction and in one or more appellate courts, as the Company shall determine; provided, however, that if the Company directs the Executive to pay such, claim and sue for a refund, the Company shall advance the amount of such payment to the Executive, on an interest-free basis and shall indemnify and hold the Executive harmless, on an after-tax basis, from any Excise Tax or income tax (including interest or penalties with respect thereto) imposed with respect to such advance or with respect to any imputed income with respect to such advance; and further provided that any extension of the statute of limitations relating to payment of taxes for the taxable year of the Executive with respect to which such contested amount is claimed to be due is limited solely to such contested amount. Furthermore, the Company's control of the contest shall be limited to issues with respect to which a Gross-Up Payment would be payable hereunder and the Executive shall be entitled to settle or contest, as the case may be, any other issue raised by the Internal Revenue Service or any other taxing authority.

(d) If, after the receipt by the Executive of an amount advanced by the Company pursuant to Section 9(c), the Executive becomes entitled to receive any refund with respect to such claim, the Executive shall (subject to the Company's complying with the requirements of Section 9(c)) promptly pay to the Company the amount of such refund (together with any interest paid or credited thereon after taxes applicable thereto). If, after the receipt by the Executive of an amount advanced by the Company pursuant to Section 9 (c), a determination is made that the Executive shall not be entitled to any refund with respect to such claim and the Company does not notify the Executive in writing of its intent to contest such denial of refund prior to the expiration of 30 days after such determination, then such advance shall be forgiven and shall not be required to be repaid and the amount of such advance shall offset, to the extent thereof, the amount of Gross-Up Payment required to be paid.

10. Confidential Information. The Executive shall hold in a fiduciary capacity for the benefit of the Company all secret or confidential information, knowledge or data relating to the Company or any of its affiliated companies, and their respective businesses, which shall have been obtained by the Executive during the Executive's employment by the Company or any of its

affiliated companies and which shall not be or become public knowledge (other than by acts by the Executive or representatives of the Executive in violation of this Agreement). After termination of the Executive's employment with the Company, the Executive shall not, without the prior written consent of the Company or as may otherwise be required by law or legal process, communicate or divulge any such information, knowledge or data to anyone other than the Company and those designated by it. In no event shall an asserted violation of the provisions of this Section 10 constitute a basis for deferring or withholding any amounts otherwise payable to the Executive under this Agreement. Any Avista Corporation Employee Confidentiality, Non-Solicitation and Invention Agreement signed by Executive is incorporated herein by reference as if set forth in full.

11. Successors. (a) This Agreement is personal to the Executive and without the prior written consent of the Company shall not be assignable by the Executive otherwise than by will or the laws of descent and distribution. This Agreement shall inure to the benefit of and be enforceable by the Executive's legal representatives.

(b) This Agreement shall inure to the benefit of and be binding upon the Company and its successors and assigns.

(c) The Company will require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business and/or assets of the Company to assume expressly and agree to perform this Agreement in the same manner and to the same extent that the Company would be required to perform it if no such succession has taken place. As used in this Agreement, "Company" shall mean the Company as herein before defined and any successor to its business and/or assets as aforesaid which assumes and agrees to perform this Agreement by operation of law, or otherwise.

12. Miscellaneous. (a) This Agreement shall be governed by and construed in accordance with the laws of the State of Washington, without reference to principles of conflict of laws. Venue for any suit, action or proceeding concerning this agreement is to be in the Superior Court of the State of Washington for Spokane County. By this Agreement, the parties confer jurisdiction over the subject matter of and parties to this Agreement to the Superior Court of the State of Washington for Spokane County. The captions of this Agreement are not part of the provisions hereof and shall have no force or effect. This Agreement may not be amended or modified otherwise than by a written agreement executed by the parties hereto or their respective successors and legal representatives.

(b) All notices and other communications hereunder shall be in writing and shall be given by hand delivery to the other party or by registered or certified mail, return receipt requested, postage prepaid, addressed as follows:

If to the Executive:

If to the Company:

Attention: General Counsel

or to such other address as either party shall have furnished to the other in writing in accordance herewith. Notice and communications shall be effective when actually received by the addressee.

(c) The invalidity or unenforceability of any provision of this Agreement shall not affect the validity or enforceability of any other provision of this Agreement.

(d) The Company may withhold from amounts payable under this Agreement such Federal, state, local or foreign taxes as shall be required to be withheld pursuant to any applicable law or regulation.

(e) The Executive's or the Company's failure to insist upon strict compliance with any provision of this Agreement or the failure to assert any right the Executive or the Company may have hereunder, including, without limitation, the right of the Executive to terminate employment for Good Reason pursuant to Section 5(c)(i)-(v) of this Agreement, shall not be deemed to be a waiver of such provision or right or any other provision or right of this Agreement.

(f) The Executive and the Company acknowledge that, except as may otherwise be provided under any other written agreement between the Executive and the Company, the employment of the Executive by the Company is "at will" and, subject to Section 1(a) hereof, prior to the Effective Date, the Executive's employment and/or this Agreement may be terminated by either the Executive or the Company at any time prior to the Effective date, in which case the Executive shall have no further rights under this Agreement. From and after the Effective date this Agreement shall supersede any other agreement between the parties with respect to the subject matter hereof.

IN WITNESS WHEREOF, the Executive has hereunto set the Executive's hand and, pursuant to the authorization from its Board of Directors, the Company has caused these presents to be executed in its name on its behalf, all as of the day and year first above written.

