BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Application of PACIFICORP for an Order Approving the Sale of its Interest in the Skookumchuck Hydroelectric Plant and for EWG Determinations	Docket No. _________ **APPLICATION**

February 2004

Application

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Application of PACIFICORP for an Order Approving the Sale of its Interest in the Skookumchuck Hydroelectric Plant and for EWG Determinations	Docket No. _________ **APPLICATION**

PacifiCorp ("PacifiCorp" or "Company") files this Application for (a) an order approving the proposed sale and transfer of PacifiCorp's interest in the Skookumchuck dam, hydroelectric facility and related assets (the "Skookumchuck Project" or "Project") to 2677588 Washington LLC ("Washington LLC"), a limited liability company formed by TransAlta USA Inc.("TransAlta"), and (b) certain public interest findings required in order for Washington LLC to qualify as an exempt wholesale generator ("EWG") under section 32 of the Public Utility Holding Company Act of 1935 ("PUHCA"). The provisions of RCW 80.12.020 and WAC 480-143-120 and –140 require the approval of the Washington Utilities and Transportation Commission ("WUTC" or "Commission") for any transaction to sell or otherwise dispose of public service company property necessary or useful in the performance of the public service company's duties to the public.

I. INTRODUCTION

A. The Parties

1. The Applicant: PacifiCorp

PacifiCorp is a public service company within the meaning of RCW 80.12.020 and serves approximately 1.5 million retail customers in six western states. In Washington, the Company provides electric service to approximately 120,000 customers in Columbia, Garfield, Kittitas, Walla Walla and Yakima counties. The full and correct name and business address for PacifiCorp are as follows:

PacifiCorp
825 NE Multnomah Boulevard
Portland, OR 97232

PacifiCorp requests that all notices, correspondence and pleadings with respect to this Application be sent to:

For PacifiCorp:	With a copy to:
Christy Omohundro Managing Director of Regulatory Policy PacifiCorp 825 NE Multnomah Blvd., Suite 800 Portland, OR 97232 Telephone: (503) 813-6092 Facsimile: (503) 813-6060 christy.omohundro@pacificorp.com	James F. Fell James C. Paine Stoel Rives LLP 900 SW Fifth Avenue, Suite 2600 Portland, OR 97204 Telephone: (503) 294-9343 Facsimile: (503) 220-2480 jffell@stoel.com / jcpaine@stoel.com

Please also send electronic copies of data requests to datarequest@pacificorp.com.

2. The Owners

The current owners of the Project are: PacifiCorp; Public Utility District No. 1 of Snohomish County, Washington; Puget Sound Energy, Inc.; City of Tacoma, Washington; Avista Corporation; City of Seattle, Washington; and Public Utility District No. 1 of Grays Harbor County, Washington (collectively, the "Owners").

3. The Purchaser

Washington LLC is a Washington limited liability company and a direct wholly-owned subsidiary of TransAlta. TransAlta is the indirect owner of the Centralia Power Plant and the Centralia Coal Mine. In 2000, the Owners sold the Centralia Power Plant to a direct wholly-owned subsidiary of TransAlta, TECWA Power Inc., and PacifiCorp sold the Centralia Coal Mine to another direct wholly-owned subsidiary of TransAlta, TECWA Fuel Inc. TECWA Power Inc. owns and operates the Centralia Power Plant as an EWG.

B. The Project

The Skookumchuck Project is an earth-fill dam and hydroelectric generating plant located in the vicinity of Centralia, Washington on property adjacent to the Centralia Power

Plant. The Skookumchuck dam was constructed in 1973 as a water storage facility for the Centralia Power Plant. In 1991, a generating plant with a capacity of approximately one megawatt was constructed at the dam. The Project includes real property and associated easements and water rights, as well as various equipment. The Project was granted an exemption from licensing as a hydropower facility by the Federal Energy Regulatory Commission ("FERC") pursuant to 16 U.S.C. §2705(d), which allows exemptions for facilities less than 5 MW. The Project is, however, subject to dam safety regulation by the FERC.

A more specific description of the facilities, real estate, water rights and other property to be transferred is contained in Schedules 2.1(a) through 2.1(e) of the Sale Agreement (hereinafter defined).

Application Exhibit No. 1 sets forth PacifiCorp's Original Cost, Accumulated Depreciation and Net Book Value of the Assets to be Transferred of the Skookumchuck Project as well as Proposed Entries to Record the Sale.

II. PROPOSED TRANSACTION

PacifiCorp proposes to sell and transfer to Washington LLC the dam, powerhouse, water rights, land, easements and other assets of the Project, including certain fixtures, contracts and other rights. The sale and transfer of the Project is governed by the Skookumchuck Facilities Purchase and Sale Agreement between the Owners and Washington LLC, dated November 25, 2003 (the "Sale Agreement"), which is attached as Exhibit ___ (RAL-2) to the testimony of Randy A. Landolt.

The aggregate sale price of the transaction is approximately $7.57 million, adjusted for changes in PacifiCorp's Net Book Value of the Facilities from September 30, 2003 to the Closing Date. See Section 2.3(a) of the Sale Agreement. PacifiCorp's share of this amount is 47.5 percent. The sale price is determined in such a manner that PacifiCorp will receive its net book value of the assets being transferred, with no appreciable gain or loss. Payment will be made by wire transfer at closing. The actual gain will not be definitively known until the closing of the transaction. Should an appreciable gain or loss occur, PacifiCorp proposes that the net gain be added to (or the net loss be subtracted from) the Company's Centralia Steam Plant and Mine sale credit, reflected in PacifiCorp's tariff Schedule 97. *See*, Section 4, Appendix B, Comprehensive Settlement, Third Supplemental Order Approving and Adopting Settlement Agreement: Rejecting Tariff Sheets; Authorizing and Requiring Compliance Filing in Docket No. UE-991832.

The proposed transaction will be carried out in the following manner. At the Closing, the Owners will transfer the Project assets into a Washington limited liability company ("LLC") that the Owners will form specifically for the special purpose of completing this transaction. The Owners will simultaneously transfer their member interests in the LLC to Washington LLC. As a result, all of the Project assets will be owned by an indirect wholly owned subsidiary of TransAlta, and TransAlta will have complete control of the Project assets.

PacifiCorp is informed that Washington LLC will continue operation of the Project to provide cooling water supply to the Centralia Power Plant, and that it will produce power from the Project either as an EWG or as a qualifying facility under the Public Utility Regulatory Policies Act of 1978. None of the electrical output of the Project will be used to serve PacifiCorp's retail customers, except perhaps indirectly, through the wholesale power markets.

III. JURISDICTION AND AUTHORITY

A. Transfer of Utility Property

A public service company must receive Commission approval for any transaction to sell property that is necessary or useful in the company's performance of its duties to the public. Specifically, RCW 80.12.020 provides:

> No public service company shall sell, lease assign or otherwise dispose of the whole or any part of its franchises, properties or facilities whatsoever, which are necessary or useful in the performance of its duties to the public, and no public service company shall, by any means whatsoever, directly or indirectly, merge or consolidate any of its franchises, properties or facilities

> with any other public service company, without having secured from the commission an order authorizing it so to do . . . .

The standard for approval of a sale is whether the proposed transaction is consistent with the public interest:

> **WAC 480-143-170 Application in the public interest.** If, upon the examination of any application and accompanying exhibits, or upon a hearing concerning the same, the commission finds the proposed transaction is not consistent with the public interest, it shall deny the application.

The Commission has further articulated this as a "no harm" standard.

> The standard in our rule does not require the Applicants to show that customers, or the public generally, will be made better off if the transaction is approved and goes forward. In our view, Applicants' initial burden is satisfied if they at least demonstrate no harm to the public interest.

PacifiCorp/ScottishPower Merger Proceeding, Docket No. UE-981627, Third Supplemental Order (April 2, 1999), p. 2; *see also, GTE/Bell Atlantic Merger Proceeding*, Docket No. UT-981367, Second Supplemental Order (1999), p. 25.

B. Required EWG Determinations

To qualify as an EWG, Washington LLC must be engaged exclusively in the business of owning or operating an "eligible facility" and selling electric energy at wholesale. If the costs of a generation facility were included in the rates of a regulated utility on October 24, 1992 (the date of enactment of section 32 of PUHCA), then in order for the facility to be considered an "eligible facility," every state commission having jurisdiction over such rates must specifically determine that allowing the facility to become an eligible facility (1) will benefit consumers, (2) is in the public interest, and (3) does not violate State law. 15 U.S.C. § 79z-5a(c). Thus, the Commission and each of PacifiCorp's other state regulatory commissions must make these determinations regarding PacifiCorp's transfer of the Skookumchuck Project.

IV. BENEFITS OF TRANSACTION

A. Compliance with State Law

The requirements of Washington law regarding the transfer of the Skookumchuck Project to Washington LLC are set forth in Section III.A of this Application, above. If the Commission approves this Application, the transfer to Washington LLC and allowing the Project to become an eligible facility will not violate Washington State law.

B. Benefits to Consumers

PacifiCorp proposes to transfer the Project to Washington LLC because a sale is a lower cost option than continuing to invest in and operate and maintain the Project.

The Skookumchuck Project has an electrical capacity of 1 MW, but because the Project is operated for purposes of supplying cooling water to the Centralia Power Plant, it has relatively low energy output. Over the last eight years, the average annual production has been 3,000 megawatt-hours. The Project's bus bar cost in fiscal year 2003 (twelve months ending March 31, 2003) was approximately $250 per MWh. The Project is interconnected with the distribution system of Puget Sound Energy, Inc. ("PSE") and historically all of the power from the Project has been sold to PSE.

As one of the Owners of the Project, PacifiCorp must pay its proportionate share of the costs of the Project. The Company's analysis demonstrates that its customers will not be harmed by the proposed transaction and will in fact benefit from it. To measure the impact on power costs, the Company compared the forecast of future power costs to the cost of power generated by the Project. While forecasts of the market price for power cannot predict the future with certainty, the forecasts provide a reasonable framework to measure potential outcomes. Here, the forecasts predict that ratepayers will see lower costs if the Project is sold because the projected cost of power from the Project substantially exceeds the projected cost of market power. Moreover, the expected impact of the sale is to lower the Company's future revenue requirement by removing the Project from the Company's rate base and revenue requirement. The expected present value of the future reduction in Washington revenue requirement is approximately $1 million.

The proposed transaction eliminates the risk that PacifiCorp will be required to fund its share of expenditures for ensuring the structural integrity of the Skookumchuck dam. PacifiCorp's share of this investment is estimated to be $4 million. The benefits from the proposed sale outweigh the risks of rising costs of continuing to own and operate the Project.

As shown by the Company's analysis, continued operation of the Project as a hydroelectric project would be uneconomic, and such operation would not be in the public interest. An alternative to the proposed sale would be discontinuing operation of the Project and draining the reservoir created by the Skookumchuck dam, which would subject the Centralia Power Plant to run-of-the-river operations. This alternative is likewise not in the public interest, as it would adversely impact the ability of the Centralia Power Plant, with over 1,200 MW of generation capacity, to produce power.

Moreover, the sale will not harm the public interest because competitive markets will be unaffected by the sale. It cannot reasonably be suggested that a 1 MW plant, with only 3,000 MWhs of annual production, could have a measurable impact on western electricity supply or any impact on wholesale electricity prices.

The financial analysis and impact on customers of the sale are discussed in greater detail in the prefiled testimony of Mr. Landolt and Mr. Johnson.

C. Public Interest Standard

The transfer of the Skookumchuck Project to Washington LLC is in the public interest because it will benefit PacifiCorp's customers by lowering the Company's costs of providing electrical service, for the reasons stated in Section IV.B of this Application, above. In addition, the transfer will give TransAlta greater control of the water flows in the Skookumchuck River for providing cooling water to the Centralia Power Plant, thus increasing the electrical output of the Centralia Power Plant for the benefit of all electricity consumers.

V. OTHER MATTERS

A. Proposed Ratemaking Treatment

Due to the manner in which the sale price is determined, the share of the sale price which PacifiCorp will receive will be essentially equal to PacifiCorp's net book value of the assets of the Skookumchuck Project being transferred under the proposed transaction. Actual figures will not be known until the transaction closes. In the event there is any gain realized on the sale, PacifiCorp proposes to credit its Washington customers with 100 percent of Washington's allocated share of the actual net gain. Should an appreciable loss be realized, PacifiCorp proposes to reduce the Centralia Steam Plant and Mine credit, reflected in the Company's Schedule 97, by an amount reflecting the realized loss. *See*, Section 4, Appendix B, Comprehensive Settlement, Third Supplemental Order Approving and Adopting Settlement Agreement: Rejecting Tariff Sheets; Authorizing and Requiring Compliance Filing in Docket No. UE-991832 requiring establishment of the sale credits.

B. Timing of Approval

PacifiCorp and the other Owners propose to transfer operation of the Skookumchuck Project to Washington LLC by March 31, 2004. Washington LLC cannot process its EWG application with the FERC until all of the Company's regulatory commissions have made the three determinations required by section 32 of PUHCA. Accordingly, PacifiCorp respectfully requests that the Commission conduct its proceedings and issue its Order by March 15, 2004.

C. Exhibits to Application

The exhibits that accompany this Application are:

1. Application Exhibit No. 1: Original Cost, Accumulated Depreciation and Net Book Value of Assets to be Transferred as well as Proposed Entries to Record the Sale.

2. Application Exhibit No. 2: PacifiCorp's most recent Forms 10-K and 10-Q as filed with the Securities and Exchange Commission.

In addition, the Sale Agreement, which is the instrument governing the transfer that is the subject of this Application, is included as an exhibit to the testimony of Randy A. Landolt at Exhibit ___ (RAL-2).

D. Prefiled Testimony Accompanying Application

The witnesses sponsoring prefiled testimony in support of this Application are:

1. Randy A. Landolt, PacifiCorp's Managing Director of Hydro Resources. Mr. Landolt describes the Company's analysis of the future economic viability of the Project, explains the possibility that the FERC will require capital investments in the Project to ensure the safety and structural integrity of the dam, and summarizes the key terms of the Sale Agreement.

2. Craig Johnson, PacifiCorp's Regulatory Consultant. Mr. Johnson describes the nature and timing of regulatory approvals that are required and the ratemaking impacts of the proposed sale.

VI. REQUEST

PacifiCorp requests a Commission order:

(a) Approving the proposed sale of the Company's interests in the Skookumchuck Project substantially in accordance with the Sale Agreement;

(b) Determining that the proposed transfer of the Skookumchuck Project to Washington LLC and allowing the Project to become an "eligible facility" within the meaning of section 32 of PUHCA (1) will benefit consumers, (2) is in the public interest, and (3) does not violate Washington State law; and

(c) Granting such other relief as the Commission deems necessary and proper.

DATED: February 10, 2004.

Respectfully submitted,

James F. Fell
James C. Paine
Stoel Rives LLP
900 SW Fifth Avenue, Suite 2600
Portland, OR 97204-1268
Telephone: (503) 294-9306 or 294-9246
Facsimile: (503) 220-2480

Of Attorneys for PacifiCorp

VERIFICATION

The undersigned hereby certifies that the information set forth in the foregoing Application is true and correct to the best of the signer's information and belief under penalty of perjury as set forth in RCW 9A.72.085.

Dated: February 6, 2004

Application Exhibit No. 1

Application Exhibit No. 1
Docket No._________

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Application of PACIFICORP for an Order Approving the Sale of its Interest in the Skookumchuck Hydroelectric Plant and for EWG Determinations	Docket No. _________

PACIFICORP

APPLICATION EXHIBIT

Proposed Entries to Record the Sale of Skookumchuck

February 2004

Proposed Entries to Record the Sale of Skookumchuck
Estimated Values as of December 5, 2003

Record receipt of proceeds from the sale of facilities to TransAlta

Account	Description	Debit	Credit
131	Cash	$ 3,557,661	
108	Accumulated Provision for Depreciation of Utility Plant		$ 3,557,661

Record sales expense

Account	Description	Debit	Credit
185	Temporary facilities	$ 110,000	
131	Cash		$ 110,000

Retire facilities from Electric Plant in Service

Account	Description	Debit	Credit
108	Accumulated Provision for Depreciation of Utility Plant	$ 8,668,529	
101	Electric Plant in Service		$ 8,668,529

Record the loss on sale and reflect the related tax expense

Account	Description	Debit	Credit
108	Accumulated Provision for Depreciation of Utility Plant	$ -	$ -
282	Accumulated Deferred Taxes	537,387	
409-411	Income Tax Expense	0	0
421.2	Loss on disposition of property	$ 68,613	
185	Temporary facilities		110,000
236	Taxes Accrued		537,387

Application Exhibit No. 2

Application Exhibit No. 2
Docket No.________

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Application of PACIFICORP for an Order Approving the Sale of its Interest in the Skookumchuck Hydroelectric Plant and for EWG Determinations	Docket No. ________

PACIFICORP

APPLICATION EXHIBIT

Company 10-K and 10-Q Forms

February 2004

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended March 31, 2003

OR

[ ] **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 1-5152

PACIFICORP

(Exact name of registrant as specified in its charter)

State of Oregon (State or other jurisdiction of incorporation or organization)	**93-0246090** (I.R.S. Employer Identification No.)
825 N.E. Multnomah Street, Portland, Oregon (Address of principal executive offices)	**97232** (Zip Code)

Registrant's telephone number, including area code: (503) 813-5000

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
8 1/4% Cumulative Quarterly Income Preferred Securities, Series A, of PacifiCorp Capital I	New York Stock Exchange
7.70% Trust Preferred Securities, Series B, of PacifiCorp Capital II	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

Title of each class

5% Preferred Stock (Cumulative; $100 Stated Value)
Serial Preferred Stock (Cumulative; $100 Stated Value)
No Par Serial Preferred Stock (Cumulative; $100 Stated 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 is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

Indicate by check mark whether the Registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).
YES [ ] NO [X]

On September 30, 2002, the aggregate market value of the shares of voting and nonvoting common equity of the Registrant held by nonaffiliates was $0.

As of May 23, 2003, there were 312,176,089 shares of common stock outstanding. All shares of outstanding common stock are indirectly owned by Scottish Power plc, 1 Atlantic Quay, Glasgow, G2 8SP, Scotland.

DOCUMENTS INCORPORATED BY REFERENCE

None.

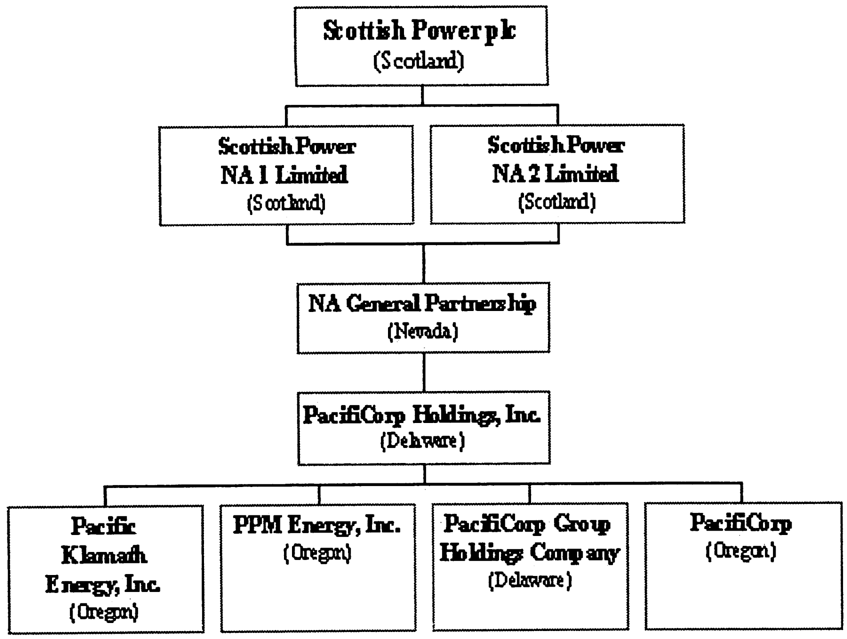
TABLE OF CONTENTS

DEFINITIONS

When the following terms are used in the text, they will have the meanings indicated:

Term	Meaning
Centralia	Centralia, Washington power plant (47.5% owned) and coal mine (100.0% owned), operated by the Company until its sale on May 4, 2000
Company	PacifiCorp and its subsidiaries
CPUC	California Public Utilities Commission
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
Hazelwood	Hazelwood Power Partnership, an Australian partnership and a 19.9% indirectly owned investment of PGHC until its sale in November 2000
IPUC	Idaho Public Utilities Commission
kWh	Kilowatt-hour(s)
MW	Megawatt
MWh	Megawatt-hour(s)
NAGP	NA General Partnership, a Nevada general partnership, the direct parent of PHI and an indirect subsidiary of ScottishPower
OPUC	Oregon Public Utility Commission
PacifiCorp	PacifiCorp, an Oregon corporation and wholly owned subsidiary of PHI
Pacific Power	Pacific Power & Light Company, the assumed business name of PacifiCorp under which it conducts a portion of its retail electric operations
PFS	PacifiCorp Financial Services, Inc., an Oregon corporation and wholly owned direct subsidiary of PGHC, and its subsidiaries
PGHC	PacifiCorp Group Holdings Company, a Delaware corporation and wholly owned subsidiary of PHI
PHI	PacifiCorp Holdings, Inc., a Delaware corporation and nonoperating U.S. holding company
PKE	Pacific Klamath Energy, Inc., an Oregon corporation and wholly owned subsidiary of PHI
PPM	PPM Energy Inc., formerly PacifiCorp Power Marketing, Inc., an Oregon corporation and wholly owned subsidiary of PHI
Powercor	Powercor Australia Ltd., a Victoria, Australia limited liability corporation and indirect, wholly owned subsidiary of PGHC, until its sale in September 2000
ScottishPower	Scottish Power plc, the indirect parent company of PacifiCorp
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
UPSC	Utah Public Service Commission
Utah Power	Utah Power & Light Company, the assumed business name of PacifiCorp under which it conducts a portion of its retail electric operations
WPSC	Wyoming Public Service Commission
WUTC	Washington Utilities and Transportation Commission

CORPORATE ORGANIZATION



PART I

ITEM 1. BUSINESS

OVERVIEW

PacifiCorp is a regulated electricity company operating in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp conducts its retail electric utility business as Pacific Power and Utah Power, and engages in electricity production and sales on a wholesale basis under the name PacifiCorp. The subsidiaries of PacifiCorp support its electric utility operations by providing coal mining facilities and services, environmental remediation and financing. The Company's goals are to provide safe, reliable, low-cost electricity to its customers, with fair and increasing earnings to shareholders. Costs incurred by the Company to provide service to its customers are expected to be included as allowable costs for ratemaking purposes. However, there can be no assurance that these costs will be fully recovered through the regulatory process.

Western United States ("U.S.") wholesale energy market prices were relatively stable during the year ended March 31, 2003 as compared to each of the years ended March 31, 2002 and 2001. The Company took several actions to maintain a balanced net energy position through the summer peak period and the remainder of the fiscal year through a combination of existing physical resources, electricity purchases, weather-related hedges and peaking generation facilities. The Company added a 120-megawatt ("MW") gas-fired peaking plant in Utah, which came on line in August 2002, and also entered into an operating lease arrangement for a 200-MW peaking plant in Utah with West Valley Leasing Company, LLC, a subsidiary of PPM Energy, Inc. ("PPM"), formerly known as PacifiCorp Power Marketing, Inc., a subsidiary of PacifiCorp Holdings, Inc. ("PHI"). These actions, as well as the utilization of other flexible physical and financial hedging instruments, assisted the Company in maintaining a balanced energy position during the year ended March 31, 2003. The Company believes that its energy position is balanced for summer 2003.

For the year ended March 31, 2003, overall retail megawatt-hour ("MWh") sales decreased approximately 1.2%. While the impact of weather was not significant for the year ended March 31, 2003, sales for the year ended March 31, 2002 were approximately 564,000 MWh, or 1.2%, higher than sales for the year ended March 31, 2003, due to the effects of weather. Excluding this weather impact, the loads for both years were relatively consistent, although load growth varied within individual states and customer classes. While residential and commercial loads reflected an increase of 1.2% and 3.6%, respectively, as a result of additional customers in the eastern portion of the Company's service territory, the industrial class showed a 3.2% decrease as a result of the effects of the economic downturn and a decrease in industrial customers.

The Company's hydroelectric resources are in watersheds with precipitation that averaged 85.0% of normal for the year ended March 31, 2003 and had ending snowpack at around 74.0% of normal. These drier than normal conditions reduced generation from Company-owned projects by 65,000 MWh as compared to the hydroelectric generation for the year ended March 31, 2002. Despite increased precipitation in April 2003, the reduced snowpack will continue to affect generation from the Company's resources for the remainder of the normal runoff period through the end of September 2003. Beginning with the next hydrologic cycle in October 2003, the Company anticipates a return to normal water conditions. In the event of below-normal hydroelectric generation, the Company will either increase output from its thermal generation resources or purchase energy in the wholesale market, which would result in increased power costs to the extent existing hedges do not offset the impact of reduced hydroelectric generation.

Concluded regulatory actions in the year ended March 31, 2003 included approval in Oregon of a $15.4 million overall rate increase effective June 1, 2002. On March 6, 2003, a general rate increase of $8.7 million, or 2.8%, was granted in Wyoming. Rate actions submitted for regulatory approval include a general rate case filed on March 18, 2003 in Oregon, requesting an increase of $57.9 million, or 7.4%, in base rates to take effect in January 2004; a general rate case filed on May 15, 2003 in Utah establishing a maximum increase of $125.0 million, or 12.5%, in base rates to take effect in April 2004; and a general rate case filed on May 27, 2003 in Wyoming, requesting an increase of $41.8 million, or 13.1%, in base rates to take effect in March 2004.

The Company also made progress toward recovering the deferred net power costs incurred during the period of extreme volatility and unprecedented high price levels beginning in summer 2000 and extending through summer

2001. These costs have been authorized for recovery as follows: (i) $147.0 million in Utah; (ii) $131.0 million, plus carrying charges, in Oregon; and (iii) $25.0 million in Idaho. The Oregon rate order is the subject of a court appeal by intervening parties, which, if successful, would require refunds of amounts collected after January 22, 2003. In Wyoming, the Company's request for recovery of deferred net power costs was denied, and, as a result, the Company wrote off the remaining net regulatory asset of $48.3 million during the year ended March 31, 2003. The Company filed a petition for rehearing on the Wyoming decision on April 4, 2003. The WPSC denied the petition on May 30, 2003. In Washington, the Company had requested recovery of approximately $17.5 million of excess power costs, which have not been deferred, or, alternatively, that the Company be allowed to file a general rate case, which is currently restricted through December 2005. This request was subsequently reduced to approximately $15.9 million based on revised estimates. A final decision in Washington is expected by June 2003. At March 31, 2003, the Company had $137.8 million of deferred power costs, net of amortization, remaining to be collected over two to three years.

The Company is subject to comprehensive regulation by the Federal Energy Regulatory Commission (the "FERC") and state and local regulatory agencies. The Company is required to comply with various permits, approvals and licenses from the governmental agencies that regulate many aspects of the Company's business, including customer rates, service territories, sales of securities, asset acquisitions and sales, accounting policies and practices, and the operation of its coal, steam and hydroelectric facilities. The Company believes that it has the necessary permits, approvals and licenses to operate its plants in material compliance with applicable requirements. The Company is also subject to regulation by the Securities and Exchange Commission (the "SEC") under the Public Utility Holding Company Act of 1935 (the "PUHCA"), which includes restrictions on securities issuances, payment of dividends and transactions with affiliates. The Company is unable to predict the impact on its operating results of future regulatory activities of these agencies.

As a result of the western energy crisis from May 2000 through June 2001, the bankruptcy filing by Enron Corp. ("Enron") and investigations by governmental authorities into electricity and natural gas trading activities, companies in the regulated and nonregulated utility business have been under an increased amount of public and regulatory scrutiny. This increased scrutiny could lead to significant changes in laws and regulations affecting the Company, including new accounting standards that could change the way the Company is required to record revenues, expenses, assets and liabilities. These types of changes in the industry and any resulting regulations may have a significant impact on the Company's results and access to capital markets.

The Company's operations are exposed to risks, including legislative and governmental regulations; volatility in the price and supply of purchased electricity, fuel and natural gas; uncertain recovery of purchased electricity and natural gas costs; weather conditions; economic conditions; availability of generation facilities; competition; technology; and availability of funding. In addition, the energy business exposes the Company to the financial, liquidity, credit, volumetric and commodity price risks associated with wholesale sales and purchases. See **ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - BUSINESS RISK** for further discussion.

The Company had 6,140 employees on March 31, 2003. Approximately 58.6% of the employees of the Company are covered by union contracts, principally with the International Brotherhood of Electrical Workers, the Utility Workers Union of America, International Brotherhood of Boilermakers and the United Mine Workers of America. In the Company's judgment, employee relations are satisfactory.

The 8 1/4% Cumulative Quarterly Income Preferred Securities (Series A Preferred Securities) of PacifiCorp Capital I, and the 7.70% Trust Preferred Securities (Series B Preferred Securities) of PacifiCorp Capital II, each a wholly owned subsidiary trust of the Company, are traded on the New York Stock Exchange. All outstanding shares of the common stock of PacifiCorp are indirectly owned by Scottish Power plc ("ScottishPower"), whose American Depository Shares ("ADS") are traded on the New York Stock Exchange.

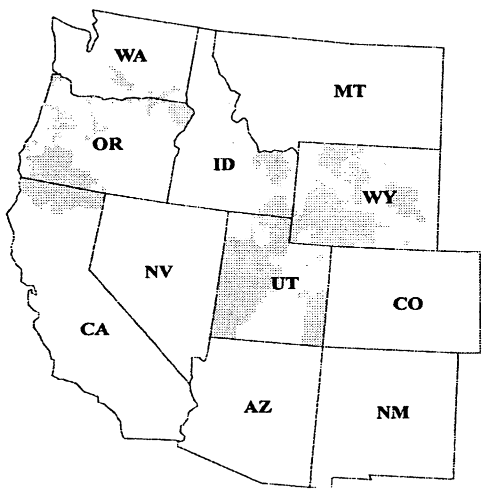
From time to time, the Company may make or issue forward-looking statements that involve a number of risks and uncertainties under the safe-harbor provisions of the Private Securities Litigation Reform Act of 1995, as described in Forward-Looking Statements under **ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**. Any forward-looking statements made or issued by the Company, including statements in this report, should be considered in light of these factors.

The website address of the Company is www.pacificorp.com. The Company makes available free of charge, on or through its website, its annual, quarterly and current reports, and any amendments to those reports, as soon as reasonably practicable after electronically filing such reports with the SEC. Information contained on the Company's website is not part of this report.

SERVICE TERRITORIES

The Company serves approximately 1.5 million retail customers in service territories aggregating about 136,000 square miles in portions of six western states: Utah, Oregon, Wyoming, Washington, Idaho and California. The combined service territory's diverse regional economy ranges from rural, agricultural and mining areas to urbanized manufacturing and government service centers. No one segment of the economy dominates the service territory, which helps mitigate the Company's exposure to economic changes. In the eastern portion of the service territory, mainly consisting of Wyoming and Utah, the principal industries are mining and extracting coal, oil, natural gas, uranium and oil shale. In the western portion of the service territory, mainly consisting of Oregon and southeastern Washington, the principal industries are agriculture and manufacturing, with pulp and paper, lumber and wood products, food processing, high technology and primary metals being the largest industrial sectors. The Company delivers electricity through approximately 57,000 miles of distribution lines and 15,000 miles of transmission lines.

The following map highlights the Company's retail service territory.



The geographic distribution of the Company's retail electric operating revenues for the year ended March 31, 2003 was as follows: Utah, 38.8%; Oregon, 31.9%; Wyoming, 12.7%; Washington, 8.2%; Idaho, 5.9%; and California, 2.5%.

In July 1998, the Company announced its intention to sell its California service territory, including its electric distribution assets. The Company and Nor-Cal Electric Authority ("Nor-Cal") have engaged in detailed negotiations with a view toward executing a definitive sale agreement. Various factors have impeded consummation of the sale transaction. In June 2002, the California county of Siskiyou filed a validation action in California Superior Court, challenging the authority of Nor-Cal to enter into such a transaction as proposed and alleging certain conflicts of interest among Nor-Cal and its advisors. The validation action is ongoing, but based on the foregoing factors, consummation of the sale is uncertain.

In February 2003, the Oregon Public Power Coalition submitted a petition to Multnomah County, Oregon, calling for an election to form a government-owned and operated electric utility in the county. The county is conducting hearings, and a public vote could occur in November 2003. If approved by the voters, the measure would result in the formation of a public utility district and could result in condemnation of the Company's property in Multnomah County, Oregon, making that property part of a government-owned and operated utility. The Company serves 68,000 homes and businesses in the county, which represents approximately 1.9 million MWh, or $108.1 million in annual revenues. The Company is vigorously opposing this action.

CUSTOMERS

Electricity sales and retail customers, by class of customer, for the years ended March 31, 2003, 2002 and 2001, were as follows:

Electric Operations	Years Ended March 31,					
	2003		2002		2001	
(Thousands of MWh)						
MWh sold						
[redacted]						
Commercial	14,006	18.1	13,810	19.2	13,634	18.0
[redacted]						
Other	631	0.8	711	1.0	705	0.9
[redacted]						
Wholesale sales	30,485	39.4	24,264	33.8	27,502	36.2
[redacted]						
Number of Retail Customers (Thousands)						
Residential	1,317	85.4%	1,296	85.4%	1,278	85.4%
[redacted]						
Industrial	34	2.2	35	2.3	35	2.3
[redacted]						
Total	1,542	100.0%	1,517	100.0%	1,496	100.0%
Residential Customers						
[redacted]						
Average annual revenue per customer	$ 701		$ 701		$ 672	
[redacted]						

As a result of the geographically diverse area of operations, the Company's service territory has historically experienced complementary seasonal load patterns. In the western portion, customer demand peaks in the winter months due to heating requirements. In the eastern portion, customer demand peaks in the summer when irrigation and air-conditioning systems are heavily used. Many factors affect per-customer consumption of electricity. For residential customers, within a given year, weather conditions are the dominant cause of usage variations from normal seasonal patterns. The majority of the growth in residential customers has been generated from the eastern portion of the Company's service territories, whereas the western portion has remained relatively flat in terms of its growth. Average annual usage for the year ended March 31, 2003 decreased generally due to the impact of the downturn in the economy on the Company's commercial and industrial customers. Price is a significant factor in usage by all customers. In response to prior region wide electricity supply shortages, the Company is actively promoting electricity conservation programs that lower customer usage.

During the year ended March 31, 2003, no single retail customer accounted for more than 1.2% of the Company's retail electric revenues and the 20 largest retail customers accounted for 13.0% of the Company's total retail electric revenues.

POWER AND FUEL SUPPLY

The Company owns, or has interests in, 17 thermal generating plants with an aggregate nameplate rating of 7,309.8 MW and plant net capability of 6,776.9 MW, 53 hydroelectric generating plants with an aggregate nameplate rating of 1,067.3 MW and plant net capability of 1,115.8 MW, and one wind generating plant with an aggregate nameplate rating and plant net capability of 32.6 MW. During the year ended March 31, 2003, the Company's thermal, hydroelectric and wind generation plants supplied 57.5%, 4.5% and 0.1%, respectively, of its energy requirements. Of the remainder, 26.0% was supplied by purchased electricity under existing short-term purchase contracts and 11.9% by long-term purchase arrangements. With its present generating facilities, under average water conditions, the Company expects that approximately 59.5% and 5.3% of its energy requirements for the year ending March 31, 2004 would be supplied by its thermal and hydroelectric plants, respectively; 21.9%

would be obtained under short-term or spot-market purchase contracts; and the remaining 13.3% through existing long-term purchase arrangements.

During the year ended March 31, 2002, the Company leased gas turbine peaking generators with 114.0 MW capacity to provide electric generation to meet system load requirements and provide voltage support in the Salt Lake Valley. The Company replaced these leased gas turbine peaking generators with a Company-owned gas-fired peaking plant in Salt Lake City, Utah, which became operational in August 2002 and consists of three generation units, each rated at 40.0 MW.

In May 2002, the Company entered into a 15-year operating lease for an electric generation facility with West Valley Leasing Company LLC, a subsidiary of PPM. The Company, at its sole option, may terminate the lease, or purchase the facility, after three years or after six years. The facility consists of five generation units, each rated at 40 MW, and is located in Utah.

To improve customer service and reliability, the Company is continuing its infrastructure improvement projects in targeted areas, particularly along Utah's Wasatch Front, where there is rapidly growing demand for electricity. The scope of this $200.0 million investment through 2005 includes transmission line upgrades, new distribution substations, upgrades to existing distribution substations and other system enhancements. These projects are intended to provide additional capacity to meet future load demands throughout the Company's system.

As of March 31, 2003, the Company had approximately 196 million tons of recoverable coal reserves in mines owned by the Company. The coal from these reserves and from long-term contracts will be used to support the Company's fuel strategy at its generation plants that are near the mines. During the year ended March 31, 2003, these mines supplied approximately 32.7% of the Company's total coal requirements, compared to approximately 32.5% during the year ended March 31, 2002. Coal is also acquired through other long-term and short-term contracts. The Company supplies its gas-fired generation plants with natural gas through long-term and short-term contracts.

WHOLESALE SALES AND PURCHASED ELECTRICITY

In addition to its base of thermal and hydroelectric generation assets, the Company utilizes a mix of long-term, short-term and spot-market purchases to meet its load obligations, wholesale obligations and balancing requirements. Many of the Company's purchased electricity contracts have fixed price components, which provide some protection against price volatility. The Company enters into such wholesale purchase and sale transactions to provide hedges against periods of variable generation or variable retail load. Generation varies with the levels of outages or transmission constraints, and retail load varies with the weather, distribution system outages and the level of economic activity. During the year ended March 31, 2003, retail loads were lower than in the previous year due to milder weather and a generally weak western U.S. economy. The Company's wholesale transactions are integral to its retail business, providing for a balanced and economically hedged position and enhancing the efficient use of its generating capacity over the long term.

Historically, the Company has been able to purchase electricity from utilities in the southwestern U.S. and the Pacific Northwest for its own requirements. The Company's transmission system connects with market hubs in the Pacific Northwest to provide access to what is normally low-cost hydroelectric generation and connects with the southwestern U.S., which provides access to normally higher-cost fossil-fuel generation. The transmission system is available for common use consistent with open-access regulatory requirements. If the Company is in a surplus electricity position, the Company is usually able to sell excess electricity into the wholesale market, subject to pricing and transmission constraints.

Under the requirements of the Public Utility Regulatory Policies Act of 1978, the Company purchases the output of qualifying facilities constructed and operated by entities that are not public utilities. During the year ended March 31, 2003, the Company purchased an average of 95 MW from qualifying facilities, compared to an average of 104 MW during the year ended March 31, 2002.

PROJECTED DEMAND

Future increases in demand are dependent upon several factors, including the impact of price movements, weather, economic conditions, Demand Side Management ("DSM") programs and changes in technology. Resource availability, price volatility and load volatility may materially impact power costs to the Company.

For the years through March 31, 2008, the Company is estimating average annual growth in retail MWh sales in the Company's franchise service territories to be in the range of 1.8% to 3.6%, dependent upon factors such as economic recovery and growth, customer numbers, weather, conservation efforts and changes in prices. If price increases occur in the region, the Company believes that demand growth may slow. The Company's financial results will be impacted by a variety of factors, including economic and demographic growth, competition and the extent of deregulation in the electric industry.

Integrated Resource Plan

The Company's Integrated Resource Plan ("IRP") provides a framework and plan for the prudent future actions required to ensure that the Company continues to provide reliable and cost-effective electric service to its customers. Projected growth rates and retirement of existing resources indicate a need of about 4,000 additional MW of capacity between 2004 and 2014. These estimates are subject to ongoing review and could be revised. The IRP and the resulting Request for Proposals ("RFP") process have been created to identify the Company's future resource mix in a coordinated process with the stakeholders in each of the six states where the Company operates. As part of the IRP process, the Company is expecting to add capacity through a combination of the following sources: base-load resources or purchases (approximately 2,100 MW), peaking resources (approximately 1,200 MW) and shaped purchased electricity resources (approximately 700 MW). The Company also plans to implement DSM programs (450 average MW) and acquire renewable energy (approximately 1,400 MW). Shaped products and electricity purchase agreements are used in an effort to optimize physical assets and reduce cost. Before the Company commits to build assets, electricity purchase agreements and shaped products are reviewed and compared for economic benefit, risk reduction and long-term optionality.

The IRP was filed with the relevant state commissions on January 24, 2003. The Company has segregated the IRP supply-side action items into a series of four separate RFPs. Each RFP focuses on a specific category of supply-side resources and provides for the staged procurement of resources in future years in order to achieve load/resource balance. The first of these four RFPs was presented for consideration to the Oregon Public Utility Commission (the "OPUC") on May 7, 2003. The expected cycle time for each RFP process is approximately six months. Approval for resources procured via the first RFP effort is expected toward the end of calendar year 2003. The subsequent three RFPs are anticipated to be released 30 to 90 days following the first RFP.

In addition to the four supply-side RFPs, the Company is preparing a separate RFP for the demand-side resources called for in the IRP. As part of the RFP process, the Company will develop and evaluate its own-build options consistent with the analyses in the IRP, such as new base-load or peaking generation facilities. The Company is also considering an additional generating unit at its Hunter station in Utah and has begun an air-quality permitting process for potential development of this unit. The RFP process includes an analysis of the customer benefits and the cost/risk balance of the available alternatives.

On March 6, 2003, the Utah Public Service Commission (the "UPSC") opened a docket to consider adopting competitive bidding rules governing the acquisition of generating resources. An industrial-customer lobbying group and other interested parties approached the UPSC after legislation to impose new rules on generation procurement and affiliate transactions failed to garner support in the Utah legislature. Four conferences to consider current regulations and investigate proposals were held during April 2003. An update conference was held with the UPSC on May 8, 2003. At this meeting, all parties confirmed their intention to hold further technical conferences. These conferences will focus on two issues: the need for short-term interim rules on resource acquisition and the requirement to develop longer-term, more fully developed rules for affiliate transactions and resource acquisition.

CAPITAL EXPENDITURE PROGRAM

The following table shows actual capital expenditures for the year ended March 31, 2003 and the Company's estimated capital expenditures for the years ending March 31, 2004 through 2006.

	Actual	Estimated		
	Years Ending March 31,			
Millions of dollars	**2003**	**2004**	**2005**	**2006**
[redacted]				
Generation and Mining	182.7	239.4	278.7	273.6
[redacted]				
Total	$550.0	$669.3	$679.7	$678.6

Actual and estimated future capital expenditures include upgrades to distribution and transmission lines and existing generation plants, connections for new customers, accommodating load growth, coal mine investments, air-quality and environmental expenditures, hydroelectric relicensing costs and information technology systems. All of these expenditures are subject to continuing review and revision by the Company, and actual costs could vary from estimates due to various factors, such as changes in business conditions, revised load-growth estimates, and increasing costs in labor, equipment and materials. The estimates of capital expenditures for the years ending March 31, 2004 through 2006 generally exclude the potential impact of future decisions regarding expansion of physical generation and transmission capacity arising from the RFP process. These additional expenditures may be significant but are spread over a number of years and are subject to future legislative and regulatory developments. They cannot be accurately estimated at this time.

COMPETITION

During the year ended March 31, 2003, the Company continued to operate its retail business under state regulation. Certain of the Company's industrial customers in Oregon have the right to choose alternative electricity suppliers and others in the Company's service territories are seeking choice of suppliers, options to build their own generation or co-generation plants, or the use of alternative energy sources such as natural gas. If these other customers gain the right to receive electricity from alternative suppliers, they will make their energy purchasing decision based upon many factors, including price, service and system reliability. Availability and price of alternative energy sources and the general demand for electricity also influence competition.

Any adoption of retail competition in the territories served by the Company and the unbundling of regulated energy service could have a significant adverse financial impact on the Company due to an impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital and could result in increased pressure to lower the price of electricity. The Company cannot predict if or when it will be subject to changes in legislation or regulation, nor can the Company predict the impact of these changes.

The regional electricity market in which the Company competes has changing transmission regulatory structures, which could affect the ownership of transmission assets and related revenues and expenses. The Company currently owns and operates transmission facilities as part of its vertically integrated utility operations. Transmission costs are not separated from, but rather are "bundled" with, generation and distribution costs in approved retail rates. In 1996, the FERC issued new rules on transmission service to facilitate competition in the wholesale market on a nationwide basis. The rules give greater flexibility and more choices to wholesale electricity customers.

On July 31, 2002, the FERC issued a Notice of Proposed Rulemaking, proposing a new Standard Market Design ("SMD") for wholesale electricity markets, relating to open-access transmission service and standard electricity market design. The SMD proposed a number of remedies aimed at removing barriers to efficient competitive wholesale markets perceived by the FERC in the wake of the FERC's Orders 888 and 2000. In an April 28, 2003 SMD White Paper, the FERC signaled a greater willingness to defer to regional solutions and not adopt overly prescriptive rules. It appears that the FERC will refocus its upcoming final rule around the formation of Regional Transmission Organizations ("RTOs") to ensure that these entities have sound wholesale market rules. Renamed the "Wholesale Power Market Platform," the FERC's new proposal retains the initial SMD requirement that jurisdictional utilities transfer control of their transmission facilities to an RTO. At the same time, the FERC affirmed that it would permit phased-in implementation and sequencing tailored to each region, and allow modifications that would benefit customers within each region. The FERC has now instituted an open-ended public comment period, specifically inviting reaction to certain aspects of the paper. It is expected that a final rule will not be issued until the U.S. Congress has completed action on pending energy legislation.

The Company, in conjunction with nine other utilities, is seeking to form an RTO ("RTO West"), in response to the FERC's Order 2000. The 10 members of RTO West would be Avista Corporation, British Columbia Hydro Power Authority, BPA, Idaho Power Company, Northwestern Energy L.L.C. (formerly Montana Power Company), Nevada Power Company, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc. and Sierra Pacific Power Company. Creation of RTO West is subject to regulatory approvals from the FERC. On September 18, 2002, the FERC voted that, with some modification and further development of certain details, the RTO West proposal satisfies the 12 characteristics and functions of the FERC's Order 2000. The states served by these utilities will likely participate in regional state committees that will be established to address significant market design features for their respective regions, such as allocation of firm transmission rights to existing capacity and cost recovery for new transmission expansion. Some of these states may also assert jurisdiction over certain matters relating to the formation of RTO West. RTO West, if and when fully implemented, would serve as an independent transmission provider for the RTO West region and have operational authority needed for bulk electricity transfers over a majority of the 60,000 miles of transmission lines owned by its members.

As a result of this changing regulatory environment, which includes open-access transmission service, the Company may be subject to a competitive market that is substantially different than the current market structure. This change in competitive market structure could affect the Company's load forecasts, plans for electricity supply and wholesale electricity sales and related revenues. The effect on the Company's net income and financial condition could vary depending on the extent to which (i) additional generation is built to compete in the wholesale market, (ii) new ways for the Company to use the wholesale market to balance its retail position are developed, or (iii) current wholesale customers elect to purchase from other suppliers after existing contracts expire.

ENVIRONMENTAL MATTERS

The Company's activities are subject to a broad array of federal, state and local laws and regulations designed to protect, restore and enhance the quality of the environment. The Company's costs of complying with complex environmental laws and regulations, as well as internal voluntary programs and goals, are significant and will continue to be so for the foreseeable future.

In the year ended March 31, 2003, the Company spent approximately $12.5 million on environmental capital projects either required by law or necessary to meet the Company's internal environmental goals. The Company currently estimates expenditures for environmental-related capital projects will total approximately $35.8 million, $86.4 million and $106.8 million in the years ending March 31, 2004, 2005 and 2006, respectively. The Company monitors these requirements and annually revises its cost estimates to meet existing legal and regulatory requirements of the various jurisdictions in which it operates.

Air Quality

The Company's fossil-fuel-fired electricity generation plants, as well as other facilities with significant air emissions, are subject to air quality regulation under federal, state and local laws and regulations. The Company believes it has all required permits and other approvals to operate its plants and that the plants are in material compliance with applicable requirements. The Company uses emission controls, low-sulfur coal, environmentally conscious plant operating practices and continuous emissions monitoring to enable its plants to comply with emissions limits, opacity limits, visibility and other air-quality requirements.

The U.S. Environmental Protection Agency (the "EPA") has initiated a regional haze program intended to improve visibility at specific federally protected areas, some of which are located near Company plants. The Company is working with the Western Regional Air Partnership to help develop the technical and policy tools needed to comply with those regulations. Carbon dioxide emissions are the subject of growing discussion and action in the context of global climate change, but such emissions are not currently subject to regulation. The Company is anticipating mitigating climate-change challenges with additions of renewable generation, conservation and thermal resources as outlined in the IRP. Likewise, carbon dioxide emissions risk has been anticipated in the Company's IRP through the use of a "carbon adder." The Company also supports development of trading and other market mechanisms, as well as offset strategies, where feasible, to reduce future compliance costs to customers. The U.S. Congress is currently considering several proposed bills that would create enforceable limits on electricity plant emissions of sulfur dioxide, carbon dioxide, oxides of nitrogen and mercury. While the Company is unable at this time to predict with certainty the level of capital expenditures relating to air quality and carbon dioxide emissions, it believes these amounts could be significant but will be spread over a number of years. The Company also believes that the impact will be mitigated by recovery through the regulatory ratemaking process.

In 1999, the EPA commenced enforcement actions alleging violations of New Source Review requirements by the owners of certain coal-fired generating plants in the eastern and midwestern U.S. The Company is not part of those actions. However, in December 2000, the EPA notified the Company that it is investigating the Company's Carbon, Dave Johnston, Huntington and Naughton coal-fired plants, and required the Company to provide information about the operation, maintenance, emissions, utilization and other aspects of these plants. In May 2003, the EPA notified the Company that it is investigating similar issues at the Bridger, Hunter and Wyodak plants. The Company is cooperating with these investigations by providing requested information to the EPA. No legal proceeding has been commenced.

Endangered Species

The federal Endangered Species Act of 1973 and similar state statutes protect species threatened with possible extinction. Protection of the habitat of endangered and threatened species makes it difficult and more costly to perform some of the Company's core activities, including the siting, construction and operation of new and existing transmission and distribution facilities, as well as hydroelectric, thermal and wind generation plants. In addition, endangered species issues impact the relicensing of existing hydroelectric generating projects, generally raising the price the Company must pay to purchase wholesale electricity from hydroelectric facilities owned by others, reducing output and increasing the costs of operating the Company's own hydroelectric resources.

Environmental Cleanups

Under the Comprehensive Environmental Response, Compensation and Liability Act; the Resource Conservation and Recovery Act; and similar state statutes, entities that disposed of, or arranged for the disposal of, hazardous materials may be liable for cleanup of the contaminated property. In addition, the current or former owners or operators of affected sites may be liable. The Company has been identified as a potentially responsible party in connection with a number of cleanup sites because of its current or past ownership or operation of the property or because the Company sent hazardous materials to the property in the past. The Company has completed several cleanup actions and is actively participating in investigations and remedial actions at other sites. The costs associated with those actions are not expected to be material to the Company's consolidated financial position, results of operations, cash flows, liquidity or capital expenditures.

Mine Reclamation

The federal Surface Mining and Reclamation Act of 1977 and similar state statutes establish operational, reclamation and closure standards that must be met during and upon completion of mining activities. These obligations mandate that mine property be restored consistent with specific standards and the approved reclamation plan. The Company's mining operations are subject to these reclamation and closure requirements. Significant expenditures are expected to be required when individual Company mining operations are closed and reclamation occurs. The costs associated with reclamation are subject to the regulatory process, and the Company expects to be allowed to recover these costs.

Water Quality

The federal Clean Water Act and individual state clean-water regulations require a permit for the discharge of wastewater, including storm-water runoff from electricity plants and coal storage areas, into surface water and ground water. The Company believes that it has management systems in place to monitor performance, identify problems and take action to ensure compliance with permit requirements. Additionally, the Company believes that it currently has, or has initiated the process to receive, all required permits.

Other Environmental Laws

The Company is required to comply with numerous other federal, state and local environmental laws in addition to those previously discussed. The Company believes that it is in material compliance with all applicable environmental laws.

REGULATION

The Company is subject to the jurisdiction of public utility regulatory authorities in each of the states in which it conducts retail electric operations. These authorities regulate various matters, including prices, services, accounting, issuances of securities and other matters. Commissioners are appointed by the respective states' governors for varying terms. The Company is a "licensee" and a "public utility" as those terms are used in the Federal Power Act ("FPA") and is therefore subject to regulation by the FERC as to accounting policies and practices, certain prices and other matters, including the terms and conditions of transmission service. Most of the Company's hydroelectric plants are licensed by the FERC as major projects under the FPA, and certain of these projects are licensed under the Oregon Hydroelectric Act. The Company is also subject to the requirements and restrictions of the PUHCA.

Federal Energy Regulatory Commission Issues

On April 26, 2001, the FERC imposed a price mitigation plan limiting prices on spot-market sales in California 24 hours a day, seven days a week. On June 19, 2001, the FERC issued an order that extended the California price limits to all wholesale spot-market sales in the entire 11-state western region. On July 17, 2002, the FERC issued an order that became effective November 1, 2002, increasing the price cap to $250.00 per MWh from the previous $91.87 per MWh. However, the order also created an automatic mitigation procedure designed to limit the ability of generators to cause prices to rise above $91.87 per MWh.

The FERC's June 19, 2001 order also required that all public utility sellers and buyers (the "Party" or "Parties") in the California Independent System Operators' (the "Cal ISO") markets participate in settlement discussions to complete the task of settling past accounts and structuring the new arrangements for California's energy future. The FERC appointed an Administrative Law Judge ("ALJ") to serve as a settlement judge. On July 12, 2001, an ALJ issued a recommendation to the FERC based upon the settlement conference, proposing a methodology to calculate refunds for spot sales made to the Cal ISO and the California Power Exchange (the "CPX") between October 2, 2000 and June 20, 2001. The FERC agreed with the ALJ-proposed methodology. A proceeding before a second ALJ was held beginning August 19, 2002 to determine each Party's refund liability. On November 20, 2002, the FERC allowed all Parties to engage in 100 days of additional discovery into market manipulation. On December 12, 2002, an ALJ issued a Certification of Proposed Findings on California Refund Liability in which the ALJ preliminarily determined that $1.2 billion was still owed to suppliers by the Cal ISO and the CPX, which amount was calculated by offsetting a $1.8 billion refund against the $3.0 billion owed to suppliers. On March 3, 2003, the Parties filed supplemental evidence of market manipulation and proposed new findings of fact. On March 20, 2003, the Parties responded to the March 3, 2003 filings. On March 26, 2003, the FERC staff issued a final report on price manipulation in western markets (the "Staff's Final Report"). Following issuance of the Staff's Final Report, the FERC issued an Order on Proposed Findings on Refund Liability adopting many of the ALJ's December 12, 2002 Proposed Findings and clarifying the method for calculating refunds for purchases made in the Cal ISO and CPX spot markets. In its order, the FERC adopted recommendations from the Staff's Final Report, including a new proxy for gas prices, which could increase the amount of refunds, if any, owed by all Parties. The FERC expects that refunds will be distributed by the end of summer 2003. The Company's level of exposure to refunds is dependent upon any final order issued by the FERC in response to the outcome of these proceedings. The Company has established a reserve of approximately $17.7 million for any refunds owed as a result of this FERC proceeding.

The FERC has also established a second proceeding to consider the possibility of requiring refunds for wholesale spot market bilateral sales in the Pacific Northwest between December 25, 2000 and June 20, 2001. In a decision issued on September 24, 2001, an ALJ recommended that the FERC should not require refunds for these sales. On December 19, 2002, the evidentiary record was reopened in this case for the purpose of allowing parties to submit additional evidence concerning potential refunds for wholesale spot market bilateral sales transactions in the Pacific Northwest for the period January 1, 2000 through June 21, 2001 and to submit proposed new and/or modified findings of fact. On March 3, 2003, parties filed supplemental evidence of market manipulation and proposed new findings of fact. On March 20, 2003, parties responded to the March 3, 2003 filings. In its March 26, 2003 report on price manipulation in western markets, the FERC staff recommended that the FERC remand back to an ALJ for consideration of the additional evidence received after the decision in September 2001. The Company's obligation to make refunds, if any, will be dependent upon any final order issued by the FERC in response to the outcome of these proceedings and cannot be determined at this time.

On May 2, 2002, the Company filed a series of complaints with the FERC against five wholesale power suppliers (the "Respondents") for charging excessive prices for wholesale electricity purchases scheduled for delivery during summer 2002. The contracts covered in the complaint were signed during a period of extreme wholesale market volatility and before the FERC imposed its Westwide spot-market price mitigation (price caps). The Company is seeking reformation of the contract prices to levels that constitute just and reasonable rates. Hearings on this proceeding were completed on January 3, 2003. On February 26, 2003, an ALJ issued an Initial Decision recommending dismissal of the Company's complaints. The Company has moved to reopen the evidentiary record in light of additional evidence. In addition, on March 28, 2003, the Company filed its Brief on Exceptions identifying the legal errors contained in the Initial Decision. The FERC staff and the Respondents filed their opposing exceptions on April 17, 2003. Oral arguments were held at the FERC on May 15, 2003, and a final order is expected by December 2003.

In May 2002, the Company responded to data requests from the FERC regarding trading practices connected with the power crisis during 2000 and 2001. The Company confirmed that it did not engage in any trading practices intended to manipulate the market as described in the FERC's data requests issued in May 2002. The Staff's Final Report recommends that the FERC issue show-cause orders to numerous market participants, including the Company, requiring them to demonstrate why their behaviors did not violate the Cal ISO and CPX tariffs as part of the ongoing FERC trading practices investigation. It is unknown at this time whether the FERC will act on the staff's recommendations.

Hydroelectric Relicensing

The Company's hydroelectric portfolio consists of 53 plants with a plant net capability of 1,115.8 MW. These plants account for about 14.1% of the Company's total generating capacity and provide operational benefits such as peaking capacity, generation, spinning reserves and voltage control.

The Company operates the majority of its hydroelectric generating portfolio under long-term licenses from the FERC. These licenses are granted by the FERC for periods of 30 to 50 years. There is a complex regulatory process that the Company must comply with to apply for new licenses that begins five and one-half years before the expiration of an existing license and involves a number of federal and state agencies, as well as other stakeholders. Some state and federal agencies and, in some cases, Native American Tribal Councils have authority to require certain terms and conditions to be included in the FERC license. Often, existing licenses expire prior to the FERC's issuing a new license. In these cases, the FERC has historically issued annual operating licenses so that the project can continue to operate while alternatives are evaluated. The Company expects that the FERC will continue this practice. Many of the Company's long-term operating licenses have expired or are expiring in the next few years and will continue to operate under annual licenses granted by the FERC. The FERC will require the Company to implement certain protection, mitigation and enhancement measures, primarily to address environmental concerns relating to fisheries, water quality, wildlife, recreation, land use, cultural resources and erosion, as conditions to the new licenses. Through this process, the Company's operations must also comply with current environmental polices such as the Clean Water Act and the Endangered Species Act of 1973.

It is difficult to determine the economic impact of any new measures, but capital expenditures and operating costs are expected to increase over the next license periods of 30 to 50 years. In addition, in-stream flow requirements and other constraints on operations may result in lower generating output and reductions in the Company's operational flexibility and ability to "shape" production into the highest-value load periods.

The Company has entered into settlement agreements with stakeholders in the licensing processes regarding measures to be included in the new licenses for the North Umpqua, Bear River and Big Fork hydroelectric projects. The Company believes that negotiating settlement agreements results in more cost-effective measures that provide a more timely response to environmental needs. The terms of these settlement agreements are incorporated into the Company's license applications with the FERC and the tribal, federal and state agencies' terms, conditions and recommendations to the FERC. As part of these settlement agreements, the Company has agreed to implement certain measures prior to and during the next license period. Most of these commitments are contingent on the Company ultimately receiving an acceptable license from the FERC. Assuming the Company is granted a new license on these projects for 30 to 35 years, these measures will cost approximately $184.5 million over the license terms.

As of March 31, 2003, the Company had incurred approximately $95.4 million in costs for ongoing hydroelectric relicensing, which are included in assets on the Company's Consolidated Balance Sheet. The Company expects that these and future costs will be found to be prudent and recoverable in rates and, as such, will not have a material adverse impact on the Company's consolidated results of operations.

The Company analyzed the costs and benefits of relicensing the Condit and American Fork hydroelectric projects and, as a result, entered into settlement agreements to remove or decommission these projects rather than to pursue new licenses. The removal of the Condit dam is projected to cost the Company approximately $19.4 million. Decommissioning of the American Fork project is expected to cost $1.0 million. These settlement agreements are contingent on acceptable orders being issued by the FERC and on obtaining all necessary permits.

Depreciation Rate Changes

On October 1, 2002, the Company filed applications with the respective regulatory commissions in Utah, Oregon, Wyoming, Washington and Idaho to change the rates of depreciation, based on a new depreciation study. The new study reflects depreciable plant balances at March 31, 2002. In Utah, settlement discussions have resulted in a stipulation with intervenors. On April 17, 2003, the UPSC approved the stipulation. The rates approved in the stipulation will reduce annual Utah allocated depreciation expense by $6.0 million. The Company and the Idaho Public Utilities Commission (the "IPUC") staff have agreed on a similar stipulation that will reduce Idaho's annual allocated depreciation expense by $0.9 million. This stipulation was filed with the IPUC on April 30, 2003. If adopted by all states, these depreciation rate changes would reduce total Company depreciation expense by $20.3 million annually, which could ultimately result in lower revenues or offset anticipated price increases. Future decisions by the commissions in Oregon, Washington and California may impact this annual expense reduction.

Trail Mountain Coal Mine Closure Costs

On February 7, 2001, the Company filed applications with the UPSC, the OPUC, the Wyoming Public Service Commission (the "WPSC") and the IPUC requesting accounting orders to defer $27.1 million in unrecovered costs associated with its Trail Mountain coal mine. The Company ceased operations at the mine on March 7, 2001. The mine is located in central Utah and supplied fuel to the Company's Hunter generating plant. In April 2001, the WPSC and the IPUC approved deferred accounting treatment of their states' share of the $27.1 million of nonrecovered Trail Mountain coal mine investment costs. Additional closure-related costs in the amount of $18.7 million were subsequently identified, and the total amount subject to possible deferral increased to approximately $45.8 million. The Company filed in Utah and Oregon to include the additional costs in its deferral application and received approval to defer the full $45.8 million for accounting purposes. In addition, the parties in Oregon signed a stipulation calling for a $1.1 million annual reduction in Oregon base rates due to the removal of the Trail Mountain coal mine assets from the rate base. The stipulation also provides for a $2.6 million annual surcharge for five years to recover Oregon's share of mine closure costs. This stipulation was approved by the OPUC on May 20, 2002. On April 4, 2002, the UPSC approved deferral of Utah's share of the $45.8 million, with a five-year amortization beginning April 1, 2001. On May 7, 2002, the Company filed a general rate case in Wyoming that sought to recover Wyoming's share of the $45.8 million, to be recovered based on a five-year amortization period beginning April 1, 2001. On March 6, 2003, the WPSC approved a stipulation that includes one-fifth of Wyoming's allocated share of Trail Mountain coal mine closure costs in annual base rates.

In April 2002, the Company established a regulatory asset for the full closure costs of the Trail Mountain coal mine, with a five-year amortization period beginning April 2001. The resulting regulatory asset at March 31, 2003 was $27.9 million, net of amortization. The reestablishment of the regulatory asset increased accumulated depreciation to reverse the effects of the retirement of the mine and decreased coal inventory costs for the closure-related costs.

Merger Credits

In connection with the merger between the Company and ScottishPower (the "Merger"), the Company was required to provide benefits to ratepayers through fixed reductions in rates, or "Merger Credits." The Company's total obligation for Merger Credits was $133.4 million through the period ending December 31, 2004. In May 2002, the UPSC allowed the Company to offset all future Merger Credits, which amounted to $20.6 million, against deferred net power costs. On June 7, 2002, the IPUC approved a stipulation agreement that allowed the Company to offset future Merger Credits against deferred net power costs in the amount of $2.3 million. These actions in Utah and Idaho eliminated the Merger Credit revenue reductions of approximately $1.1 million per month, which were set to expire December 31, 2003. In February 2003, the Company recorded $6.0 million in liabilities and current expenses for Merger Credits that will be refunded to Oregon customers during the calendar year ending December 31, 2003. Through March 31, 2003, the Company had provided an aggregate of $64.2 million in Merger Credits and interest to its customers through reduced rates. As of March 31, 2003, the Company was still obligated to provide $27.2 million of Merger Credits to customers in Oregon and Washington, through either bill credits or lower base rates.

Regulatory Established Returns

The regulatory commissions in the various states where the Company conducts its business approve an appropriate level of cost recovery for debt, preferred equity and common equity, which results in an allowed return on rate base ("ROR") for the Company's regulated utility business, including an allowed return on equity ("ROE") representing a return on shareholder investment. The Utah, Oregon and Wyoming commissions have approved RORs in recent general rate cases of 8.9%, 8.6% and 8.4%, respectively, and ROEs of 11.0%, 10.8% and 10.8%, respectively. Rate cases are underway in Utah, Oregon, Wyoming and California, in which the Company has requested an ROE of 11.5% in each of these states. Commissions in Washington and Idaho have not had recent hearings in which there was a specific finding of fact on allowed ROR or ROE. However, these commissions monitor the Company's achieved ROR and ROE for appropriateness under current market conditions.

Legislative Actions

The U.S. Senate has begun consideration of a comprehensive energy bill. The provisions of this proposed bill include repealing the PUHCA; prohibiting the FERC from making final its SMD rulemaking prior to July 1, 2005; extending the renewable-energy production tax credit for three years; authorizing federal utilities to participate in RTOs; establishing a process for developing mandatory reliability standards; reforming certain elements of the hydroelectric licensing process; enabling companies to use biodiesel to meet their alternative-fuel fleet requirements; and allowing Native American Tribes to enter into arrangements for energy facilities on tribal land. On April 11, 2003, the U.S. House of Representatives passed its version of comprehensive energy legislation. The bill contains many of the same proposals included in the U.S. Senate bill. The Company is unable to predict the prospects for enactment of a comprehensive energy bill, the specific content of final legislation or what material impact, if any, the outcome of this legislation may have on the Company's consolidated financial position, results of operations, cash flows, liquidity or capital expenditures.

Among the legislative measures approved in the Company's service territory, Senate Bill 61 in Utah has an impact on regulation and will go into effect in early summer 2003. This legislation provides an option for the UPSC to use a future test-year period in utility rate cases that more appropriately reflects the cost of providing service, and to reduce the period between capital investment or cost incurrence and recovery in rates.

Under the terms of legislation recently approved in Wyoming, the Consumer Advocate Staff (the "CAS") will no longer report to the WPSC. Under the new statute, the CAS will be headed by a director who is appointed by, and reports directly to, the Governor. The CAS will continue to intervene in utility rate cases to represent the interests of all customers.

Concluded Regulatory Actions

Oregon - On May 20, 2002, the OPUC approved a one-year $15.4 million overall rate increase effective June 1, 2002 for the Company's Oregon customers, to cover increases in power costs. This increase included an $18.7 million one-year surcharge relating to higher market costs for summer purchases and resolved a number of other outstanding issues. The Industrial Customers of Northwest Utilities (the "ICNU") requested limited reconsideration of the portion of this order relating to the lease of the West Valley, Utah generating units, involving $1.2 million of revenues annually. On August 8, 2002, the OPUC ordered this reconsideration. The ICNU, the Company and the OPUC staff have filed testimony. Opening briefs were filed April 11, 2003; reply briefs were filed on April 18, 2003; and an order from an ALJ is expected in summer 2003.

On May 13, 2003, the OPUC approved the Company's request to begin amortizing its year-ended March 31, 2002 costs under Oregon Senate Bill 1149 ("SB 1149") effective May 21, 2003. See Deregulation - *Oregon* below. The total costs of $5.2 million will be amortized on a straight-line basis over a five-year period, resulting in an annual rate increase of $1.1 million, or 0.1%. The amortization is subject to refund pending completion of an OPUC staff audit, which is scheduled to occur sometime in summer 2003.

Wyoming - On May 7, 2002, the Company filed a general rate case seeking a permanent $30.7 million, or 9.8%, increase in electricity rates for its Wyoming customers. On December 18, 2002, the Company revised the requested increase to $21.4 million. On January 17, 2003, the Company and the WPSC staff reached agreement on certain issues, which resulted in the Company revising its requested increase to $20.0 million, or 6.4%. The Company's filing also included a request to recover the replacement power costs resulting from the outage of the Company's Hunter No. 1 generating plant and a proposal for recovering deferred net power costs as discussed under Deferred

Net Power Costs - *Wyoming*. Hearings in this case were held during January 2003. On March 6, 2003, the WPSC granted the Company a general rate increase of approximately $8.7 million, or 2.8%, and reduced the Company's ROE from 11.0% to 10.8%. On April 4, 2003, the Company filed a request for rehearing to reconsider the Company's request for recovery of power costs and the order's adoption of the reduced ROE. The WPSC heard oral arguments on May 8, 2003 and denied the petition on May 30, 2003. See Deferred Net Power Costs - *Wyoming* below.

Idaho - On January 7, 2002, the Company filed a request with the IPUC to recover $38.0 million of deferred net power costs through a temporary 24-month surcharge on customer bills and to implement a new credit to pass through Residential Exchange Program benefits from two Bonneville Power Administrative ("BPA") settlement agreements. Pass-throughs of BPA credits do not affect Company earnings. In addition, the Company requested an adjustment of individual rate classes to more closely reflect the actual cost of service and proposed a rate mitigation policy to ensure that no customer class would receive a rate increase during the period in which the proposed surcharge is in effect. Parties to the proceeding agreed to a stipulation that would allow recovery of $25.0 million of the deferred net power costs. This recovery would be achieved through a $22.7 million power cost surcharge over two years, plus termination of future Merger Credits in the amount of $2.3 million. The IPUC approved the stipulation on June 7, 2002. On June 28, 2002, the Company filed a petition asking the IPUC to reconsider the portion of its June 7, 2002 order requiring that the Company implement a one-time refund of $1.1 million relating to procedural issues in the form of a $20.00 per customer credit. Two individuals also filed petitions for reconsideration of several aspects of the IPUC's order approving the stipulation. On July 24, 2002, the IPUC granted the Company's petition for reconsideration and denied the petitions from the two other parties. Hearings on the reconsideration were held on September 10, 2002. On October 25, 2002, the IPUC ordered the one-time refund of $1.1 million to be reduced to $10,000.

Rate Actions Submitted for Regulatory Approval

Utah - The Company commenced a general rate case on May 15, 2003 based on the year ended March 31, 2003 and including known and measurable changes that will occur by January 1, 2004. The initial filing included a projected revenue requirement increase of $125.0 million that serves as a cap on the amount the Company can receive in the case. A subsequent detailed filing will be made in July 2003 identifying the final requested amount under this cap. If approved, the effective date of the increase would be January 1, 2004, although the Company would not collect any increase until April 1, 2004.

Oregon - On March 18, 2003, the Company filed a general rate case with the OPUC to recover rising costs, including insurance premiums, pension funding and health care. Similar cost trends are being experienced by many businesses across the country, including others in the utility sector. In addition, the filing requested an ROE of 11.5% to compensate the Company for general risks relating to the western U.S. utility environment, as well as some additional risks relating to utility industry restructuring in Oregon and multijurisdictional operations. The Company has requested an annual increase of $57.9 million, or 7.4%, in base rates to take effect in January 2004.

Wyoming - On May 27, 2003, the Company filed a general rate case with the WPSC to recover rising costs (including insurance premiums, pension funding and health care costs) and requested an increase in the ROE to 11.5% to compensate the Company for general risks relating to the western U.S. utility environment, as well as some additional risks relating to multijurisdictional operations. The Company has requested an annual increase of $41.8 million, or 13.1%, in base rates to take effect in March 2004.

California - On March 16, 2001, the Company filed an interim rate relief request with the California Public Utilities Commission (the "CPUC") as Phase I in an effort to seek an increase in electricity rates for its customers in California. Subsequently, on December 20, 2001, the Company filed a general rate case to increase rates to compensatory levels. If approved by the CPUC, customer rates would increase 29.4% overall, or $16.0 million annually, with an authorized ROE of 11.5%. The annual amount requested incorporated the Phase I interim amount. On June 27, 2002, the CPUC approved an interim increase of $0.01 per kilowatt-hour ("kWh") for certain customers, or approximately $4.7 million annually, or 8.8%, overall. This rate increase is subject to refund pending the outcome of the general rate case. On December 26, 2001, the California Office of Ratepayer Advocates ("ORA") filed a motion to dismiss or defer the Company's general rate case request. The Company responded to ORA's motion on January 10, 2002. Following the expiration of the protest period, on February 25, 2002, the Company filed a motion for a prehearing conference to identify parties of record, establish a procedural schedule and address other issues. A discovery process began in mid-October 2002 and is ongoing. A prehearing conference was held on February 25, 2003. The CPUC and intervenor filed their testimony on May 23, 2003 for results of operations and are scheduled to file testimony on June 4, 2003 for cost allocation and rate design issues. Evidentiary hearings are scheduled for the week beginning June 23, 2003.

Deferred Net Power Costs

The Company filed applications in Utah, Oregon, Wyoming, Washington and Idaho seeking deferred accounting treatment for net power costs materially in excess of the power costs assumed in setting existing retail rates. The applications sought to defer these power cost variances beginning November 1, 2000. As discussed below, the Company received authorization to defer some power costs in excess of those included in retail rates in all the states where requests to do so were made. At March 31, 2003, the Company had remaining deferred power costs, net of amortization, of $137.8 million, including carrying costs.

Utah - In Utah, pursuant to the UPSC's approval of deferred accounting treatment for replacement power costs resulting from the Hunter No. 1 outage, the Company filed on August 23, 2001 seeking permission to recover $103.5 million in replacement power costs over a 12-month period. On November 2, 2001, the UPSC allowed the Company to apply overcollections under an interim relief order from an earlier general rate case toward Hunter No. 1 replacement power costs on an interim basis, subject to refund. The amount of the interim relief was approximately $29.5 million annually.

Also in Utah, on September 21, 2001, the Company filed for permission to defer $109.0 million of net power costs above the level adopted in the UPSC's rate order of September 10, 2001. These costs were incurred during the period May 9, 2001 through September 30, 2001. A hearing relating to the deferral was held on December 7, 2001.

On May 1, 2002, the UPSC issued an order approving a stipulation agreement regarding recovery of deferred and nondeferred net power costs referred to above. The order allowed the Company to continue collecting a $29.5 million annual surcharge until March 31, 2004 and to apply $34.7 million of revenue already collected (subject to refund) against deferred net power costs. The order also allowed the Company to offset deferred net power costs against a regulatory liability of $27.0 million relating to the gain from the May 2000 sale of the Centralia, Washington electricity plant and coal mine ("Centralia"). These offsets reduced the regulatory asset for deferred net power costs. In addition, the UPSC allowed the elimination of $20.6 million for the final two years of Merger Credits associated with the Merger. This action eliminated the Merger Credit revenue reduction of approximately $1.0 million per month that was set to expire December 31, 2003. The Company recorded additional deferred net power costs of $37.9 million and committed not to file a general rate case with a rate effective date prior to January 1, 2004, with certain exceptions. This order should allow the Company to recover a total of $147.0 million of deferred net power costs in Utah by March 31, 2004. One party opposed the rate spread provisions of the stipulation and filed a petition with the Utah Supreme Court for review of the order. The case has been assigned to the Utah Court of Appeals.

Oregon - The November 2000 Oregon deferred-accounting filing encompassed all power costs that vary from the level in Oregon rates during the period from November 1, 2000 through September 9, 2001, including costs to replace lost generation resulting from the Hunter No. 1 outage. On January 18, 2001, the Company requested a 3.0%, or $22.8 million, annual rate increase effective February 1, 2001, to provide partial recovery of post-October 31, 2000 power cost variances attributable to Oregon, over an amortization period. This 3.0% rate increase was the maximum allowed on an annual basis for the recovery of deferred costs under the Oregon statutes then in force. On February 13, 2001, the OPUC authorized deferred accounting for power costs of $22.8 million. On February 21, 2001, the OPUC authorized the 3.0% rate increase effective February 21, 2001, subject to refund, pending the outcome of a separate phase of the proceeding to examine the prudence of these expenditures.

The Company filed with the OPUC on September 20, 2001 to increase the level of recovery of deferred net power costs incurred to serve Oregon customers from the then current 3.0% amortization level, or $22.8 million awarded in February 2001, to 6.0%, the maximum allowed on an annual basis for recovery of deferred costs under a change in Oregon law. On October 22, 2001, the OPUC suspended the Company's request pending the outcome of the prudence phase of the proceeding.

In December 2001, the Company and the OPUC staff reached a stipulation in the prudence phase of the Company's deferred net power cost proceeding. The stipulation provided that the Company would be permitted to recover 85.0% of the deferred net power costs in Oregon, or about $131.0 million, plus carrying charges. The stipulation allowed the Company to seek increased recovery in the event the Company's appeal of the Commission's order limiting deferrals is successful. On July 18, 2002, the OPUC issued an order approving the stipulation and ending the prudence phase of the proceeding. On September 16, 2002, the Citizens' Utility Board (the "CUB") and the ICNU appealed this decision to the Marion County, Oregon Circuit Court. On October 11, 2002, the Company moved to intervene in this action. On March 26, 2003, the court issued a letter affirming the OPUC's July 18, 2002 order. The ICNU and the CUB are likely to appeal to the Oregon Court of Appeals.

On August 6, 2002, the OPUC allowed the Company to increase the amortization level from 3.0% to 6.0%. The new rates were effective August 8, 2002. As of March 31, 2003, the Company had received $7.3 million in revenues as a result of this OPUC action. On August 19, 2002, the CUB and the ICNU filed a complaint with the OPUC, requesting that the OPUC require the Company to discontinue amortization of the additional 3.0%, challenging the approval itself based on procedural technicalities during the approval proceeding. On October 10, 2002, the Company filed a stipulation and tariff to allow the OPUC to reopen consideration of the increase in amortization of the deferred power costs from 3.0% to 6.0%. Subject to regulatory approval, the Company and the CUB have reached a stipulation agreement that the amortization level will remain at 6.0% and that the amounts amortized after the OPUC implements the tariff will be subject to refund. The refund will occur if an order or ruling is issued declaring all or a portion of these deferred costs imprudent or otherwise disallowing recovery. On October 14, 2002, the ICNU filed a response to the Company's motion to implement the stipulation and proposed tariff. The ICNU's response asked that the motion be denied as being procedurally improper. On December 10, 2002, the OPUC approved the voluntary stipulation and ordered the Company to file a tariff to implement the change. The tariff was approved by the OPUC, with an effective date of January 22, 2003. Amounts subject to refund would include only those collections occurring after January 22, 2003. On February 7, 2003, the ICNU filed a motion requesting the OPUC to reconsider parts of its December 10, 2002 order relating to conclusions regarding the August 6, 2002 decision to increase the amortization level. The OPUC denied this motion on March 27, 2003.

In addition, the ICNU and the CUB have filed a complaint against the Company regarding the implementation of the August 2002 rate change. The ICNU and the CUB filed opening briefs on March 27, 2003. The Company and the OPUC filed their respective briefs on April 23, 2003. The CUB and the ICNU filed their joint reply brief on May 7, 2003.

While the 6.0% increase established the maximum annual rate to be recovered, the Company continued to pursue the total amount to be recovered through its October 2, 2001 appeals to the Marion County, Oregon Circuit Court, mentioned above, of two OPUC orders. These orders established the mechanism to determine the amount of power costs to defer. On June 6, 2002, the Marion County, Oregon Circuit Court upheld the OPUC decision. On October 9, 2002, the Company appealed this decision to the Oregon Court of Appeals. On November 27, 2002, the Company filed its opening brief. The ICNU filed a response brief on January 14, 2003. The OPUC filed its brief on February 12, 2003, and the Company submitted its reply on March 5, 2003. Oral arguments have been set for July 17, 2003.

On September 7, 2001, the OPUC endorsed an agreement on deferral of net power costs after September 2001. From September 10, 2001 until May 31, 2002, the Company deferred the difference between 83.0% of actual net power costs and the new Oregon baseline power cost in tariffs. This mechanism was terminated on May 31, 2002, concurrent with the effective date of the settlement approved on May 20, 2002.

Wyoming - In Wyoming, on November 1, 2000, the Company filed for deferred accounting treatment of net power costs that vary from costs included in determining retail rates. On April 3, 2001, the Company filed an application to recover the excess power costs accrued during the period November 30, 2000 through January 31, 2001. On November 20, 2001, following an order by the WPSC dismissing the majority of the Company's case based on a procedural issue, the Company requested authority to withdraw its deferred net power cost recovery filing without prejudice. On November 26, 2001, the WPSC granted this request. On May 7, 2002, the Company filed a request to recover replacement power costs of $30.7 million, resulting from the outage of the Company's Hunter No. 1 generating plant and a proposal for recovering deferred net power costs authorized by the WPSC in December 2000, for $60.3 million. On March 6, 2003, the WPSC denied recovery of the Hunter No. 1 replacement power costs and the deferred net power costs. As a result, the Company wrote-off the remaining net asset of $48.3 million during the year ended March 31, 2003. The Company filed a petition for rehearing on the decision on April 4, 2003. The WPSC denied the petition on May 30, 2003.