____
[Executive]

AVISTA CORPORATION

By: _______________________________

CHANGE OF CONTROL AGREEMENT

AGREEMENT by and between Washington Water Power, a Washington corporation (the "Company") and ________________________ (the "Executive"), dated as of the _____ day of ____________, 19___.

The Board of Directors of the Company (the "Board"), has determined that it is in the best interests of the Company and its shareholders to assure that the Company will have the continued dedication of the Executive, notwithstanding the possibility, threat or occurrence of a Change of Control (as defined below) of the Company. The Board believes it is imperative to diminish the inevitable distraction of the Executive by virtue of the personal uncertainties and risks created by a pending or threatened Change of Control and to encourage the Executive's full attention and dedication to the Company currently and in the event of any threatened or pending Change of Control, and to provide the Executive with compensation and benefits arrangements upon a Change of Control which ensure that the compensation and benefits expectations of the Executive will be satisfied and which are competitive with those of other corporations. Therefore, in order to accomplish these objectives, the Board has caused the Company to enter into this Agreement.

NOW, THEREFORE, IT IS HEREBY AGREED AS FOLLOWS:

1. Certain Definitions. (a) The "Effective Date" shall mean the first date during the Change of Control Period (as defined in Section 1(b)) on which a Change of Control (as defined in Section 2) occurs. Anything in this Agreement to the contrary notwithstanding, if a Change of Control occurs and if the Executive's employment with the Company is terminated prior to the date on which the Change of Control occurs, and if it is reasonably demonstrated by the Executive that such termination of employment (i) was at the request of a third party who has taken steps reasonably calculated to effect a Change of Control or (ii) otherwise arose in connection with or anticipation of a Change of Control, then for all purposes of this Agreement the "Effective Date" shall mean the date immediately prior to the date of such termination of employment.

(b) The "Change of Control Period" shall mean the period commencing on the date hereof and ending on the third anniversary of the date hereof; provided, however, that commencing on the date one year after the date hereof, and on each annual anniversary of such date (such date and each annual anniversary thereof shall be hereinafter referred to as the "Renewal Date"), unless previously terminated, the Change of Control Period shall be automatically extended so as to terminate three years from such Renewal Date, unless at least 60 days prior to the Renewal Date the Company shall give notice to the Executive that the Change of Control Period shall not be so extended.

2. Change of Control. For the purpose of this Agreement, a "Change of Control" shall mean:

(a) The acquisition by any individual, entity or group (within the meaning of Section 13(d)(3) or 14(d)(2) of the Securities Exchange Act of 1934, as amended (the

"Exchange Act")) (a "Person") of beneficial ownership (within the meaning of Rule 13d-3 promulgated under the Exchange Act) of 20% or more of either (i) the than outstanding shares of common stock of the Company (the "Outstanding Company Common Stock") or (ii) the combined voting power of the then outstanding voting securities of the Company entitled to vote generally in the election of directors (the "Outstanding Company Voting Securities"); provided, however, that for purposes of this subsection (a), the following acquisitions shall not constitute a Change of Control: (i) any acquisition directly from the Company, (ii) any acquisition by the Company, (iii) any acquisition by any employee benefit plan (or related trust) sponsored or maintained by the Company or any corporation controlled by the Company or (iv) any acquisition by any corporation pursuant to a transaction which complies with clauses (i), (ii) and (iii) of subsection (c) of this Section 2; or

(b) Individuals who, as of the date hereof, constitute the Board (the "Incumbent Board") cease for any reason to constitute at least a majority of the Board; provided, however, that any individual becoming a director subsequent to the date hereof whose election, or nomination for election by the Company's shareholders, was approved by a vote of at least a majority of the directors then comprising the Incumbent Board shall be considered as though such individual were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as a result of an actual or threatened election contest with respect to the election or removal of directors or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board; or

(c) Consummation of a reorganization, merger or consolidation or sale or other disposition of all or substantially all of the assets of the Company (a "Business Combination"), in each case, unless, following such Business Combination, (i) all or substantially all of the individuals and entities who were the beneficial owners, respectively, of the Outstanding Company Common Stock and Outstanding Company Voting Securities immediately prior to such Business Combination beneficially own, directly or indirectly, more than 50% of, respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation resulting from such Business Combination (including, without limitation, a corporation which as a result of such transaction owns the Company or all or substantially all of the Company's assets either directly or through one or more subsidiaries) in substantially the same proportions as their ownership, immediately prior to such Business Combination of the outstanding Company Common Stock and Outstanding Company Voting Securities, as the case may be, (ii) no Person (excluding any corporation resulting from such Business Combination or any employee benefit plan (or related trust) of the Company or such corporation resulting from such Business Combination) beneficially owns, directly or indirectly, 20% or more of, respectively, the then outstanding shares of common stock of the corporation resulting from such Business Combination or the combined voting power of the then outstanding voting securities of such corporation except to the extent that such ownership existed prior to the Business Combination and (iii) at least a majority of the members of the board of directors of the corporation resulting from such Business Combination were members of the Incumbent Board at the time of the execution of the initial agreement, or of the action of the Board, providing for such Business Combination; or

(d) Approval by the shareholders of the Company of a complete liquidation or dissolution of the Company.

3. Employment Period. The Company hereby agrees to continue the Executive in its employ, and the Executive hereby agrees to remain in the employ of the Company subject to the terms and conditions of this Agreement, for the period commencing on the Effective Date and ending on the third anniversary of such date (the "Employment Period").