Washington - On April 5, 2002, the Company filed a petition with the Washington Utilities and Transportation Commission (the "WUTC") seeking authority to begin deferring net power costs in excess of those included in rates as of June 1, 2002 for later recovery in rates, either through a power cost adjustment mechanism or a limited rate adjustment. Under the rate plan approved by the WUTC in August 2000 at the conclusion of the Company's last general rate case in Washington, there are limitations on the Company's ability to request changes to general rates prior to January 2006. On October 18, 2002, the Company filed testimony and supporting documents, requesting deferral and recovery of excess power costs estimated at the time to be $17.5 million, including carrying charges, or, alternatively, to allow the Company to file a general rate case, which is currently restricted through December 2005. Based on actual data through December 2002, the deferral is expected to total $15.9 million. Hearings were held March 20-24, 2003, and a decision is expected by June 2003.

Idaho - On March 28, 2003, the Company filed an application with the IPUC to defer certain costs for regulatory purposes. The costs include approximately $2.5 million in excess costs incurred for forward electricity purchases made during the western energy crisis for summer 2002, as well as $3.5 million in federal and state tax audit determination payments made during the year ended March 31, 2003 as a result of Internal Revenue Service (the "IRS") income tax audits. Other regulatory action in Idaho regarding deferred net power costs is described under Concluded Regulatory Actions - *Idaho.*

Demand-Side Management

The Company continues to offer its energy exchange program in its service territories in Utah, Oregon, Wyoming, Washington and Idaho. This program consists of optional, supplemental services that give participating customers an opportunity to reduce their electricity usage in exchange for a payment at times and at prices determined by the Company. The program is designed to help address periods of high wholesale prices and peaks in demand when they occur. Customers with usage as low as one MW may participate in the program. As part of the RFP process, the Company is preparing a separate RFP for the demand-side resources called for in the IRP.

In Utah, the Company is working on several programs. The Company filed an evaporative cooling and central air conditioning incentive program to reduce summer peak loads by encouraging installation of either evaporative cooling or high-efficiency central (also known as unitary) air-conditioning equipment. This program was approved by the UPSC on March 24, 2003. On April 9, 2003, the Company filed an air-conditioning load-control services program to help the Company manage the growth of weather-driven peak loads. This program was approved by the UPSC on May 14, 2003. On April 24, 2003, the Company filed a request for an experimental interruptible-service rider to reduce peak summer loads. The requested effective implementation date of this program is June 1, 2003. On May 5, 2003, the Company filed a refrigerator recycling program, which is intended to encourage customers to remove and recycle secondary refrigerators and/or to upgrade primary refrigerators to more energy-efficient models. The Company has requested that this program be approved by June 16, 2003.

The Company has also filed for a DSM tariff in Utah. This tariff would allow the Company to recover DSM expenditures through a surcharge to customer bills. Several technical conferences have been held with interested parties, and hearings have been scheduled for mid-August 2003.

On January 31, 2003, the Company filed an irrigation load-control credit program with the IPUC. This optional program would offer participants load-control billing credits in exchange for prescheduled load-control events during three and a half months of the summer irrigation season (June 1 through September 15). On March 17, 2003, the IPUC approved the program.

Multistate Process (the "MSP")

The Company continues its active involvement in a collaborative process with the six states it serves, to develop mutually acceptable solutions to the problems faced by the Company and the states as a result of the Company's multistate operations. These problems pertain to the allocation of some of the cost of the Company's existing investments and the recovery of the cost of future investments. Between April and December 2002, the Company and key parties from Utah, Oregon, Wyoming, Washington and Idaho, along with a key monitoring contact from California, analyzed over 50 options, which were narrowed to two possibilities. Both seek to clarify roles and responsibilities, including cost allocations for future generation resources, providing states with the ability to independently implement state energy policy objectives, and to achieve permanent consensus on each state's responsibility for the costs and entitlement to the benefits of the Company's existing assets. A second phase of the collaborative process is under way, in which the parties will further assess the two proposals, with the goal of agreeing to a single proposal in July 2003.

The MSP was initiated in response to the Company's Structural Realignment Proposal (the "SRP"), which would change the Company's legal and regulatory structure and result in the creation of six state electric distribution companies, a generation company that also holds transmission assets, and a service company, which are all intended to be subsidiaries of the holding company. Individual state proceedings and schedules for the SRP are on hold so long as reasonable progress is made through the MSP. Any proposal that results from the MSP must be subsequently approved by the utility commissions in Utah, Oregon, Wyoming, Washington, Idaho and California. Approval from the FERC may also be required.

Deregulation

Industry restructuring to open the electric wholesale market to competition was initially promoted by passage of the Energy Policy Act of 1992 (the "Energy Act"). The Energy Act gave the FERC authority to require electric utilities to provide infrastructure and transmit electricity to or for wholesale purchasers and sellers. The Energy Act also created a new class of independent power plant owners that are able to sell generation only in wholesale markets. Deregulation in the states where the Company operates has varied significantly. No significant actions have occurred in Utah, Wyoming, Washington or Idaho. Oregon and California developments are discussed below.

Oregon - During 1999, SB 1149 was enacted in Oregon requiring competition for all nonresidential customers of both the Company and Portland General Electric Company. Under the legislation, the Company is required to unbundle rates for generation, transmission, distribution and other retail services, and to offer residential customers a cost of service rate option and a portfolio of rate options that include new renewable-energy resources and market-based generation. SB 1149 authorizes the OPUC to make decisions on certain matters, in particular the method for valuation of stranded costs/benefits. The Company continues to participate in the OPUC proceedings to establish the rules and procedures related to SB 1149. Implementation of SB 1149 began March 1, 2002, when the Company provided all customers with a cost of service rate option for an indefinite period and allowed industrial and large commercial customers a choice of energy provider. For the calendar year ending December 31, 2003, 26 customers, representing less than three average MW of load, elected an alternative plan. To date, adoption of SB 1149 has not had a significant financial impact on the Company's results.

California - In 1998, California became one of the first states in the country to implement electric industry restructuring with the goal of establishing a competitive market for electric generation. The framework for electric industry restructuring was established in Assembly Bill 1890 ("AB 1890"), passed by the California Legislature and signed by the Governor in 1996. Under AB 1890, large utilities were encouraged to divest a significant portion of their owned generation portfolio in order to reduce their market power and encourage development of a competitive power supply market. Certain plant types, primarily nuclear and hydroelectric plants, and small and multi-jurisdictional utilities were excluded. Beginning March 31, 1998, Californians were given the choice to purchase electricity from generation providers other than the traditional utilities ("direct access"). For those customers who did not choose direct access, investor-owned utilities were to continue to purchase electric power on their behalf. Investor-owned utilities continued to provide distribution services to substantially all customers within their service territories, including those customers who chose direct access. However, in response to the western power crisis, the CPUC suspended the ability of customers to choose suppliers, on a prospective basis, in fall 2001.

As required by AB 1890, electric rates for all customers were frozen at the level in effect on June 10, 1996, and, beginning January 1, 1998, rates for residential and small commercial customers were reduced by 10.0% from 1996 levels. On June 27, 2002, the CPUC approved an interim increase of $0.01 per kWh for certain customers, or approximately $4.7 million, or 8.8%, annually, overall.

In July 1998, the Company announced its intention to sell its California service territory, including its electric distribution assets, to Nor-Cal. Consummation of the sale is uncertain. See SERVICE TERRITORIES.

ITEM 2. PROPERTIES

The Company owns, or has an interest in, 53 hydroelectric generating plants with an aggregate nameplate rating of 1,067.3 MW and plant net capability of 1,115.8 MW. It also owns or has interests in 17 thermal-electric generating plants with an aggregate nameplate rating of 7,309.8 MW and plant net capability of 6,776.9 MW. The Company also jointly owns one wind electricity generating plant with an aggregate nameplate rating and plant net capability of 32.6 MW. The following table summarizes the Company's existing generating facilities:

	Location	Energy Source	Unit Installation Date(s)	Nameplate Rating (MW)	Plant Net Capability (MW)
HYDROELECTRIC PLANTS (a)					
Swift (b)	Cougar, WA	Lewis River	1958	240.0	263.6
Merwin	Ariel, WA	Lewis River	1931–1958	135.0	144.0
Yale	Amboy, WA	Lewis River	1953	134.0	134.0
Five North Umpqua Plants	Toketee Falls, OR	N. Umpqua River	1950–1956	133.5	136.5
John C. Boyle	Keno, OR	Klamath River	1958	80.0	84.0
Copco Nos. 1 and 2 Plants	Hornbrook, CA	Klamath River	1918–1925	47.0	54.5
Clearwater Nos. 1 and 2 Plants	Toketee Falls, OR	Clearwater River	1953	41.0	41.0
Grace	Grace, ID	Bear River	1908–1923	33.0	33.0
Prospect No. 2	Prospect, OR	Rogue River	1928	32.0	34.0
Cutler	Collingston, UT	Bear River	1927	30.0	29.1
Oneida	Preston, ID	Bear River	1915–1920	30.0	28.0
Iron Gate	Hornbrook, CA	Klamath River	1962	18.0	19.5
Soda	Soda Springs, ID	Bear River	1924	14.0	14.0
Fish Creek	Toketee Falls, OR	Fish Creek	1952	11.0	12.0
33 Minor Hydroelectric Plants (c)	Various	Various	1896–1990	88.8*	88.6*
Subtotal (53 Hydroelectric Plants)				1,067.3	1,115.8
THERMAL ELECTRIC PLANTS					
Jim Bridger	Rock Springs, WY	Coal–Fired	1974–1979	1,541.1*	1,413.4*
Huntington	Huntington, UT	Coal–Fired	1974–1977	996.0	895.0
Dave Johnston	Glenrock, WY	Coal–Fired	1959–1972	816.8	762.0
Naughton	Kemmerer, WY	Coal–Fired	1963–1971	707.2	700.0
Hunter Nos. 1 and 2	Castle Dale, UT	Coal–Fired	1978–1980	727.9*	662.5*
Hunter No. 3	Castle Dale, UT	Coal–Fired	1983	495.6	460.0
Cholla No. 4	Joseph City, AZ	Coal–Fired	1981	414.0*	380.0*
Wyodak	Gillette, WY	Coal–Fired	1978	289.7*	268.0*
Carbon	Castle Gate, UT	Coal–Fired	1954–1957	188.6	175.0
Craig Nos. 1 and 2	Craig, CO	Coal–Fired	1979–1980	172.1*	165.0*
Colstrip Nos. 3 and 4	Colstrip, MT	Coal–Fired	1984–1986	155.6*	144.0*
Hayden Nos. 1 and 2	Hayden, CO	Coal–Fired	1965–1976	81.3*	78.0*
Blundell	Milford, UT	Geothermal	1984	26.1	23.0
Gadsby	Salt Lake City, UT	Gas–Fired	1951–2002	392.6	349.0
Hermiston	Hermiston, OR	Gas–Fired	1996	237.0*	236.0*
Little Mountain	Ogden, UT	Gas–Fired	1971	16.0	14.0
James River	Camas, WA	Black Liquor	1996	52.2	52.0
Subtotal (17 Thermal Electric Plants)				7,309.8	6,776.9
OTHER PLANTS					
Foote Creek	Arlington, WY	Wind Turbines	1998	32.6*	32.6*
Subtotal (1 Other Plant)				32.6	32.6
Total Hydro, Thermal and Other Generating Facilities (71)				8,409.7	7,925.3

* Jointly owned plants; amount shown represents the Company's share only.

(a) Hydroelectric project locations are stated by locality and river watershed.

(b) On April 21, 2002, a failure occurred in the Swift power canal on the Lewis River in the state of Washington. The power canal and associated 70-MW hydroelectric facility ("Swift No. 2") are owned by Cowlitz County Public Utility District ("Cowlitz"). It is anticipated that Cowlitz will repair Swift No. 2 in time for a calendar-year 2005 startup. The failure impacted, but did not damage, the Company-owned and operated 240-MW Swift No. 1 hydroelectric facility ("Swift No. 1"), which is upstream of the Swift power canal, by restricting both flow and generation flexibility ("shaping"). Repairs to the canal were completed and Swift No. 1 was returned to full capacity levels as of mid-July 2002 (though with limited shaping capabilities). Environmental, operations safety and fish mitigation issues remain to be resolved before full use of Swift No. 1 can resume. The Company continues to seek ways to mitigate any capacity and shaping limitations and to recover any business losses. The full impact of the Swift power canal outage and plans for repair of the Swift No. 2 facility are still being determined. The Company is seeking reimbursement from Cowlitz of the Company's expenditures associated with the Swift No. 2 failure, including canal modifications and energy replacement costs. This event is not expected to have a significant impact on the Company's consolidated financial position or results of operations.

(c) The Company is currently negotiating with the FERC and other interested parties to decommission the Condit, Powerdale and American Fork plants that have a combined net capability of 21.9 MW. In addition, the Company has entered into a sales agreement for the Naches and Naches Drop hydroelectric plants located near Yakima, Washington, with a combined net capability of 7.7 MW. The final phase of the sale is scheduled to close in September 2003.

The Company's generating facilities are interconnected through its own transmission lines or by contract through the transmission lines of other transmission owners. Substantially all of the Company's generating facilities and reservoirs are managed on a coordinated basis to obtain maximum load-carrying capability and efficiency. Portions of the Company's transmission and distribution systems are located, by franchise or permit, upon public lands, roads and streets and, by easement or license, upon the lands of other third parties.

Substantially all of the Company's electric utility property is subject to the lien of the Company's Mortgage and Deed of Trust.

The following table describes the Company's recoverable coal reserves as of March 31, 2003. All coal reserves are dedicated to nearby Company-operated generating plants. Recoverability by surface mining methods typically ranges from 90.0% to 95.0%. Recoverability by underground mining techniques ranges from 50.0% to 70.0%. The Company believes that the respective coal reserves assigned to the Craig, Huntington, Hunter and Jim Bridger plants, together with coal available under both long-term and short-term contracts with external suppliers, will be sufficient to provide these plants with fuel that meets the Clean Air Act standards effective in 1999, for their current economically useful lives. Blending of Company-owned and contracted coal, together with electricity plant control technologies for controlling sulfur and other emissions, are utilized to meet the applicable standards. The sulfur content of the coal reserves ranges from 0.30% to 0.94%, and the British Thermal Units value per pound of the reserves ranges from 8,600 to 12,400. Coal reserve estimates are subject to adjustment as a result of the development of additional data, new mining technology and changes in regulation and economic factors affecting the utilization of such reserves. Recoverable coal reserves at March 31, 2003, based on most recent engineering studies, were as follows:

Location	Plant Served	Recoverable Tons (in Millions)	
Craig, CO	Craig	49	(a)
Emery County, UT	Huntington and Hunter	54	(b)
Rock Springs, WY	Jim Bridger	93	(c)

(a) These coal reserves are leased and mined by Trapper Mining, Inc., a Delaware nonstock corporation operated on a cooperative basis, in which the Company has an ownership interest of 21.4%.

(b) These coal reserves are mined by subsidiaries of PacifiCorp and are in underground mines.

(c) These coal reserves are leased and mined by Bridger Coal Company, a joint venture between Pacific Minerals, Inc. and a subsidiary of Idaho Power Company. Pacific Minerals, Inc., a subsidiary of PacifiCorp, has a two-thirds interest in the joint venture.

Most of the Company's coal reserves are held pursuant to leases from the federal government through the Bureau of Land Management and from certain states and private parties. The leases generally have multiyear terms that may be renewed or extended and require payment of rents and royalties. In addition, federal and state regulations require that comprehensive environmental protection and reclamation standards be met during the course of mining operations and upon completion of mining activities. In the year ended March 31, 2003, the Company expended $12.5 million in reclamation costs and accrued $18.5 million of estimated final mining reclamation costs for the Glenrock Mine. The Company and Idaho Power have previously contributed funds to a trust for the reclamation of the Bridger Mine. Due to recent declines in the equity markets, the funds have experienced declines in fair value, which may require the Company to resume funding in order to meet the reclamation obligations. At March 31, 2003, these reclamation funds totaled $68.5 million, of which the Company's portion is $45.7 million, and the Company had an accrued reclamation liability for all mine reclamation of $121.6 million.

ITEM 3. LEGAL PROCEEDINGS

The Company is a party from time to time in various legal claims, actions and complaints. Although it is impossible to predict with certainty whether or not the Company will ultimately be successful in its legal proceedings or, if not, what the impact might be, management believes that disposition of these matters will not have a material adverse effect on the Company's consolidated financial results. See **ITEM 1. BUSINESS -** REGULATION for information concerning pending regulatory proceedings.

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

No information is required to be reported pursuant to this item.

PART II

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

PacifiCorp is an indirect subsidiary of ScottishPower, which owns all 312,176,089 shares of PacifiCorp's outstanding common stock. Therefore, there is no public market for PacifiCorp's common stock. Dividend information required by this item is included in QUARTERLY FINANCIAL DATA under **ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA**.

The Company is restricted from paying dividends or making other distributions without prior OPUC approval, to the extent such payment or distribution would reduce the Company's common stock equity below a specified percentage of its total capitalization. The percentage of total capitalization increases over time from 35.0% after December 31, 1999 to 40.0% after December 31, 2004. As of March 31, 2003, the minimum ratio was 38.0%. In addition, the Company must give the OPUC 30 days' prior notice of any special cash dividend or any transfer involving more than five percent of the Company's retained earnings in a six-month period. The Company is also subject to maximum debt-to-total capitalization ratios under various debt agreements.

Under the PUHCA, the Company may pay dividends out of capital or unearned surplus only with SEC approval. Dividends from earned surplus are permitted without approval. The Company has received approval to pay dividends out of unearned surplus of the lesser of $900.0 million or the proceeds received from sales of nonutility assets. At March 31, 2003, $300.0 million was available for dividends out of unearned surplus.

On December 19, 2002, the Company issued 14,851,485 shares of its common stock to PHI at a total price of $150.0 million, or $10.10 per share.

ITEM 6. SELECTED FINANCIAL DATA

SELECTED FINANCIAL INFORMATION (UNAUDITED)

(Millions of dollars, except per share and employee amounts)	Years Ended March 31, 2003	2002	2001	2000	Three Months Ended March 31, 1999	Year Ended December 31, 1998
Revenues						
[redacted]						
Australian Operations	—	—	399.3	617.6	147.0	614.5
[redacted]						
Total	$ 3,593.4	$4,235.3	$ 5,055.7	$3,986.9	$ 959.8	$ 5,580.4
Income (Loss) from Operations						
[redacted]						
Australian Operations	—	27.4	(133.1)	125.1	34.8	114.5
[redacted]						
Total	$ 488.9	$ 641.0	$ 339.8	$ 705.1	$ 227.5	$ 680.8
[redacted]						
Earnings Contribution (Loss)						
Continuing operations						
Electric Operations	$ 134.7	$ 232.8	$ 110.1	$ 10.9	$ 75.4	$ 130.5
[redacted]						
Other Operations (a)	—	20.5	(29.0)	13.8	0.7	(52.2)
[redacted]						
Discontinued operations (b)	—	146.7	—	1.1	—	(146.7)
[redacted]						
Total	$ 132.8	$ 314.6	$ (106.1)	$ 64.8	$ 86.5	$ (55.4)
[redacted]						
Common dividends paid per share	$ —	$ 1.00	$ 1.12	$ 0.85	$ 0.27	$ 1.08

	March 31, 2003	2002	2001	2000	December 31, 1998
Capitalization					
[redacted]					
Long-term debt	3,417.6	3,553.8	2,906.9	4,045.7	4,383.5
[redacted]					
Junior subordinated debentures	—	—	—	175.8	175.8
[redacted]					
Preferred stock	41.3	41.3	41.5	41.5	66.4
[redacted]					
Total	$ 7,224.0	$ 7,224.7	$ 7,170.7	$ 8,954.7	$ 9,657.3
[redacted]					
Total Employees	6,140	6,287	6,626	8,832	9,120

(a) Other Operations includes the operations of PPM and Pacific Klamath Energy, Inc. ("PKE") until their transfer in March 2001 and of PacifiCorp Financial Services, Inc. ("PFS"), as well as the activities of PacifiCorp Group Holdings Company ("PGHC"), including financing costs and elimination entries, until their transfer in February 2002.

(b) Amounts in 2002 represent the collection of a contingent note receivable relating to the discontinued operations of a former mining and resource development business, NERCO, Inc. ("NERCO"). The amount in 2000 represents discontinued operations of TPC Corporation.

(c) Represents the effect of implementation of Statement of Financial Accounting Standards ("SFAS") No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS No. 133"), in the year ended March 31, 2002 and Revised Issue C15, *Normal Purchase and Normal Sales Exception for Certain Option-Type Contracts and Forward Contracts in Electricity* ("Issue C15"), and Issue C16, *Applying the Normal Purchases and Normal Sales Exception to Contracts that Combine a Forward Contract and a Purchased Option Contract* ("Issue C16"), in the year ended March 31, 2003.

ELECTRIC OPERATIONS (UNAUDITED)

	Years Ended March 31,				Three Months Ended March 31,	Year Ended December 31,
(Millions of dollars, except as noted)	2003	2002	2001	2000	1999	1998
Revenues						
[redacted]						
Commercial	763.4	747.7	710.5	667.2	159.0	653.5
[redacted]						
Other	31.4	34.5	32.5	30.4	7.2	30.2
[redacted]						
Wholesale sales	1,052.0	1,684.7	2,078.1	1,029.1	240.0	2,583.6
[redacted]						
Total	3,593.4	4,222.7	4,534.2	3,292.2	807.2	4,845.1
Expenses						
[redacted]						
Fuel	482.2	490.9	491.0	512.3	126.5	506.6
[redacted]						
Depreciation and amortization	434.3	401.3	389.0	379.9	88.6	353.5
[redacted]						
Taxes, other than income taxes	93.4	90.7	97.5	99.3	25.9	97.5
[redacted]						
Special charges	—	—	—	—	—	123.4
[redacted]						
Other operating income		(21.0)	(30.6)	—	—	—
[redacted]						
Income from Operations	488.9	598.6	453.1	587.8	195.6	571.8
[redacted]						
Interest income	(21.6)	(28.9)	(10.7)	(5.0)	—	—
[redacted]						
Merger costs	—	—	9.3	190.5	—	13.2
[redacted]						
Income tax expense	97.2	138.6	87.6	125.2	53.8	102.9
[redacted]						
Cumulative effect of accounting change	(1.9)	(112.8)	—	—	—	—
[redacted]						
Preferred Dividend Requirement	(7.3)	(12.7)	(17.9)	(18.9)	(4.8)	(19.3)
[redacted]						
Total assets	$10,993.0	$10,877.6	$11,050.7	$11,243.3		$ 12,051.8
[redacted]						

(a) Does not reflect elimination of interest on intercompany borrowing arrangements includes income taxes on a separate-company basis.

ELECTRIC OPERATIONS STATISTICS (UNAUDITED)

	Years Ended March 31,				Three Months Ended March 31,	Year Ended December 31,
	2003	2002	2001	2000	1999	1998
Energy Sales (Thousands of MWh)						
[redacted]						
Commercial	14,006	13,810	13,634	12,827	2,993	12,299
[redacted]						
Other	631	711	705	663	153	651
[redacted]						
Wholesale sales	30,485	24,264	27,502	34,327	9,636	94,077
[redacted]						
Energy Source						
Coal	57.5%	62.6%	56.0%	58.0%	54.0%	51.0%
[redacted]						
Other	0.1	0.2	4.0	3.0	3.0	2.0
[redacted]						
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Number of Retail Customers (Thousands)						
[redacted]						
Commercial	186	182	179	174	169	174
[redacted]						
Other	5	4	4	4	5	5
[redacted]						
Residential Customers						
Average annual usage (kWh)	10,182	10,411	10,614	10,463		10,443
[redacted]						
Revenue per kWh	6.9¢	6.7¢	6.3¢	6.1¢		6.2¢
Miles of Line						
[redacted]						
Distribution						
— overhead	43,765	43,800	43,700	43,600		45,000
[redacted]						
System Peak Demand (MW)						
Net system load (a)						
— summer	8,549	7,899	8,056	7,570		7,666
[redacted]						
Total firm load (b)						
— summer	9,542	10,029	10,115	10,494		11,629
[redacted]						

(a) Excludes off-system sales.

(b) Includes firm off-system sales.

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

OVERVIEW

The Company has separated its nonutility operations from its regulated utility operations through corporate restructuring, in order to facilitate an increased focus on its regulated energy businesses in the western U.S. On December 31, 2001, NA General Partnership ("NAGP") transferred all of the common stock of the Company to PHI. The Company then transferred all of the capital stock of PGHC to PHI in February 2002. PGHC includes the wholly owned subsidiary, PFS, a financial services business. As a result of this transfer, the operations of PGHC are included in the Company's Statements of Consolidated Income and Statements of Consolidated Cash Flows for the year ended March 31, 2001 and for the first 10 months of the year ended March 31, 2002, but are not included for the year ended March 31, 2003.

In March 2001, the Company sold its interest in PPM and PKE, two nonutility energy companies, to PHI. As a result, the operations of the transferred companies are included in the Company's Statements of Consolidated Income and Statements of Consolidated Cash Flows for the year ended March 31, 2001, but are not included for the years ended March 31, 2003 and 2002.

PGHC, while a subsidiary of the Company, completed the sales of its ownership of Powercor Australia Ltd. ("Powercor") on September 6, 2000 and its 19.9% interest in Hazelwood Power Partnership ("Hazelwood") on November 17, 2000. Powercor, an indirectly owned subsidiary of the Company, and Hazelwood represented the entire Australian Operations segment of the Company. Australian Operations' financial results for the period from January 1, 2000 to the respective dates of sale are included in the Company's financial results for the year ended March 31, 2001.

FORWARD-LOOKING STATEMENTS

The information in the tables and text in this document includes certain forward-looking statements that involve a number of risks and uncertainties under the safe-harbor provisions of the Private Securities Litigation Reform Act of 1995 that may influence the financial performance and earnings of the Company. When used in this report on Form 10-K, the words "estimates," "expects," "anticipates," "forecasts," "plans," "intends" and variations of such words and similar expressions are intended to identify forward-looking statements that involve risks and uncertainties. There can be no assurance that the results predicted would be realized. Actual results may vary from those represented by the forecasts, and those variations may be material. The following are among the factors that could cause actual results to differ materially from the forward-looking statements:

- changes in prices and availability of wholesale electricity, natural gas, fuel costs and other changes in operating costs, which could affect the Company's cost recovery;
- changing conditions in wholesale power markets, such as general credit constraints and thin trading volumes, that could make it difficult for the Company to enter into purchase and sale agreements;
- the actions of securities rating agencies, including the determination of whether or when to make changes in the Company's credit ratings and the impact of current or lowered ratings and other financial market conditions on the ability of the Company to obtain needed financing on reasonable terms or at all;
- actions by state and federal regulatory bodies setting rates and adopting or modifying cost recovery, accounting and rate-setting mechanisms, as well as legislative or judicial actions affecting the same matters;
- the effects of increased competition in energy-related businesses, including new market entrants and the effects of new technologies that may be developed in the future;
- attempts by municipalities within the Company's service territory to form public power entities and/or acquire the Company's facilities;
- hydroelectric conditions and gas and coal production levels, which could have a potentially serious impact on electric capacity and cost and on the Company's ability to generate electricity;

- changes in weather conditions and other natural disasters that could affect customer demand or electricity supply;
- the impact from the possible formation of an RTO and the impact from the implementation of the FERC's proposed SMD;
- the impact of enhanced physical and information security requirements imposed through legislation or regulation;
- the outcome of pending IRS tax audits and settlements;
- the impact of regional, national and international economic and political conditions, including acts of terrorism, war or similar events;
- employee work-force factors, including strikes, work stoppages, availability of qualified employees or loss of key executives;
- the ability to obtain adequate insurance coverage and the cost of such insurance;
- changes in, and compliance with, environmental and endangered species laws, regulations, decisions, and policies;
- industrial, commercial and residential growth and demographic patterns in the Company's service territories;
- competition and supply in bulk electricity and natural gas markets;
- unscheduled generation outages and disruption or constraints to transmission or distribution facilities;
- changes in regulatory or other legislation, including industry restructuring and deregulation initiatives;
- the outcome of threatened or pending litigation;
- changes in tax rates and/or policies;
- changes in actuarial assumptions and the return on assets associated with the Company's pension plan, which could impact future funding obligations, costs and pension plan liabilities;
- increasing health care costs associated with employee health insurance premiums and the obligation to provide postretirement health care benefits;
- unanticipated delays or changes in construction costs relating to present or future generating facilities;
- new accounting pronouncements;
- the outcome of rate cases submitted for regulatory approval; and
- the cost, feasibility and eventual outcome of hydroelectric facility relicensing proceedings.

Any forward-looking statements issued by the Company should be considered in light of these factors. The Company assumes no obligation to update or revise any forward-looking statements to reflect actual results, changes in assumptions or changes in other factors affecting such forward-looking statements or if the Company later becomes aware that these assumptions are not likely to be achieved.

CRITICAL ACCOUNTING POLICIES

The preparation of 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 results of operations and the reported amounts of assets and liabilities in the consolidated financial statements. The estimates and assumptions may change as time passes and accounting guidance evolves. Management bases its estimates and assumptions on historical experience and on other various judgments that it believes are reasonable at the time of application. Changes in these estimates and assumptions could have a material impact on the consolidated financial statements. If estimates and assumptions are different than the actual amounts recorded, adjustments are made in subsequent periods to take into consideration the new information. Critical accounting policies, in addition to certain less significant accounting policies, are discussed with senior members of management and the Company's Board of Directors (the "Board"), as appropriate. Those policies that management considers critical are described below.

Regulation

The Company prepares its consolidated financial statements in accordance with SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71"). A regulated company must satisfy the following conditions in order to apply the accounting policies and practices of SFAS No. 71 an independent regulator must set rates to cover specific costs of delivering service, and the service territory must lack competitive pressures to reduce rates below the rates set by the regulator. SFAS No. 71 requires the Company to reflect the impact of regulatory decisions in its consolidated financial statements and requires that certain costs be deferred on the balance sheet until matching revenues can be recognized. Similarly, certain items may be deferred as regulatory liabilities and amortized to the income statement as rates to customers are reduced. SFAS No. 71 provides that regulatory assets may be capitalized if it is probable that future revenue in an amount at least equal to the capitalized costs will result from the inclusion of those costs in allowable costs for ratemaking purposes. In addition, the rate action should permit recovery of the specific previously incurred cost rather than provide for expected levels of similar future costs.

If the Company should determine in the future that it no longer meets the criteria for continued application of SFAS No. 71, the Company could be required to write off its regulatory assets and liabilities unless regulators specify some other means of recovery or refund. The Company intends to seek recovery of costs, including stranded costs, in the event of deregulation. However, due to the current lack of definitive legislation, the Company cannot predict whether it will be successful. If the Company stopped applying SFAS No. 71 to its regulated operations, it would write off the related balances of its regulatory assets as an expense on its income statement. Based on the balances of the Company's regulatory assets at March 31, 2003, if the Company had stopped applying SFAS No. 71 to its remaining regulated operations, it would have recorded an extraordinary loss, after tax, of approximately $918.2 million. While regulatory orders and market conditions may affect the Company's cash flows, its cash flows would not be affected if it stopped applying SFAS No. 71, unless a regulatory order limited its ability to recover the cost of that regulatory asset.

At March 31, 2003, the Company's SFAS No. 71 regulatory assets and liabilities for all states totaled $1,682.8 million and $137.0 million, respectively. As a result of potential regulatory and/or legislative actions in Utah, Oregon, Wyoming, Washington and Idaho, the Company may have regulatory asset write-offs and charges for impairment of long-lived assets in future periods. Impairment would be measured in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* ("SFAS No. 144"), which requires the recognition of impairment of long-lived assets when book values exceed expected future cash flows. Integral parts of future cash-flow estimates include estimated future prices to be received, the expected future cash cost of operations, sales and load growth forecasts and the nature of any legislative or regulatory cost-recovery mechanisms.

Revenue Recognition

Electricity sales to retail customers are determined based on meter readings taken throughout the month. The Company accrues an estimate of unbilled revenues each month for electric service provided after the meter reading date to the end of the month, after removing estimates for line losses. This estimate is based on the Company's total electricity delivered during the month and sales based on meter readings. At March 31, 2003, the amount accrued for unbilled revenues was $109.2 million. There are several estimates in the determination of the unbilled revenue, relating to weather conditions and economic impacts. The estimates can vary significantly from period to period depending on monthly weather patterns, customers' space heating and cooling, or changing irrigation patterns due to precipitation conditions.

Contingencies

The Company follows SFAS No. 5, *Accounting for Contingencies* ("SFAS No. 5"), to determine accounting and disclosure requirements for contingencies. The Company operates in a highly regulated environment. Governmental bodies such as the FERC, the SEC, the IRS, the Department of Labor, the EPA and others have authority over various aspects of the Company's business operations and public reporting. Reserves are established when required in management's judgment, and disclosures are made when appropriate regarding litigation, assessments and creditworthiness of customers or counterparties, among others. The evaluation of these contingencies is performed by various specialists inside and outside of the Company. Accounting for contingencies requires significant judgment by management regarding the estimated probabilities and ranges of exposure to potential liability. Management's assessment of the Company's exposure to contingencies could change as new developments occur or more information becomes available. The outcome of the contingencies could vary significantly and could materially impact the consolidated results of operations, cash flows and financial position of the Company. Management has applied its best judgment in applying SFAS No. 5 to these matters.

Asset Retirement Obligations

SFAS No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143"), requires the fair value of an asset retirement obligation to be recorded as a liability in the period in which the obligation is incurred. A legal obligation is a liability that a party is required to settle as a result of an existing or enacted law, statute, ordinance or contract. At the same time the liability is recorded, the costs of the asset retirement obligation will be recorded as an addition to the carrying amount of the related asset. Over time, the liability is accreted to its present value and the addition to the carrying amount of the asset is depreciated over the asset's useful life. Upon retirement of the asset, the Company will settle the retirement obligation against the recorded balance of the liability. Any difference in the final retirement obligation cost and the liability will result in either a gain or loss.

The Company adopted SFAS No. 143 on April 1, 2003, as required. The Company has identified legal obligations to retire generation plant assets and to incur removal costs and reclamation costs for certain environmental obligations at various generating facilities. The Company has estimated that its share of the cost to remove these facilities and settle the obligations is approximately $79.4 million at the date of retirement.

The Company has various transmission and distribution lines that operate under various land leases and rights-of-way that contain end dates and restorative clauses. The Company operates its transmission and distribution lines as if they will be operated in perpetuity and would continue to be used or sold without land remediation. As a result, the Company does not recognize the costs of final removal of the transmission and distribution lines in the financial statements.

The Company has legal obligations at its coal mines to perform reclamation as defined in the mine permits. The Company has estimated its cost for reclamation at the date of mine closure to be approximately $279.7 million.

Upon adoption of SFAS No. 143 on April 1, 2003, the Company recorded an asset retirement obligation liability at its net present value of $196.1 million, increased net depreciable assets by $37.3 million, removed $163.1 million of costs accrued for final removal from accumulated depreciation and reclamation liabilities and will result in a cumulative pretax effect of a change in accounting principle of $4.3 million, which, if approved by state regulators, will be recorded primarily as a net regulatory liability. The Company expects that adopting SFAS No. 143 will result in a reduction to depreciation charged throughout the year. Accretion and depreciation expense in the first year of adoption are expected to be $8.0 million and $2.7 million, respectively.

Amounts recorded under SFAS No. 143 are subject to various assumptions and determinations, such as determining whether a legal obligation exists to remove assets, estimating the fair value of the costs of removal, estimating when final removal will occur and the credit-adjusted risk-free interest rates to be utilized in discounting future liabilities. Changes that may arise over time with regard to these assumptions will change amounts recorded in the future as expenses for asset retirement obligations.

If the Company retires any asset at the end of its useful life without a legal obligation to do so, the Company will record retirement costs at that time as incurred. The Company expects to recover asset retirement costs through the ratemaking process and has requested authorization from the state regulatory commissions to record a Regulatory asset or a Regulatory liability on the Company's Consolidated Balance Sheet to account for the difference between asset retirement costs as currently approved in rates and its obligations under SFAS No. 143.

Pensions

The Company has defined-benefit pension plans that cover substantially all employees, and the Company also provides certain post-retirement benefits. The Company accounts for these plans in accordance with SFAS No. 87, *Employers' Accounting for Pensions* ("SFAS No. 87"), and SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other than Pensions* ("SFAS No. 106"). The expense and benefit obligations relating to the Company's pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including discount rates, expected returns on plan assets, compensation increases, Company contributions and health care cost trend rates. These actuarial assumptions are reviewed annually and modified as appropriate. The effect of modifications is generally recorded or amortized over future periods. The Company believes that the assumptions utilized in recording obligations under the plans are reasonable based on prior experience, market conditions and the advice of plan actuaries.

The PacifiCorp Retirement Plan (the "Plan") currently has assets with a fair value that is less than the accumulated benefit obligation under the Plan, primarily due to declines in the equity markets. As a result, the Company recognized a minimum pension liability in the fourth quarter of the year ended March 31, 2003. The liability adjustment was primarily recorded as a noncash increase of $234.5 million to Regulatory assets and did not affect the consolidated results of operations. The Company requested and received accounting orders from the regulatory commissions in Utah, Oregon and Wyoming to classify this charge as a Regulatory asset instead of a charge to Other comprehensive income. The Company has determined that SFAS No. 87 and SFAS No. 106 costs are currently recoverable in rates. This increase to Regulatory assets will be adjusted in future periods as the difference between the fair value of the trust assets and the accumulated benefit obligation changes.

The Company's contributions to the Plan have exceeded the minimum funding requirements of the Employee Retirement Income Security Act ("ERISA"). The Company's funding policy is to contribute amounts that are not less than the minimum amounts required to be funded under ERISA. The Company made $26.4 million in cash contributions to the Plan during the year ended March 31, 2003 and made $4.2 million in cash contributions to the Plan during the year ended March 31, 2002. The amount of the Company's funding obligation for the year ending March 31, 2004 is expected to be approximately $33.4 million. The Company is funding the Plan at what it believes to be an adequate level. As a result of significant declines in the equity markets, the Company currently expects to make larger cash contributions in the future. Such cash requirements could be material to the Company's cash flows. The Company believes it has adequate access to capital resources to support these contributions.

The Company discounted its future pension and other postretirement plan obligations using a rate of 6.75% at March 31, 2003, compared to 7.50% at March 31, 2002. The Company chooses a discount rate, which reflects yields on high-quality fixed-income investments. The pension liability and future pension expense both increase as the discount rate is reduced.

At March 31, 2003, the Company assumed that the Plan's assets would generate a long-term rate of return of 8.75%. This rate is lower than the rate of 9.25% used at March 31, 2002. In establishing its assumption as to the expected return on Plan assets, the Company reviews the Plan's asset allocation and develops return assumptions for each asset class based on historical performance and independent advisors' forward-looking views of the financial markets. Pension expense increases as the expected rate of return on Plan assets decreases.

Based on the above assumptions, the Company expects to record pension expenses of $23.2 million for the year ending March 31, 2004, as compared to $11.9 million for the year ended March 31, 2003.

The following table reflects the sensitivities of the March 31, 2003 disclosures and the projected pension expense for the year ending March 31, 2004, associated with a change in certain actuarial assumptions by the indicated percentage:

Actuarial Assumption	**Change in Assumption**	**Impact on Projected Benefit Obligation Increase (Decrease)**	**Impact on Minimum Pension Liability Increase (Decrease)**	**Impact on Pension Cost Increase (Decrease)**
[redacted]				
Expected long-term return on plan assets	+0.5	—	—	(4.6)
[redacted]				
Discount rate	+0.5	(64.9)	(62.3)	(1.3)

The Company expects to record other postretirement benefit expense of $27.9 million for the year ending March 31, 2004, as compared to $23.5 million for the year ended March 31, 2003.

In valuing its postretirement benefit obligation, the Company must make an assumption regarding future increases in health care costs. A one percentage-point increase in assumed health care cost trend rates would increase the postretirement benefit obligation by approximately $25.9 million and the related Plan expense by approximately $4.2 million. A similar decrease in assumed health care cost trend rates would decrease the postretirement benefit obligation by approximately $22.6 million and the related Plan expense by approximately $2.5 million.

RESULTS OF OPERATIONS

Western U.S. wholesale energy market prices were relatively stable during the year ended March 31, 2003, as compared to each of the years ended March 31, 2002 and 2001. The Company took several actions to maintain a balanced net energy position through the summer peak period and the remainder of the fiscal year through a combination of existing physical resources, electricity purchases, weather-related hedges and peaking generation facilities. The Company added a 120-MW gas-fired peaking plant in Utah, which came on line in August 2002, and also entered into an operating lease arrangement for a 200-MW peaking plant in Utah with West Valley Leasing Company, LLC, a subsidiary of PPM. These actions, as well as the utilization of other flexible physical and financial hedging instruments, assisted the Company in maintaining a balanced energy position during the year ended March 31, 2003. The Company believes that its energy position is balanced for summer 2003.

For the year ended March 31, 2003, overall retail MWh sales decreased approximately 1.2%. While the impact of weather was not significant for the year ended March 31, 2003, sales for the year ended March 31, 2002 were approximately 564,000 MWh, or 1.2%, higher than sales for the year ended March 31, 2003, due to the effects of weather. Excluding this weather impact, the loads for both years were relatively consistent, although load growth varied within individual states and customer classes. While residential and commercial loads reflected an increase of 1.2% and 3.6%, respectively, as a result of additional customers in the eastern portion of the Company's service territory, the industrial class showed a 3.2% decrease as a result of the effects of the economic downturn and a decrease in industrial customers.

The Company's hydroelectric resources are in watersheds with precipitation that averaged 85.0% of normal for the year ended March 31, 2003 and had ending snowpack at around 74.0% of normal. These drier than normal conditions reduced generation from Company-owned projects by 65,000 MWh, as compared to the hydroelectric generation for the year ended March 31, 2002. Despite increased precipitation in April 2003, the reduced snowpack will continue to affect generation from the Company's resources for the remainder of the normal runoff period through the end of September 2003. Beginning with the next hydrologic cycle in October 2003, the Company anticipates a return to normal water conditions. In the event of below-normal hydroelectric generation, the Company will either increase output from its thermal generation resources or purchase energy in the wholesale market, which would result in increased power costs to the extent existing hedges do not offset the impact of reduced hydroelectric generation.

Concluded regulatory actions in the year ended March 31, 2003 included approval in Oregon of a $15.4 million overall rate increase effective June 1, 2002. On March 6, 2003, a general rate increase of $8.7 million, or 2.8%, was granted in Wyoming. Rate actions submitted for regulatory approval included a general rate case filed on March 18, 2003 in Oregon requesting an increase of $57.9 million, or 7.4%, in base rates to take effect in January 2004; a general rate case filed on May 15, 2003 in Utah establishing a maximum increase of $125.0 million, or 12.5%, in base rates to take effect in April 2004; and a general rate case filed on May 27, 2003 in Wyoming, requesting an increase of $41.8 million, or 13.1%, in base rates to take effect in March 2004.

The Company also made progress toward recovering the deferred net power costs incurred during the period of extreme volatility and unprecedented high price levels beginning in summer 2000 and extending through summer 2001. These costs have been authorized for recovery as follows: (i) $147.0 million in Utah; (ii) $131.0 million, plus carrying charges, in Oregon; and (iii) $25.0 million in Idaho. The Oregon rate order is the subject of a court appeal by intervening parties, which, if successful, would require refund of amounts collected after January 22, 2003. In Wyoming, the Company's request for recovery of deferred net power costs was denied, and, as a result, the Company wrote off the remaining net regulatory asset of $48.3 million during the year ended March 31, 2003. The Company filed a petition for rehearing on the Wyoming decision on April 4, 2003. The WPSC denied the petition on May 30, 2003. In Washington, the Company had requested recovery of approximately $17.5 million of excess power costs, which have not been deferred, or, alternatively, that the Company be allowed to file a general rate case, which is currently restricted through December 2005. This request was subsequently reduced to approximately $15.9 million based on revised estimates. A final decision in Washington is expected by June 2003. At March 31, 2003, the Company had $137.8 million of deferred power costs, net of amortization, remaining to be collected over two to three years.

Earnings (Loss) Overview of the Company

(Millions of dollars)	Years Ended March 31,		
	2003	2002	2001
Earnings (loss) contribution on common stock:			
Electric Operations	$134.7	$ 232.8	$ 110.1
Australian Operations (a)	—	27.4	(187.2)
Other Operations (b)	—	20.5	(29.0)
Continuing operations	134.7	280.7	(106.1)
Discontinued operations	—	146.7	—
Cumulative effect of accounting change	(1.9)	(112.8)	—
Total	$132.8	$ 314.6	$ (106.1)

(a) The Australian Operations were sold in fall 2000.

(b) All Other Operations were transferred to PHI on February 4, 2002.

The Company's earnings contribution on common stock for the year ended March 31, 2003 was $132.8 million, as compared to $314.6 million for the year ended March 31, 2002 and a loss of $106.1 million for the year ended March 31, 2001. The Company's underlying results for the year ended March 31, 2003, as compared to the years ended March 31, 2002 and 2001, improved after taking into account rate increases, lower net power costs and the effect of the following items:

(i) Included in Electric Operations results is the unrealized gain of $3.1 million, pretax, on SFAS No. 133 derivative instruments for the year ended March 31, 2003, as compared to $182.8 million, pretax, and none for the years ended March 31, 2002 and 2001, respectively;

(ii) A $27.4 million pretax gain in the year ended March 31, 2002 relating to additional proceeds from the sale of the Australian Operations. In the year ended March 31, 2001, the Company recorded a $184.2 million pretax loss on the sale of the Australian Operations;

(iii) Other Operations income for the year ended March 31, 2002 included a gain on the sale of the synthetic fuel operations of $11.3 million pretax. The year ended March 31, 2001 included operating losses from the synthetic fuel operations;

(iv) The $146.7 million, after tax, of income in the year ended March 31, 2002 from the discontinued operations of a former mining and resource development business; and

(v) The negative cumulative effect of accounting change of $1.9 million, after tax, due to the Derivatives Implementation Group revised Issue C15 and Issue C16 in the year ended March 31, 2003, as compared to the negative cumulative effect of accounting change of $112.8 million, after tax, due to the adoption of SFAS No. 133 in the year ended March 31, 2002.

REVENUES

(Millions of dollars)	Years Ended March 31,		
	2003	2002	2001
Electric Operations			
Residential	$ 914.7	$ 901.7	$ 852.1
Commercial	763.4	747.7	710.5
Industrial	699.2	705.1	730.1
Other retail revenues	31.4	34.5	32.5
Wholesale sales	1,052.0	1,684.7	2,078.1
Other revenues	132.7	149.0	130.9
Total	3,593.4	4,222.7	4,534.2
Australian Operations	—	—	399.3
Other operations	—	12.6	122.2
Total Revenues	$3,593.4	$4,235.3	$5,055.7
Energy sales (Millions of kWh)			
Electric Operations			
Residential	13,287	13,395	[illegible]
Commercial	14,006	13,810	13,634
Industrial	19,048	19,611	[illegible]
Other	631	711	705
Wholesale sales	30,485	24,264	[illegible]
Total	77,457	71,791	75,955

Electric Operations

Residential revenues for the year ended March 31, 2003 increased $13.0 million, or 1.4%, from the year ended March 31, 2002 primarily due to increases of $17.8 million from higher rates approved by state regulatory agencies and $12.5 million relating to growth in the average number of residential customers of 1.6%, primarily in Utah and Oregon. These increases were partially offset by a decrease of $17.3 million from lower average customer usage due to milder weather as compared to the year ended March 31, 2002. Residential revenues for the year ended March 31, 2002 increased $49.6 million, or 5.8%, from the year ended March 31, 2001, due to $53.6 million in price increases, mainly in Utah and Oregon, and $12.0 million relating to growth in the average number of residential customers of 1.5%. These increases were partially offset by $11.1 million from lower volumes due to weather impacts and $4.8 million due to decreases in average customer usage.

Commercial revenues for the year ended March 31, 2003 increased $15.7 million, or 2.1%, from the year ended March 31, 2002, due to increases of $16.7 million from growth in the average number of commercial customers and $6.8 million from higher rates, offset in part by $7.8 million in reduced revenue from lower average customer usage due to current economic conditions. Commercial revenues for the year ended March 31, 2002 increased $37.2 million, or 5.2%, from the year ended March 31, 2001 primarily due to $32.7 million in price increases. A 2.3% increase in the average number of commercial customers increased revenues $17.7 million, and higher volumes due to weather resulted in a $7.9 million increase. These increases were partially offset by the $21.2 million impact of lower customer usage.

Industrial revenues for the year ended March 31, 2003 decreased $5.9 million, or 0.8%, from the year ended March 31, 2002, due to a $27.0 million decrease caused by reduced customer numbers and lower average customer usage mainly as a result of a weaker economy. This decrease was partially offset by a $21.1 million increase resulting from higher rates. Industrial revenues for the year ended March 31, 2002 decreased $25.0 million, or 3.4%, from the year ended March 31, 2001, due to a $40.8 million decrease from a reduction in energy volumes due to reduced customer usage. This decrease was partially offset by a $15.8 million increase resulting from higher prices.

Wholesale sales for the year ended March 31, 2003 decreased $632.7 million, or 37.6%, from the year ended March 31, 2002. This decrease in revenues resulted from the sharp decline in prices realized for short-term and spot-market sales as compared to those in the year ended March 31, 2002, the impact of which was $1.9 billion. Factors contributing to the lower market prices included new generation in the western U.S., the continuing effect of the FERC market mitigation and lower average natural gas prices paid as compared to average prices paid in the year ended March 31, 2002. In addition, demand growth in the Western Electricity Coordinating Council (the "WECC") area was lower than the 10-year average, due to slower than historical U.S. economic growth and weather, which was milder than the year ended March 31, 2002 and normal weather patterns. The decrease due to prices was partially offset by a $1.3 billion, or 25.6%, increase due to higher volumes, as the Company sold excess power in the short-term, daily and hourly markets. Wholesale sales for the year ended March 31, 2002 decreased $393.4 million, or 18.9%, from the year ended March 31, 2001. Lower short-term and spot-market sales prices contributed $601.0 million to the decrease, and lower long-term sales volumes contributed $201.6 million. These decreases were partially offset by $373.1 million from higher volumes of short-term and spot-market sales and $35.6 million in higher long-term sales prices.

Other revenues for the year ended March 31, 2003 decreased $16.3 million, or 10.9%, from the year ended March 31, 2002, primarily due to a $26.8 million decrease in wheeling revenues, primarily due to lower volumes, a $6.1 million decrease from the amortization of the Centralia gain, a $6.0 million decrease relating to recognition of Oregon Merger Credits and lower DSM revenues of $3.6 million. These decreases were partially offset by a $20.7 million release of reserves on an electricity sales contract following a settlement of a dispute with respect to the contract and a $4.6 million increase in sales under a contract for renewable power. Other revenues for the year ended March 31, 2002 increased $18.1 million, or 13.8%, from the year ended March 31, 2001, due to $23.8 million from the amortization of the Centralia gain liability that offset revenue reductions in other revenue categories, $12.1 million in wheeling revenues from increased usage of the Company's transmission system by third parties and $8.3 million from lower reserves. These increases were partially offset by a $14.9 million decrease in revenues due to lower load growth than anticipated by the alternative form of regulation in Oregon and a $12.4 million decrease due to DSM activities.

Australian Operations

The Australian Operations consisted of Powercor and a 19.9% interest in Hazelwood and were sold in fall 2000.

Other Operations

Revenues for the year ended March 31, 2002 decreased $109.6 million, or 89.7%, from the year ended March 31, 2001, primarily due to a $64.0 million decrease as a result of the sale of the synthetic-fuel operations, a decrease of $23.8 million due to the transfer of PPM and PKE to PHI and a $20.0 million decrease in interest income due to the collection of a contingent note receivable held by PGHC.

OPERATING EXPENSES

(Millions of dollars)	Years Ended March 31,		
	2003	2002	2001
Electric Operations			
Purchased electricity	$1,212.6	$2,038.8	$2,478.4
Fuel	482.2	490.9	491.0
Other operations and maintenance	603.9	560.6	534.8
Depreciation and amortization	434.3	401.3	389.0
Administrative and general	281.2	245.6	121.0
Taxes, other than income taxes	93.4	90.7	97.5
Unrealized (gain) loss on SFAS No. 133 – derivative instruments	(3.1)	(182.8)	—
Total	3,104.5	3,645.1	4,111.7
Australian Operations	—	—	314.8
Other Operations	—	9.0	135.8
Total operating expenses	$3,104.5	$3,654.1	$4,562.3

Electric Operations

Purchased electricity expense for the year ended March 31, 2003 decreased $826.2 million, or 40.5%, from the year ended March 31, 2002, primarily due to a $1.9 billion decrease from prices incurred for short-term and spot market purchases, which were 68.3% lower than average prices incurred for the year ended March 31, 2002. Lower market prices resulted from the same factors mentioned above for lower wholesale sales. Increased wholesale purchase volumes added $928.1 million, or 24.7 %, to purchased electricity expense as the Company increased the volume of system-balancing activities to balance its load requirements and to replace thermal generation lost from outages. These actions offset lower hydroelectric generation caused by below-normal precipitation levels. Purchased power costs also increased $185.5 million for the year ended March 31, 2003, as compared to the year ended March 31, 2002 due to lower deferrals of purchased power costs. Purchased electricity expense for the year ended March 31, 2002 decreased $439.6 million, or 17.7%, from the year ended March 31, 2001, primarily due to lower short-term and spot market purchase volumes of 15.6%, which decreased costs $295.1 million; lower long-term purchase volumes of 11.5%, which decreased costs $104.7 million; and lower short-term, spot-market and long-term purchase prices of $70.8 million. While long-term prices per MWh dropped 11.2%, short-term prices only dropped 1.4%. These decreases were partially offset by a $46.2 million increase in DSM costs.

Fuel expense for the year ended March 31, 2003 decreased $8.7 million, or 1.8%, from the year ended March 31, 2002, due to decreases of $20.7 million from lower natural gas volumes, $16.5 million from lower natural gas prices and $9.7 million from lower coal volumes, partially offset by the $21.2 million incremental impact from the Company's lease of the West Valley gas-fired facility and an increase of $17.0 million from higher coal prices caused by higher employee benefit costs at Company-owned mines and the costs of external coal purchases. Fuel expense was comparable in the years ended March 31, 2002 and 2001.

Other operations and maintenance expense for the year ended March 31, 2003 increased $43.3 million, or 7.7%, from the year ended March 31, 2002, primarily due to the establishment of a $20.0 million reserve for FERC and California exposures in the year ended March 31, 2003; a $19.2 million increase in employee costs, including pensions and health care; an increase of $17.5 million for mine reclamation costs; an increase of $12.1 million in rent expense in the year ended March 31, 2003 for the West Valley operating lease; increased generation materials and contract services of $10.2 million, primarily due to the scope and timing of generating plant overhauls, and an $8.8 million increase due to lower capitalized costs. These increases were partially offset by a $22.1 million decrease resulting from the temporary lease of a generating turbine in the year ended March 31, 2002; a decrease of $13.7 million in DSM costs; and an $8.0 million reserve for bad debts recorded in the year ended March 31, 2002.

Other operations and maintenance expense for the year ended March 31, 2002 increased $25.8 million, or 4.8%, from the year ended March 31, 2001, primarily due to $24.7 million for the lease of a new generating turbine, $20.4 million in increased generation costs, increases in employee-related expenses of $5.9 million and tree-trimming costs of $1.4 million. These increases were partially offset by decreases due to the level and timing of capital projects and related expenditures of $31.6 million.

Depreciation and amortization expense for the year ended March 31, 2003 increased $33.0 million, or 8.2%, from the year ended March 31, 2002, primarily due to a $14.4 million increase due to the termination at March 31, 2002 of a two-year depreciation expense reduction ordered by state regulatory commissions; increased expenditures on Property, plant and equipment, which resulted in a $9.5 million increase in depreciation expense; increased amortization of Regulatory assets and liabilities of $4.7 million; and increased software amortization of $4.2 million. Depreciation and amortization expenses for the year ended March 31, 2002 increased $12.3 million, or 3.2%, from the year ended March 31, 2001, primarily due to an increase in Property, plant and equipment that resulted in an $8.4 million increase and increased software amortization of $3.4 million.

Administrative and general expenses for the year ended March 31, 2003 increased $35.6 million, or 14.5%, from the year ended March 31, 2002, primarily due to increased property and liability insurance costs of $31.7 million resulting from higher premiums, insurance reserves and storm damage, and increased employee expenses, including pensions and health care, of $6.0 million, offset by a $2.0 decrease in consulting expense. Administrative and general expenses for the year ended March 31, 2002 increased $124.6 million, or 103.0%, from the year ended March 31, 2001. Employee-related expenses increased by $44.0 million. Administrative and general expenses for the year ended March 31, 2002 included $16.9 million for the amortization of deferred transition costs allowed by state regulators. The level and timing of expenditures capitalized in 2002 fell from 2001 levels and resulted in a $38.3 million increase in expense. Additional consulting and outside services added $9.7 million to expense, asset reserves added $5.4 million, lower charge-backs to Powercor added $2.8 million and increased insurance premiums added $2.9 million.

Taxes, other than income taxes, for the year ended March 31, 2003 increased $2.7 million, or 3.0%, from the year ended March 31, 2002, primarily due to settlements and adjustments that lowered property tax expense during the year ended March 31, 2002. Taxes, other than income taxes in the year ended March 31, 2002, decreased $6.8 million, or 7.0%, from the year ended March 31, 2001, primarily due to lower property tax expense resulting from the favorable resolution of outstanding property tax appeals and lower franchise taxes.

The Unrealized gain on SFAS No. 133 derivative instruments for the year ended March 31, 2003 was $3.1 million, as compared to $182.8 million for the year ended March 31, 2002, primarily due to implementation of Issue C15 on July 1, 2001, which resulted in the designation of the majority of the Company's short-term contracts as normal purchases and sales. The Unrealized gain on SFAS No. 133 derivative instruments for the year ended March 31, 2002 pertains to the Company's short-term sales obligations being favorably impacted by lower forward market prices that resulted from the significant changes in market fundamentals.

Australian Operations

The Australian Operations consisted of Powercor and a 19.9% interest in Hazelwood and were sold in fall 2000.

Other Operations

Operating expenses for the year ended March 31, 2002 decreased $126.8 million, or 93.4%, primarily due to the sale of the synthetic-fuel operations that resulted in a $98.4 million decrease and a $21.3 million decrease due to the transfer of PGHC to PHI.

OTHER OPERATING INCOME

Other operating income for the year ended March 31, 2002 increased $1.8 million. During the year ended March 31, 2002, the Company recorded $21.0 million relating to a regulatory settlement that resulted in the establishment of a regulatory asset. The Company also recorded an $11.3 million gain on the sale of the synthetic-fuel operations. Included within Other operating income in 2001 was income of $43.5 million relating to rate orders received which provided recovery for previously denied costs and resulted in the establishment of regulatory assets. In addition, the Company recorded a loss on the sale of Centralia of $13.9 million in the year ended March 31, 2001.

(GAIN) LOSS ON SALE OF OPERATING ASSETS

The $27.4 million Gain on sale of operating assets for the year ended March 31, 2002 pertained to further proceeds received in June 2001 from the resolution of a contingency under the provisions of the sale of the Australian Operations. In the year ended March 31, 2001, the Company recorded a $184.2 million loss on the sale of the Australian Operations.

INTEREST EXPENSE AND OTHER (INCOME) EXPENSE

	Years Ended March 31,		
(Millions of dollars)	**2003**	**2002**	**2001**
Interest expense	$270.3	$227.7	$290.4
Interest income	(21.6)	(47.5)	(32.6)
Interest capitalized	(18.0)	(6.9)	(12.9)
Minority interest and other (a)	19.0	(1.8)	2.7
Total	$249.7	$171.5	$247.6

(a) Minority interest and other includes payments of $28.3 million on Preferred Securities of wholly owned subsidiary trusts for each of the three years ended March 31.

Interest expense for the year ended March 31, 2003 increased $42.6 million, or 18.7%, primarily due to higher average long-term debt balances and a $20.9 million increase in interest expense for regulatory liabilities. These increases were partially offset by lower average short-term and variable-interest rates. The Company issued $800.0 million of new long-term debt in November 2001. Interest expense for the year ended March 31, 2002 decreased $62.7 million, or 21.6%, as compared to the year ended March 31, 2001, primarily due to the sale of the Australian Operations and lower interest rates.

Interest income for the year ended March 31, 2003 decreased $25.9 million, or 54.5%, primarily as a result of an $11.1 million decrease in interest income on regulatory assets and lower average notes-receivable balances due to the transfer of PGHC to PHI in February 2002. These decreases were partially offset by the recognition of $1.1 million of interest income on an electricity sales contract settlement in September 2002 and $1.5 million of interest income on the settlement of an excise tax case with the state of Washington in March 2002. Interest income for the year ended March 31, 2002 increased $14.9 million, or 45.7%, as compared to the year ended March 31, 2001 primarily due to a $24.4 million increase in interest income for regulatory assets, partially offset by lower average interest rates.

Interest capitalized increased $11.1 million, as compared to the year ended March 31, 2002, due to higher capitalization rates, as a return on equity component was included, and higher qualifying construction work-in-progress balances. Interest capitalized for the year ended March 31, 2002 decreased $6.0 million, or 46.5%, as compared to the year ended March 31, 2001, due to lower capitalization rates, partially offset by higher qualifying construction work-in-progress balances.

Minority interest and other increased $20.8 million. Minority interest was constant year over year. Of the increase, $18.9 million pertained to Other income and expense of PGHC in the year ended March 31, 2002. During the year ended March 31, 2002, PGHC recorded $9.3 million in gains on sales of leased aircraft owned by PFS, $4.8 million in gains on various settlements and $3.7 million in gains on sales of nonutility investments. Other expense for Electric Operations increased in part due to the reversal in the year ended March 31, 2003 of a previously recorded gain of $3.4 million as a result of a regulatory order.

INCOME TAX EXPENSE

Income tax expense for the year ended March 31, 2003 decreased $78.9 million from the year ended March 31, 2002. The decline in the tax expense was primarily due to the lower taxable income in the year ended March 31, 2003 and the additional tax reserves established in the year ended March 31, 2002 for the amounts proposed as a result of the IRS audit. Income tax expense for the year ended March 31, 2002 decreased $4.3 million, or 2.4%, from the year ended March 31, 2001 primarily due to reduced taxable income.

The Company's combined federal and state effective income tax rate from continuing operations was 40.6%, 37.5% and 195.7% for the years ended March 31, 2003, 2002 and 2001, respectively. The tax rate for the year ended March 31, 2003 varied from the statutory rate, primarily due to the tax effects of the regulatory treatment of depreciation, which were partially offset by income tax credits. The tax rate for the year ended March 31, 2002 was approximately the same as the statutory rate. The tax rate for the year ended March 31, 2001 varied significantly from the statutory rate, primarily due to the substantially nondeductible losses on the sales of the Australian operations and reserves for tax on outstanding IRS examination issues.

DISCONTINUED OPERATIONS

The Company recognized $146.7 million of income during the year ended March 31, 2002, as a result of collecting a contingent note receivable relating to the discontinued operations of its former mining and resource development business, NERCO, which was sold in 1993. This note from the buyer was recorded at the date of the NERCO sale, along with a corresponding deferred gain. Payments on this note were contingent upon the buyer receiving payment under a coal supply contract. The Company recognized this gain on a cost-recovery basis as payments were received from the buyer. In June 2001, the Company received full payment of the remaining balance of the note and recognized the remaining balance of the deferred gain. Deferred tax expense of $36.4 million was recognized on the gain in June 2001.

CUMULATIVE EFFECT OF ACCOUNTING CHANGE

The Company recorded a $1.9 million loss from the implementation of revised Issue C15 and Issue C16 during the year ended March 31, 2003 and recorded a $112.8 million loss from the implementation of SFAS No. 133 during the year ended March 31, 2002.

LIQUIDITY AND CAPITAL RESOURCES

OPERATING ACTIVITIES

Net cash flows provided by operating activities increased by $339.0 million to $681.6 million for the year ended March 31, 2003, as compared to $342.6 million for the year ended March 31, 2002. During the year ended March 31, 2003, the Company received cash recoveries of $111.1 million of previously deferred net power costs. In addition, the Company received $44.0 million during the year ended March 31, 2003 of additional cash revenues from general rate case increases. Net cash flows provided by operating activities decreased $302.1 million for the year ended March 31, 2002 from the year ended March 31, 2001. This decrease was largely due to the impact of significantly higher purchased electricity prices, combined with regulated rates that did not reflect the costs to purchase power, a portion of which was deferred under accounting orders, which were only partially offset by cash from working capital increases. The $706.4 million change in Accounts payable and accrued liabilities between the years ended March 31, 2002 and 2001 primarily reflected the higher amounts paid for electricity and larger income tax accruals for the year ended March 31, 2001.

INVESTING ACTIVITIES

Capital spending totaled $550.0 million for the year ended March 31, 2003 compared with $505.3 million for the year ended March 31, 2002. The increase was primarily due to expenditures for new generation, network growth, system upgrades and other capital projects. Proceeds from a finance note repayment in the year ended March 31, 2002 represented the payment of a note receivable held by PGHC relating to the discontinued operations of NERCO. Certain types of investing activities for the year ended March 31, 2002 do not appear in the year ended March 31, 2003, due to the transfer of PGHC and its subsidiaries from PacifiCorp to PHI.

FINANCING ACTIVITIES

Net cash used in financing activities was $161.9 million for the year ended March 31, 2003, as compared to net cash provided by financing activities of $244.3 million for the year ended March 31, 2002. Net short-term borrowings decreased $152.5 million, proceeds from long-term debt issuance decreased $791.1 million and common stock issuance increased $150.0 million. On December 19, 2002, the Company issued 14,851,485 shares of its common stock to PHI at a total price of $150.0 million, or $10.10 per share. The Company used the proceeds from the sale of these shares to repay debt and for general corporate purposes. The decreased utilization of external financing reflects the significant improvement in cash generated by operations.

The Company's short-term borrowings are supported by $800.0 million of revolving credit agreements. As of March 31, 2003, these facilities were fully available and had no borrowings outstanding. In addition to these committed credit facilities, the Company had $123.2 million of money market accounts included in Cash and temporary cash investments at March 31, 2003, available to meet its liquidity needs.

For the year ended March 31, 2003, the Company issued no long-term debt and made scheduled long-term debt repayments of $144.6 million. For the year ended March 31, 2002, the Company had proceeds from long-term debt issuance of $791.1 million and made scheduled long-term debt repayments of $59.0 million. The Company has an effective shelf registration statement for up to $1.1 billion of long-term debt, of which the issuance of $800.0 million has been authorized by the applicable regulatory commissions, subject to certain conditions. Any such issuance would be subject to market conditions.

For the year ended March 31, 2003, the Company redeemed, at par, $7.5 million of its preferred stock, of which $3.8 million was pursuant to its mandatory scheduled redemption. During the year ended March 31, 2002, the Company redeemed, at par, $100.0 million of its preferred stock pursuant to its scheduled mandatory redemption.

For the year ended March 31, 2003, no dividends were declared or paid on common stock. During the year ended March 31, 2002, the Company declared dividends on common stock of $240.8 million and paid dividends on common stock of $298.6 million. The dividends were declared at a rate that was consistent with the Company's historic pre-Merger rate per share. On April 17, 2003, the Board declared a dividend on common stock of $40.1 million, payable on May 28, 2003. The Company declared dividends of $7.2 million and paid dividends of $7.3 million on preferred stock during the year ended March 31, 2003 and had $1.8 million in preferred dividends declared but unpaid at March 31, 2003. The Company declared dividends of $9.8 million and paid dividends of $11.7 million on preferred stock during the year ended March 31, 2002 and had $1.9 million in preferred dividends declared but unpaid at March 31, 2002.

Management expects existing funds and cash generated from operations, together with existing credit facilities, to be sufficient to fund liquidity requirements for the next 12 months. However, many participants in the electric utility industry have experienced a period of negative news and ratings downgrades. While the Company to date has been able to adequately fund itself and expects to be able to continue to do so, further negative information about other industry participants may make it more difficult and expensive for the Company to obtain necessary financing or replace financing agreements at their maturity. If market conditions warrant during the year ending March 31, 2004, the Company may seek to issue long-term debt and redeem outstanding long-term debt to reduce its overall debt service costs.

CAPITALIZATION

	March 31,			
(Millions of dollars, except percentages)	**2003**		**2002**	
[redacted]				
Long-term debt	3,417.6	47.3	3,553.8	49.2
[redacted]				
Preferred stock	108.0	1.5	115.5	1.6
[redacted]				
Total Capitalization	$7,224.0	100.0%	$ 7,224.7	100.0%

The Company manages its capitalization and liquidity position through policies established by senior management and the Board. These policies, subject to periodic review and revision, have resulted from a review of historical and projected practices for businesses and industries that have financial and operating characteristics similar to those of the Company.

The Company's policies attempt to balance the interests of all shareholders, ratepayers and creditors. In addition, given the changes that are occurring within the industry and market segments in which the Company operates, these policies are intended to remain sufficiently flexible to allow the Company to respond to these changes.

On a consolidated basis, the Company attempts to maintain total debt at approximately 48.0% to 54.0% of capitalization. The total debt-to-capitalization ratio was 49.6% at March 31, 2003. The Company expects to maintain, over time, its capital structure in accordance with its targets. The Company has made commitments in connection with the Merger not to make distributions that result in a reduction of common equity, without approval, to below 38.0% of total capitalization, excluding short-term debt and current maturities of long-term debt, increasing over time to 40.0%.

VARIABLE-RATE LIABILITIES

	March 31,	
(Millions of dollars)	**2003**	**2002**
[redacted]		
Variable rate long-term debt	654.5	654.5
[redacted]		
Percentage of Total Capitalization	9.4%	11.5%

The Company's capitalization policy targets consolidated variable-rate liabilities at between 10.0% and 25.0% of total capitalization. The Company was slightly below the target range at March 31, 2003, but anticipates that variable-rate exposure will be within the range during the year ending March 31, 2004.

AVAILABLE CREDIT FACILITIES

At March 31, 2003, the Company had $800.0 million of committed bank revolving credit agreements that became effective June 4, 2002: one facility for $500.0 million, having a 364-day term plus a one-year term loan option, and the other facility for $300.0 million, having a three-year term. At March 31, 2003, these facilities were fully available and there were no borrowings outstanding. The Company is currently seeking to replace the existing $500.0 million credit facility. While the Company believes the facility will be successfully replaced at costs marginally higher than the existing facility, no assurance can be given as to this outcome. Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt, of which $25.0 million was outstanding at March 31, 2003 at a weighted average rate of 1.4%.

At March 31, 2003, the Company had $517.8 million of standby letters of credit and standby bond purchase agreements available to provide credit enhancement and liquidity support for variable-rate pollution-control revenue bond obligations. These committed bank arrangements expire periodically through the year ending March 31, 2006.

LIMITATIONS

In addition to the Company's capital structure policies, its debt capacity is also governed by its contractual commitments. The Company's credit agreement contains customary covenants and default provisions, including covenants to maintain a debt-to-capitalization ratio. The Company's principal debt limitations are a 60.0% debt-to-defined capitalization test and an interest coverage covenant contained in its principal credit agreements. Based on the Company's most restrictive agreement, management believes that the Company could have borrowed an additional $1.9 billion at March 31, 2003. The Company was in compliance with the covenants of its credit agreement as of March 31, 2003.

Under the Company's principal credit agreements, it is an event of default if any person or group, other than ScottishPower, acquires 35.0% or more of the Company's common shares or if, during any period of 14 consecutive months, individuals who were directors of the Company on the first day of such period (and any new directors whose election or nomination was approved by such individuals and directors) cease to constitute a majority of the Board.

CREDIT RATINGS

The Company's credit ratings at March 31, 2003 were as follows:

	Moody's	S & P
Senior secured debt	A3	A
Senior unsecured debt	Baa1	BBB+
Preferred stock	Baa3	BBB
Commercial paper	P-2	A-2

The Company's credit ratings are unchanged from March 31, 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.

The Company has no rating-downgrade triggers that would accelerate the maturity dates of its debt. A change in ratings is not an event of default, nor is the maintenance of a specific minimum level of credit rating a condition to drawing upon the Company's credit agreements. However, interest rates on loans under the credit agreements and commitment fees are tied to credit ratings and would increase or decrease when ratings are changed. A ratings downgrade may reduce the accessibility and increase the cost of the Company's commercial paper program, its principal source of short-term borrowing, and may result in the requirement that the Company post collateral under certain of the Company's power purchase and other agreements.

In addition, a number of the Company's agreements in the wholesale electric, wholesale gas and energy derivatives markets contain provisions that provide the right for either counterparty to receive cash or other security if mark-to-market exposures on a net basis exceed certain negotiated threshold levels. Generally, these threshold levels change based on long-term unsecured ratings. As such, a ratings downgrade could require the Company to provide additional funds to a counterparty if threshold amounts were exceeded. At March 31, 2003, the Company estimates that a one level downgrade, by either Standard & Poor's or Moody's, of its senior unsecured debt ratings would not result in any cash or collateral requirements.

OFF-BALANCE SHEET ARRANGEMENTS

The Company is generally required to obtain state regulatory commission approval prior to guaranteeing debt or obligations of other parties. In November 2002, the Financial Accounting Standards Board (the "FASB") issued Interpretation No. 45, *Accounting and Disclosure Requirements for Guarantees* ("FIN No. 45"). FIN No. 45

requires disclosure of certain direct and indirect guarantees. Also, FIN No. 45 requires recognition of a liability at inception for certain new or modified guarantees issued after December 31, 2002. The adoption of FIN No. 45 in January 2003 did not have a material impact on the consolidated financial statements. The following indemnification obligations of the Company fall within the definitions of "indirect guarantees" under FIN No. 45.

On May 4, 2000, the Company and other joint owners completed the sale to Transalta of an electricity plant and coal mine located in Centralia, Washington. Under the agreement relating to the plant, the joint owners agreed to indemnify Transalta if it were to incur certain losses after the closing date and arising as a result of certain breaches of covenants. Under the agreement relating to the mine, the Company provided similar indemnity. The maximum indemnification obligation under these agreements, with respect to the Company, is limited to $556.0 million, less a deductible of 1.0% of the purchase price (approximately $1.0 million). No indemnity claims have been made to date.

In connection with the sale of the Company's Montana service territory, the Company entered into a purchase and sale agreement with Flathead Electric Cooperative ("Flathead") dated October 9, 1998. Under the agreement, the Company indemnified Flathead for losses, if any, occurring after the closing date and arising as a result of certain breaches of warranty or covenants. The indemnification has a cap of $10.0 million. Two indemnity claims relating to environmental issues have been tendered, but remediation costs for these claims, if any, are not expected to be material.

The Company believes that the likelihood that it would be required to perform or otherwise incur any significant losses associated with any of these obligations is remote.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

The table below shows the Company's contractual obligations as of March 31, 2003.

Contractual Obligations

	Payments Due by Period				
(Millions of dollars)	**2004**	**2005 - 2006**	**2007 - 2008**	**Thereafter**	**Total**
Short-term debt, including interest	$ 25.0	$ —	$ —	$ —	$ 25.0
Long-term debt, including interest (a)	291.2	821.0	785.6	4,003.4	5,901.2
Capital lease minimum payments	3.4	6.9	[illegible]	52.2	69.8
Junior subordinated debentures (b)	28.3	56.6	56.6	1,164.3	1,305.8
Preferred stock	3.8	7.5	56.2	—	67.5
Power contract commitments (c)	823.4	1,218.5	926.7	3,158.0	6,126.6
Purchase obligations (d)	58.7	3.2	—	—	61.9
Operating leases	20.2	26.9	4.0	9.8	60.9
Hydroelectric (e)	[illegible]	18.7	[illegible]	78.2	[illegible]
Total contractual cash obligations	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

(a) There have been no significant increases to the long-term obligations during the year ended March 31, 2003. The long-term debt matures at various dates through fiscal year 2032 and bears interest principally at fixed rates. Interest on variable long-term debt is set at the March 31, 2003 rates. The Company uses the proceeds from debt financing for general corporate purposes, including construction, improvement or maintenance of its utility system and the repayment of commercial paper and other short-term debt.

(b) Wholly owned subsidiary trusts of the Company (the "Trusts") have issued, in public offerings, redeemable preferred securities (the "Preferred Securities") representing preferred undivided beneficial interests in the assets of the Trusts, with liquidation amounts of $25.00 per Preferred Security. The sole assets of the Trusts are Junior Subordinated Deferrable Interest Debentures (the "Junior Debentures") of the Company that bear interest at the same rates as the Preferred Securities to which they relate, and certain rights under related guarantees by the Company. These Junior Debentures are unsecured and junior in terms of preference to all senior debt, including unsecured senior obligations. Under certain conditions, the Company may defer interest on the Junior Debentures.

(c) The Company's power contract commitments include purchases of coal, electricity and natural gas. The Company manages its energy resource requirements by integrating long-term, short-term and spot-market purchases with its own generating resources to dispatch the system economically and to meet commitments for wholesale sales and retail load growth. As part of its energy resource portfolio, the Company acquires a portion of its resource requirements through long-term purchases and/or exchange agreements.

(d) These contractual obligations include commitments for capital expenditures.

(e) The Company has entered into settlement agreements with various interested parties that are incorporated into the FERC hydroelectric licenses. Hydroelectric licenses have varying expiration dates, and many expire within the next five years. The contractual commitments listed here expire with the license expiration dates. However, the Company plans to acquire new licenses that will allow for continued operation for more than 30 years and expects contractual commitments to increase.

Commercial Commitments

The Company's commercial commitments include surety bonds that provide indemnities for the Company in relation to various commitments it has to third parties for obligations in the event of default on behalf of the Company. The majority of these bonds are continuous in nature and renew annually. The estimates are based on current information and actual amounts may vary due to rate changes or changes to the general operations of the Company. The Company expects the level of its surety bonding beyond the year ended March 31, 2003 to remain at the historical average of approximately $30.0 million. As of March 31, 2003, the Company had $29.8 million, $21.1 million, $0.6 million and $0.3 million surety bond commitments for the years ending March 31, 2004, 2005-2006, 2007-2008 and thereafter, respectively.

INFLATION

The Company is subject to rate-of-return regulation and the impact of inflation on the level of cost recovery under regulation varies by state depending upon the type of test-period convention used in the state. In the Company's state jurisdictions, a 12-month period of historical costs is typically used as the basis for developing a "test year," which may also include various adjustments to eliminate abnormal or one-time events, normalize cost levels, or escalate the historical costs to a future level when the new rates will actually be in effect. To the extent that the levels of costs beyond the historical 12-month period can be established either through known adjustments or through the escalation of cost levels in establishing prices, the Company can mitigate the impacts of inflationary pressures. The Company is seeking to establish a uniform use of future test periods to deal with the rising cost of service and required capital investment.

NEW ACCOUNTING STANDARDS

In June 2001, the FASB issued SFAS No. 143. The statement requires the fair value of an asset retirement obligation to be recorded as a liability in the period in which the obligation was incurred. At the same time the liability is recorded, the costs of the asset retirement obligation must be recorded as an addition to the carrying amount of the related asset. Over time, the liability is accreted to its present value, and the addition to the carrying amount of the asset is depreciated over the asset's useful life. Upon retirement of the asset, the Company will settle the retirement obligation against the recorded balance of the liability. Any difference in the final retirement obligation cost and the liability will result in either a gain or loss. The Company adopted this statement as of April 1, 2003.

The Company has been recording retirement obligations relating to mining reclamation and closure costs prior to adoption of the standard. In addition, the Company has been recording accumulated removal costs as a part of accumulated depreciation in accordance with regulatory accounting. As a result of adoption of the standard, the net difference between these previously recorded amounts that qualify as asset retirement obligations and the fair value amounts determined under SFAS No. 143 will be recognized as a cumulative effect of a change in accounting principle, net of related income taxes. The Company expects to recover asset retirement costs through the ratemaking process and has requested authorization from the state regulatory commissions to record a Regulatory asset or Regulatory liability on the Consolidated Balance Sheet to account for the difference between asset retirement costs as currently approved in rates and obligations under SFAS No. 143.

Upon adoption of SFAS No. 143 on April 1, 2003 the Company recorded an asset retirement obligation liability at its net present value of $196.1 million, increased net depreciable assets by $37.3 million, removed $163.1 million of costs accrued for final removal from accumulated depreciation and reclamation liabilities and will result in a cumulative pretax effect of a change in accounting principle of $4.3 million, which if approved by state regulators, will be recorded primarily as a net regulatory liability. Accretion and depreciation expense in the first year of adoption are expected to be $8.0 million and $2.7 million, respectively.

In June 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities* ("SFAS No. 146"), which requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred instead of at the date of the company's commitment to an exit plan. SFAS No. 146 is effective for exit or disposal activities that are initiated after December 31, 2002 and had no effect on the Company's financial position or results of operations.

In April 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* ("SFAS No. 149"). This statement amends and clarifies financial reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities. This statement is effective for contracts entered into or modified after June 30, 2003. The Company is currently evaluating the impact of adopting this statement on its consolidated financial position and results of operations.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity* ("SFAS No. 150"). This statement affects the accounting for certain financial instruments that, under previous guidance, issuers could account for as equity. The new statement requires that those instruments be classified as liabilities. Most of this statement is effective for financial instruments entered into or modified after May 31, 2003 and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. The Company is currently evaluating the impact of adopting this statement on its consolidated financial position and results of operations.