4. Terms of Employment. (a) Position and Duties. (i) During the Employment Period, (A) the Executive's position (including status, offices, titles and reporting requirements), authority, duties and responsibilities shall be at least commensurate in all material respects with the most significant of those held, exercised and assigned at any time during the 120-day period immediately preceding the Effective Date and (B) the Executive's services shall be performed at the location where the Executive was employed immediately preceding the Effective Date or any office or location less than 35 miles from such location.

(ii) During the Employment Period, and excluding any periods of vacation and sick leave to which the Executive is entitled, the Executive agrees to devote reasonable attention and time during normal business hours to the business and affairs of the Company and, to the extent necessary to discharge the responsibilities assigned to the Executive hereunder, to use the Executive's reasonable best efforts to perform faithfully and efficiently such responsibilities. During the Employment Period it shall not be a violation of this Agreement for the Executive to (A) serve on corporate, civic or charitable boards or committees, (B) deliver lectures, fulfill speaking engagements or teach at educational institutions and (C) manage personal investments, so long as such activities do not significantly interfere with the performance of the Executive's responsibilities as an employee of the Company in accordance with this Agreement. It is expressly understood and agreed that to the extent that any such activities have been conducted by the Executive prior to the Effective Date, the continued conduct of such activities (or the conduct of activities similar in nature and scope thereto) subsequent to the Effective Date shall not thereafter be deemed to interfere with the performance of the Executive's responsibilities to the Company.

(b) Compensation. (i) Base Salary. During the Employment Period, the Executive shall receive an annual base salary ("Annual Base Salary"), which shall be paid at a monthly rate, at least equal to twelve times the highest monthly base salary paid or payable, including any base salary which has been earned but deferred, to the Executive by the Company and its affiliated companies in respect of the twelve-month period immediately preceding the month in which the Effective Date occurs. During the Employment Period, the Annual Base Salary shall be reviewed no more than 12 months after the last salary increase awarded to the Executive prior to the Effective Date and thereafter at least annually. Any increase in Annual Base Salary shall not serve to limit or reduce any other obligation to the Executive under this Agreement. Annual Base Salary shall not be reduced after any such increase and the term Annual Base Salary as utilized in this Agreement shall refer to Annual Base Salary as so increased. As used in this Agreement, the term "affiliated companies" shall include any company controlled by, controlling or under common control with the Company.

(ii) Annual Bonus. In addition to Annual Base Salary, the Executive shall be awarded, for each fiscal year ending during the Employment Period, an annual bonus (the "Annual Bonus") in cash at least equal to the Executive's highest bonus under the Company's [Annual Incentive Plans], or any comparable bonus under any predecessor or successor plan, for the last three full fiscal years prior to the Effective Date (annualized in the event that the Executive was not employed by the Company for the whole of such fiscal year) (the "Recent Annual Bonus"). Each such Annual Bonus shall be paid no later than the end of the third month of the fiscal year next following the fiscal year for which the Annual Bonus is awarded, unless the Executive shall elect to defer the receipt of such Annual Bonus.

(iii) Incentive, Savings and Retirement Plans. During the Employment Period, the Executive shall be entitled to participate in all incentive, savings and retirement plans, practices, policies and programs applicable generally to other peer executives of the Company and its affiliated companies, but in no event shall such plans, practices, policies and programs provide the Executive with incentive opportunities (measured with respect to both regular and special incentive opportunities, to the extent, if any, that such distinction is applicable), savings opportunities and retirement benefit opportunities, in each case, less favorable, in the aggregate, than the most favorable of those provided by the Company and its affiliated companies for the Executive under such plans, practices, policies and programs as in effect at any time during the 120-day period immediately preceding the Effective Date or if more favorable to the Executive, those provided generally at any time after the Effective Date to other peer executives of the Company and its affiliated companies.

(iv) Welfare Benefit Plans. During the Employment Period, the Executive and/or the Executive's family, as the case may be, shall be eligible for participation in and shall receive all benefits under welfare benefit plans, practices, policies and programs provided by the Company and its affiliated companies (including, without limitation, medical, prescription, dental, disability, employee life, group life, accidental death and travel accident insurance plans and programs) to the extent applicable generally to other peer executives of the Company and its affiliated companies, but in no event shall such plans, practices, policies and programs provide the Executive with benefits which are less favorable, in the aggregate, than the most favorable of such plans, practices, policies and programs in effect for the Executive at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive, those provided generally at any time after the Effective Date to other peer executives of the Company and its affiliated companies.

(v) Expenses. During the Employment Period, the Executive shall be entitled to receive prompt reimbursement for all reasonable expenses incurred by the Executive in accordance with the most favorable policies, practices and procedures of the Company and its affiliated companies in effect for the Executive at any time during the 120-

day period immediately preceding the Effective Date or, if more favorable to the Executive, as in effect generally at any time thereafter with respect to other peer executives of the Company and its affiliated companies.

(vi) Fringe Benefits. During the Employment Period, the Executive shall be entitled to fringe benefits, including, without limitation, tax and financial planning services, payment of club dues, and, if applicable, use of an automobile and payment of related expenses, in accordance with the most favorable plans, practices, programs and policies of the Company and its affiliated companies in effect for the Executive at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive, as in effect generally at any time thereafter with respect to other peer executives of the Company and its affiliated companies.