In January 2003, the FASB issued FASB Interpretation No. 46, *Consolidation of Variable-Interest Entities* ("FIN No. 46"), which requires existing unconsolidated variable-interest entities to be consolidated by their primary beneficiaries if the entities do not effectively disperse risks among parties involved. FIN No. 46 applies immediately to variable-interest entities created after January 31, 2003 and applies, for periods beginning after June 15, 2003, to variable-interest entities acquired before February 1, 2003. The Company does not believe the implementation of FIN No. 46 will have a material impact on its financial position or results of operations.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

BUSINESS RISK

The Company participates in a wholesale energy market that includes: public utility companies; electricity and natural gas marketers, which may or may not be affiliated with public utility companies; government entities; and others. The participants in this market trade, or otherwise buy and sell, not only electricity and natural gas as commodities, but also derivative commodity instruments such as futures, swaps, options and other financial instruments. The pricing in this wholesale market is largely market-based and most transactions are conducted on an "over-the-counter" basis, there being no central clearing mechanism (except in the case of specific instruments traded on the commodity exchanges).

The Company is subject to the various risks inherent in the energy business, including market risk, operating risk, regulatory risk, political risk, security risk, credit risk, interest rate risk, insurance risk and pension risk. Due to global uncertainties, including war and terrorism, the nation's economy and financial markets have been disrupted. The total effects of these matters and other such incidences are not known at this time.

Market Risk

In general, market risk is the risk of fluctuations in the market price of electricity and fuel, as well as volumetric risk caused by changes in weather, the economy, unanticipated generation or network outages and customer behavior. Market price is influenced primarily by factors relating to supply and demand. Those factors include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric availability, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, changes in technology and other factors.

While the Company plans for resources to meet its current and expected retail and wholesale load obligations, resource availability, price volatility and load volatility may materially impact the power costs to the Company and profits from excess electricity sales in the future. Prices paid by the Company to provide certain load balancing resources to supply its load may exceed the amounts it receives through retail rates and wholesale prices.

Operating Risk

Operating risk is the risk that assets and mechanical systems, as well as business processes and procedures, might not perform as expected, with the result that the Company may be unable to meet a portion of its obligations without resorting to an unanticipated market transaction. Operating risk is primarily mitigated through a combination of sound maintenance practices, prudent and safe operational processes and insurance products, such as business interruption insurance.

Regulatory Risk

The Company is subject to the jurisdiction of federal and state regulatory authorities. The FERC establishes tariffs under which the Company provides wheeling service to the wholesale market and the retail market for states allowing retail competition, establishes both cost-based and market-based tariffs under which the Company sells electricity at wholesale and has licensing authority over most of the Company's hydroelectric generation facilities. The utility regulatory commissions in each state independently determine the rates the Company may charge its retail customers in that state. Each state's rate setting process is based upon the state commission's acceptance of an allocated share of total Company costs as its "responsibility." When different states adopt different methods to address this "interjurisdictional cost allocation" issue, some costs may not be incorporated into rates in any state. Ratemaking is done on the basis of "normalized" costs, so if in a specific year realized costs are higher than normal, rates will not be sufficient to cover those costs. Likewise, if in a given year costs are lower than normal or revenues are higher, the Company retains the resulting higher-than-normal profit. Each commission sets rates based on a "test year" of its choosing. In states that use a historical test year, rate adjustments could follow cost increases, or decreases, by up to two years. Regulatory lag results in a delay in recovery of costs currently incurred but not in rates, and also imposes a time-value-of-money burden on the Company. Further, each commission decides what level of expense and investment is "necessary, reasonable and prudent" in providing service. If a commission decides that part of the Company's costs do not meet this standard, such costs will be "disallowed" and not recovered in rates. For these reasons, the rates authorized by the regulators may be less than the costs to the Company to provide electrical service to its customers in a given period.

Nearly all of the Company's hydroelectric projects are in some stage of the FERC relicensing under the FPA. The relicensing process is a political and public regulatory process that involves sensitive resource issues. The Company is unable to predict the requirements that may be imposed during the relicensing process, the economic impact of those requirements, whether new licenses will ultimately be issued or whether the Company will be willing to meet the relicensing requirements to continue operating its hydroelectric projects.

Federal, state and local authorities regulate many of the Company's activities pursuant to laws designed to restore, protect and enhance the quality of the environment. The Company is unable to accurately predict what material impact, if any, future changes in environmental laws and regulations may have on the Company's consolidated financial position, results of operations, cash flows, liquidity and capital expenditure requirements.

Political Risk

The Company conducts its business in conformance with a multitude of federal and state laws. The U.S. Congress is considering significant changes in energy, air quality and tax policy. Energy legislation recently passed by the U.S. House of Representatives would make some changes in federal law that would affect the Company. The proposed changes effect the hydroelectric licensing process under the FPA and extension of the renewable energy production tax credit, which would likely benefit the Company's efforts to develop, acquire and maintain a low-cost generation portfolio. Changes to the Clean Air Act contemplated by the proposed Clear Skies Act are being monitored closely by the Company because they may impact requirements for several emissions from fossil-fueled generation plants.

The laws of the states in which the Company operates affect the Company's generation, transmission and distribution business. All but two of the legislatures monitored by the Company have concluded their regular business for their legislative year. The Company is not aware of any new laws positively or negatively affecting the Company in any significant manner, based on a review of bills passed by the Oregon, Washington and Idaho legislatures during their just-completed legislative sessions. Wyoming enacted an exemption to the state sales tax for renewable-energy equipment, which may make development of wind energy resources in the state more economically viable. Wyoming also passed legislation revamping the consumer advocate staff role in commission proceedings. Utah enacted legislation authorizing the UPSC to use a forward-looking test year of up to 20 months in setting rates. This mechanism, if properly implemented, should enable the UPSC to set consistent rates that more accurately reflect costs during the actual rate period. California is expected to consider legislation repealing or reforming many elements of its 1996 restructuring law.

Security Risk

The emergence of terrorism threats, both domestic and foreign, is a risk to the entire utility industry, including the Company. Specific potential disruptions to operations and information technologies or destruction of facilities from terrorism are not readily determinable. The Company has identified critical assets, created a management structure to respond to threats and developed several approaches to security to meet the changed environment. A project is underway to implement a comprehensive security plan, starting with the most critical assets, to mitigate terrorism risks and to prepare contingency plans in case the Company's facilities are targeted. Additionally the FERC is promulgating standards to which the Company will be subject.

Credit Risk

There has been a decrease in the number of counterparties in the wholesale energy markets with whom the Company has been able to prudently transact business for purposes of servicing its regulated customers. This decline is due to an overall lower credit ratings trend in the energy industry and the concern that these counterparties may face a liquidity crisis and be unable to meet their obligations. In addition, some counterparties are focusing less of their efforts on merchant energy trading, are pursuing lower risk/slower growth opportunities, are strengthening their balance sheets in order to maintain or achieve an investment grade rating or are looking to sell their energy trading divisions or to exit the marketplace entirely.

Credit risk relates to the risk of loss that might occur as a result of nonperformance by counterparties of their contractual obligations to make or take delivery of electricity, natural gas or other commodities and to make financial settlements thereon. Credit risk may be concentrated to the extent that one or more groups of counterparties have similar economic, industry or other characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. In addition, 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 involving other market participants that have a direct or indirect relationship with such counterparty. The Company seeks to mitigate credit risk (and concentrations thereof) by applying specific eligibility criteria to prospective counterparties. However, despite mitigation efforts, defaults by counterparties occur from time to time. The Company continues to actively monitor the creditworthiness of those counterparties with whom it executes wholesale energy and gas purchase and sales transactions within the WECC, including those in California, and uses a variety of risk mitigation techniques to limit its exposure where it believes appropriate. When the Company considers a new business venture or asset purchase, market liquidity and the ability to optimize the investment are main considerations. The Company, like all participants in the regional market, has exposure to other participants that may have credit exposure to the utilities in California. To mitigate exposure to the financial risks of wholesale counterparties, the Company has entered into netting, margining, guarantee and prepayment arrangements. Counterparties may be assessed late fees for delayed receipts. If required, collection rights are exercised, including application of the counterparty's credit support arrangement.

Interest Rate Risk

The Company manages its interest rate risk exposure principally by maintaining a blend of fixed- and variable-rate debt. The majority of debt is fixed-rate securities, portions of which are callable at fixed prices at the Company's option. Changing interest rates will affect interest paid on variable-rate debt and interest earned by the Company's pension plan assets and mining reclamation trust funds. The Company's principal source of variable-rate debt is commercial paper, other short-term borrowings and pollution control revenue bonds remarketed on a periodic basis. Commercial paper and other short-term borrowing are commonly refinanced with fixed-rate long-term debt when needed and when interest rates are considered favorable.

Any adverse change to the Company's credit rating could negatively impact the Company's ability to borrow and the interest rates that are charged. The activity in the western electricity markets has had a negative impact on the willingness of the financial markets to provide financing on conditions and at rates that have historically been available to the Company.

Insurance Risks

The Company continues to experience risk relating to increases in various insurance costs and premiums, as well as available insurance coverage for certain property and liability exposures. The Company's health care costs continue to rise faster than inflation, but not greater than the general industry trend.

The Company has faced a significantly changed insurance market over the past two years. Significant reductions in market capacity and an increase in the incidents of losses worldwide contributed to unprecedented insurance program costs.

Those increased costs came in the form of increased premiums for coverage, as well as substantial increases in self-insured retentions and exposures. Restrictions on the type of coverage available, the scope of the coverage and the limits of coverage were common. In addition, some insurance carriers are now requiring additional security for the self-insured exposures presented by some coverages. As a result, the Company has been required to post letters of credit as security for certain insurance programs, such as surety bonds, workers' compensation and black lung disease coverage. Due to the changes in the market, the Company reevaluated each exposure to ensure that all critical coverage that could be obtained was pursued and critically evaluated. This evaluation resulted in the purchase of business interruption insurance in addition to some of the more traditional property and liability coverage elements. While the Company has elected to purchase terrorism insurance, which is now available with the passage of the Terrorism Re-Insurance Act, coverage gaps pertaining to the Company's transmission and distribution assets and limits on earthquake and flood coverage persist.

Pension Risks

As a result of the decline in the equity markets and low interest rates, the Company anticipates that pension expense and Company cash contributions into the pension trust will increase significantly in the near future. The Company is exposed to further increases in both expense and contribution levels if the equity markets underperform the Company's long-term return expectations. In addition, low interest rates increase both funding requirements and expense levels since the Company's pension liability increases as the discount rate declines. To the extent that actual interest rates fall below currently assumed levels, pension expense and contribution requirements will increase.

RISK MANAGEMENT

The Company has a risk management committee responsible for the oversight of market and credit risk relating to the energy transactions of the Company. The risk management committee consists of the chief executive officer, officers from the finance, regulation, strategy, legal, wholesale marketing and independent risk management group areas. To limit the Company's exposure to market risk, the risk management committee, with the approval of the Board, sets policies and limits and approves energy strategies, which are reviewed frequently to respond to changing market conditions. To limit the Company's exposure to credit risk in these activities, the risk management committee reviews counterparty credit exposure, as well as credit policies and limits, on a monthly basis.

Risk is an inherent part of the Company's business and activities. The risk management process established by the Company is designed to identify, assess, monitor and manage each of the various types of risk involved in its business and activities and to measure quantitative market risk exposure and identify qualitative market risk exposure in its businesses. To assist in managing the volatility relating to these exposures, the Company enters into various transactions, including derivative transactions, consistent with the Company's risk management policy. The risk management policy governs energy transactions and is designed for hedging the Company's existing energy and asset exposures. The policy also governs the Company's use of derivative instruments, as well as its energy purchase and sales practices, and describes the Company's credit policy and management information systems required to effectively monitor such derivative use. The Company's risk management policy provides for the use of only those instruments that have a close volume or price correlation with its portfolio of assets, liabilities or anticipated transactions. The risk management policy includes, as its objective, a policy that such instruments will be primarily used for hedging and not for speculation.

The Company continues to take steps to manage commodity price volatility and reduce exposure. These steps included adding to the generation portfolio and entering into transactions that help to shape the Company's system resource portfolio, including physical hedging products and financially settled (temperature-related) derivative instruments that reduce volume and price risk on days with weather extremes. In addition, a financial hydroelectric generation hedge is in place for the next three years to reduce volume and price risks associated with the Company's hydroelectric generation availability.

RISK MEASUREMENT

Interest Rate Exposure

In accordance with established policies, the Company may use interest rate swaps, forwards, futures and collars to adjust the characteristics of its liability portfolio. This strategy is consistent with the Company's capital structure policy, which provides guidance on overall debt to equity and variable-rate debt as a percent of capitalization levels. At March 31, 2003, the Company had no financial derivatives in effect relating to its interest rate exposure.

The Company's risk to interest rate changes is primarily a noncash fair market value exposure and generally not a cash or current interest expense exposure. This result is due to the size of the Company's fixed-rate, long-term debt portfolio relative to variable rate debt.

The tests discussed below for exposure to interest rate fluctuations are based on a Value-at-Risk ("VaR") approach using a one-year horizon and a 95.0% confidence level and assuming a one-day holding period in normal market conditions. The VaR model is a risk analysis tool that attempts to measure the potential change in fair value, earnings or cash flow from changes in market conditions and does not purport to represent actual losses (or gains) in fair value that may be incurred by the Company.

The table below shows the potential loss in fair market value ("FMV") of the Company's interest-rate-sensitive positions, for continuing operations, as of March 31, 2003 and 2002, as well as the Company's quarterly high and low potential losses.

(Millions of dollars)	Confidence Interval	Time Horizon	March 31, 2002	2003 Quarterly High	2003 Quarterly Low	March 31, 2003
Interest Rate Sensitive Portfolio - FMV	95.0%	1 Day	$ (28.8)	$ (27.1)	$ (18.2)	$ (18.2)

The decrease in potential loss from March 31, 2002 to March 31, 2003 was primarily due to a decline in interest rate volatility.

Commodity Price Exposure

The Company's market risk to commodity price change is primarily related to its fuel and electricity commodities, which are subject to fluctuations due to unpredictable factors, such as weather, which impacts energy supply and demand. The Company's energy purchase and sales activities are governed by the Company's risk management policy and the risk levels established as part of that policy.

The Company's energy commodity price exposure arises principally from its electric supply obligation in the western U.S. The Company manages this risk principally through the operation of its 8,409.7-MW generation and transmission system in the western U.S. and through its wholesale energy purchase and sales activities. Physically settled contracts are utilized to hedge the Company's excess or shortage of net electricity for future months. The Company has also entered into several financially settled (temperature-related) derivative instruments that reduce volume and price risk on days with weather extremes. In addition, a financial hydroelectric generation hedge is in place for the next three years to reduce volume and price risks associated with the Company's hydroelectric generation availability.

In January 2002, the Company began measuring the market risk in its electricity and natural gas portfolio daily utilizing a historical VaR approach, as well as other measurements of net position. The Company also monitors its portfolio exposure to market risk in comparison to established thresholds and measures its open positions subject to price risk in terms of volumes at each delivery location for each forward time period.

VaR computations for the electricity and natural gas commodity portfolio are based on a historical simulation technique, utilizing historical price changes over a specified period to simulate potential forward energy market price curve movements to estimate the potential unfavorable impact of such price changes on the portfolio positions scheduled to settle within the following 24 months. The quantification of market risk using VaR provides a consistent measure of risk across the Company's continually changing portfolio. VaR represents an estimate of reasonably possible changes in fair value that would be measured on its portfolio assuming hypothetical movements in future market rates and is not necessarily indicative of actual results that may occur.

The Company's VaR computations for its electricity and natural gas commodity portfolio utilize several key assumptions, including a 99.0% confidence level for the resultant price changes and a holding period of five days. The calculation includes short-term derivative commodity instruments held for trading and balancing purposes, the expected resource and demand obligations from the Company's long-term contracts, the expected generation levels from the Company's generation assets and the expected retail and wholesale load levels. Optionality embedded within the Company's long-term contracts, generation assets and other derivative instruments with option characteristics within the energy portfolio are treated in the historical simulation of VaR as static delta positions through the simulation process. Option deltas are recalculated on a daily basis to determine the portfolio position changes due to changes in market prices.

As of March 31, 2003, the Company's estimated potential five-day unfavorable impact on fair value of the electricity and natural gas commodity portfolio over the next 24 months was $17.6 million, as measured by the VaR computations described above, compared to $16.3 million as of March 31, 2002. The average daily VaR (five-day holding periods) for the year ended March 31, 2003 was $19.2 million. The maximum and minimum VaR measured during the year ended March 31, 2003 was $35.7 million and $9.5 million, respectively. The Company maintained compliance with its VaR limit procedures during the year ended March 31, 2003. 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 hedging and balancing the Company's energy commodity portfolio were not material as of March 31, 2003.

The following table shows the changes in the fair value of energy-related contracts subject to the requirements of SFAS No. 133 from April 1, 2002 to March 31, 2003 and quantifies the reasons for the changes.

(Millions of dollars)

Fair value of contracts outstanding at the beginning of the period	$ (505.9)
Cumulative effect of accounting change (a)	(3.0)
Contracts realized or otherwise settled during the period	108.4
Changes in fair values attributable to changes in valuation assumptions (b)	193.0
Other changes in fair values (c)	(298.2)
Fair value of contracts outstanding at the end of the period (d)	$ (505.7)

(a) The cumulative effect of accounting change records the impact of Revised Issue C15 and Issue C16.

(b) Reflects changes in the fair value of the mark-to-market values as a result of applying refinements in valuation modeling techniques.

(c) Other changes in fair values reflect commodity price risk, which is influenced by contract size, term, location and unique or specific contract terms.

(d) The Company has also recorded $506.9 million in net regulatory assets, as authorized by regulatory orders received, with respect to these contracts.

The forward market price curve is derived using daily market quotes from independent energy brokers, as well as direct information received from third-party offers and actual transactions executed by the Company. For contracts extending past 2006, the forward prices also include the use of a fundamentals model (cost-to-build approach) due to the limited market information available past 2006. The fundamentals model is updated as warranted, at least quarterly, to reflect changes in the market. Short-term contracts, without explicit or embedded optionality, are valued based upon the relevant portion of the forward market price curve. Contracts with explicit or embedded optionality and long-term contracts are valued by separating each contract into its component physical and financial forward, swap and option legs. Forward and swap legs are valued against the appropriate market curve. The optionality is valued using a modified Black-Scholes model or a stochastic simulation (Monte Carlo) approach. Each option component is modeled and valued separately using the appropriate forward market price curve.

The Company also manages its exposure to price and volume risk by purchasing weather hedges. These products are designed to protect the Company from the effects of weather on its hydroelectric generation and load forecast. The Company records these instruments in its financial statements at market value in accordance with Emerging Issues

Task Force No. 99-2, *Accounting for Weather Derivatives*. At March 31, 2003, the net value of these instruments was a liability of $3.5 million.

The Company's valuation models and assumptions are continuously updated to reflect current market information, and an evaluation and refinement of model assumptions are performed on a periodic basis.

The following table shows summarized information with respect to valuation techniques and contractual maturities of the Company's energy-related contracts qualifying as derivatives under SFAS No. 133 as of March 31, 2003.

	Fair Value of Contracts at Period-End				
(Millions of dollars)	**Maturity less than 1 year**	**Maturity 2-3 years**	**Maturity 4-5 years**	**Maturity in excess of 5 years**	**Total Fair Value**
Prices based on models and other valuation methods	$ 15.5	$ (12.4)	$ (39.7)	$ (469.1)	$ (505.7)

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF MANAGEMENT

The management of PacifiCorp and its subsidiaries (the "Company") are responsible for preparing the accompanying consolidated financial statements and ensuring their integrity and objectivity. The statements were prepared in accordance with accounting principles generally accepted in the United States of America. The financial statements include amounts that are based on management's best estimates and judgments. Management also prepared the other information in this annual report on Form 10-K and is responsible for its accuracy and consistency with the financial statements.

The Company's financial statements were audited by PricewaterhouseCoopers LLP ("PricewaterhouseCoopers"), independent public accountants. Management made available to PricewaterhouseCoopers all the Company's financial records and related data, as well as the minutes of directors' meetings.

Management of the Company established and maintains an internal control structure that provides reasonable assurance as to the integrity and reliability of the financial statements, the protection of assets from unauthorized use or disposition and the prevention and detection of materially fraudulent financial reporting. The Company maintains an internal auditing program that independently assesses the effectiveness of the internal control structure and recommends possible improvements. PricewaterhouseCoopers considered that internal control structure in connection with its audits. Management reviews significant recommendations by the internal auditors and PricewaterhouseCoopers concerning the Company's internal control structure and ensures that appropriate cost-effective actions are taken.

The Company's "Guide to Business Conduct" is distributed to employees throughout the Company to provide a basis for ethical standards and conduct. The guide addresses, among other things, potential conflicts of interests and compliance with laws, including those relating to financial disclosure and the confidentiality of proprietary information. In addition, the Company recently adopted and implemented the "PacifiCorp Code of Ethics for Principal Officers" in response to the Sarbanes-Oxley Act of 2002.

Judith A. Johansen
President and Chief Executive Officer

Richard D. Peach
Chief Financial Officer

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Shareholders of PacifiCorp:

In our opinion, the accompanying consolidated balance sheets and the related statements of consolidated income (loss), changes in common shareholder's equity and cash flows present fairly, in all material respects, the financial position of PacifiCorp and its subsidiaries at March 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended March 31, 2003 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 3 to the Consolidated Financial Statements, the Company changed its method of accounting for derivative instruments as of April 1, 2001.

PricewaterhouseCoopers LLP
Portland, Oregon
May 7, 2003

PACIFICORP AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED INCOME (LOSS)

(Millions of dollars)	Years Ended March 31,		
	2003	2002	2001
Revenues	$ 4,593.4	$ 4,235.3	$ 5,055.9
Operating expenses			
Purchased electricity	1,212.6	2,038.8	2,636.0
Fuel	482.2	490.9	491.0
Other operations and maintenance	603.9	562.8	705.2
Depreciation and amortization	434.3	403.0	429.0
Administrative and general	281.2	250.6	200.8
Taxes, other than income taxes	95.4	90.8	100.2
Unrealized gain on SFAS No. 133 derivative instruments	(3.1)	(182.8)	—
Total	3,104.5	3,654.1	4,562.3
Other operating income	—	(32.4)	(30.6)
Gain (loss) on sale of operating assets		(27.4)	183.4
Income from operations	488.9	641.0	339.8
Interest expense and other (income) expense			
Interest expense	230.3	227.7	290.4
Interest income	(21.6)	(47.5)	(32.6)
Interest capitalized	(18.0)	(6.9)	(12.9)
Minority interest and other	19.0	(1.8)	2.7
Total	249.7	171.5	247.6
Income from continuing operations before income taxes and cumulative effect of accounting change	239.2	469.5	92.2
Income tax expense	97.2	176.1	180.4
Income (loss) from continuing operations before cumulative effect of accounting change	142.0	293.4	(88.2)
Discontinued operations (less applicable income tax expense: $104.4/2002)	—	146.7	—
Income (loss) before cumulative effect of accounting change	142.0	440.1	(88.2)
Cumulative effect of accounting change (less applicable income tax benefit: $1.1/2003 and $69.0/2002) (Note 3)	(1.9)	(112.8)	
Net income (loss)	140.1	327.3	(88.2)
Preferred dividend requirement	(7.3)	(12.7)	(17.9)
Earnings (loss) on common stock	$ 132.8	$ 314.6	$ (106.1)

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

(Millions of dollars)	March 31, 2003	March 31, 2002
ASSETS		
Current assets		
[redacted]		
Accounts receivable less allowance for doubtful accounts: $36.3/2003 and $34.8/2002	253.2	249.1
[redacted]		
Inventories at average cost		
Materials and supplies	99.4	93.5
[redacted]		
SFAS No. 133 current assets	107.2	51.3
[redacted]		
Total current assets	812.2	760.2
Property, plant and equipment		
[redacted]		
Transmission	2,328.9	2,250.7
[redacted]		
Other	1,935.1	1,848.3
[redacted]		
Total	13,516.8	13,098.9
[redacted]		
Total property, plant and equipment – net	8,033.6	7,969.5
Other assets		
[redacted]		
SFAS No. 133 regulatory asset	506.9	468.4
[redacted]		
Deferred charges and other	342.1	366.2
[redacted]		
Total assets	$ 10,993.0	$ 10,877.6

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS, continued

(Millions of dollars)	March 31, 2003	March 31, 2002
LIABILITIES, REDEEMABLE PREFERRED STOCK AND SHAREHOLDERS' EQUITY		
Current liabilities		
[redacted]		
Notes payable and commercial paper	25.0	177.5
[redacted]		
Accrued employee expenses	105.9	91.8
[redacted]		
Interest payable	67.9	100.8
[redacted]		
Other	159.0	142.0
[redacted]		
Deferred credits		
Income taxes	1,480.2	1,434.8
[redacted]		
Regulatory liabilities	137.0	219.7
[redacted]		
Other	650.1	443.7
[redacted]		
Long-term debt, net of current maturities	3,417.6	3,553.8
Commitments and contingencies (Note 9)		
[redacted]		
Preferred stock subject to mandatory redemption	66.7	74.2
[redacted]		
Common equity		
Common shareholder's capital	2,892.1	2,742.1
[redacted]		
Accumulated other comprehensive income (loss):		
Unrealized (loss) gain on available for sale securities, net of tax of $(1.5)/2003 and $0.6/2002	(1.7)	0.7
[redacted]		
Unrealized loss on derivative financial instruments, net of tax of $14.7/2002	—	(24.0)
[redacted]		
Total liabilities, redeemable preferred stock and shareholders' equity	$10,993.0	$10,877.6

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED CASH FLOWS

(Millions of dollars)	Years Ended March 31,		
	2003	2002	2001
Cash flows from operating activities			
[redacted]			
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Gain on disposal of discontinued operations	—	(146.7)	—
[redacted]			
Unrealized gain on SFAS No. 133 derivative instruments	(3.1)	(182.8)	—
[redacted]			
Depreciation and amortization	434.3	403.0	429.0
[redacted]			
(Gain) loss on sale of subsidiary and assets	(3.7)	(52.6)	189.2
[redacted]			
Regulatory asset establishment	—	(21.0)	(35.1)
[redacted]			
Changes in other regulatory assets/liabilities	131.1	65.0	16.4
[redacted]			
Inventories	(17.8)	7.0	(9.3)
[redacted]			
Other	26.1	(33.4)	(32.1)
[redacted]			
Cash flows from investing activities			
Capital expenditures	(550.0)	(505.3)	(485.7)
[redacted]			
Advances to ScottishPower	—	(627.4)	(396.0)
[redacted]			
Proceeds from finance note repayment	—	189.9	—
[redacted]			
Proceeds from sales of finance assets and principal payments	—	36.0	48.5
[redacted]			
Purchases of available for sale securities	(134.3)	(152.0)	(114.5)
[redacted]			
Net cash (used in) provided by investing activities	(525.1)	(568.4)	231.8
Cash flows from financing activities			
[redacted]			
Proceeds from long-term debt	—	791.1	1,114.0
[redacted]			
Dividends paid	(7.3)	(310.3)	(347.7)
[redacted]			
Redemptions of preferred stock	(7.5)	(100.0)	—
[redacted]			
Net cash (used in) provided by financing activities	(161.9)	244.3	(891.3)
[redacted]			
Cash and cash equivalents at beginning of year	157.9	139.4	154.2
[redacted]			

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED CHANGES IN COMMON SHAREHOLDER'S EQUITY

(Millions of dollars, thousands of shares)	Common Shareholder's Capital		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Comprehensive Income (Loss)
	Shares	Amounts			
[redacted]					
Comprehensive loss					
Net loss	—	—	(88.2)	—	$ (88.2)
Other comprehensive income (loss)					
[redacted]					
Realization of foreign exchange loss included in net income, net of tax of $55.6	—	—	—	85.7	85.7
[redacted]					
Cash dividends declared					
Preferred stock	—	—	(15.4)	—	—
[redacted]					
Balance at March 31, 2001	297,325	3,284.9	128.6	0.9	$ (60.1)
Comprehensive income					
[redacted]					
Other comprehensive income (loss)					
Unrealized loss on available-for-sale securities, net of tax of $-	—	—	—	(0.2)	(0.2)
[redacted]					
Loss on derivative financial instruments, net of tax of $(70.2)	—	—	—	(115.1)	(115.1)
[redacted]					
Cash dividends declared					
Preferred stock	—	—	(9.8)	—	—
[redacted]					
Transfer of Holdings	—	(542.8)	(32.2)	—	—
[redacted]					
Comprehensive income					
Net income	—	—	140.1	—	$ 140.1
Other comprehensive income (loss)					
[redacted]					
Minimum pension liability, net of tax of $(0.8)	—	—	—	(1.4)	(1.4)
[redacted]					
Sale of common stock to parent	14,851	150.0	—	—	—
Cash dividends declared					
[redacted]					
Balance at March 31, 2003	312,176	$ 2,892.1	$ 305.9	$ (3.1)	$ 160.3

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - Summary of Significant Accounting Policies

Nature of operations - The Company (which includes PacifiCorp and its subsidiaries) is a United States ("U.S.") electricity company operating in six western states. The Company conducts its retail electric utility business as Pacific Power and Utah Power and engages in electricity production and sales on a wholesale basis. The subsidiaries of PacifiCorp support its electric utility operations by providing coal mining facilities and services, environmental remediation and financing.

Basis of presentation - The consolidated financial statements of the Company include its integrated electric utility operations and its wholly owned and majority-owned subsidiaries. Significant intercompany transactions and balances have been eliminated upon consolidation.

After obtaining the necessary regulatory approvals, on December 31, 2001, NA General Partnership ("NAGP") contributed all of the common stock of the Company to PacifiCorp Holdings, Inc. ("PHI"), a direct wholly owned subsidiary of NAGP. NAGP is a wholly owned subsidiary of Scottish Power plc ("ScottishPower"). On February 4, 2002, PacifiCorp transferred all of the capital stock of PacifiCorp Group Holdings Company ("PGHC"), to PHI. This was a noncash transaction that resulted in a net reduction in shareholder's equity of $575.0 million. PGHC includes the wholly owned subsidiary PacifiCorp Financial Services, Inc. ("PFS"), a financial services business. Accordingly, the consolidated results of operations, assets and liabilities of PGHC and its subsidiaries are not included with those of PacifiCorp commencing February 4, 2002.

In March 2001, the Company sold its interest in PPM Energy, Inc. ("PPM"), formerly PacifiCorp Power Marketing, and Pacific Klamath Energy to PHI, as further discussed in NOTE 17.

The Company completed the sales of its ownership of Powercor Australia Ltd. ("Powercor") on September 6, 2000 and its 19.9% interest in Hazelwood Power Partnership ("Hazelwood") on November 17, 2000, as further discussed in NOTE 17. Powercor and Hazelwood represented all of the Australian Operations segment of the Company.

On November 29, 1999, the Company and ScottishPower completed a merger under which the Company became an indirect subsidiary of ScottishPower (the "Merger"). As a result of regulatory requirements and the existence of debt instruments that are secured by the assets of the Company, the basis of assets and liabilities reported in the Company's financial statements has not been revised to reflect the acquisition of the Company by ScottishPower. The assets, liabilities and shareholder's equity continue to be presented at historical cost.

Change in fiscal year - In connection with the Merger, the Company's year-end changed from December 31 to March 31. The Australian Operations' year-end remained December 31 after the Merger. Consequently, the Company's statements of consolidated loss and consolidated cash flows for the year ended March 31, 2001 include Australian Operation's financial statements for the period from January 1, 2000 to the respective dates of sale.

Use of estimates - The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements. Actual results could differ from those estimates.

Regulation - Accounting for the electric utility business conforms with accounting principles generally accepted in the United States of America as applied to regulated public utilities and as prescribed by agencies and the commissions of the various locations in which the electric utility business operates. The Company prepares its financial statements as they relate to Electric Operations in accordance with Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71") as further discussed in NOTE 2.

Foreign currency - The financial statements for foreign subsidiaries, which were sold in fall 2000, were prepared in currencies other than the U.S. dollar. The income statement amounts were translated at average exchange rates for the year, while the assets and liabilities were translated at year-end exchange rates. Translation adjustments were included in Accumulated other comprehensive income (loss), a separate component of Common equity. All gains and losses resulting from foreign currency transactions were included in the determination of net income.

Cash and cash equivalents - For the purposes of these financial statements, the Company considers all liquid investments with maturities of three months or less, at the time of acquisition, to be cash equivalents.

Allowance for doubtful accounts - The Company's estimate for its allowance for doubtful accounts relating to trade receivables is based on two methods. The amounts calculated from each of these methods are combined to determine the total amount reserved. First, the Company evaluates specific accounts for which it has information that the customer may be unable to meet its financial obligations. In these cases, the Company uses its judgment, based on the best available facts and circumstances and records a specific reserve for that customer against amounts due to reduce the receivable to the amount that is expected to be collected. These specific reserves are reevaluated and adjusted as additional information is received that impacts the amount reserved. Second, a general reserve is established for all customers based on historical experience. The Company provided $13.9 million, $16.0 million and $10.6 million for doubtful accounts for the years ended March 31, 2003, 2002 and 2001, respectively. Write-offs of uncollectible accounts were $12.4 million, $8.8 million and $10.8 million for the years ended March 31, 2003, 2002 and 2001, respectively.

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

Property, plant and equipment - Property, plant and equipment are stated at original cost of contracted services, direct labor and materials, interest capitalized during construction and indirect charges for engineering, supervision and similar overhead items. The cost of depreciable electric utility properties retired, including the cost of removal, less salvage, is charged to accumulated depreciation. The costs of major overhaul activities and other repairs and maintenance are expensed as the costs are incurred.

Depreciation and amortization - At March 31, 2003, the average depreciable lives of Property, plant and equipment by category for Electric Operations were: Production, 41 years; Transmission, 58 years; Distribution, 42 years and Other, 20 years. Average amortization life on computer software is eight years.

Depreciation and amortization are generally computed by the straight-line method in one of the following two manners, either as prescribed by the Company's various regulatory jurisdictions for Electric Operations' regulated assets, or over the assets' estimated useful lives. Composite depreciation rates on utility plants (excluding amortization of capital leases) in the Electric and Australian Operations were 3.2%, 3.1% and 3.1% of average depreciable assets for the years ended March 31, 2003, 2002 and 2001, respectively.

Asset impairments - Long-lived assets to be held and used by the Company are reviewed for impairment when events or circumstances indicate costs may not be recoverable. Such reviews are performed in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* ("SFAS No. 144"), which the Company adopted February 1, 2002, effective as of April 1, 2001. The impacts of regulation on cash flows are considered when determining impairment. Impairment losses on long-lived assets are recognized when book values exceed expected undiscounted future cash flows with the impairment measured on a discounted future cash flows basis.

Allowance for Funds Used During Construction - The Allowance for Funds Used During Construction (the "AFUDC") represents the cost of both debt and equity funds used to finance utility property additions during construction. As prescribed by regulatory authorities, the AFUDC is capitalized as a part of the cost of utility property and is recorded in the Statement of Consolidated Income (Loss) as Interest capitalized. Under regulatory rate practices, the Company is generally permitted to recover the AFUDC, and a fair return thereon, through its rate base after the related utility property is placed in service.

The composite capitalization rates for the years ended March 31, 2003, 2002 and 2001 were 7.2%, 3.6% and 7.3%, respectively. The Company's AFUDC rates do not exceed the maximum allowable rates determined by regulatory authorities.

Derivatives - As discussed in NOTE 3, the Company adopted SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by SFAS No. 138, effective April 1, 2001. The statement requires that the Company recognize all derivatives, as defined in the statement, on the balance sheet at fair value. Derivatives, or any portion thereof, that are not an effective hedge are adjusted to fair value through income. If a derivative qualifies as an effective hedge, changes in the fair value of the derivative are either offset against the change in fair value of the hedged asset, liability or firm commitment recognized in earnings or are recognized in Accumulated other comprehensive income (loss) until the hedged items are recognized in earnings.

Deferred charges and other - Deferred charges and other are composed primarily of funds held in trust for the final reclamation of a leased coal mining property, investments to fund environmental remediation, unamortized debt expense, long term customer loans and receivables, certain employee benefit plan assets and net amounts for corporate-owned life insurance.

The Company maintains a trust relating to final reclamation of a leased coal mining property. Amounts funded are based on estimated future reclamation costs and estimated future coal deliveries. In the years ended March 31, 2003 and 2002, the Company reviewed funding requirements based on estimated future gains and interest earnings on trust assets and the projected future reclamation liability. The Company determined that no funding was required in those years. Securities held in the reclamation trust fund are recorded at market value in accordance with SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities*, as discussed in NOTE 5. Trust assets include debt and equity securities classified as available for sale. Securities available for sale are carried at fair value with net unrealized gains or losses excluded from income and reported as Accumulated other comprehensive income (loss). Realized gains or losses are determined on the specific identification method.

Income taxes - The Company uses the liability method of accounting for deferred income taxes. Deferred tax liabilities and assets reflect the expected future tax consequences, based on enacted tax law, of temporary differences between the tax bases of assets and liabilities and their financial reporting amounts.

Historically, Electric Operations did not provide deferred taxes on many of the timing differences between book and tax depreciation. In prior years, these benefits were flowed through to the utility customer as prescribed by the Company's various regulatory jurisdictions. Deferred income tax liabilities and Regulatory assets have been established for those flow-through tax benefits, as shown in NOTE 15.

Investment tax credits for regulated Electric Operations are deferred and amortized to income over periods prescribed by the Company's various regulatory jurisdictions.

Provisions for U.S. income taxes for the year ended March 31, 2001 were made on the undistributed earnings of the Company's international businesses.

Stock-based compensation - As permitted by SFAS No. 123, *Accounting for Stock-Based Compensation*, the Company has elected to account for its stock-based compensation arrangements under the intrinsic value recognition and measurement principles of Accounting Principles Board ("APB") Opinion No. 25, *Accounting for Stock Issued to Employees* ("APB No. 25"), and related interpretations in accounting for employee stock options issued to Company employees. Under APB No. 25, because the exercise price of employee stock options equals the market price of the underlying stock on the date of grant, no compensation expense is recorded. All options are issued in ScottishPower American Depository Shares ("ADS"), as discussed in NOTE 14. Had the Company determined compensation cost based on the fair value at the grant date for all stock options vesting in each period under SFAS No. 123, the Company's net income would have been reduced to the pro forma amounts below:

	Years Ended March 31,		
(Millions of dollars)	**2003**	**2002**	**2001**
Net income (loss) as reported	$ 140.1	$ 327.3	$ (88.2)
Stock-based employee compensation expense	(1.6)	(2.2)	(3.4)
Pro forma net income (loss)	$ 138.5	$ 325.1	$ (91.6)

Revenue recognition - The Company records electric utility operating revenues when it delivers electricity to its customers. The determination of the energy sales to the customers is based on a reading of their meters, which reading is staggered throughout the month. The Company accrues estimated unbilled revenues for electric services provided after the meter read date to the month-end, based upon the Company's total energy delivery.

New accounting standards - In June 2001, the Financial Accounting Standards Board (the "FASB") issued SFAS No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143"). The statement requires the fair value of an asset retirement obligation to be recorded as a liability in the period in which the obligation was incurred. At the same time the liability is recorded, the costs of the asset retirement obligation must be recorded as an addition to the carrying amount of the related asset. Over time, the liability is accreted to its present value and the addition to the carrying amount of the asset is depreciated over the asset's useful life. Upon retirement of the asset, the Company will settle the retirement obligation against the recorded balance of the liability. Any difference in the final retirement obligation cost and the liability will result in either a gain or loss. The Company adopted this statement as of April 1, 2003.

The Company has been recording retirement obligations relating to mining reclamation and closure costs prior to adoption of the standard. In addition, the Company has been recording accumulated removal costs as a part of accumulated depreciation in accordance with regulatory accounting. As a result of adoption of the standard, the net difference between these previously recorded amounts that qualify as asset retirement obligations and the fair value amounts determined under SFAS No. 143 will be recognized as a cumulative effect of a change in accounting principle, net of related income taxes. The Company expects to recover asset retirement costs through the ratemaking process and has requested authorization from the state regulatory commissions to record a Regulatory asset or Regulatory liability on the Consolidated Balance Sheet to account for the difference between asset retirement costs as currently approved in rates and obligations under SFAS No. 143.