(vii) Office and Support Staff. During the Employment Period, the Executive shall be entitled to an office or offices of a size and with furnishings and other appointments, and to exclusive personal secretarial and other assistance, at least equal to the most favorable of the foregoing provided to the Executive by the Company and its affiliated companies at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive, as provided generally at any time thereafter with respect to other peer executives of the Company and its affiliated companies.

(viii) Vacation. During the Employment Period, the Executive shall be entitled to paid vacation in accordance with the most favorable plans, policies, programs and practices of the Company and its affiliated companies as in effect for the Executive at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive, as in effect generally at any time thereafter with respect to other peer executives of the Company and its affiliated companies.

5. Termination of Employment. (a) Death or Disability. The Executive's employment shall terminate automatically upon the Executive's death during the Employment Period. If the Company determines in good faith that the Disability of the Executive has occurred during the Employment Period (pursuant to the definition of Disability set forth below), it may give to the Executive written notice in accordance with Section 12(b) of this Agreement of its intention to terminate the Executive's employment. In such event, the Executive's employment with the Company shall terminate effective on the 30th day after receipt of such notice by the Executive (the "Disability Effective Date"), provided that, within the 30 days after such receipt, the Executive shall not have returned to full-time performance of the Executive's duties. For purposes of this Agreement, "Disability" shall mean the absence of the Executive from the Executive's duties with the Company on a full-time basis for 180 consecutive business days as a result of incapacity due to mental or physical illness which is determined to be total and permanent by a physician selected by the Company or its insurers and acceptable to the Executive or the Executive's legal representative.

(b) Cause. The Company may terminate the Executive's employment during the Employment Period for Cause. For purposes of this Agreement, "Cause" shall mean:

(i) the willful and continued failure of the Executive to perform substantially the Executive's duties with the Company or one of its affiliates (other than any such failure resulting from incapacity due to physical or mental illness), after a written demand for substantial performance is delivered to the Executive by the Board or the Chief Executive Officer of the Company which specifically identifies the manner in which the Board or Chief Executive Officer believes that the Executive has not substantially performed the Executive's duties, or

(ii) the willful engaging by the Executive in illegal conduct or gross misconduct which is materially and demonstrably injurious to the Company.

For purposes of this provision, no act or failure to act, on the part of the Executive, shall be considered "willful" unless it is done, or omitted to be done, by the Executive in bad faith or without reasonable belief that the Executive's action or omission was in the best interests of the Company. Any act, or failure to act, based upon authority given pursuant to a resolution duly adopted by the Board or upon the instructions of the Chief Executive Officer or a senior officer of the Company or based upon the advice of counsel for the Company shall be conclusively presumed to be done, or omitted to be done, by the Executive in good faith and in the best interests of the Company. The cessation of employment of the Executive shall not be deemed to be for Cause unless and until there shall have been delivered to the Executive a copy of a resolution duly adopted by the affirmative vote of not less than three-quarters of the entire membership of the Board at a meeting of the Board called and held for such purpose (after reasonable notice is provided to the Executive and the Executive is given an opportunity, together with counsel, to be heard before the Board), finding that, in the good faith opinion of the Board, the Executive is guilty of the conduct described in subparagraph (i) or (ii) above, and specifying the particulars thereof in detail.

(c) Good Reason. The Executive's employment may be terminated by the Executive for Good Reason. For purposes of this Agreement, "Good Reason" shall mean:

(i) the assignment to the Executive of any duties inconsistent in any respect with the Executive's position (including status, offices, titles and reporting requirements), authority, duties or responsibilities as contemplated by Section 4(a) of this Agreement, or any other action by the Company which results in a diminution in such position, authority, duties or responsibilities, excluding for this purpose an isolated, insubstantial and inadvertent action not taken in bad faith and which is remedied by the Company promptly after receipt of notice thereof given by the Executive;

(ii) any failure by the Company to comply with any of the provisions of Section 4(b) of this Agreement, other than an isolated, insubstantial and inadvertent failure not occurring in bad faith and which is remedied by the Company promptly after receipt of notice thereof given by the Executive;

(iii) the Company's requiring the Executive to be based at any office or location other than as provided in Section 4(a)(i)(B) hereof or the Company's requiring the Executive to travel on Company business to a substantially greater extent than required immediately prior to the Effective Date

(iv) any purported termination by the Company of the Executive's employment otherwise than as expressly permitted by this Agreement; or

(v) any failure by the Company to comply with and satisfy Section 11(c) of this Agreement.

For purposes of this Section 5(c), any good faith determination of "Good Reason" made by the Executive shall be conclusive. Anything in this Agreement to the contrary notwithstanding, a termination by the Executive for any reason during the 30-day period immediately following the first anniversary of the Effective Date shall be deemed to be a termination for Good Reason for all purposes of this Agreement.

(d) Notice of Termination. Any termination by the Company for Cause, or by the Executive for Good Reason, shall be communicated by Notice of Termination to the other party hereto given in accordance with Section 12(b) of this Agreement. For purposes of this Agreement, a "Notice of Termination" means a written notice which (i) indicates the specific termination provision in this Agreement relied upon, (ii) to the extent applicable, sets forth in reasonable detail the facts and circumstances claimed to provide a basis for termination of the Executive's employment under the provision so indicated and (iii) if the Date of Termination (as defined below) is other than the date of receipt of such notice, specifies the termination date (which date shall be not more than thirty days after the giving of such notice). The failure by the Executive or the Company to set forth in the Notice of Termination any fact or circumstance which contributes to a showing of Good Reason or Cause shall not waive any right of the Executive or the Company, respectively, hereunder or preclude the Executive or the Company, respectively, from asserting such fact or circumstance in enforcing the Executive's or the Company's rights hereunder.