Upon adoption of SFAS No. 143 on April 1, 2003, the Company recorded an asset retirement obligation liability at its net present value of $196.1 million, increased net depreciable assets by $37.3 million, removed $163.1 million of costs accrued for final removal from accumulated depreciation and reclamation liabilities and will result in a cumulative pretax effect of a change in accounting principle of $4.3 million, which if approved by state regulators, will be recorded primarily as a net regulatory liability. Accretion and depreciation expense in the first year of adoption are expected to be $8.0 million and $2.7 million, respectively.

In June 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities* ("SFAS No. 146"), which requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred instead of at the date of the company's commitment to an exit plan. SFAS No. 146 is effective for exit or disposal activities that are initiated after December 31, 2002 and had no effect on the Company's financial position or results of operations.

In April 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* ("SFAS No. 149"). This statement amends and clarifies financial reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities. This statement is effective for contracts entered into or modified after June 30, 2003. The Company is currently evaluating the impact of adopting this statement on its consolidated financial position and results of operations.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity* ("SFAS No. 150"). This statement affects the accounting for certain financial instruments that, under previous guidance, issuers could account for as equity. The new statement requires that those instruments be classified as liabilities. Most of this statement is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. The Company is currently evaluating the impact of adopting this statement on its consolidated financial position and results of operations.

In January 2003, the FASB issued FASB Interpretation No. 46, *Consolidation of Variable-Interest Entities* ("FIN No. 46"), which requires existing unconsolidated variable-interest entities to be consolidated by their primary beneficiaries if the entities do not effectively disperse risks among parties involved. FIN No. 46 applies immediately to variable-interest entities created after January 31, 2003 and applies for periods beginning after June 15, 2003, to variable-interest entities acquired before February 1, 2003. The Company does not believe the implementation of FIN No. 46 will have a material impact on its financial position or results of operations.

Reclassification - Certain amounts from prior years have been reclassified to conform to the 2003 method of presentation. These reclassifications had no effect on previously reported consolidated net income (loss).

NOTE 2 - Accounting for the Effects of Regulation

Regulated utilities have historically applied the provisions of SFAS No. 71,which is based on the premise that regulators will set rates that allow for the recovery of a utility's costs, including cost of capital. Accounting under SFAS No. 71 is appropriate as long as (i) rates are established by or subject to approval by independent, third-party regulators, (ii) rates are designed to recover the specific enterprise's cost of service, and (iii) in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be collected from customers.

SFAS No. 71 provides that regulatory assets may be capitalized if it is probable that future revenue in an amount at least equal to the capitalized costs will result from the inclusion of that cost in allowable costs for ratemaking purposes. In addition, the rate action should permit recovery of the specific previously incurred costs rather than provide for expected levels of similar future costs. The Company records regulatory assets and liabilities based on management's assessment that it is probable that a cost will be recovered (asset) or that an obligation has been incurred (liability). The final outcome, or additional regulatory actions, could change management's assessment in future periods. A regulator can provide current rates intended to recover costs that are expected to be incurred in the future, with the understanding that if those costs are not incurred, future rates will be reduced by corresponding amounts. If current rates are intended to recover such costs, the Company recognizes amounts charged, pursuant to such rates, as liabilities and takes those amounts to income only when the associated costs are incurred. In applying SFAS No. 71, the Company must give consideration to changes in the level of demand or competition during the cost recovery period. In accordance with SFAS No. 71, Electric Operations capitalizes certain costs as regulatory assets in accordance with regulatory authority whereby those costs will be expensed and recovered in future periods.

The Emerging Issues Task Force (the "EITF") of the FASB concluded in 1997 that SFAS No. 71 should be discontinued when detailed legislation or regulatory orders regarding competition are issued. Additionally, the EITF concluded that regulatory assets and liabilities applicable to businesses being deregulated should be written off unless their realization is provided for through future regulated cash flows. The Company continuously evaluates the appropriateness of applying SFAS No. 71 to each of its jurisdictions. At March 31, 2003, management concluded that SFAS No. 71 was appropriate for the Electric Operations. However, if deregulation activities progress, the Company may in the future be required to discontinue its application of SFAS No. 71 to all or a portion of its business. If the Company stopped applying SFAS No. 71 to its regulated operations, it would write off the related balances of its regulatory assets as an expense on its income statement. Based on the balances of the Company's regulatory assets at March 31, 2003, if the Company had stopped applying SFAS No. 71 to its remaining regulated operations, it would have recorded an extraordinary loss, after tax, of approximately $918.2 million. While regulatory orders and market conditions may affect the Company's cash flows, its cash flows would not be affected if it stopped applying SFAS No. 71 unless a regulatory order limited its ability to recover the cost of that regulatory asset.

The Company is subject to the jurisdiction of public utility regulatory authorities of each of the states in which it conducts retail electric operations, as to prices, services, accounting, issuance of securities and other matters. The jurisdictions in which the Company operates are in various stages of evaluating deregulation. At present, the Company is subject to cost based rate making for its Electric Operations business. The Company is a "licensee" and a "public utility" as those terms are used in the Federal Power Act (the "FPA") and is, therefore, subject to regulation by the Federal Energy Regulatory Commission (the "FERC") as to accounting policies and practices, certain prices and other matters.

The Company has made progress toward recovering the deferred net power costs incurred during the period of extreme volatility and unprecedented high price levels beginning in summer 2000 and extending through summer 2001. These costs have been authorized for recovery as follows: (i) $147.0 million in Utah; (ii) $131.0 million, plus carrying charges, in Oregon; and (iii) $25.0 million in Idaho. The Oregon rate order is the subject of a court appeal by intervening parties, which, if successful, would require refunds of amounts collected after January 22, 2003. In Wyoming, the Company's request for recovery of deferred net power costs was denied, and, as a result, the Company wrote off the remaining net regulatory asset of $48.3 million during the year ended March 31, 2003. The Company filed a petition for rehearing on the Wyoming decision on April 4, 2003. The WPSC denied the petition on May 30, 2003. In Washington, the Company had requested recovery of approximately $17.5 million of excess power costs, which have not been deferred, or, alternatively, that the Company be allowed to file a general rate case, which is currently restricted through December 2005. This request was subsequently reduced to approximately $15.9 million based on revised estimates. A final decision in Washington is expected by June 2003. At March 31, 2003, the Company had $137.8 million of deferred power costs, net of amortization, remaining to be collected over two to three years.

Deferred accounting treatment for the effects of SFAS No. 133 on the financial statements of the Company has been granted in all the states the Company serves. The regulatory orders direct the deferral, as a regulatory asset or liability, of the effects of fair valuing long-term contracts that are included in the Company's rates.

Regulatory assets include the following:

(Millions of dollars)	March 31, 2003	March 31, 2002
[redacted]		
Transition Plan costs - retirement and severance (b)	55.1	78.6
[redacted]		
Demand-side resource costs	45.7	49.3
[redacted]		
Utah and Oregon asset writebacks (d)	27.0	40.2
[redacted]		
SFAS No. 133 regulatory asset (e)	506.9	468.4
[redacted]		
Minimum pension liability offset (g)	234.5	—
[redacted]		
Total	$1,682.8	$1,626.7

(a) Excludes $91.4 million and $99.3 million as of March 31, 2003 and 2002, respectively, of investment tax credits.

(b) Represents the unamortized amount of retirement and severance costs relating to a transition plan that the state commissions allowed to be deferred and amortized.

(c) Represents the deferred net power costs that vary from costs included in determining retail rates in Utah, Oregon and Idaho.

(d) A Utah Public Service Commission ("UPSC") order during the year ended March 31, 2001 allowed recovery of early retirement and pension costs, reclamation costs and Year 2000 and other information system costs that had previously been written off. A UPSC order during the year ended March 31, 2002 allowed recovery of an additional $21.0 million of mine reclamation, information system and transition costs that had previously been written-off. An Oregon Public Utility Commission (the "OPUC") order during the year ended March 31, 2001 allowed recovery of Year 2000 information system costs.

(e) Represents the current and noncurrent mark-to-market derivative adjustments on long-term purchased electricity contracts per SFAS No. 133.

(f) Represents the State of Oregon Senate Bill 1149 ("SB 1149") related transition and implementation costs allowed to be recovered by a systems benefit charge allotted to associated customers effective March 1, 2002.

(g) See NOTE 14 – Employment Benefit Plans.

At March 31, 2003, $56.1 million of regulatory assets have been provided by regulators without a return on investment to the Company. The remaining recovery period for these assets is approximately two years.

Regulatory liabilities include the following:

(Millions of dollars)	March 31, 2003	March 31, 2002
[redacted]		
Centralia gain (a)	66.5	115.3
[redacted]		
Utah rate refund	—	34.7
[redacted]		
Total	$137.0	$219.7

(a) Represents the gain on the sale of the Centralia, Washington power plant and coal mine ("Centralia") that is being returned to customers as ordered by the state commissions in connection with approving the sale. The gain amounts claimed by the jurisdictions the Company serves exceeded the actual gain on the transaction by $13.9 million resulting in a loss on sale that was recorded in Other operating income in the year ended March 31, 2001. The Company is no longer required to return a portion of the gain relating to Utah customers as discussed in Deferred Net Power Costs below.

The Company evaluates the recovery of all regulatory assets periodically and as events occur. The evaluation includes the probability of recovery as well as changes in the regulatory environment. Because of the potential regulatory and/or legislative action in Utah, Oregon, Wyoming, Washington and Idaho, the Company may have regulatory asset write-offs and charges for impairment of long-lived assets in future periods. Impairment would be measured in accordance with the Company's asset impairment policy, as discussed in NOTE 1.

Depreciation Rate Changes

On October 1, 2002, the Company filed applications with the respective regulatory commissions in Utah, Oregon, Wyoming, Washington and Idaho to change the rates of depreciation based on a new depreciation study. The new study reflects depreciable plant balances at March 31, 2002. In Utah, settlement discussions have resulted in a stipulation with intervenors. On April 17, 2003, the UPSC approved the stipulation. The rates approved in the stipulation will reduce annual Utah allocated depreciation expense by $6.0 million. The Company and the Idaho Public Utilities Commission (the "IPUC") staff have agreed on a similar stipulation that will reduce Idaho's annual allocated depreciation expense by $0.9 million. This stipulation was filed with the IPUC on April 30, 2003. If adopted by all states, these depreciation rate changes would reduce total Company depreciation expense by $20.3 million annually, which could ultimately result in lower revenues or offset anticipated price increases. Future decisions by the commissions in Oregon, Washington and California may impact this annual expense reduction.

Trail Mountain Coal Mine Closure Costs

On February 7, 2001, the Company filed applications with the UPSC, the OPUC, the Wyoming Public Service Commission (the "WPSC") and the IPUC requesting accounting orders to defer $27.1 million in unrecovered costs associated with its Trail Mountain coal mine. The Company ceased operations at the mine on March 7, 2001. The mine is located in central Utah and supplied fuel to the Company's Hunter generating plant. In April 2001, the WPSC and the IPUC approved deferred accounting treatment of their state's share of the $27.1 million of nonrecovered Trail Mountain coal mine investment costs. Additional closure-related costs in the amount of $18.7 million were subsequently identified, and the total amount subject to possible deferral increased to approximately $45.8 million. The Company filed in Utah and Oregon to include the additional costs in its deferral application and received approval to defer the full $45.8 million for accounting purposes. In addition, the parties in Oregon signed a stipulation calling for a $1.1 million annual reduction in Oregon base rates due to the removal of the Trail Mountain coal mine assets from the rate base. The stipulation also provides for a $2.6 million annual surcharge for five years to recover Oregon's share of mine closure costs. This stipulation was approved by the OPUC on May 20, 2002. On April 4, 2002, the UPSC approved deferral of Utah's share of the $45.8 million with a five-year amortization beginning April 1, 2001. On May 7, 2002, the Company filed a general rate case in Wyoming that sought to recover Wyoming's share of the $45.8 million, to be recovered based on a five-year amortization period beginning April 1, 2001. On March 6, 2003, the WPSC approved a stipulation that includes one-fifth of Wyoming's allocated share of Trail Mountain coal mine closure costs in annual base rates.

In April 2002, the Company established a regulatory asset for the full closure costs of the Trail Mountain coal mine with a five-year amortization period beginning April 2001. The resulting regulatory asset at March 31, 2003 was $27.9 million, net of amortization. The reestablishment of the regulatory asset increased accumulated depreciation to reverse the effects of the retirement of the mine and decreased coal inventory costs for the closure-related costs.

Merger Credits

In connection with the merger between the Company and ScottishPower (the "Merger"), the Company was required to provide benefits to ratepayers through fixed reductions in rates, or "Merger Credits." The Company's total obligation for Merger Credits was $133.4 million through the period ending December 31, 2004. In May 2002, the UPSC allowed the Company to offset all future Merger Credits, which amounted to $20.6 million, against deferred net power costs. On June 7, 2002, the IPUC approved a stipulation agreement that allowed the Company to offset future Merger Credits against deferred net power costs in the amount of $2.3 million. These actions in Utah and Idaho eliminated the Merger Credit revenue reductions of approximately $1.1 million per month, which were set to expire December 31, 2003. In February 2003, the Company recorded $6.0 million in liabilities and current expenses for Merger Credits that will be refunded to Oregon customers during the calendar year ending December 31, 2003. Through March 31, 2003, the Company had provided an aggregate of $64.2 million in Merger Credits and interest to its customers through reduced rates. At March 31, 2003, the Company was still obligated to provide $27.2 million of Merger Credits to customers in Oregon and Washington, through either bill credits or lower base rates.

Concluded Regulatory Actions

Oregon - On May 20, 2002, the OPUC approved a one-year $15.4 million overall rate increase effective June 1, 2002 for the Company's Oregon customers to cover increases in power costs. This increase included an $18.7 million one-year surcharge relating to higher market costs for summer purchases and also resolved a number of other outstanding issues. The Industrial Customers of Northwest Utilities (the "ICNU") requested limited reconsideration of the portion of this order relating to the lease of the West Valley, Utah generating units, involving $1.2 million of revenues annually. On August 8, 2002, the OPUC ordered this reconsideration. The ICNU, the Company and the OPUC staff have filed testimony. Opening briefs were filed April 11, 2003, reply briefs were filed on April 18, 2003 and an order from an administrative law judge is expected in summer 2003.

On May 13, 2003, the OPUC approved the Company's request to begin amortizing its year ended March 31, 2002 costs under SB 1149 effective May 21, 2003. See Deregulation - *Oregon* below. The total costs of $5.2 million will be amortized on a straight-line basis over a five-year period, resulting in an annual rate increase of $1.1 million, or 0.1%. The amortization is subject to refund pending completion of an OPUC staff audit, which is scheduled to occur sometime in summer 2003.

Wyoming - On May 7, 2002, the Company filed a general rate case seeking a permanent $30.7 million, or 9.8%, increase in electricity rates for its Wyoming customers. On December 18, 2002, the Company revised the requested increase to $21.4 million. On January 17, 2003, the Company and the WPSC staff reached agreement on certain issues, which resulted in the Company revising its requested increase to $20.0 million, or 6.4%. The Company's filing also included a request to recover the replacement power costs resulting from the outage of the Company's Hunter No. 1 generating plant and a proposal for recovering deferred net power costs as discussed under Deferred Net Power Costs - *Wyoming*. Hearings in this case were held during January 2003. On March 6, 2003, the WPSC granted the Company a general rate increase of approximately $8.7 million, or 2.8%, and reduced the Company's return on equity ("ROE") from 11.0% to 10.8%. On April 4, 2003, the Company filed a request for rehearing to reconsider the Company's request for recovery of power costs and the order's adoption of the reduced ROE. The WPSC heard oral arguments on May 8, 2003 and denied the petition on May 30, 2003. See Deferred Net Power Costs - *Wyoming* below.

Idaho - On January 7, 2002, the Company filed a request with the IPUC to recover $38.0 million of deferred net power costs through a temporary 24-month surcharge on customer bills and to implement a new credit to pass through Residential Exchange Program benefits from two Bonneville Power Administration ("BPA") settlement agreements. Pass-throughs of BPA credits do not affect Company earnings. In addition, the Company requested an adjustment of individual rate classes to more closely reflect the actual cost of service and proposed a rate mitigation policy to ensure that no customer class would receive a rate increase during the period in which the proposed surcharge is in effect. Parties to the proceeding agreed to a stipulation that would allow recovery of $25.0 million of the deferred net power costs. This recovery would be achieved through a $22.7 million power cost surcharge over two years plus termination of future Merger Credits in the amount of $2.3 million. The IPUC approved the stipulation on June 7, 2002. On June 28, 2002, the Company filed a petition asking the IPUC to reconsider the portion of its June 7, 2002 order requiring that the Company implement a one-time refund of $1.1 million relating to procedural issues in the form of a $20.00 per customer credit. Two individuals also filed petitions for reconsideration of several aspects of the IPUC's order approving the stipulation. On July 24, 2002, the IPUC granted the Company's petition for reconsideration and denied the petitions from the two other parties. Hearings on the reconsideration were held on September 10, 2002. On October 25, 2002, the IPUC ordered the one-time refund of $1.1 million to be reduced to $10,000.

Rate Actions Submitted for Regulatory Approval

Utah - The Company commenced a general rate case on May 15, 2003 based on the year ended March 31, 2003 and including known and measurable changes that will occur by January 1, 2004. The initial filing included a projected revenue requirement increase of $125.0 million that serves as a cap on the amount the Company can receive in the case. A subsequent detailed filing will be made in July 2003 identifying the final requested amount under this cap. If approved, the effective date of the increase would be January 1, 2004, although the Company would not collect any increase until April 1, 2004.

Oregon - On March 18, 2003, the Company filed a general rate case with the OPUC to recover rising costs, including insurance premiums, pension funding and health care. Similar cost trends are being experienced by many businesses across the country, including others in the utility sector. In addition, the filing requested an ROE of

11.5% to compensate the Company for general risks relating to the western U.S. utility environment, as well as some additional risks relating to utility industry restructuring in Oregon and multijurisdictional operations. The Company has requested an annual increase of $57.9 million, or 7.4%, in base rates to take effect in January 2004.

Wyoming - On May 27, 2003, the Company filed a general rate case with the WPSC to recover rising costs (including insurance premiums, pension funding and health care costs) and requested an increase in the ROE to 11.5% to compensate the Company for general risks relating to the western U.S. utility environment, as well as some additional risks relating to multijurisdictional operations. The Company has requested an increase of $41.8 million, or 13.1%, in base rates to take effect in March 2004.

California - On March 16, 2001, the Company filed an interim rate relief request with the California Public Utilities Commission (the "CPUC") as Phase I in an effort to seek an increase in electricity rates for its customers in California. Subsequently, on December 20, 2001, the Company filed a general rate case to increase rates to compensatory levels. If approved by the CPUC, customer rates would increase 29.4% overall or $16.0 million annually, with an authorized return on equity of 11.5%. The annual amount requested incorporated the Phase I interim amount. On June 27, 2002, the CPUC approved an interim increase of $0.01 per kilowatt-hour ("kWh") for certain customers, or approximately $4.7 million annually, or 8.8%, overall. This rate increase is subject to refund pending the outcome of the general rate case. On December 26, 2001, the California Office of Ratepayer Advocates ("ORA") filed a motion to dismiss or defer the Company's general rate case request. The Company responded to ORA's motion on January 10, 2002. Following the expiration of the protest period, on February 25, 2002 the Company filed a motion for a prehearing conference to identify parties of record, establish a procedural schedule and address other issues. A discovery process began in mid-October 2002 and is ongoing. A prehearing conference was held on February 25, 2003. The CPUC and intervenor filed their testimony on May 23, 2003 for results of operations and are scheduled to file testimony on June 4, 2003 for cost allocation and rate design issues. Evidentiary hearings are scheduled for the week beginning June 23, 2003.

Deferred Net Power Costs

The Company filed applications in Utah, Oregon, Wyoming, Washington and Idaho seeking deferred accounting treatment for net power costs materially in excess of the power costs assumed in setting existing retail rates. The applications sought to defer these power cost variances beginning November 1, 2000. As discussed below, the Company received authorization to defer some power costs in excess of those included in retail rates in all the states where requests to do so were made. At March 31, 2003, the Company had remaining deferred power costs, net of amortization, of $137.8 million, including carrying costs.

Utah - In Utah, pursuant to the UPSC's approval of deferred accounting treatment for replacement power costs resulting from the Hunter No. 1 outage, the Company filed on August 23, 2001 seeking permission to recover $103.5 million in replacement power costs over a 12-month period. On November 2, 2001, the UPSC allowed the Company to apply overcollections under an interim relief order from an earlier general rate case toward Hunter No. 1 replacement power costs on an interim basis, subject to refund. The amount of the interim relief was approximately $29.5 million annually.

Also in Utah, on September 21, 2001, the Company filed for permission to defer $109.0 million of net power costs above the level adopted in the UPSC's rate order of September 10, 2001. These costs were incurred during the period May 9, 2001 through September 30, 2001. A hearing relating to the deferral was held on December 7, 2001.

On May 1, 2002, the UPSC issued an order approving a stipulation agreement regarding recovery of deferred and nondeferred net power costs referred to above. The order allowed the Company to continue collecting a $29.5 million annual surcharge until March 31, 2004 and to apply $34.7 million of revenue already collected (subject to refund) against deferred net power costs. The order also allowed the Company to offset deferred net power costs against a regulatory liability of $27.0 million relating to the gain from the May 2000 sale of Centralia. These offsets reduced the regulatory asset for deferred net power costs. In addition, the UPSC allowed the elimination of $20.6 million for the final two years of Merger Credits associated with the Merger. This action eliminated the Merger Credit revenue reduction of approximately $1.0 million per month that was set to expire December 31, 2003. The Company recorded additional deferred net power costs of $37.9 million and committed not to file a general rate case with a rate effective date prior to January 1, 2004, with certain exceptions. This order should allow the Company to recover a total of $147.0 million of deferred net power costs in Utah by March 31, 2004. One party opposed the rate spread provisions of the stipulation and filed a petition with the Utah Supreme Court for review of the order. The case has been assigned to the Utah Court of Appeals.

Oregon - The November 2000 Oregon deferred-accounting filing encompassed all power costs that vary from the level in Oregon rates during the period from November 1, 2000 through September 9, 2001, including costs to replace lost generation resulting from the Hunter No. 1 outage. On January 18, 2001, the Company requested a 3.0%, or $22.8 million, annual rate increase effective February 1, 2001, to provide partial recovery of post-October 31, 2000 power cost variances attributable to Oregon, over an amortization period. This 3.0% rate increase was the maximum allowed on an annual basis for the recovery of deferred costs under the Oregon statutes then in force. On February 13, 2001, the OPUC authorized deferred accounting for power costs of $22.8 million. On February 21, 2001, the OPUC authorized the 3.0% rate increase effective February 21, 2001, subject to refund, pending the outcome of a separate phase of the proceeding to examine the prudence of these expenditures.

The Company filed with the OPUC on September 20, 2001 to increase the level of recovery of deferred net power costs incurred to serve Oregon customers from the then current 3.0% amortization level, or $22.8 million awarded in February 2001, to 6.0%, the maximum allowed on an annual basis for recovery of deferred costs under a change in Oregon law. On October 22, 2001, the OPUC suspended the Company's request pending the outcome of the prudence phase of the proceeding.

In December 2001, the Company and the OPUC staff reached a stipulation in the prudence phase of the Company's deferred net power cost proceeding. The stipulation provided that the Company would be permitted to recover 85.0% of the deferred net power costs in Oregon, or about $131.0 million, plus carrying charges. The stipulation allowed the Company to seek increased recovery in the event the Company's appeal of the Commission's order limiting deferrals is successful. On July 18, 2002, the OPUC issued an order approving the stipulation and ending the prudence phase of the proceeding. On September 16, 2002, the Citizens' Utility Board (the "CUB") and the ICNU appealed this decision to the Marion County, Oregon Circuit Court. On October 11, 2002, the Company moved to intervene in this action. On March 26, 2003, the court issued a letter affirming the OPUC's July 18, 2002 order. The ICNU and the CUB are likely to appeal to the Oregon Court of Appeals.

On August 6, 2002, the OPUC allowed the Company to increase the amortization level from 3.0% to 6.0%. The new rates were effective August 8, 2002. As of March 31, 2003, the Company had received $7.3 million in revenues as a result of this OPUC action. On August 19, 2002, the CUB and the ICNU filed a complaint with the OPUC, requesting that the OPUC require the Company to discontinue amortization of the additional 3.0%, challenging the approval itself based on procedural technicalities during the approval proceeding. On October 10, 2002, the Company filed a stipulation and tariff to allow the OPUC to reopen consideration of the increase in amortization of the deferred power costs from 3.0% to 6.0%. Subject to regulatory approval, the Company and the CUB have reached a stipulation agreement that the amortization level will remain at 6.0% and that the amounts amortized after the OPUC implements the tariff will be subject to refund. The refund will occur if an order or ruling is issued declaring all or a portion of these deferred costs imprudent or otherwise disallowing recovery. On October 14, 2002, the ICNU filed a response to the Company's motion to implement the stipulation and proposed tariff. The ICNU's response asked that the motion be denied as being procedurally improper. On December 10, 2002, the OPUC approved the voluntary stipulation and ordered the Company to file a tariff to implement the change. The tariff was approved by the OPUC with an effective date of January 22, 2003. Amounts subject to refund would include only those collections occurring after January 22, 2003. On February 7, 2003, the ICNU filed a motion requesting the OPUC to reconsider parts of its December 10, 2002 order relating to conclusions regarding the August 6, 2002 decision to increase the amortization level. The OPUC denied this motion on March 27, 2003.

In addition, the ICNU and the CUB have filed a complaint against the Company regarding the implementation of the August 2002 rate change. The ICNU and the CUB filed opening briefs on March 27, 2003. The Company and the OPUC filed their respective briefs on April 23, 2003. The CUB and the ICNU filed their joint reply brief on May 7, 2003.

While the 6.0% increase established the maximum annual rate to be recovered, the Company continued to pursue the total amount to be recovered through its October 2, 2001 appeals, to the Marion County, Oregon Circuit Court, mentioned above, of two OPUC orders. These orders established the mechanism to determine the amount of power costs to defer. On June 6, 2002, the Marion County, Oregon Circuit Court upheld the OPUC decision. On October 9, 2002, the Company appealed this decision to the Oregon Court of Appeals. On November 27, 2002, the Company filed its opening brief. The ICNU filed a response brief on January 14, 2003. The OPUC filed its brief on February 12, 2003, and the Company submitted its reply on March 5, 2003. Oral arguments have been set for July 17, 2003.

On September 7, 2001, the OPUC endorsed an agreement on deferral of net power costs after September 2001. From September 10, 2001 until May 31, 2002, the Company deferred the difference between 83.0% of actual net power costs and the new Oregon baseline power cost in tariffs. This mechanism was terminated on May 31, 2002, concurrent with the effective date of the settlement approved on May 20, 2002.

Wyoming - In Wyoming, on November 1, 2000, the Company filed for deferred accounting treatment of net power costs that vary from costs included in determining retail rates. On April 3, 2001, the Company filed an application to recover the excess power costs accrued during the period November 30, 2000 through January 31, 2001. On November 20, 2001, following an order by the WPSC dismissing the majority of the Company's case based on a procedural issue, the Company requested authority to withdraw its deferred net power cost recovery filing without prejudice. On November 26, 2001, the WPSC granted this request. On May 7, 2002, the Company filed a request to recover replacement power costs of $30.7 million, resulting from the outage of the Company's Hunter No. 1 generating plant and a proposal for recovering deferred net power costs authorized by the WPSC in December 2000, for $60.3 million. On March 6, 2003, the WPSC denied recovery of the Hunter No. 1 replacement power costs and the deferred net power costs. As a result, the Company wrote off the remaining net asset of $48.3 million, during the year ended March 31, 2003. The Company filed a petition for rehearing on the decision on April 4, 2003. The WPSC denied the petition on May 30, 2003.

Washington - On April 5, 2002, the Company filed a petition with the Washington Utilities and Transportation Commission (the "WUTC") seeking authority to begin deferring net power costs in excess of those included in rates as of June 1, 2002 for later recovery in rates, either through a power cost adjustment mechanism or a limited rate adjustment. Under the rate plan approved by the WUTC in August 2000 at the conclusion of the Company's last general rate case in Washington, there are limitations on the Company's ability to request changes to general rates prior to January 2006. On October 18, 2002, the Company filed testimony and supporting documents, requesting deferral and recovery of excess power costs estimated at the time to be $17.5 million, including carrying charges, or, alternatively, to allow the Company to file a general rate case, which is currently restricted through December 2005. Based on actual data through December 2002, the deferral is expected to total $15.9 million. Hearings were held March 20-24, 2003, and a decision is expected by June 2003.

Idaho - On March 28, 2003, the Company filed an application with the IPUC to defer certain costs for regulatory purposes. The costs include approximately $2.5 million in excess costs incurred for forward electricity purchases made during the western energy crisis for summer 2002, as well as $3.5 million in federal and state tax audit determination payments made during the year ended March 31, 2003 as a result of Internal Revenue Service (the "IRS") income tax audits. Other regulatory action in Idaho regarding deferred net power costs is described under Concluded Regulatory Actions - *Idaho*.

NOTE 3 - Derivative Instruments

On April 1, 2001, the Company adopted SFAS No. 133, as amended by SFAS No. 138 and numerous interpretations of the Derivatives Implementation Group (the "DIG") that are approved by the FASB, collectively "SFAS No. 133." Under SFAS No. 133, derivative instruments are recorded on the Consolidated Balance Sheet as an asset or liability measured at estimated fair value, with changes in fair value recognized currently in earnings unless specific hedge accounting criteria are met. As contracts settle, they are recorded in the Statements of Consolidated Income (Loss).

The Company's primary business is to serve its retail customers. The Company's business is exposed to risks relating to, but not limited to, changes in certain commodity prices and counterparty performance. The Company enters into derivative instruments, including electricity, natural gas, oil and coal forward, option and swap contracts, and weather contracts to manage its exposure to commodity price and volume risk and to ensure supply, thereby attempting to minimize variability in net power costs for customers. The Company has policies and procedures to manage the risks inherent in these activities and a risk management committee to monitor compliance with the Company's risk management policies and procedures.

In June 2002, the Company's SFAS No. 133 contract assessments were updated to reflect the revised Issue C15, *Normal Purchase and Normal Sales Exception for Certain Option-Type Contracts and Forward Contracts in Electricity* ("Issue C15"), guidance from the DIG, effective April 1, 2002. The revision to Issue C15 includes criteria to be considered for designation of a contract as a "capacity contract" and disallows the use of the exception for contracts that include a pricing element that is not clearly and closely related to the price of energy. The effects of adoption of the revised Issue C15 at April 1, 2002 resulted in a cumulative effect of accounting change adjustment of $2.1 million unfavorable (net of a tax benefit of $1.3 million) on the Company's Consolidated Statements of

Income (Loss). For contracts qualifying for deferred accounting under SFAS No. 71, the effect of adopting the revised Issue C15 was $0.7 million favorable to the Company.

In October 2001, the DIG issued guidance under Issue C16, *Applying the Normal Purchases and Normal Sales Exception to Contracts that Combine a Forward Contract and a Purchased Option Contract* ("Issue C16"). The guidance disallows normal purchases and normal sales treatment for commodity contracts (other than power contracts) that contain volumetric variability or optionality. Issue C16 was effective April 1, 2002. The effects of adoption of Issue C16 at April 1, 2002 resulted in a cumulative effect of accounting change adjustment of $0.2 million favorable (net of tax of $0.2 million) on the Company's Consolidated Statements of Income (Loss). For contracts qualifying for deferred accounting under SFAS No. 71, the effect of adopting Issue C16 was $126.5 million unfavorable to the Company. The applicable contracts pertain to the purchase and transport of natural gas. The costs of these contracts have been allowed in rates and the liability is, therefore, offset by a corresponding amount included in regulatory assets.

In June 2002, the EITF reached a partial consensus on Issue No. 02-3, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities* ("EITF No. 02-3"). The partial consensus requires that all mark-to-market 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* ("EITF No. 98-10") be presented on a net basis in the income statement and that the gross transaction volume be disclosed for those energy trading contracts that are physically settled. The net presentation requirement is effective beginning in the first interim period ending after July 15, 2002 and the disclosure requirements are effective for financial statements issued for fiscal years ending after July 15, 2002. Reclassification of all historical periods is required. The impact to the Company of adopting EITF No. 02-3 was immaterial.

The risk management process established by the Company is designed to identify, assess, monitor and manage each of the various types of risk involved in its business and activities and measure quantitative market risk exposure and to identify qualitative market risk exposure in its businesses. To assist in managing the volatility relating to these exposures, the Company enters into various transactions, including derivative transactions, consistent with the Company's risk management policy. The risk management policy governs energy purchase and sales activities and is designed for hedging the Company's existing energy and asset exposures. The policy also governs the Company's use of derivative instruments as well as its energy purchase and sales practices and describes the Company's credit policy and management information systems required to effectively monitor such derivative use. The Company's risk management policy provides for the use of only those instruments that have a close volume or price correlation with its portfolio of assets, liabilities or anticipated transactions. The risk management policy includes, as its objective, that such instruments will be primarily used for hedging and not for speculation.

The accounting treatment for the various classifications of derivative financial instruments under SFAS No. 133 is as follows:

Normal purchases and normal sales - The contracts that qualify as normal purchases and normal sales are excluded from the requirements of SFAS 133. The realized gains and losses on these contracts are reflected in the income statement at the contract settlement date.

Cash flow hedge - The unrealized gains and losses relating to these forward contracts are included in Accumulated other comprehensive income (loss), a component of shareholder's equity. As the forward contracts are settled, the realized gains and losses are recorded on the Statements of Consolidated Income (Loss) as a component of Operating revenues or Purchased electricity and the unrealized gains and losses are reversed from Accumulated other comprehensive income (loss).

Trading activity - The unrealized gains and losses relating to these forward contracts are reflected in the Statements of Consolidated Income (Loss) as a component of Operating revenues. As the forward contracts are settled, the realized gains or losses are recorded and the unrealized gains and losses are reversed.

The Company has the following types of commodity transactions:

Coal, natural gas and other fuel purchase contracts - The Company enters into long-term and short-term coal, natural gas, diesel and other purchase contracts to provide adequate fuel resources to its electricity generation facilities and its other fuel needs. These contracts generally have limited optionality and require the Company to take physical delivery of the commodity. These contracts are generally determined to be normal purchases and normal sales contracts under SFAS No. 133.

Weather derivatives - To a limited degree, the Company has executed contracts to hedge changes in hydroelectric generation due to variation in streamflows. The Company has also executed contracts to hedge changes in retail electricity demand due to abnormal ambient temperatures. These contracts are not exchange traded and settlement is based on climatic or other physical variables. Therefore, on a periodic basis, the Company estimates and records a gain or loss in earnings corresponding to the total expected future cash flow from these contracts in accordance with EITF No. 99-2, *Accounting for Weather Derivatives*. At March 31, 2003, the amount recorded for these contracts was a $3.5 million unrealized loss.

Wholesale electricity purchase and sales contracts - The Company makes continuing projections of future retail and wholesale loads and future resource availability to meet these loads based on a number of criteria, including historic load and forward market and other economic information and experience. Based on these projections, the Company purchases and sells electricity on a forward yearly, quarterly, monthly, daily and hourly basis to match actual resources to actual energy requirements and sells any surplus at the best available price. This process involves hedging transactions, which include the purchase and sale of firm capacity and energy under long-term contracts, forward physical or financial contracts for the purchase and sale of a specified amount of capacity or energy at a specified price over a given period of time (typically for one month, three months or one year) and forward purchases and sales of transmission service.

Upon adoption of SFAS No. 133 on April 1, 2001, all wholesale contracts were examined and it was determined that some of the forward contracts for the purchase or sale of wholesale electricity were considered to be derivatives based on the accounting guidance at that time. The effects of changes in fair value of certain derivative instruments entered into to hedge the Company's future retail resource requirements are subject to regulation and, therefore, are deferred pursuant to SFAS No. 71. The Company requested and received deferred accounting orders for the effects of SFAS No. 133 as it relates to the change in fair value of long-term wholesale electricity contracts not meeting the definition of normal purchases and normal sales contracts. At the date of adopting SFAS No. 133, the Company recorded a net regulatory asset relating to the fair value of long-term wholesale contracts (which did not meet the definition of normal purchases and normal sales contracts) of $711.0 million. Short-term wholesale electricity purchase contracts not meeting the definition of normal purchases and normal sales contracts were designated as cash flow hedges to hedge the risk of changes in the cost of providing electricity to serve the Company's retail load. These hedges were fully effective. At the date of adopting SFAS No. 133, the Company recorded an unrealized after tax gain of $617.2 million as a component of equity related to the fair value of short-term wholesale purchase contracts. Short-term wholesale electricity sales contracts not meeting the definition of normal purchases and normal sales contracts were marked to market through income, resulting in a $112.8 million after tax loss on adoption of SFAS No. 133.

In June 2001, the DIG issued guidance which provided that certain forward electricity purchase or sales agreements, including capacity contracts, could be excluded from the requirements of SFAS No. 133 by expanding the normal purchases and normal sales exclusion. The Company implemented this new guidance, on a prospective basis, beginning July 1, 2001. As a result, substantially all of the Company's short-term wholesale electricity contracts were determined to meet the normal purchases and normal sales exclusion. No further market value changes were recognized for those excluded contracts and unrealized gains (losses) recorded in Other comprehensive income relating to the existing cash flow hedges as of July 1, 2001 were realized by September 30, 2002.

To mitigate exposure to credit risk, the Company has entered into master netting agreements with most of its significant trading counterparties. Unrealized gains and losses on contracts with parties under master netting agreements are presented net on the financial statements.

The following table summarizes the SFAS No. 133 movements for the year ended March 31, 2003:

(Millions of dollars)	Net Asset (Liability)	Regulatory Net Asset (Liability)	Deferred Tax Asset (Liability)	Accumulated Income (Loss)	Other Comprehensive Income (Loss)
Balance at March 31, 2002	$ (505.9)	$ 368.4	$ 14.2	$ 0.7	$ (24.0)
Cumulative effect of accounting change	(3.0)	—	1.1	(1.9)	—
Settlements	108.4	(69.7)	(14.6)	0.1	24.0
Changes in valuation assumptions	193.0	(193.4)	0.3	(0.2)	—
Other changes in fair value	(298.2)	301.6	(1.0)	2.4	—
Balance at March 31, 2003	$ (505.7)	$ 506.9	$ —	$ 1.1	$ —

Short-term contracts, without explicit or embedded optionality, are valued based upon the relevant portion of the forward market price curve. Contracts with explicit or embedded optionality and long-term contracts are valued by separating each contract into its component physical and financial forward, swap and option legs. Forward and swap legs are valued against the appropriate market curve. The optionality is valued using a modified Black-Scholes model approach or a stochastic simulation (Monte Carlo) approach. Each option component is modeled and valued separately using the appropriate forward market price curve.

The forward market price curve is derived using daily market quotes from independent energy brokers, as well as direct information received from third-party offers and actual transactions executed by the Company. For contracts extending past 2006, the forward prices also include the use of a fundamentals model (cost-to-build approach), due to the limited information available past 2006. The fundamentals model is updated as warranted, at least quarterly, to reflect changes in the market.

As the FASB continues to issue interpretations, the Company may change the conclusions that it has reached and, as a result, the accounting treatment and financial statement impact could change in the future.

NOTE 4 - Related Party Transactions

There are no loans or advances between PacifiCorp and ScottishPower or between PacifiCorp and PHI. Loans from the Company to ScottishPower or PHI are prohibited under the Public Utility Holding Company Act of 1935 ("PUHCA"). Loans from ScottishPower or PHI to PacifiCorp generally require state regulatory and Securities and Exchange Commission (the "SEC") approval. Affiliate transactions with the Company are subject to certain approval and reporting requirements of the regulatory authorities.

The tables below detail the Company's related party transactions and balances with other unconsolidated related parties.

(Millions of dollars)	March 31, 2003	March 31, 2002
Amounts due from affiliated entities:		
ScottishPower (a)	$ 0.1	$0.5
PHI subsidiaries (b)	2.4	3.5
	$ 2.5	$4.0
Amounts due to affiliated entities:		
ScottishPower (c)	$ 2.6	$0.8
PHI subsidiaries (d)(e)	37.0	6.3
	$39.6	$7.1

(Millions of dollars)	Years Ended March 31,		
	2003	2002	2001
Revenues from affiliated entities:			
[redacted]			
Expenses incurred from affiliated entities:			
ScottishPower (c)	$ 10.0	$ 16.5	$ 8.8
[redacted]			
	$ 23.0	$ 16.5	$ 8.8
Expenses recharged to affiliated entities:			
[redacted]			
PHI subsidiaries (b)	7.1	—	—
[redacted]			
Interest income from affiliated entities:			
ScottishPower (h)	$ —	$ 9.5	$ 14.0
[redacted]			
Total affiliated interest income	$ —	$ 16.2	$ 14.0
Interest expense to affiliated entities:			
[redacted]			
Total affiliated interest expense	$ 0.1	$ 0.1	$ —

(a) Amounts due from affiliates are included in Other current assets on the Balance Sheet. The Company recharges to ScottishPower payroll costs and related benefits of employees working on international assignment to ScottishPower.