(e) Date of Termination. "Date of Termination" means (i) if the Executive's employment is terminated by the Company for Cause, or by the Executive for Good Reason, the date of receipt of the Notice of Termination or any later date specified therein, as the case may be, (ii) if the Executive's employment is terminated by the Company other than for Cause or Disability, the Date of Termination shall be the date on which the Company notifies the Executive of such termination and (iii) if the Executive's employment is terminated by reason of death or Disability, the Date of Termination shall be the date of death of the Executive or the Disability Effective Date, as the case may be.

6. Obligations of the Company upon Termination. (a) Good Reason; Other Than for Cause, Death or Disability. If, during the Employment Period, the Company shall terminate the Executive's employment other than for Cause or Disability or the Executive shall terminate employment for Good Reason:

(i) the Company shall pay to the Executive in a lump sum in cash within 30 days after the Date of Termination the aggregate of the following amounts:

A. the sum of (1) the Executive's Annual Base Salary through the Date of Termination to the extent not theretofore paid, (2) the product of (x) the higher of (I) the Recent Annual Bonus and (II) the Annual Bonus paid or payable, including any bonus or portion thereof which has been earned but deferred (and annualized for any fiscal year consisting of less than twelve full months or during which the Executive was employed for less than twelve full months), for the most recently completed fiscal year during the Employment Period, if any (such higher amount being referred to as the "Highest-Annual Bonus") and (y) a fraction, the numerator of which is the number of days in the current fiscal year through the Date of Termination, and the denominator of which is 365 and (3) any compensation previously deferred by the Executive (together with any accrued interest or earnings thereon) and any accrued vacation pay, in each case to the extent not theretofore paid (the sum of the amounts described in clauses (1),(2), and (3) shall be hereinafter referred to as the "Accrued Obligations"); and

B. the amount equal to the product of (1) three and (2) the sum of (x) the Executive's Annual Base Salary and (y) the Highest Annual Bonus; and

C. an amount equal to the excess of (a) the actuarial equivalent of the benefit under the Company's qualified defined benefit retirement plan (the "Retirement Plan") (utilizing actuarial assumptions no less favorable to the Executive than those in effect under the Company's Retirement Plan immediately prior to the Effective Date), and any excess or supplemental retirement plan in which the Executive participates (together, the "SERP") which the Executive would receive if the Executive's employment continued for three years after the Date of Termination assuming for this purpose that all accrued benefits are fully vested, and, assuming that the Executive's compensation in each of the three years is that required by Section 4(b)(i) and Section 4(b)(ii), over (b) the actuarial equivalent of the Executive's actual benefit (paid or payable), if any, under the Retirement Plan and the SERP as of the Date of Termination;

(ii) for three years after the Executive's Date of Termination, or such longer period as may be provided by the terms of the appropriate plan, program, practice or policy, the Company shall continue benefits to the Executive and/or the Executive's family at least equal to those which would have been provided to them in accordance with the plans, programs, practices and policies described in Section 4(b)(iv) of this Agreement if the Executive's employment had not been terminated or, if more favorable to the Executive, as in effect generally at any time thereafter with respect to other peer executives of the Company and its affiliated companies and their families, provided, however, that if the Executive becomes reemployed with another employer and is eligible to receive medical or other welfare benefits under another employer provided plan, the medical and other welfare benefits described herein shall be secondary to those provided under such other plan during such applicable period of eligibility. For purposes of determining eligibility (but not the time of commencement of benefits) of the Executive for retiree benefits pursuant to such plans, practices, programs and policies, the Executive shall be considered to have remained employed until three years after the Date of Termination and to have retired on the last day of such period;

(iii) the Company shall, at its sole expense as incurred, provide the Executive with outplacement services the scope and provider of which shall be selected by the Executive in his sole discretion; and

(iv) to the extent not theretofore paid or provided, the Company shall timely pay or provide to the Executive any other amounts or benefits required to be paid or provided or which the Executive is eligible to receive under any plan, program, policy or practice or contract or agreement of the Company and its affiliated companies (such other amounts and benefits shall be hereinafter referred to as the "Other Benefits").

(b) Death. If the Executive's employment is terminated by reason of the Executive's death during the Employment Period, this Agreement shall terminate without further obligations to the Executive's legal representatives under this Agreement, other than for payment of Accrued Obligations and the timely payment or provision of Other Benefits. Accrued Obligations shall be paid to the Executive's estate or beneficiary, as applicable, in a lump sum in cash within 30 days of the Date of Termination. With respect to the provision of Other Benefits, the term Other Benefits as utilized in this Section 6(b) shall include, without limitation, and the Executive's estate and/or beneficiaries shall be entitled to receive, benefits at least equal to the most favorable benefits provided by the Company and affiliated companies to the estates and beneficiaries of peer executives of the Company and such affiliated companies under such plans, programs, practices and policies relating to death benefits, if any, as in effect with respect to other peer executives and their beneficiaries at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive's estate and/or the Executive's beneficiaries, as in effect on the date of the Executive's death with respect to other peer executives of the Company and its affiliated companies and their beneficiaries.

(c) Disability. If the Executive's employment is terminated by reason of the Executive's Disability during the Employment Period, this Agreement shall terminate without further obligations to the Executive, other than for payment of Accrued Obligations and the timely payment or provision of Other Benefits. Accrued Obligations shall be paid to the Executive in a lump sum in cash within 30 days of the Date of Termination. With respect to the provision of Other Benefits, the term Other Benefits as utilized in this Section 6(c) shall include, and the Executive shall be entitled after the Disability Effective Date to receive, disability and other benefits at least equal to the most favorable of those generally provided by the Company and its affiliated companies to disabled executives and/or their families in accordance with such plans, programs, practices and policies relating to disability, if any, as in effect generally with respect to other peer executives and their families at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive and/or the Executive's family, as in effect at any time thereafter generally with respect to other peer executives of the Company and its affiliated companies and their families.

(d) Cause; Other than for Good Reason. If the Executive's employment shall be terminated for Cause during the Employment Period, this Agreement shall terminate without further obligations to the Executive other than the obligation to pay to the Executive (x) his Annual Base Salary through the Date of Termination, (y) the amount of any compensation previously deferred by the Executive, and (z) Other Benefits, in each case to the extent theretofore unpaid. If the Executive voluntarily terminates employment during the Employment Period, excluding a termination for Good Reason, this Agreement shall terminate without further obligations to the Executive, other than for Accrued obligations and the timely payment or provision of Other Benefits. In such case, all Accrued Obligations shall be paid to the Executive in a lump sum in cash within 30 days of the Date of Termination.

7. Non-exclusivity of Rights. Nothing in this Agreement shall prevent or limit the Executive's continuing or future participation in any plan, program, policy or practice provided by the Company or any of its affiliated companies and for which the Executive may qualify, nor, subject to Section 12(f), shall anything herein limit or otherwise affect such rights as the Executive may have under any contract or agreement with the Company or any of its affiliated companies. Amounts which are vested benefits or which the Executive is otherwise entitled to receive under any plan, policy, practice or program of or any contract or agreement with the company or any of its affiliated companies at or subsequent to the Date of Termination shall be payable in accordance with such plan, policy, practice or program or contract or agreement except as explicitly modified by this Agreement.

8. Full Settlement. The Company's obligation to make the payments provided for in this Agreement and otherwise to perform its obligations hereunder shall not be affected by any set-off, counterclaim, recoupment, defense or other claim, right or action which the Company may have against the Executive or others. In no event shall the Executive be obligated to seek other employment or take any other action by way of mitigation of the amounts payable to the Executive under any of the provisions of this Agreement and such amounts shall not be reduced whether or not the Executive obtains other employment. The Company agrees to pay as incurred, to the full extent permitted by law, all legal fees and expenses which the Executive may reasonably incur as a result of any contest (regardless of the outcome thereof) by the Company, the Executive or others of the validity or enforceability of, or liability under, any provision of this Agreement or any guarantee of performance thereof (including as a result of any contest by the Executive about the amount of any payment pursuant to this Agreement), plus in each case interest on any delayed

payment at the applicable Federal rate provided for in Section 7872(f)(2)(A) of the Internal Revenue Code of 1986, as amended (the "Code").

9. Certain Additional Payments by the Company.

(a) Anything in this Agreement to the contrary notwithstanding and except as set forth below, in the event it shall be determined that any payment or distribution by the Company to or for the benefit of the Executive (whether paid or payable or distributed or distributable pursuant to the terms of this Agreement or otherwise, but determined without regard to any additional payments required under this Section 9) (a "Payment") would be subject to the excise tax imposed by Section 4999 of the Code or any interest or penalties are incurred by the Executive with respect to such excise tax (such excise tax, together with any such interest and penalties, are hereinafter collectively referred to as the "Excise Tax"), then the Executive shall be entitled to receive an additional payment (a "Gross-Up Payment") in an amount such that after payment by the Executive of all taxes (including any interest or penalties imposed with respect to such taxes), including, without limitation, any income taxes (and any interest and penalties imposed with respect thereto) and Excise Tax imposed upon the Gross-Up Payment, the Executive retains an amount of the Gross-Up Payment equal to the Excise Tax imposed upon the Payments. Notwithstanding the foregoing provisions of this Section 9(a), if it shall be determined that the Executive is entitled to a Gross-Up Payment, but that the Payments do not exceed 110% of the greatest amount (the "Reduced Amount") that could be paid to the Executive such that the receipt of Payments would not give rise to any Excise Tax, then no Gross-Up Payment shall be made to the Executive and the Payments, in the aggregate, shall be reduced to the Reduced Amount.