(b) Amounts shown relate to activities of the Company and its subsidiaries with PHI and its subsidiaries. Expenses recharged reflect costs for support services to PHI and its subsidiaries.

(c) These expenses and liabilities primarily represent payroll costs and related benefits of ScottishPower employees working for the Company.

(d) Includes current portion of income taxes payable to PHI of $37.3 million and $5.3 million at March 31, 2003 and 2002, respectively. PHI is the tax paying entity for the consolidated group.

(e) Short-term demand loans to PacifiCorp, in accordance with regulatory authorizations, are included in Notes payable and commercial paper.

(f) These revenues represent wheeling revenues received from PPM.

(g) These expenses represent primarily operating lease payments for a generation facility owned by a subsidiary of PPM, as discussed below.

(h) PGHC, while a subsidiary of the Company, had a note receivable, interest receivable and related interest income from a directly owned subsidiary of ScottishPower.

Interest rates on related party borrowings approximate lender's short-term borrowing cost or cost of capital as required by the relevant regulatory approval or exemption. The average rates for the years ended March 31, 2003, 2002 and 2001 were 1.7%, 3.0% and 6.3%, respectively.

In May 2002, the Company entered into a 15-year operating lease on an electric generation facility with West Valley Leasing Company LLC, a subsidiary of PPM, which was approved by the OPUC. The facility consists of five generation units each rated at 40 megawatts ("MW") and is located in Utah. The Company, at its sole option, may terminate the lease, or purchase the facility, after three years and after six years. Scheduled lease payments are $3.0 million annually per unit. All of these units were operational at the end of July 2002.

NOTE 5 - Securities Available for Sale

The amortized cost and fair value of reclamation trust securities and other investments, included in Deferred charges and other assets on the Company's Consolidated Balance Sheet, which are classified as available for sale, were as follows:

(Millions of dollars)	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
March 31, 2003				
Money market account	$ 4.0	$ —	$ —	$ 4.0
Mutual fund account	30.7	—	(0.3)	30.4
Debt securities	21.5	1.0	—	22.5
Equity securities	47.0	1.2	(5.9)	42.3
Total	$ 103.2	$ 2.2	$ (6.2)	$ 99.2
March 31, 2002				
Money market account	$ 2.8	$ —	$ —	$ 2.8
Mutual fund account	29.3	—	(0.5)	28.8
Debt securities	26.9	0.5	(0.2)	27.2
Equity securities	50.3	5.8	(3.4)	52.7
Total	$ 109.3	$ 6.3	$ (4.1)	$ 111.5

The quoted market price of securities is used to estimate their fair value.

The amortized cost and estimated fair value of debt securities at March 31, 2003 and 2002 by contractual maturities are shown below. Actual maturities may differ from contractual maturities because borrowers may have the right to call or prepay obligations with or without call or prepayment penalties.

	March 31,			
	2003		2002	
(Millions of dollars)	Amortized Cost	Estimated Fair Value	Amortized Cost	Estimated Fair Value
Debt securities				
Due in one year or less	$ 1.1	$ 1.1	$ —	$ —
Due after one year through five years	3.1	3.4	6.0	6.1
Due after five years through ten years	8.9	9.4	8.7	8.8
Due after ten years	8.4	8.6	12.2	12.3
Money market account	4.0	4.0	2.8	2.8
Mutual fund account	30.7	30.4	29.3	28.8
Equity securities	47.0	42.3	50.3	52.7
Total	$ 103.2	$ 99.2	$ 109.3	$ 111.5

Proceeds, gross gains and gross losses from realized sales of available-for-sale securities using the specific identification method were as follows for the years ended March 31, 2003, 2002 and 2001:

	Years Ended March 31,		
(Millions of dollars)	2003	2002	2001
Proceeds	$ 132.9	$ 120.9	$ 119.9
Gross gains	$ 2.6	$ 4.5	$ 11.8
Gross losses	(8.7)	(12.1)	(7.9)
Net (losses) gains	$ (6.1)	$ (7.6)	$ 3.9

NOTE 6 - Short-Term Debt and Borrowing Arrangements

The Company's short-term debt and borrowing arrangements were as follows:

(Millions of dollars)	Balance	Average Interest Rate
[redacted]		
March 31, 2002	177.5	2.2

At March 31, 2003, the Company had $800.0 million of committed bank revolving credit agreements that became effective June 4, 2002; one facility for $500.0 million having a 364-day term plus a one-year term loan option, and the other facility for $300.0 million having a three-year term. The Company is currently seeking to replace the existing $500.0 million facility. While the Company believes the facility will be successfully replaced at costs marginally higher than the existing facility, no assurance can be given as to this outcome. As of March 31, 2003, these facilities were fully available and there were no borrowings outstanding.

NOTE 7 - Long-Term Debt

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

(Millions of dollars)	Rates	March 31, 2003	March 31, 2002
First mortgage bonds			
[redacted]			
Maturing 2009 through 2013	6.4%–9.2%	979.3	1,078.1
[redacted]			
Maturing 2019 through 2023	8.1%–8.5%	184.0	30.7
[redacted]			
Maturing 2029 through 2033	7.7%	300.0	300.0
Guaranty of pollution control revenue bonds			
[redacted]			
Maturing 2031	6.2%	12.7	12.7
[redacted]			
Maturing 2025 (a)(b)	Variable	175.8	175.8
[redacted]			
Funds held by trustees		(2.1)	(2.0)
Capitalized lease obligations			
[redacted]			
Unamortized premium or discount		(4.4)	(5.0)
[redacted]			
Less current maturities		(136.1)	(143.9)
[redacted]			
Subsidiaries			
8.6% Note due 2005		4.4	5.0
[redacted]			
Total		3.8	4.4
[redacted]			

(a) Secured by pledged first mortgage bonds generally at the same interest rates, maturity dates and redemption provisions as the pollution control revenue bonds.

(b) Interest rates fluctuate based on various rates, primarily on certificate of deposit rates, interbank borrowing rates, prime rates or other short-term market rates.

First mortgage bonds of the Company may be issued in amounts limited by Electric Operations' property, earnings and other provisions of the mortgage indenture. Approximately $12.0 billion of the eligible assets (based on original cost) of PacifiCorp are subject to the lien of the mortgage. Approximately $1.5 billion of first mortgage bonds were redeemable at the Company's option at March 31, 2003 at redemption prices dependent upon U.S. Treasury yields. Approximately $654.5 million of pollution control revenue bonds were redeemable at the Company's option at par at March 31, 2003. Subsidiary notes are redeemable at the subsidiary's option at face amount. The remaining long-term debt was not redeemable at March 31, 2003.

On November 21, 2001, the Company issued $500.0 million of its 6.9% Series of First Mortgage Bonds due November 15, 2011 and $300.0 million of its 7.7% Series of First Mortgage Bonds due November 15, 2031. The Company used the proceeds for general corporate purposes, including the repayment of commercial paper and short-term debt borrowed from PGHC. The Company has an effective shelf registration statement for up to $1.1 billion of long-term debt, of which $800.0 million has been authorized to be issued by the applicable regulatory commissions, subject to certain conditions. Any such issuance would be subject to market conditions.

The annual maturities of long-term debt, capitalized lease obligations and redeemable preferred stock outstanding are $140.4 million, $243.8 million, $289.2 million, $243.0 million and $173.0 million for the years ending March 31, 2004 through 2008, respectively.

The Company made interest payments, net of capitalized interest, of $287.9 million, $246.7 million and $337.5 million for the years ended March 31, 2003, 2002 and 2001, respectively. This includes interest on leveraged lease debt that is netted against revenue on leveraged leases for the year ended March 31, 2001 and for nine months of the year ended March 31, 2002.

NOTE 8 - Environmental Costs, Mine Reclamation and Closure Costs

The Company's mining operations are subject to reclamation and closure requirements. Reclamation and closure costs are estimated based on engineering studies. The Company monitors these requirements and periodically revises its cost estimates to meet existing legal and regulatory requirements of the various jurisdictions in which it operates. The Company expenses current mine reclamation costs. Costs for future reclamation are accrued using the units-of-production method such that estimated final mine reclamation and closure costs are fully accrued at completion of mining activities, except where the Company has decided to close a mine. The Company believes that it has adequately provided for its reclamation obligations, assuming ongoing operations of its mines. Total estimated final reclamation costs, including the Company's and minority interest joint owners' portions, for all mines with which the Company is involved was $215.0 million at March 31, 2003. These amounts are expected to be paid over the next 30 years.

The liabilities for environmental cleanup-related costs are generally recorded on an undiscounted basis. These liabilities are recorded in the Company's Consolidated Balance Sheet in Deferred credits - Other at March 31, 2003 and 2002 as follows:

	March 31,	
(Millions of dollars)	2003	2002
[redacted]		
Environmental remediation (b)	37.1	40.3
[redacted]		
Total	$191.9	$194.7

(a) Amounts include the Company's and minority interest joint owners' portions of mine reclamation costs. Amount also includes $9.3 million and $12.2 million at March 31, 2003 and 2002, respectively, that is included in Current liabilities - Other.

(b) Expected to be paid over 19 years. Amount also includes $1.3 million at March 31, 2003 and 2002 that is included in Current liabilities - Other.

(c) Expected to be paid over 22 years.

The Company had trust fund assets included in Deferred Charges and Other of $68.5 million and $80.4 million at March 31, 2003 and 2002, respectively, relating to mine reclamation, including the minority interest joint owners' portions.

NOTE 9 - Commitments and Contingencies

The Company follows SFAS No. 5, *Accounting for Contingencies* ("SFAS No. 5"), to determine accounting and disclosure requirements for contingencies. The Company operates in a highly regulated environment. Governmental bodies such as the FERC, the SEC, the IRS, the Department of Labor, the United States Environmental Protection Agency (the "EPA") and others have authority over various aspects of the Company's business operations and public reporting. Reserves are established when required in management's judgment, and disclosures regarding litigation, assessments and creditworthiness of customers or counterparties, among others, are made when appropriate. The evaluation of these contingencies is performed by various specialists inside and outside of the Company.

Litigation - From time to time, the Company and its subsidiaries are parties to various legal claims, actions and complaints, certain of which involve material amounts. Although the Company is unable to predict with certainty whether it will ultimately be successful in these legal proceedings or, if not, what the impact might be, management currently believes that disposition of these matters will not have a materially adverse effect on the Company's consolidated financial position or results of operations.

Environmental issues - The Company is subject to numerous environmental laws including the Federal Clean Air Act, as enforced by the EPA and various state agencies; the 1990 Clean Air Act Amendments; the Endangered Species Act of 1973, particularly as it relates to certain endangered species of fish; the Comprehensive Environmental Response, Compensation and Liability Act of 1980, relating to environmental cleanups; and the Resource Conservation and Recovery Act of 1976 and the Clean Water Act, relating to water quality. These laws could potentially impact future operations. Contingencies identified at March 31, 2003 principally consist of Clean Air Act matters, which are the subject of discussions with the EPA and state regulatory authorities. The Company expects that future costs relating to these matters may be significant and consist primarily of capital expenditures. The Company expects these costs will be included in rates and, as such, will not have a material adverse impact on the Company's consolidated results of operations.

Hydroelectric relicensing - The Company's hydroelectric portfolio consists of 53 plants with a plant net capability of 1,115.8 MW. Ninety-seven percent of the installed capacity is regulated by the FERC through 20 individual licenses. Nearly all of the Company's hydroelectric projects are in some stage of relicensing under the FPA. Hydroelectric relicensing and the related environmental compliance requirements are subject to uncertainties. The Company expects that future costs relating to these matters may be significant and consist primarily of additional relicensing costs, operations and maintenance expense and capital expenditures. Electricity generation reductions may result from the additional environmental requirements. The Company has accumulated approximately $95.4 million in costs for ongoing hydroelectric relicensing that are reflected in assets on the Consolidated Balance Sheet. The Company expects that these and future costs will be included in rates and, as such, will not have a material adverse impact on the Company's consolidated results of operations.

Swift power canal - On April 21, 2002, a failure occurred in the Swift power canal on the Lewis River in the state of Washington. The power canal and associated 70-MW hydroelectric facility ("Swift No. 2") are owned by Cowlitz County Public Utility District ("Cowlitz"). It is anticipated that Cowlitz will repair Swift No. 2 in time for a calendar-year 2005 startup. The failure impacted, but did not damage, the Company-owned and operated 240-MW Swift No. 1 hydroelectric facility ("Swift No. 1"), which is upstream of the Swift power canal, by restricting both flow and generation flexibility ("shaping"). Repairs to the canal were completed and Swift No. 1 was returned to full capacity levels as of mid-July 2002 (though with limited shaping capabilities). Environmental, operations safety and fish mitigation issues remain to be resolved before full use of Swift No. 1 can resume. The Company continues to seek ways to mitigate any capacity and shaping limitations and to recover any business losses. The full impact of the Swift power canal outage and plans for repair of the Swift No. 2 facility are still being determined. The Company is seeking reimbursement from Cowlitz of the Company's expenditures associated with the Swift No. 2 failure, including canal modifications and energy replacement costs. This event is not expected to have a significant impact on the Company's consolidated financial position or results of operations.

California and Enron Reserves - Beginning in summer 2000, market conditions in California resulted in defaults of amounts due to the Company from certain counterparties in California. In addition, in December 2001, Enron Corp. ("Enron") declared bankruptcy and defaulted on certain wholesale contracts. The Company has provided reserves for its California exposures and its Enron receivable, net of the effect of applying the master netting agreement with Enron, in the aggregate amount of $14.3 million.

The Company is also a party to a FERC proceeding that is investigating potential refunds for energy transactions in the California market during past periods of high energy prices. The Company established a reserve of $17.7 million for these refunds. The Company's ultimate exposure to refunds is dependent upon any order issued by the FERC in this proceeding. See NOTE 2 - Regulation.

Guarantees - The Company is generally required to obtain state regulatory commission approval prior to guaranteeing debt or obligations of other parties. In November 2002, the FASB issued Interpretation No. 45, *Accounting and Disclosure Requirements for Guarantees* ("FIN No. 45"). FIN No. 45 requires disclosure of certain direct and indirect guarantees. Also, FIN No. 45 requires recognition of a liability at inception for certain new or modified guarantees issued after December 31, 2002. The adoption of FIN No. 45 in January 2003 did not have a material impact on the consolidated financial statements. The following indemnification obligations of the Company fall within the definitions of "indirect guarantees" under FIN No. 45.

On May 4, 2000, the Company and other joint owners completed the sale to Transalta of an electricity plant and coal mine located in Centralia, Washington. Under the agreement relating to the plant, the joint owners agreed to indemnify Transalta if it were to incur certain losses after the closing date and arising as a result of certain breaches of covenants. Under the agreement relating to the mine, the Company provided similar indemnity. The maximum indemnification obligation under these agreements, with respect to the Company, is limited to $556.0 million, less a deductible of 1.0% of the purchase price (approximately $1.0 million). No indemnity claims have been made to date.

In connection with the sale of the Company's Montana service territory, the Company entered into a purchase and sale agreement with Flathead Electric Cooperative ("Flathead") dated October 9, 1998. Under the agreement, the Company indemnified Flathead for losses, if any, occurring after the closing date and arising as a result of certain breaches of warranty or covenants. The indemnification has a cap of $10.0 million. Two indemnity claims relating to environmental issues have been tendered, but remediation costs for these claims, if any, are not expected to be material.

The Company believes that the likelihood that it would be required to perform or otherwise incur any significant losses associated with any of these obligations is remote.

Construction - The Company has an ongoing construction program and, as a part of this program, substantial commitments have been made. The Company estimates spending $669.3 million, $679.7 million and $678.6 million for the years ending March 31, 2004, 2005 and 2006, respectively. At March 31, 2003, the Company had firm commitments for construction costs of $61.9 million.

Leases - The Company has certain properties under leases with various expiration dates and renewal options. Rentals on lease renewals are subject to negotiation. Certain leases provide for options to purchase at fair market value. The Company is also committed to pay all taxes, expenses of operation (other than depreciation) and maintenance applicable to the leased property.

Net rent expense for the years ended March 31, 2003, 2002 and 2001 was $7.3 million, $27.1 million and $8.7 million, respectively. During the year ended March 31, 2002, the Company leased a new generating turbine that added $24.7 million to rent expense. Future minimum lease payments under noncancellable operating leases are $5.5 million, $4.9 million, $4.5 million, $2.6 million and $1.4 million for 2004 through 2008, respectively, and $9.8 million thereafter.

Future minimum lease payments under capital leases are $3.4 million, $3.4 million, $3.5 million, $3.6 million and $3.7 million for the years ended March 31, 2004 through 2008, respectively, and $52.2 million thereafter. The amount of interest in those lease payments is $42.1 million.

Future minimum lease payments on the West Valley City, Utah lease discussed in NOTE 4 are $14.7 million, $14.7 million, $2.8 million, none and none for the years ending March 31, 2004 through 2008, respectively.

Long-term wholesale sales and purchased electricity contracts - The Company manages its energy resource requirements by integrating long-term firm, short-term and spot-market purchases with its own generating resources to economically dispatch the system (within the boundaries of the FERC requirements) and meet commitments for wholesale sales and retail load growth. The long-term wholesale sales commitments include contracts with minimum sales requirements of $313.4 million, $263.7 million, $223.3 million, $183.1 million and $141.6 million for the years ending March 31, 2004 through 2008, respectively and $1.1 billion thereafter. As part of its energy resource portfolio, the Company acquires a portion of its electricity through long-term purchases and/or exchange agreements which require minimum fixed payments of $386.0 million, $363.9 million, $337.2 million, $366.3 million and $247.4 million for the years ending March 31, 2004 through 2008, respectively, and $2.3 billion thereafter.

Excluded from the minimum fixed annual payments above are commitments to purchase electricity from several hydroelectric projects under long-term arrangements with public utility districts. These purchases are made on a "cost of service" basis for a stated percentage of project output and for a like percentage of project annual costs (operating expenses and debt service). These costs are included in operations expense. The Company is required to pay its portion of operating costs and its portion of the debt service, whether or not any electricity is produced. The arrangements provide for nonwithdrawable electricity and the majority also provide for additional electricity, withdrawable by the districts upon one to five years' notice. For the year ended March 31, 2003, such purchases approximated 2.4% of energy requirements.

At March 31, 2003, the Company's share of long-term arrangements with public utility districts was as follows:

Generating Facility	Year Contract Expires	Capacity (kW)	Percentage of Output	Annual Costs (a)
Wanapum	2009	155,444	18.7%	$ 7.0
Priest Rapids	2005	109,602	13.9	4.0
Rocky Reach	2011	64,297	5.3	3.4
Wells	2018	59,617	6.9	2.2
Total		388,960		$ 16.6

(a) Annual costs in millions of dollars. Includes debt service totaling $6.5 million. The Company's minimum debt service obligation was $8.5 million at March 31, 2003 and $8.0 million, $6.9 million, $9.2 million, $12.1 million and $12.3 million for the years ending March 31, 2004 through 2008, respectively.

The Company has a 4.0% interest in the Intermountain Power Project (the "Project"), located in central Utah. The Company and the city of Los Angeles have agreed that the City will purchase capacity and energy from Company plants equal to the Company's 4.0% entitlement of the Project at a price equivalent to 4.0% of the expenses and debt service of the Project.

Short-term wholesale sales and purchased electricity contracts - At March 31, 2003, the Company had short-term wholesale forward sales commitments that included contracts with minimum sales requirements of $218.4 million, $122.7 million and $16.4 million for the years ended March 31, 2004, 2005 and 2006, respectively. At March 31, 2003, short-term forward purchase agreements require minimum fixed payments of $178.7 million, $68.6 million and $30.6 million for the years ending March 31, 2004, 2005 and 2006, respectively.

Fuel contracts - The Company has "take or pay" coal and natural gas contracts that require minimum fixed payments of $258.7 million, $231.9 million, $186.3 million, $154.2 million and $158.8 million for the years ending March 31, 2004 through 2008, respectively, and $932.0 million thereafter.

Resource management - The Company, as a public utility and a franchise supplier, has an obligation to manage resources to supply its customers. Rates charged to most customers are tariff rates authorized by regulatory agencies as discussed in NOTE 2.

NOTE 10 - Jointly Owned Facilities

At March 31, 2003, the Company's participation in jointly owned facilities was as follows:

(Millions of dollars)	Company Share	Plant in Service	Accumulated Depreciation/ Amortization	Construction Work in Progress
[redacted]				
Colstrip Nos. 3 and 4 (b)	10.0	234.1	104.4	7.1
[redacted]				
Foote Creek	78.8	37.0	5.8	—
[redacted]				
Hayden Station No. 2	12.6	26.2	10.3	0.1
[redacted]				
Hunter No. 1	93.8	285.5	128.7	0.3
[redacted]				
Jim Bridger Nos. 1 - 4 (b)	66.7	840.0	411.7	12.6
[redacted]				
Wyodak	80.0	305.8	138.6	0.4
[redacted]				
Unallocated acquisition adjustments (e)		141.2	51.4	—
[redacted]				

(a) The Centralia plant was sold on May 4, 2000. The joint owners of the plant retained ownership in the Skookumchuck Dam and related facilities.

(b) Includes kilovolt lines and substations.

(c) Additionally, the Company has contracted to purchase the remaining 50.0% of the output of the plant.

(d) Plant, inventory, fuel and decommissioning costs totaling $14.9 million relating to the Trojan Plant were included in regulatory assets at March 31, 2003.

(e) Represents the excess of the cost of the acquired interest in purchased facilities over their original net book value.

Under the joint agreements, each participating utility is responsible for financing its share of construction, operating and leasing costs. The Company's portion is recorded in its applicable operations, maintenance and tax accounts, which is consistent with wholly owned plants.

NOTE 11 - Guaranteed Preferred Beneficial Interests In Company's Junior Subordinated Debentures

Wholly owned subsidiary trusts of the Company (the "Trusts") have issued, in public offerings, redeemable preferred securities ("Preferred Securities") representing preferred undivided beneficial interests in the assets of the Trusts, with liquidation amounts of $25.00 per Preferred Security. The sole assets of the Trusts are Junior Subordinated Deferrable Interest Debentures of the Company that bear interest at the same rates as the Preferred Securities to which they relate and certain rights under related guarantees by the Company.

Preferred Securities outstanding were as follows:

(Millions of dollars, Thousands of Preferred Securities)	March 31, 2003	March 31, 2002
[redacted]		
5,400 7.70% Trust Preferred Securities, Series B, with Trust assets of $139.2 million (b)	131.0	130.9
[redacted]		

(a) Amount is net of unamortized issuance costs of $6.2 million and $6.4 million at March 31, 2003 and 2002, respectively.

(b) Amount is net of unamortized issuance costs of $4.0 million and $4.1 million at March 31, 2003 and 2002, respectively.

All of the 8.25% Cumulative Quarterly Income Preferred Securities, Series A, and 7.70% Trust Preferred Securities, Series B, were redeemable at the Company's option at face amount at March 31, 2003.

NOTE 12 - Common and Preferred Stock

Common Stock - The Company has one class of common stock with no par value. A total of 750,000,000 shares were authorized, and 312,176,089 and 297,324,604 shares were issued and outstanding at March 31, 2003 and 2002, respectively.

On August 22, 2002, the Company's Board of Directors (the "Board") approved the issuance of up to 50 million additional shares of its common stock ("Shares") to be sold, from time to time, to its direct parent, PHI, in such amounts and at such times as would be determined by the Company, subject to regulatory approval, which has been received. Issuance and sale of the Shares is subject to the receipt of cash for the Shares in an amount per share not less than the book value of the Shares at the end of the month prior to the date of the issuance. On December 19, 2002, the Company issued 14,851,485 Shares to PHI, receiving $150.0 million in cash proceeds, equal to $10.10 per share, the book value of the Shares at the end of November 2002. Proceeds were used to repay debt and for general corporate purposes.

Common Dividend Restrictions - ScottishPower is the sole indirect shareholder of the Company's common stock. The Company is restricted from paying dividends or making other distributions without prior OPUC approval to the extent such payment or distribution would reduce the Company's common stock equity below a specified percentage of its total capitalization. The percentage of total capitalization increases over time from 35.0% after December 31, 1999 to 40.0% after December 31, 2004. As of March 31, 2003, the minimum ratio was 38.0%. In addition, the Company must give the OPUC 30 days' prior notice of any special cash dividend or any transfer involving more than 5.0% of the Company's retained earnings in a six-month period. The Company is also subject to maximum debt to total capitalization levels under various debt agreements.

Under the PUHCA, the Company may pay dividends out of capital or unearned surplus only with SEC approval. Dividends from earned surplus are permitted without approval. The Company has received approval to pay dividends out of unearned surplus of the lesser of $900.0 million or the proceeds received from sales of nonutility assets. At March 31, 2003, $300.0 million was available for dividends out of unearned surplus.

Preferred Stock

(Thousands of shares)	
At March 31, 2001	2,165
Redemptions and repurchases	(1,000)
At March 31, 2002	1,165
Redemptions and repurchases	(75)
At March 31, 2003	1,090

Generally, preferred stock is redeemable at stipulated prices plus accrued dividends, subject to certain restrictions. Upon voluntary or involuntary liquidation, all preferred stock is entitled to stated value or a specified preference amount per share plus accrued dividends. Any premium paid on redemptions of preferred stock is capitalized, and recovery is sought through future rates. Dividends on all preferred stock are cumulative.

(Millions of dollars, thousands of shares)	March 31, 2003		March 31, 2002	
Series	Shares	Amount	Shares	Amount
Subject to Mandatory Redemption				
No Par Serial Preferred, $100 stated value, 16,000 shares authorized				
[redacted]				
Not subject to Mandatory Redemption				
Serial Preferred, $100 stated value, 3,500 Shares authorized				
4.52%	2	0.2	2	0.2
[redacted]				
4.72	70	6.9	70	6.9
[redacted]				
5.40	66	6.6	66	6.6
[redacted]				
7.00	18	1.8	18	1.8
[redacted]				
	415	41.3	415	41.3
[redacted]				

Mandatory redemption requirements at stated value plus accrued dividends on No Par Serial Preferred Stock are as follows: 37,500 shares of the $7.48 series are redeemable on each June 15 from 2002 through 2006, with all shares outstanding on June 15, 2007 redeemable on that date. If the Company is in default in its obligation to make any future redemptions on the $7.48 series, it may not pay cash dividends on common stock.

The Company had $1.8 million and $1.9 million in preferred dividends declared but unpaid at March 31, 2003 and 2002, respectively.

NOTE 13 - Fair Value of Financial Instruments

	March 31, 2003		March 31, 2002	
(Millions of dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
[redacted]				
Preferred Securities	341.8	353.3	341.5	348.6
[redacted]				

(a) Includes long-term debt classified as currently maturing, less capitalized lease obligations.

The carrying value of cash and cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments.

The fair value of the Company's long-term debt and redeemable preferred stock has been estimated by discounting projected future cash flows, using the current rate at which similar loans would be made to borrowers with similar credit ratings and for the same maturities. Current maturities of long-term debt were included. The fair value of Preferred Securities was estimated using quoted market prices at March 31, 2003 and 2002.

NOTE 14 - Employment Benefit Plans

Retirement plans - The Company has pension plans covering substantially all employees. Benefits under the plan in the U.S. are based on the employee's years of service and average monthly pay in the 60 consecutive months of highest pay out of the last 120 months, with adjustments to reflect benefits estimated to be received from Social Security. Pension costs are funded annually by no more than the maximum amount that can be deducted for federal income tax purposes. At March 31, 2003, plan assets were primarily invested in common stocks, bonds and U.S. government obligations.

Components of the net periodic pension benefit cost (income) and significant assumptions are summarized as follows:

(Millions of dollars)	Years Ended March 31, 2003	2002	2001
Service cost	$ 21.6(a)	$ 14.9	$ 19.5
Interest cost	76.8	80.1	82.4
Expected return on plan assets	(92.8)	(99.9)	(105.8)
Amortization of unrecognized net obligation	8.4	8.4	8.4
Unrecognized prior service cost	2.1	0.5	0.5
Unrecognized gain	(4.2)	(10.3)	(9.7)
Net periodic pension benefit cost (income)	$ 11.9	$ (6.1)	$ (4.7)
Discount rate	6.75%	7.50%	7.75%
Expected long-term rate of return on assets	8.75	9.25	9.25
Rate of increase in compensation levels	4.00	4.00	4.00

(a) Includes a contribution of $5.0 million to the PacifiCorp/IBEW Local 57 Retirement Trust Fund.

The change in the projected benefit obligation, change in plan assets and funded status are as follows:

(Millions of dollars)	March 31, 2003	2002
Change in projected benefit obligation		
Projected benefit obligation - beginning of year	$ 1,079.3	$ 1,129.4
Service cost	16.6	14.9
Interest cost	76.8	80.1
Plan amendments	—	18.0(b)
Special termination benefits	(4.1)(a)	0.8
Actuarial loss	97.5	7.2
Benefits paid	(114.5)	(129.6)
Divestiture	—	(41.5)(c)
Projected benefit obligation - end of year	$ 1,151.6	$ 1,079.3
Change in plan assets		
Plan assets at fair value - beginning of year	$ 826.2	$ 1,152.6
Actual return on plan assets	(60.0)	(147.7)
Company contributions	29.5	7.3
Benefits paid	(114.5)	(129.6)
Divestiture	—	(56.4)
Plan assets at fair value - end of year	$ 681.2	$ 826.2
Reconciliation of accrued pension cost and total amount recognized		
Funded status of the plan	$ (470.4)	$ (253.1)
Unrecognized net loss	325.6	71.1
Unrecognized prior service cost	11.0	13.1
Unrecognized net transition obligation	32.8	41.2
Accrued pension cost	$ (101.0)	$ (127.7)
Accrued benefit liability	$ (381.5)	$ (169.0)
Intangible asset	43.8	41.3
Accumulated other comprehensive income	2.2	
Regulatory assets	234.5	—
Accrued pension cost	$ (101.0)	$ (127.7)

(a) Represents an adjustment to the obligation to provide benefits to employees who elected a special termination benefit in the year ended March 31, 2001 but revoked the election in the year ended March 31, 2003.

(b) Represents an increase in the Company's projected benefit obligation as a consequence of the ad hoc cost of living benefit increase for retired employees that was approved on March 13, 2002.

(c) Represents a reduction in the Company's projected benefit obligation and assets as a consequence of the transfer of obligation to a new plan being jointly administered by the International Brotherhood of Electrical Workers Local Union 57 and the Company. The new plan was created according to negotiated agreements between the Union and the Company. As a result of these agreements, the nature of the Company's obligation changed from a fixed future benefit to a fixed percentage of pay commitment.

The PacifiCorp Retirement Plan and the Supplemental Executive Retirement Plan, together the "Plans," currently have assets with a fair value that is less than the accumulated benefit obligation under the Plans primarily due to declines in the equity markets. As a result, the Company recognized a minimum pension liability in the fourth quarter of the year ended March 31, 2003. The liability adjustment was recorded as a noncash charge of $234.5 million to Regulatory assets, $43.8 million to Intangible assets and $2.2 million of Other comprehensive income, and did not affect the consolidated results of operations. The Company requested and received accounting orders from the regulatory commissions in Utah, Oregon and Wyoming to classify this charge as a regulatory asset instead of a charge to Other comprehensive income. The Company has determined that SFAS No. 87, *Employers' Accounting for Pensions* ("SFAS No. 87"), and SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other than Pensions* ("SFAS No. 106") costs for the PacifiCorp Retirement Plan are currently recoverable in rates. This increase to Regulatory assets will be adjusted in future periods as the difference between the fair value of the trust assets and the accumulated benefit obligation changes.

Employee Savings and Stock Ownership Plan - The Company has an employee savings and stock ownership plan that qualifies as a tax-deferred arrangement under the Internal Revenue Code. Participating U.S. employees may defer up to 25.0% of their compensation, subject to certain statutory limitations. The Company matches 50.0% of employee contributions on amounts deferred up to 6.0% of total compensation with that portion vesting over five years. The Company makes an additional contribution equal to a percentage of the employee's eligible earnings. These contributions are immediately vested. Company contributions to the Savings and Stock Ownership Plan were $17.4 million, $16.8 million and $18.0 million for the years ended March 31, 2003, 2002 and 2001, respectively, and represent amounts expensed for such periods.

Other Postretirement Benefits - Electric Operations provides health care and life insurance benefits through various plans for eligible retirees on a basis substantially similar to those who are active employees. The cost of postretirement benefits is accrued over the active service period of employees. The transition obligation represents the unrecognized prior service cost and is being amortized over a period of 20 years. The Company funds postretirement benefit expense through a combination of funding vehicles. The Company contributed $22.6 million for the year ended March 31, 2003 and nothing for the years ended March 31, 2002 and 2001. These funds are invested in common stocks, bonds and U.S. government obligations.

Components of the net periodic postretirement benefit cost and significant assumptions are summarized as follows:

	Years Ended March 31,		
(Millions of dollars)	2003	2002	2001
Service cost	$ 5.6	$ 5.2	$ [illegible]
Interest cost	34.2	28.6	27.7
Expected return on plan assets	(28.5)	(29.2)	[illegible]
Amortization of unrecognized net obligation	12.2	12.2	12.2
Unrecognized gain		(4.5)	[illegible]
Regulatory deferral	1.1	1.5	1.5
Net periodic postretirement benefit cost	$ 24.6	$ [illegible]	$ [illegible]
Discount rate	6.75%	7.50%	7.75%
Estimated long-term rate of return on assets	8.75	9.25	[illegible]
Initial health care cost trend rate - under 65	9.50	10.50	6.00
Initial health care cost trend rate - over 65	11.50	12.50	6.50
Ultimate health care cost trend rate	5.00	5.00	4.50

The change in the accumulated postretirement benefit obligation (the "APBO"), change in plan assets and funded status are as follows:

	March 31,	
(Millions of dollars)	**2003**	**2002**
Change in accumulated postretirement benefit obligation		
[redacted]		
Service cost	5.6	5.2
[redacted]		
Plan participant contributions	6.1	5.4
[redacted]		
Actuarial loss	40.8	77.0
[redacted]		
Accumulated postretirement benefit obligation - end of year	$ 522.4	$ 470.4
Change in plan assets		
[redacted]		
Actual return on plan assets	(21.4)	(18.0)
[redacted]		
Plan participant contributions	6.1	5.4
[redacted]		
Plan assets at fair value - end of year	$ 218.0	$ 262.5
Reconciliation of accrued postretirement costs and total amount recognized		
[redacted]		
Unrecognized net transition obligation	119.0	131.2
[redacted]		
Accrued postretirement benefit cost, before final contribution	(42.0)	(24.1)
[redacted]		
Accrued postretirement cost	$ (20.9)	$ (24.1)

(a) Represents an adjustment to the obligation to provide benefits to employees who elected a special termination benefit in the year ended March 31, 2001, but revoked the election in the year ended March 31, 2003.

The assumed health care cost rate of increase gradually declines over four to seven years. The health care cost trend rate assumption has a significant effect on the amounts reported. Increasing the assumed health care cost trend rate by one percentage point would have increased the APBO as of March 31, 2003 by $25.9 million and the annual net periodic postretirement benefit costs by $4.2 million. Decreasing the assumed health care cost trend rate by one percentage point would have reduced the APBO as of March 31, 2003 by $22.6 million and the annual net periodic postretirement benefit costs by $2.5 million.

Postemployment Benefits - Electric Operations provides certain postemployment benefits to former and inactive employees and their dependants during the period following employment but before retirement. The costs of these benefits are accrued as they are incurred. Benefits include salary continuation, severance benefits, disability benefits and continuation of health care benefits for terminated and disabled employees and workers compensation benefits. Accrued costs for postemployment benefits were $5.2 million, $5.4 million and $8.7 million for the years ended March 31, 2003, 2002 and 2001, respectively.

Stock Option Incentive Plan - During 1997, the Company adopted a Stock Option Incentive Plan (the "Option Plan"). The exercise price of options granted under the Option Plan was 100.0% of the fair market value of the common stock on the day prior to the date of the grant. Stock options generally became exercisable in two or three equal installments on each of the first through third anniversaries of the grant date. The maximum exercise period under the Option Plan was 10 years. The Option Plan expired on November 29, 2001.

Upon completion of the Merger, all stock options granted prior to January 1999 became 100.0% vested. All outstanding stock options were converted into options to purchase ScottishPower ADS. Stock options to purchase ScottishPower ADS granted in connection with the Merger vest over the same number of years as stock options granted prior to the Merger.

The table below summarizes the stock option activity under the Option Plan.

	Number of Shares	Weighted Average Price
ScottishPower ADS		
Outstanding options at March 31, 2000	4,768,155	$ 33.76
Granted	114,150	25.06
Exercised	(76,885)	30.05
Forfeited	(1,079,400)	33.90
Outstanding options at March 31, 2001	3,727,020	33.49
Granted	824,750	25.68
Exercised	(24,665)	26.94
Forfeited	(560,109)	32.74
Outstanding options at March 31, 2002	3,966,996	32.01
Granted	—	
Exercised		
Forfeited	(563,745)	34.06
Outstanding options at March 31, 2003	3,403,251	31.67

Information with respect to options outstanding and options exercisable as of March 31, 2003 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
$25.06 - $36.64	2,737,760	$ 29.45	6.1	2,104,695	$ 30.10
$39.99 - $43.83	665,491	40.81	4.3	665,491	40.81
Total	3,403,251	31.67	5.8	2,770,186	32.68

At March 31, 2002, options for 2,773,244 ScottishPower ADS were exercisable with a weighted average exercise price of $34.14 per share. The weighted average life of the options outstanding at March 31, 2002 was six years.

The fair value of options granted was $3.4 million and $0.4 million for the years ended March 31, 2002 and 2001, respectively. The fair value of each option grant was estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions used:

	Years Ended March 31,	
	2002	2001
Dividend yield	6.70%	6.40%
Risk-free interest rate	4.77	4.90
Volatility	30.00	25.50
Expected life of the options (years)	5	10

NOTE 15 - Income Taxes

The Company, as a wholly owned subsidiary, is included in a consolidated tax return. Under the terms of the Company's tax sharing agreement, the Company's provision for income taxes has been computed on the basis that it files a separate consolidated income tax returns with its subsidiaries. Amounts payable for federal and state taxes are remitted to the Company's parent.

The Company's combined federal and state effective income tax rate from continuing operations were 40.6%, 37.5% and 195.7% for the years ended March 31, 2003, 2002 and 2001, respectively.

The difference between taxes calculated as if the statutory federal tax rate of 35.0% was applied to income from continuing operations before income taxes and the recorded tax expense is reconciled as follows:

	Years Ended March 31,		
(Millions of dollars)	**2003**	**2002**	**2001**
Computed federal income taxes	$ 83.7	$ 164.3	$ 32.3
Increase (reduction) in taxes resulting from:			
Effect of regulatory treatment of depreciation differences	15.6	13.7	21.4
Depletion	0.7	(1.5)	(3.0)
Tax credits	(13.4)	(10.8)	(9.4)
Sale of Australian Electric Operations (a)	-	(9.9)	74.3
Tax reserves (b)	4.5	20.9	66.2
Income taxed at less than statutory rate	(3.7)	(4.6)	(4.0)
Corporate-owned life insurance	(2.1)	(3.3)	(3.0)
Nontaxable income	(0.1)	(1.4)	(2.4)
All other	3.8	(4.8)	(3.7)
State income tax	8.2	13.5	11.7
Income tax expense on income from continuing operations before cumulative effect of accounting change	$ 97.2	$ 176.1	$ 180.4

(a) The Company did not have enough capital gains to offset the capital losses resulting from the sale of the Australian Operations in the year ended March 31, 2001. In accordance with U.S. federal income tax law, a portion of the excess capital loss was reattributed to another member of the federal consolidated tax return so that a benefit could be taken during the year ended March 31, 2001.

(b) The Company has established, and periodically reviews, an estimated contingent tax reserve on its consolidated balance sheet to provide for the possibility of adverse outcomes in tax proceedings.

The Company has concluded its settlement discussions with the IRS Appeals Division for the 1991, 1992 and 1993 tax years. A tax payment of $10.3 million was made upon settlement.

The examination of the Company's 1994 through 1998 tax years was completed in July 2002. The IRS issued a Revenue Agent's Report on July 31, 2002 for these years. Further, the IRS also issued a Revenue Agent's Report on July 17, 2002 containing solely the issues agreed upon with the Company. The tax impact for the agreed upon issues is a liability of $40.9 million, for which a contingency tax reserve was previously provided. The Company has filed an administrative appeal for the unresolved issues and believes that final settlement and payment will not have a material adverse impact upon its consolidated financial position or results of operations.

The IRS started its examination of the 1999 and 2000 tax years in September 2002.