(b) Subject to the provisions of Section 9(c), all determinations required to be made under this Section 9, including whether and when a Gross-Up Payment is required and the amount of such Gross-Up Payment and the assumptions to be utilized in arriving at such determination, shall be made by Deloitte and Touche or such other certified public accounting firm as may be designated by the Executive (the "Accounting Firm") which shall provide detailed supporting calculations both to the Company and the Executive within 15 business days of the receipt of notice from the Executive that there has been a Payment, or such earlier time as is requested by the Company. In the event that the Accounting Firm is serving as accountant or auditor for the individual, entity or group effecting the Change or Control, the Executive shall appoint another nationally recognized accounting firm to make the determinations required hereunder (which accounting firm shall then be referred to as the Accounting Firm hereunder). All fees and expenses of the Accounting Firm shall be borne solely by the Company. Any Gross-Up Payment, as determined pursuant to this Section 9, shall be paid by the Company to the Executive within five days of the receipt of the Accounting Firm's determination. Any determination by the Accounting Firm shall be binding upon the Company and the Executive. As a result of the uncertainty in the application of Section 4999 of the Code at the time of the initial determination by the Accounting Firm hereunder, it is possible that Gross-Up Payments which will not have been made by the Company should have been made ("Underpayment"), consistent with the calculations required to be made hereunder. In the event that the Company exhausts its remedies pursuant to Section 9(c) and the Executive thereafter is required to make a payment of any Excise Tax, the Accounting Firm shall determine the amount of the Underpayment that has occurred and any such Underpayment shall be promptly paid by the Company to or for the benefit of the Executive.

(c) The Executive shall notify the Company in writing of any claim by the Internal Revenue Service that, if successful, would require the payment by the Company of the Gross-Up Payment. Such notification shall be given as soon as practicable but no later than ten business days after the Executive is informed in writing of such claim and shall apprise the Company of the nature of such claim and the date on which such claim is requested to be paid. The Executive shall not pay such claim prior to the expiration of the 30-day period following the date on which it gives such notice to the Company (or such shorter period ending on the date that any payment of taxes with respect to such claim is due). If the Company notifies the Executive in writing prior to the expiration of such period that it desires to contest such claim, the Executive shall:

(i) give the Company any information reasonably requested by the Company relating to such claim,

(ii) take such action in connection with contesting such claim as the Company shall reasonably request in writing from time to time, including, without limitation, accepting legal representation with respect to such claim by an attorney reasonably selected by the Company,

(iii) cooperate with the Company in good faith in order to effectively contest such claim, and

(iv) permit the Company to participate in any proceedings relating to such claim;

provided, however, that the Company shall bear and pay directly all costs and expenses (including additional interest and penalties) incurred in connection with such contest and shall indemnify and hold the Executive harmless, on an after tax basis, for any Excise Tax or income tax (including interest and penalties with respect thereto) imposed as a result of such representation and payment of costs and expenses. Without limitation on the foregoing provisions of this Section 9(c), the Company shall control all proceedings taken in connection with such contest and, at its sole option, may pursue or forgo any and all administrative appeals, proceedings, hearings and conferences with the taxing authority in respect of such claim and may, at its sole option, either direct the Executive to pay the tax claimed and sue for a refund or contest the claim in any permissible manner, and the Executive agrees to prosecute such contest to a determination before any administrative tribunal, in a court of initial jurisdiction and in one or more appellate courts, as the Company shall determine; provided, however, that if the Company directs the Executive to pay such claim and sue for a refund, the Company shall advance the amount of such payment to the Executive, on an interest-free basis and shall indemnify and hold the Executive harmless, on an after-tax basis, from any Excise Tax or income tax (including interest or penalties with respect thereto) imposed with respect to such advance or with respect to any imputed income with respect to such advance; and further provided that any extension of the statute of limitations relating to payment of taxes for the taxable year of the Executive with respect to which such contested amount is claimed to be due is limited solely to such contested amount. Furthermore, the Company's control of the contest shall be limited to issues with respect to which a Gross-Up Payment would be payable hereunder and the Executive shall be entitled to settle or contest, as the case may be, any other issue raised by the Internal Revenue Service or any other taxing authority.

(d) If, after the receipt by the Executive of an amount advanced by the Company pursuant to Section 9(c), the Executive becomes entitled to receive any refund with respect to such claim, the Executive shall (subject to the Company's complying with the requirements of Section 9(c)) promptly pay to the Company the amount of such refund (together with any interest paid or credited thereon after taxes applicable thereto). If, after the receipt by the Executive of an amount advanced by the Company pursuant to Section 9(c), a determination is made that the Executive shall not be entitled to any refund with respect to such claim and the Company does not notify the Executive in writing of its intent to contest such denial of refund prior to the expiration of 30 days after such determination, then such advance shall be forgiven and shall not be required to be repaid and the amount of such advance shall offset, to the extent thereof, the amount of Gross-Up Payment required to be paid.

10. Confidential Information. The Executive shall hold in a fiduciary capacity for the benefit of the Company all secret or confidential information, knowledge or data relating to the Company or any of its affiliated companies, and their respective businesses, which shall have been obtained by the Executive during the Executive's employment by the Company or any of its affiliated companies and which shall not be or become public knowledge (other than by acts by the Executive or representatives of the Executive in violation of this Agreement). After termination of the Executive's employment with the Company, the Executive shall not, without the prior written consent of the Company or as may otherwise be required by law or legal process, communicate or divulge any such information, knowledge or data to anyone other than the Company and those designated by it. In no event shall an asserted violation of the provisions of this Section 10 constitute a basis for deferring or withholding any amounts otherwise payable to the Executive under this Agreement.

11. Successors. (a) This Agreement is personal to the Executive and without the prior written consent of the Company shall not be assignable by the Executive otherwise than by will or the laws of descent and distribution. This Agreement shall inure to the benefit of and be enforceable by the Executive's legal representatives.

(b) This Agreement shall inure to the benefit of and be binding upon the Company and its successors and assigns.

(c) The Company will require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business and/or assets of the Company to assume expressly and agree to perform this Agreement in the same manner and to the same extent that the Company would be required to perform it if no such succession had taken place. As used in this Agreement, "Company" shall mean the Company as hereinbefore defined and any successor to its business and/or assets as aforesaid which assumes and agrees to perform this Agreement by operation of law, or otherwise.

12. Miscellaneous. (a) This Agreement shall be governed by and construed in accordance with the laws of the State of Washington, without reference to principles of conflict of laws. The captions of this Agreement are not part of the provisions hereof and shall have no force or effect. This Agreement may not be amended or modified otherwise than by a written agreement executed by the parties hereto or their respective successors and legal representatives.

(b) All notices and other communications hereunder shall be in writing and shall be given by hand delivery to the other party or by registered or certified mail, return receipt requested, postage prepaid, addressed as follows:

If to the Executive:

If to the Company:

Attention: General Counsel

or to such other address as either party shall have furnished to the other in writing in accordance herewith. Notice and communications shall be effective when actually received by the addressee.

(c) The invalidity or unenforceability of any provision of this Agreement shall not affect the validity or enforceability of any other provision of this Agreement.

(d) The Company may withhold from any amounts payable under this Agreement such Federal, state, local or foreign taxes as shall be required to be withheld pursuant to any applicable law or regulation.

(e) The Executive's or the Company's failure to insist upon strict compliance with any provision of this Agreement or the failure to assert any right the Executive or the Company may have hereunder, including, without limitation, the right of the Executive to terminate employment for Good Reason pursuant to Section 5(c)(i)-(v) of this Agreement, shall not be deemed to be a waiver of such provision or right or any other provision or right of this Agreement.

(f) The Executive and the Company acknowledge that, except as may otherwise be provided under any other written agreement between the Executive and the Company, the employment of the Executive by the Company is "at will" and, subject to Section 1(a) hereof, prior to the Effective Date, the Executive's employment and/or this Agreement may be terminated by either the Executive or the Company at any time prior to the Effective Date, in which case the Executive shall have no further rights under this Agreement. From and after the Effective Date this Agreement shall supersede any other agreement between the parties with respect to the subject matter hereof.

IN WITNESS WHEREOF, the Executive has hereunto set the Executive's hand and, pursuant to the authorization from its Board of Directors, the Company has caused these presents to be executed in its name on its behalf, all as of the day and year first above written.

[Executive]

WASHINGTON WATER POWER

By_________________________________

EXHIBIT 12

AVISTA CORPORATION

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

	Years Ended December 31				
	2002	2001	2000	1999	1998
Fixed charges, as defined:					
Interest expense	$96,475	$100,841	$64,846	$61,703	$66,158
Amortization of debt expense and premium - net	8,861	5,639	3,409	3,044	2,859
Interest portion of rentals	6,140	5,140	4,324	4,645	4,301
Total fixed charges	$111,476	$111,620	$72,579	$69,392	$73,318
Earnings, as defined:					
Income from continuing operations	$34,310	$59,605	$101,055	$28,662	$78,316
Add (deduct):					
Income tax expense	29,994	34,386	76,998	16,897	43,430
Total fixed charges above	111,476	111,620	72,579	69,392	73,318
Total earnings	$175,780	$205,611	$250,632	$114,951	$195,064
Ratio of earnings to fixed charges	1.58	1.84	3.45	1.66	2.66
Fixed charges and preferred dividend requirements:					
Fixed charges above	$111,476	$111,620	$72,579	$69,392	$73,318
Preferred dividend requirements (1)	4,502	3,835	41,820	34,003	13,057
Total	$115,978	$115,455	$114,399	$103,395	$86,375
Ratio of earnings to fixed charges and preferred dividend requirements	1.52	1.78	2.19	1.11	2.26

(1) Preferred dividend requirements have been grossed up to their pre-tax level.

Exhibit 21

Avista Corporation

SUBSIDIARIES OF REGISTRANT

Subsidiary	State or Country of Incorporation
Avista Capital, Inc.	Washington
Avista Advantage, Inc.	Washington
Avista Communications, Inc.	Washington
Avista Development, Inc.	Washington
Avista Energy, Inc.	Washington
Avista Energy Canada LTD	Canada
Copac Management, Inc.	Canada
Avista Laboratories, Inc.	Washington
H2Fuel, LLC	Washington
Avista Power, LLC	Washington
Avista Services, Inc.	Washington
Avista Turbine Power, Inc.	Washington
Avista Rathdrum, LLC	Washington
Coyote Springs 2, LLC	Delaware
Rathdrum Power, LLC	Idaho
Avista Ventures, Inc.	Washington
Pentzer Corporation	Washington
Pentzer Venture Holdings II, Inc.	Washington
Bay Area Manufacturing, Inc.	Washington
Advanced Manufacturing and Development, Inc.	California
Avista Receivables Corporation	Washington
Spokane Energy, LLC	Delaware

Exhibit 99(a)

AVISTA CORPORATION

CERTIFICATION OF CORPORATE OFFICERS
(Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)

Each of the undersigned, Gary G. Ely, Chairman of the Board, President and Chief Executive Officer of Avista Corporation (the "Company"), and Malyn K. Malquist, Senior Vice President and Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Company's Annual Report on Form 10-K for the year ended December 31, 2002 fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Company.

March 14, 2003

/s/ Gary G. Ely

Gary G. Ely
Chairman of the Board, President and
Chief Executive Officer

/s/ Malyn K. Malquist

Malyn K. Malquist
Senior Vice President and
Chief Financial officer