The provision for income taxes is summarized as follows:

(Millions of dollars)	Years Ended March 31, 2003	2002	2001
Current			
[redacted]			
State	11.2	11.1	16.6
[redacted]			
Deferred			
Federal	38.6	63.2	(18.4)
[redacted]			
Total	39.7	71.7	(17.0)
[redacted]			
Total Income tax expense	$ 97.2	$ 176.1	$ 180.4

The tax effects of significant items comprising the Company's net deferred tax liability were as follows:

(Millions of dollars)	March 31, 2003	2002
Deferred tax liabilities		
[redacted]		
Regulatory assets	550.3	574.2
[redacted]		
	1,604.0	1,557.4
Deferred tax assets		
[redacted]		
Book reserves not currently deductible for tax	(41.2)	(43.8)
[redacted]		
Leases	(15.0)	(13.2)
[redacted]		
	(123.8)	(122.6)
[redacted]		

The Company made net income tax payments of $82.2 million and $83.1 million for the years ended March 31, 2003 and 2002, respectively, and received net income tax refunds of $63.9 million for the year ended March 31, 2001. The income tax payments include payments for current federal and state income taxes, as well as amounts paid in settlement of prior years' liabilities as a result of income tax proceedings.

NOTE 16 - Discontinued Operations

The Company recognized $146.7 million of income in the year ended March 31, 2002 as a result of collecting a contingent note receivable relating to the discontinued operations of its former mining and resource development business, NERCO, Inc. ("NERCO"), which was sold in 1993. This note from the buyer was recorded at the date of the NERCO sale along with a corresponding deferred gain. Payments on this note were contingent upon the buyer receiving payment under a coal supply contract. The Company recognized this gain on a cost-recovery basis as payments were received from the buyer. In June 2001, the Company received $189.9 million, which was full payment of the remaining balance of the note and recognized the remaining balance of the deferred gain. Deferred tax expense of $36.4 million was recognized on the gain in June 2001.

NOTE 17 - Dispositions

On December 31, 2001, NAGP contributed all of the common stock of PacifiCorp to PHI. On February 4, 2002, PacifiCorp transferred all of the capital stock of PGHC to PHI. Accordingly, the results of operations and assets of PGHC are not included with those of PacifiCorp commencing February 4, 2002.

In October 2001, PFS sold its synthetic fuel operations. The sale resulted in a gain of approximately $11.3 million, pretax.

During the year ended March 31, 2002, the Company sold aircraft owned by subsidiaries of PFS. PFS received proceeds of approximately $36.0 million and recorded a $9.3 million pretax gain on the sale.

In connection with an internal restructuring of the Company, the Company transferred its interest in two nonutility energy companies to PHI in March 2001. The transfer price of $72.4 million was based on an estimate of market value and was financed through a loan from PGHC. The income and cash flow impacts from the two companies are included in the 2001 results, but the assets and liabilities associated with those businesses were removed from the consolidated balance sheet upon the transfer to PHI. No gain was recognized on the transfer. The difference between the transfer price and the book value was recorded as an adjustment to equity.

During the year ended March 31, 2001, PGHC completed the sale of its ownership of Powercor and its 19.9% interest in Hazelwood for approximately AUS $2.4 billion and approximately AUS $88.0 million, respectively. Powercor and Hazelwood represented all of the Australian Operations segment of the Company. The Company recorded an after tax loss on the sale of $197.7 million. In June 2001, upon resolution of a contingency under the provisions of the Powercor sale agreement, PGHC received further proceeds due from the sale that resulted in income of $27.4 million in 2002.

The gain (loss) on the sale of the Australian Operations for the years ended March 31, 2002 and 2001 was as follows:

	March 31, 2002		March 31, 2001	
(Millions of dollars)	**Pretax**	**After tax**	**Pretax**	**After tax**
Australian Operations:				
Gain (loss) on sale	$27.4	$ 27.4	$ (109.1)	$ (109.1)(a)
Loss due to cumulative unfavorable changes in foreign exchange rate	—	—	(108.5)	(108.5)
Total Australian Operations	27.4	27.4	(217.6)	(217.6)
Other Operations:				
Loss on repayment of debt	—	—	(1.9)	(1.9)
Net gain on swap settlement	—	—	35.3	21.8
Total Other Operations	—	—	33.4	19.9
Total gain (loss) on sale	$27.4	$ 27.4	$ (184.2)	$ (197.7)

(a) The Company did not have enough capital gains to offset this capital loss and does not anticipate any further tax benefit from this loss.

In July 1998, the Company announced its intention to sell its California service territory, including its electric distribution assets. The Company and Nor-Cal Electric Authority ("Nor-Cal") have engaged in detailed negotiations with a view toward executing a definitive sale agreement. Various factors have impeded consummation of the sale transaction. Most recently, in June 2002, the California county of Siskiyou filed a validation action in California Superior Court, challenging the authority of Nor-Cal to enter into such a transaction as proposed and alleging certain conflicts of interest among Nor-Cal and its advisors. The validation action is ongoing, but based on the foregoing factors, consummation of the sale is uncertain.

On May 4, 2000, the utility partners, including the Company, who owned the 1,340-MW coal-fired Centralia Power Plant sold the plant and the adjacent coal mine, which was wholly owned and operated by the Company, for approximately $500.0 million. The Company operated the plant and owned a 47.5% share. The Company recorded a loss of approximately $13.9 million on the sale.

All assets subject to disposition continued to be utilized in operations of the Company. As such, no separate accounting treatment or classification has been given to such assets.

NOTE 18 - Concentration of Customers

During the year ended March 31, 2003, no single retail customer accounted for more than 1.2% of the Company's Electric Operations' retail electric revenues and the 20 largest retail customers accounted for 13.0% of total retail electric revenues. The geographical distribution of the Company's Electric Operations' retail operating revenues for the year ended March 31, 2003 was Utah, 38.8%; Oregon, 31.9%; Wyoming, 12.7%; Washington, 8.2%; Idaho 5.9%; and California, 2.5%.

NOTE 19 - Segment Information

The Company previously operated in two business segments (excluding other and discontinued operations): Electric Operations and Australian Operations. The Australian Operations were sold in fall 2000. The Company currently has one segment, Electric Operations, which includes the regulated retail and wholesale electric operations in the six western states in which it operates. Australian Operations included the deregulated electric operations in Australia. Other Operations consisted of PFS, the western energy trading activities and other energy development businesses, as well as the activities of PGHC, including financing costs. PGHC and its subsidiaries, including PFS, were transferred to PHI in February 2002 as discussed in NOTE 1.

NOTE 20 - Subsequent Events

On April 17, 2003, the Board declared a dividend on common stock of 12.86 cents per share for a total of $40.1 million, payable on May 28, 2003.

In addition, certain regulatory actions that occurred after March 31, 2003 are described in NOTE 2.

SUPPLEMENTAL INFORMATION

QUARTERLY FINANCIAL DATA (UNAUDITED)

(Millions of dollars, except per share amounts)	Quarters Ended June 30	September 30	December 31	March 31
2003				
[redacted]				
Income from operations	122.9	132.2	124.2	109.6
[redacted]				
Cumulative effect of accounting change	(1.9)	—	—	—
[redacted]				
Earnings on common stock	33.7	29.7	37.9	31.5
[redacted]				
Common dividends paid per share	—	—	—	—
2002				
[redacted]				
Income from operations (a)	299.6(c)	(1.7)	120.3	222.8
[redacted]				
Discontinued operations	146.7	—	—	—
[redacted]				
Net income (loss)	198.2	(30.2)	46.3	113.0
[redacted]				
Common dividends declared per share	$ 0.27	$ 0.27	$ —	$ 0.27
[redacted]				

(a) Certain amounts from prior years have been reclassified to conform to the year ended March 31, 2003 method of presentation.

(b) Short term and spot-market Wholesale sales averaged $188.89, $117.34, $34.15 and $25.17 per MWh in the first, second, third and fourth quarters of 2002, respectively.

(c) Includes a $178.1 million gain on application of SFAS No. 133, effective April 1, 2001, and a $27.4 million gain on the sale of the Australian Operations.

See NOTE 16 for information regarding discontinued operations.

On March 31, 2003, there was one common shareholder of record.

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

No information is required to be reported pursuant to this item.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following is a list of directors of the Company as of March 31, 2003.

Ian M. Russell, (50). Chairman of the Board of the Company. Director since November 1999.

Mr. Russell was appointed Chief Executive of ScottishPower in April 2001 and Chairman of PacifiCorp in January 2002. He previously served as Deputy Chief Executive of ScottishPower since November 1998, having previously been appointed Finance Director of ScottishPower in April 1994 and serving in both capacities from November 1998 to December 1999. In his present capacity, he is responsible for United Kingdom and U.S. operations.

Judith A. Johansen, (44). President and Chief Executive Officer of the Company. Director since December 2000.

Ms. Johansen was elected President and Chief Executive Officer on June 4, 2001 and served as Executive Vice President since December 1, 2000. She was Administrator and Chief Executive Officer of the BPA in Portland, Oregon from June 1998 to November 2000. From 1996 to May 1998, Ms. Johansen was vice president of business development with Avista Energy and from 1994 to 1996 was BPA's Vice President for Generation Supply.

Barry G. Cunningham, (58). Senior Vice President of the Company since February 2002. Director since April 2002.

Mr. Cunningham was named PacifiCorp's Senior Vice President of Generation in February 2002. Mr. Cunningham joined PacifiCorp in 1977 and served as Vice President in 1999 and as Assistant Vice President from 1998 to 1999.

Nolan E. Karras, (58). Director since February 1993.

Mr. Karras is President of The Karras Company, Inc., investment advisers, Roy, Utah, and has served in that capacity since 1983. He is Chief Executive Officer of Western Hay Company, Inc., a nonexecutive director of Scottish Power plc and Beneficial Life Insurance Company and is a Registered Principal for Raymond James Financial Services. He also served as a Member of the Utah House of Representatives from 1981 to 1990 and as Speaker of the Utah House of Representatives from 1989 to 1990. At present, Mr. Karras serves as the Chair of the Utah State Board of Regents.

William D. Landels, (60). Executive Vice President of the Company. Director since November 1999.

Mr. Landels has been with ScottishPower since 1985. He was elected Executive Vice President and Director of the Company effective upon the Merger with ScottishPower in November 1999. Prior to that, he served with the ScottishPower Group in various senior management roles, including as Managing Director of Manweb, Managing Director of Energy Supply and Managing Director of Distribution.

Andrew N. MacRitchie, (39). Executive Vice President of the Company. Director since May 2000.

Mr. MacRitchie was elected Executive Vice President in May 2000. Mr. MacRitchie has been with ScottishPower since 1986. He served as the Transition Director for the PacifiCorp Merger from December 1999 to May 2000. He served as ScottishPower's U.S. Chief of Staff on the PacifiCorp Merger from December 1998 to December 1999, and, prior to that, he served as Manager, Business and Organizational Development.

Michael J. Pittman, (50). Senior Vice President of the Company. Director since May 2000.

Mr. Pittman was elected a Senior Vice President of the Company in May 2000. He formerly served as a Vice President of the Company from May 1993. Mr. Pittman is Chair of the PacifiCorp Foundation for Learning.

A. Richard Walje, (51). Senior Vice President of the Company. Director since July 2001.

Mr. Walje was named PacifiCorp's Vice President and Chief Information Officer in May 2000 and Senior Vice President of Corporate Business Services in May 2001. Mr. Walje also served as PacifiCorp's Vice President for Transmission and Distribution Operations and Customer Service from 1998 to 2000. Mr. Walje also serves on the PacifiCorp Foundation Board of Directors.

Matthew R. Wright, (38). Executive Vice President of the Company. Director since July 2001.

Mr. Wright was appointed Executive Vice President of Power Delivery in January 2002. Mr. Wright served as Senior Vice President of Strategy and Planning in 2001 and as Vice President of Regulation from 1999 to 2001. Prior to joining PacifiCorp, Mr. Wright served the ScottishPower group in various management positions since 1995.

The following is a list of the executive officers of the Company not named above. There are no family relationships among the executive officers of the Company. Officers of the Company are normally elected annually.

Richard D. Peach, (39). Chief Financial Officer since January 2003. Director since May 2003.

Mr. Peach was named the Company's Chief Financial Officer effective January 2003. Mr. Peach served as Senior Vice President of Finance since March 2002. Prior to his appointment as Chief Financial Officer, Mr. Peach was also Group Controller for ScottishPower since March 2000 and served in a various management positions since 1995. In May 2003, Mr. Peach was named a Director of PacifiCorp.

Donald N. Furman, (46). Senior Vice President since July 2001.

Mr. Furman was named PacifiCorp's Senior Vice President of Regulation and Government Affairs in July 2001. Mr. Furman served as Vice President of Transmission and Business Development from 1997 to 2001 and as President of PPM from 1995 to 1997.

Andrew P. Haller, (51). Senior Vice President, General Counsel and Corporate Secretary since December 2000. Director since May 2003.

Mr. Haller was chief executive for the U.S. operations of Kvaerner Process prior to joining PacifiCorp. Mr. Haller began his career with Kvaerner in 1987, and held various senior counsel and management positions, including Senior Vice President and General Counsel-Americas. From 1998 to 1999, he served as the Associate General Counsel for the parent company, Kvaerner ASA, in its U.S. corporate headquarters. In May 2003, Mr. Haller was named a Director of PacifiCorp.

Robert A. Klein, (age 55), Senior Vice President, since August 2001.

Mr. Klein has served as the Company's Senior Vice President of Commercial and Trading since August 2001 and was named ScottishPower's Energy Risk Director in March 2003. Prior to joining the Company in December 2000, Mr. Klein served as Senior Vice President and General Manager of Equitable Resources' deregulated marketing business from 1998 to 1999 and as Director of Corporate Risk for Coral Equity from 1997 to 1998.

Robert Moir, (53). Senior Vice President since February 2002.

Mr. Moir was named PacifiCorp's Senior Vice President of Distribution in February 2002. Mr. Moir served as Vice President since May 2000. Mr. Moir has been with ScottishPower since 1967.

Bruce N. Williams, (44). Treasurer since February 2000.

Mr. Williams has been with PacifiCorp since 1985. Prior to being elected Treasurer, he served as Assistant Treasurer of the Company.

In addition to its Guide to Business Conduct, which is distributed to all employees and provides a basis for employee ethical standards and conduct, the Board has approved and implemented a "Code of Ethics for Principal Officers," as discussed in Section 406 of the Sarbanes-Oxley Act of 2002.

ITEM 11. EXECUTIVE COMPENSATION

BOARD REPORT ON EXECUTIVE COMPENSATION

INTRODUCTION

The Board submits this Board Report on Executive Compensation, which outlines the compensation provided to its executive officers. The Remuneration Committee of the Board of Directors of ScottishPower (the "Remuneration Committee"), assisted by its outside advisors, has the responsibility to recommend compensation levels and executive compensation plans for officers of the Company and to administer executive compensation plans as authorized. The Remuneration Committee is composed entirely of independent, nonemployee directors. The Remuneration Committee must approve any stock-based compensation. The following describes the components of the Company's executive compensation program and the basis upon which recommendations and determinations were made for the period from April 1, 2002 to March 31, 2003.

COMPENSATION PHILOSOPHY

The Company's philosophy is that executive compensation should be linked closely to corporate performance and increases in shareholder value. The Company's compensation program has the following objectives:

(i) provide competitive total compensation that enables the Company to attract and retain key executives;

(ii) provide variable compensation opportunities that are linked to Company and individual performance; and

(iii) establish an appropriate balance between incentives focused on short-term objectives and those encouraging sustained earnings performance and increases in shareholder value.

Qualifying compensation for deductibility under Internal Revenue Code ("IRC") Section 162(m) is one of the factors the Remuneration Committee considers in designing its incentive compensation arrangements. IRC Section 162(m) limits to $1.0 million the annual deduction by a publicly held corporation of compensation paid to any executive, except with respect to certain forms of incentive compensation that qualify for exclusion. Although it is the Board's intent to design and administer compensation programs that maximize deductibility, the Remuneration Committee views the objectives outlined above as more important than compliance with the technical requirements necessary to exclude compensation from the deductibility limit of IRC Section 162(m). Nevertheless, the Remuneration Committee believes that nearly all compensation paid to the executive officers for services rendered in the year ended March 31, 2003 is fully deductible.

COMPENSATION PROGRAM COMPONENTS

In the year ended March 31, 2003, the Remuneration Committee focused its market-based comparisons on the relevant industry for each officer. The Remuneration Committee utilized the U.S. electric utility industry as its exclusive basis for market comparison for positions with a principal focus on electric operations. For positions with a corporate-wide focus, the Remuneration Committee used a weighting of approximately 67.0% general industry and 33.0% electric utility industry. In all cases, compensation is targeted at market median levels, with an assumption that total compensation greater than market median, in any specific time period, anticipates that Company performance exceed the median performance of peer companies.

The Company's executive compensation programs have three principal elements: Base Salary, Annual Incentive Compensation and Long-Term Incentive Compensation, as described below.

Base Salaries

Base salaries and target incentive amounts are reviewed for adjustment at least annually based upon competitive pay levels, individual performance and potential, and changes in duties and responsibilities. Base salary and the incentive target are set at a level such that total annual compensation for satisfactory performance would approximate the midpoint of pay levels in the comparison group used to develop competitive data. In the year ended March 31, 2003, the base salary of each executive officer was increased, based on market analysis, to reflect competitive market changes, individual performance and changes in the responsibilities of some officers.

Annual Incentive Compensation

All PacifiCorp officers (except ScottishPower executives on international assignment), including those listed in the Summary Compensation Table, participated in the Company's Annual Incentive Program. Performance goals were based on PacifiCorp performance, operational performance and individual performance, and may include ScottishPower performance based on the level, influence and impact of the officer.

Long-Term Incentive Compensation

Historically, the Board annually reviewed and approved grants of restricted stock and stock options under the Stock Incentive Plan. However, on November 29, 2001, the Stock Incentive Plan expired. Restricted stock and stock option awards made under the Stock Incentive Plan on or before April 24, 2001 will continue to remain outstanding until such time as they become vested or expire.

Restricted stock awards under the Stock Incentive Plan are subject to terms, conditions and restrictions determined by the Board to be consistent with the plan and the best interests of the shareholders. In general, restricted stock awards vest over a four-year period from the date of grant, subject to compliance with the stock ownership and other terms of the grant. The restrictions include stock transfer restrictions and forfeiture provisions designed to facilitate the participants' achievement of specified stock ownership goals. Participants are also required to invest their own personal resources in ScottishPower ADS or ordinary shares ("Ordinary Shares") in order to meet the vesting requirements associated with these grants. The Summary Compensation Table below shows the grants of restricted stock made to the listed executive officers under the Stock Incentive Plan in the years ended March 31, 2002 and 2001.

On April 25, 2002, the Remuneration Committee approved grants of stock options and performance share awards under ScottishPower's Executive Share Option Plan 2001 ("ExSOP") and the Long-Term Incentive Plan ("LTIP"), respectively, for a select group of executive officers and other senior managers. See Long-Term Incentive Plan below. Two separate ExSOP grants were awarded on May 2, 2002 to senior managers of the Company. The first grant is a standard grant, which has a three-year vesting schedule starting on the first anniversary of the grant date, and the second grant is a one-time enhanced grant, which has a three year cliff vesting based on performance.

All stock options awarded to officers and senior management of the Company in the years ended March 31, 2003, 2002 and 2001 are nonstatutory, nondiscounted options with a three-year vesting requirement and a 10-year term from the date of the grant.

SCOTTISHPOWER EXECUTIVE OFFICERS ON INTERNATIONAL ASSIGNMENT

Executive officers who are international assignees from ScottishPower are maintained on their home country remuneration program. The compensation for these individuals is determined by the Remuneration Committee. ScottishPower's compensation philosophy and components are the same as PacifiCorp's except as noted below.

Annual Performance-Related Bonus

Executives on international assignment participate in ScottishPower's performance-related pay schemes. All payments under the schemes are nonpensionable and noncontractual and are subject to the approval of the Remuneration Committee.

The fiscal 2003 scheme for executive officers provided a bonus of up to a maximum of 60.0% of salary determined by PacifiCorp performance, operational performance and individual performance.

Long-Term Incentive Plan

The LTIP links the rewards closely between management and shareholders, and focuses on long-term corporate performance. The award will vest only if the Remuneration Committee is satisfied that certain threshold performance measures are achieved. The number of shares that actually vest is dependent upon the Company's comparative Total Shareholder Return performance, over a three-year performance period. ExSOP grants to ScottishPower executives at PacifiCorp on international assignment are subject to the performance criterion that the average annual percentage increase in the ScottishPower's earnings per share ("EPS") be at least 3.0% (adjusted for any increase in the Retail Price Index). This criterion is assessed at the end of the third financial year, the first year being the financial year starting immediately before the date of the grant. If not satisfied on the third anniversary, the criterion may be retested, from the same base, on the fourth and fifth anniversaries of the grant. Unvested options lapse at the fifth anniversary.

COMPENSATION OF THE CHIEF EXECUTIVE OFFICER

On June 4, 2001, Ms. Johansen assumed responsibilities as Chief Executive Officer and President of PacifiCorp. Ms. Johansen has a base salary of $500,000 and a maximum annual incentive award of 75.0% of base salary. She is also eligible for participation in the LTIP and ExSOP.

The Board Report on Executive Compensation detailed above has been submitted by all the members of the Board as listed in **ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE COMPANY**.

EXECUTIVE COMPENSATION

The following table sets forth information concerning compensation for services in all capacities to the Company for the years ended March 31, 2003, 2002 and 2001 of those persons who were the Chief Executive Officer of the Company during any portion of the year ended March 31, 2003 and the four other most highly compensated executive officers of the Company who were serving as executive officers at the end of the last completed fiscal year.

Summary Compensation Table

				Long-Term Compensation				
Name and Principal Position	**Year**	**Annual Compensation (a) Salary**	**Bonus (c)**	**Restricted Stock Awards (d)**	**Securities Underlying Options (e)**	**LTIP Payout (f)**	**ScottishPower Performance Shares (g)**	**All Other Compensation (h)**
Judith A. Johansen	2003	$ 492,444	$149,767	$ —	61,825	$ —	9,199	$ 32,657
President and Chief	2002	360,501	12,902	141,683	57,350	—	—	11,707
Executive Officer	2001	410,834	150,000	131,138	57,350	—	—	3,169
William D. Landels (b)....	2003	431,890	116,141	—	79,433	—	31,773	85,462
Executive Vice President	2002	421,409	61,818	—	39,855	—	25,781	[illegible]
	2001	323,899	80,570	—	—	—	14,408	107,030
Andrew P. Haller	2003	310,930	132,026	—	19,165	23,659	5,656	12,650
Senior Vice President,...	2002	299,425	8,392	112,768	56,800	23,644	—	10,524
General Counsel and	2001	286,042	410,000	104,375	56,800	—	—	2,917
Corporate Secretary								
Michael J. Pittman..........	2003	300,000	47,057	—	50,954	—	7,581	28,310
Senior Vice President	2002	275,167	150,008	53,203	13,500	—	—	20,449
	2001	249,749	—	—	—	—	—	12,813
A. Richard Walje	2003	275,500	95,550	—	24,840	—	6,570	[illegible]
Senior Vice President....	2002	240,375	128,854	53,203	14,000	12,222	—	19,606
	2001	240,002	[illegible]	—	—	19,729	—	158,724

(a) May include amounts deferred pursuant to the Compensation Reduction Plan, under which key executives and directors may defer receipt of cash compensation until retirement or a preset future date. Amounts deferred are invested in ScottishPower ADS or a cash account on which interest is paid at a rate equal to the Moody's Intermediate Corporate Bond Yield for AA-rated Public Utility Bonds.

(b) Salary includes foreign housing benefits paid to Mr. Landels. These amounts were $99,285.00, $126,610.58 and $66,322.75 for the years ended March 31, 2003, 2002 and 2001, respectively.

(c) Amounts in this column for the year ended March 31, 2003 include a promotion bonus in the amount of $41,556 for Ms. Johansen. Amounts in this column for the year ended March 31, 2002 include a retention bonus in the amount of $125,610 and $104,000 for Messrs. Pittman and Walje, respectively. Amounts in this column for the year ended March 31, 2001 include special bonuses and hire-on bonuses. These amounts are $150,000 and $110,000 for Ms. Johansen and Mr. Haller, respectively.

(d) On March 31, 2003, the aggregate value of all restricted stock holdings, based on the market value of ScottishPower ADS at March 31, 2003, without giving effect to the diminution of value attributed to the restrictions on such stock, was $146,939, $116,951, $46,900 and $46,900, for Ms. Johansen and Messrs. Haller, Pittman and Walje, respectively. The aggregate number of restricted share holdings was 6,125, 4,875, 1,955 and 1,955 for Ms. Johansen and Messrs. Haller, Pittman and Walje, respectively. Regular quarterly dividends are paid on the restricted stock. Participants may defer receipt of restricted stock awards to their stock accounts under the Compensation Reduction Plan.

(e) Amounts for the year ended March 31, 2003 represent the number of ADS option shares awarded under the ScottishPower ExSOP during the year ended March 31, 2003, except for Mr. Landels' options, which are for ScottishPower Ordinary Shares. Amounts shown for the years ended March 31, 2002 and 2001 represent the number of ADS options awarded under the PacifiCorp Stock Incentive Plan.

(f) Represents the dollar value of restricted stock shares awarded under the PacifiCorp Stock Incentive Plan that vested and were distributed to the named officer.

(g) Represents the number of ScottishPower ADS, except for Mr. Landels, which are Ordinary Shares, contingently granted in 2003, 2002 and 2001 that can be earned under the terms of the ScottishPower LTIP.

(h) Amounts shown for the year ended March 31, 2003 include:

   (i) Company contributions to the PacifiCorp K Plus Employee Savings and Stock Ownership Plan for each of Ms. Johansen and Messrs. Haller, Pittman and Walje were $11,487, $11,613, $9,450 and $9,905, respectively.

   (ii) Portions of premiums on term life insurance policies that PacifiCorp paid for Ms. Johansen and Messrs. Haller, Pittman and Walje in the amounts of $683, $425, $410 and $373, respectively. These benefits are available to all employees.

   (iii) This column also includes vehicle allowances paid to Ms. Johansen and Messrs. Landels, Haller, Pittman and Walje in the amounts of $9,000, $12,000, $9,000, $9,000, and $9,000, respectively.

   (iv) During each of the years ended March 31, 2003, 2002 and 2001, Mr. Landels purchased 411 shares under the ScottishPower Employee Share Ownership Plan. Under the terms of the plan, ScottishPower matches the number of shares bought by the individual. The value of the 411 shares bought by ScottishPower for Mr. Landels was $2,321 for each of the years ended March 31, 2003, 2002 and 2001.

   (v) Includes additional international assignment payments of $71,141, $112,150 and $92,709 for the years ended March 31, 2003, 2002 and 2001, respectively, for cost of living and foreign service premium, according to the terms of Mr. Landels' contract.

Option Grants in Last Fiscal Year

Name	Individual Grants(a)				Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Option Term	
	Number of Securities Underlying Options Granted (b)	% of Total Options Granted to Employees in Fiscal Year	Exercise or Base Price £ or $/Sh	Expiration Date	5%	10%
[redacted]						
Judith A. Johansen	61,825	6.32	$ 23.55	May 2, 2012	$ 915,658	$ 2,320,455
[redacted]						
Michael J. Pittman	50,954	5.20	23.55	May 2, 2012	754,653	1,912,438
[redacted]						

(a) All options are for ScottishPower ADS, except Mr. Landels' options, which are for ScottishPower Ordinary Shares. One ScottishPower ADS is equal to four ScottishPower Ordinary Shares. All options awarded were ScottishPower ExSOP grants, dated May 2, 2002.

(b) All standard options become exercisable for one-third of the shares covered by the option on each of the first three anniversaries of the grant date and all enhanced options become exercisable after the third anniversary of the grant date. Mr. Landels' options can be exercised only between the third and tenth anniversaries of the date of the grant, and exercise is subject to the satisfaction of a performance condition, that being a predetermined level of EPS growth over a maximum of a three-year performance period from the date of the grant.

Aggregated Option Exercises in 2003 and Year-End Option Values

Name	Shares Acquired on Exercise	Value Realized	Number of Securities Underlying Unexercised Options at March 31, 2003 (a)		Value of Unexercised In-the-Money Options at March 31, 2003	
			Exercisable	Unexercisable	Exercisable	Unexercisable
[redacted]						
Judith A. Johansen	$ —	$ —	57,349	119,176	$ —	$ 27,203
[redacted]						
Michael J. Pittman	—	—	121,983	114,058	—	22,420
[redacted]						

(a) All options are for ScottishPower ADS, except Mr. Landels' options, which were for ScottishPower Ordinary Shares, and include options granted under the PacifiCorp Stock Incentive Plan and the ExSOP.

Severance Arrangements

The Company's Executive Severance Plan provides severance benefits to certain executive-level employees who are designated by the Board, including the executive officers named in the Summary Compensation Table (other than Mr. Landels). Severance benefits are payable for voluntary terminations as a result of a "material alteration in position" that has a detrimental impact on the executive's employment or involuntary terminations (including a Company-initiated resignation) for reasons other than cause. A "material alteration in position" includes:

- a material reduction in the scope of the executive's duties and responsibilities or authority; or
- any reduction in base pay or a reduction in annualized base salary and target annual bonus of at least 15.0%, if the change is not due to a general reduction unrelated to the change in assignment.

The Executive Severance Plan also provides enhanced severance benefits in the event of certain terminations during the 24-month period following a qualifying change-in-control transaction. Executives designated by the Board are eligible for change-in-control benefits resulting from either a Company-initiated termination without "cause" or a resignation generally within two months after a "material alteration in position." For this purpose, "cause" means the executive's gross misconduct or gross negligence or conduct that indicates a reckless disregard for the consequences and has a material adverse effect on the Company or its affiliates, and "material alteration in position" means:

- a change in reporting relationship to a lower level;
- a material reduction in the scope of duties and responsibilities or in authority;
- relocation of work location to an office more than 100 miles from the executive's office or more than 60 miles from the executive's home; or
- a "material reduction in compensation," which includes any reduction in annualized base salary or a reduction in the annualized base salary and target bonus opportunity combined of at least 15.0%, if the change is not due to a general reduction unrelated to the change in assignment.

If qualified for the enhanced severance benefits, an executive would receive severance pay in an amount equal to either two, two and one-half or three times the "annual cash compensation" of such executive, depending on the level set by the Board. "Annual cash compensation" is defined as annualized base salary, target annual incentive opportunity and annualized auto allowance in effect on the earlier of a material alteration or termination, whichever is greater. The Company is required to make an additional payment to compensate the executive for the effect of any excise tax. The executive would also receive continuation of subsidized health insurance from six to 24 months depending on length of service and a minimum of 12 months' executive-level outplacement services.

The Executive Severance Plan does not apply to a termination for reasons of normal retirement, death or total disability or to a termination for cause or a voluntary termination other than as specified above. Except in the event of a change-in-control, the definition of cause is determined by the Company in its discretion and by the Board in the event of an appeal by the employee.

Other than in connection with a change in control, executives named in the Summary Compensation Table (other than Mr. Landels) are eligible for a severance payment equal to one or two times the executive's total cash compensation, six months of health insurance benefits and outplacement benefits. For this purpose, total cash compensation includes annualized base salary, the target annual incentive opportunity and the annualized auto allowance in effect on the earlier of a material alteration or termination.

Retirement Plans

The Company has adopted noncontributory defined benefit retirement plans for its employees, other than employees subject to collective bargaining agreements that do not provide for coverage. Certain executive officers, including the executive officers named in the Summary Compensation Table, other than Mr. Landels, are also eligible to participate in the Company's nonqualified supplemental executive retirement plan. The following description assumes participation in both the retirement plans and the supplemental plan. Participants receive benefits at retirement payable for life based on length of service with the Company and average pay in the 60 consecutive months of highest pay out of the last 120 months, and pay for this purpose would include salary and annual incentive plan payments reflected in the Summary Compensation Table above. Benefits are based on 50.0% of final average pay plus up to an additional 15.0% of final average pay depending upon whether the Company meets certain performance goals set for each fiscal year by the Board. Participants may also elect actuarially equivalent alternative forms of benefits. Retirement benefits are reduced to reflect Social Security benefits as well as certain prior employer retirement benefits. Participants are entitled to receive full benefits upon retirement after age 60 with at least 15 years of service. Participants are also entitled to receive reduced benefits upon early retirement after age 55 or after age 50 with at least 15 years of service and five years of participation in the supplemental plan.

The following table shows the estimated annual retirement benefit payable upon retirement at age 60 as of March 31, 2003. Amounts in the table reflect payments from the retirement plan and the supplemental plan combined.

Estimated Annual Pension At Retirement (a)

Annual Pay at Retirement Date	Years of Service (b)			
	5	15	25	30
$ 200,000	$ 43,333	$130,000	$130,000	$130,000
400,000	86,667	260,000	260,000	260,000
600,000	130,000	390,000	390,000	390,000
800,000	173,333	520,000	520,000	520,000
1,000,000	216,667	650,000	650,000	650,000

(a) The benefits shown in this table assume that the individual will remain in the employ of the Company until retirement at age 60, that the plans will continue in their present form and that the Company achieves its performance goals under the supplemental plan in all years.

(b) The number of credited years of service used to compute benefits under the plans for Ms. Johansen and Messrs. Haller, Walje and Pittman are two, two, 17 and 23, respectively.

Retention Agreements

To retain executives who would otherwise have had the right to resign for any reason between 12 and 14 months following the ScottishPower Merger and qualify for the enhanced change-in-control supplemental retirement benefits, the Company entered into retention agreements with qualifying executives (Messrs. Pittman and Walje). Those retention agreements provided for the same enhanced supplemental retirement benefits if the qualifying executives satisfied the retention criteria. Qualifying executives were required to waive their rights to unilaterally resign and receive the enhanced supplemental retirement benefits, but they are now eligible to receive these same enhancements since they have continued employment through the established retention date of December 1, 2002.

These retention agreements also require qualifying executives to waive any rights to executive severance benefits, which they may have otherwise claimed due to material alterations in their positions as of the date of the retention agreement. Unless there is a subsequent “involuntarily termination” or “material alteration” in position as defined in the Severance Plan, this waiver of severance benefits applies to these executives through November 28, 2004. The executives’ waiver of severance benefits was in exchange for the enhanced supplemental retirement benefits described above, retention bonuses determined individually in the Company’s discretion for each executive and special stock option awards that vest over a three-year retention period at 25.0% for each of the first two years and 50.0% in the third year.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

All common shares of the Company are indirectly owned by Scottish Power plc, 1 Atlantic Quay, Glasgow, G2 8SP, Scotland. The Company has no compensation plans under which equity securities of the Company are authorized to be issued.

The following table sets forth certain information as of March 31, 2003 regarding the beneficial ownership of ScottishPower Ordinary Shares by (1) each of the executive officers named in the Summary Compensation Table under **ITEM 11. EXECUTIVE COMPENSATION** above, (2) each director of the Company as detailed under **ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT** and (3) all executive officers and directors as a group. As of March 31, 2003, each of the directors and executive officers identified above and all directors and executive officers of the Company as a group owned less than 1% of the outstanding Ordinary Shares of ScottishPower.

Beneficial Owner	**Number of shares at March 31, 2003 (a)(b)**
[redacted]	
William D. Landels	12,667
[redacted]	
Michael J. Pittman	123,584
[redacted]	
Barry G. Cunningham	53,435
[redacted]	
Andrew N. MacRitchie	15,802
[redacted]	
Matthew R. Wright	6,415
[redacted]	

(a) Includes ownership of (i) shares held by family members even though beneficial ownership of such shares may be disclaimed, (ii) shares held for the account of such persons pursuant to the Company's Compensation Reduction Plan and the Company's K Plus Savings and Stock Ownership Plan and (iii) shares granted and vested or unvested shares for which the individual has voting but not investment power under the Company's Stock Incentive Plan.

(b) Options granted in ScottishPower ADS under the Company's Stock Incentive Plan have been converted into options in Ordinary Shares in the above table. One ADS equates to four Ordinary Shares.

On May 10, 2003, LTIP awards in the amount of 49,833, 34,971, 21,936, 31,395 and 28,779 were awarded to Ms. Johansen and Messrs. Landels, Haller, Pittman and Walje, respectively. Options under the ExSOP in the amount of 61,475, 58,285, 13,530, 38,729 and 17,751 were awarded to Ms. Johansen and Messrs. Landels, Haller, Pittman and Walje, respectively. All awards were for ADS, except for Mr. Landels, which were for Ordinary Shares.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

RELATED TRANSACTIONS

According to the terms of Andrew Haller's offer letter, the Company made a $200,000 loan to Mr. Haller on May 21, 2001 for the repayment of obligations to his former employer. The promissory note documenting such loan, as amended, includes the following terms: (i) initial payment of $35,000 was due on December 1 and paid on December 31, 2001; (ii) a second payment of $32,988.56 was due and paid on June 30, 2002; (iii) the remaining $143,855.55 is payable in five equal payments of $32,988.56 on June 30 in each year from 2003 to 2006. As of March 31, 2003, the outstanding loan balance was $148,974.29, including accrued interest.

All other information required by this item is set forth in **ITEM 11. EXECUTIVE COMPENSATION** and in **ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT** above.

ITEM 14. CONTROLS AND PROCEDURES

(a) The principal executive officer and principal financial officer of the Company have evaluated the effectiveness of the Company's disclosure controls and procedures pursuant to Rule 13a-14 under the Securities Exchange Act of 1934 as of a date within 90 days prior to the filing date of this report. Based on that evaluation, such officers have concluded that the Company's disclosure controls and procedures are effective to ensure that material information relating to the Company and its subsidiaries is made known to such officers in a timely manner for inclusion in the Company's periodic filings with the SEC.

(b) There were no significant changes in the Company's internal controls or in other factors that could significantly affect these controls after the date of their most recent evaluation by the Company's principal executive officer and principal financial officer.

ITEM 15. AUDIT FEES AND SERVICES

Not applicable for the fiscal year covered by this report.

PART IV

ITEM 16. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) 1. The list of all financial statements filed as a part of this report is included in **ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.**

2. Schedules:*

* All schedules have been omitted because of the absence of the conditions under which they are required or because the required information is included elsewhere in the financial statements included under **ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.**

3. Exhibits:

Exhibit Number	Exhibit Title
2.1(a)*	Agreement and Plan of Merger, dated as of December 6, 1998, by and among Scottish Power plc, NA General Partnership, Scottish Power NA 1 Limited and Scottish Power NA 2 Limited. (Exhibit 1 to the Form 6-K, dated December 11, 1998, filed by Scottish Power plc, File No. 1-14676).
2.1(b)*	Amended and Restated Agreement and Plan of Merger, dated as of December 6, 1998, as amended as of January 29, 1999 and February 9, 1999, and amended and restated as of February 23, 1999, by and among New Scottish Power PLC, Scottish Power plc, NA General Partnership and PacifiCorp (Exhibit (2)b, Form 10-K for year ended December 31, 1998, File No. 1-5152).
3.1*	Third Restated Articles of Incorporation of the Company (Exhibit (3)b, Form 10-K for the year ended December 31, 1996, File No. 1-5152).
3.2*	Bylaws of the Company effective November 29, 1999 (Exhibit (3)b, Form 10-K for the year ended March 31, 2000, File No. 1-5152).
4.1*	Mortgage and Deed of Trust dated as of January 9, 1989, between the Company and Morgan Guaranty Trust Company of New York (The Chase Manhattan Bank, successor), Trustee, Ex. 4-E, Form 8-B, File No. 1-5152 as supplemented and modified by fourteen Supplemental Indentures as follows:

Exhibit Number	File Type	File Date	File Number
(4)(b)			33-31861
(4)(a)	8-K	January 9, 1990	1-5152
4(a)	8-K	September 11, 1991	1-5152
4(a)	8-K	January 7, 1992	1-5152
4(a)	10-Q	Quarter ended March 31, 1992	1-5152
4(a)	10-Q	Quarter ended September 30, 1992	1-5152
4(a)	8-K	April 1, 1993	1-5152
4(a)	10-Q	Quarter ended September 30, 1992	1-5152
4(a)	10-Q	Quarter ended September 30, 1993	1-5152
(4)b	10-K	Quarter ended June 30, 1994	1-5152
(4)b	10-K	Quarter ended December 31, 1994	1-5152
(4)b	10-K	Quarter ended December 31, 1995	1-5152
(4)b	10-K	Quarter ended December 31, 1996	1-5152
99(a)	8-K	November 21, 2001	1-5152

4.2*	Third Restated Articles of Incorporation and Bylaws. See 3.1 and 3.2 above.

In reliance upon item 601(4)(iii) of Regulation S-K, various instruments defining the rights of holders of long-term debt of the Registrant and its subsidiaries are not being filed because the total amount authorized under each such instrument does not exceed 10% of the total assets of the Registrant and its subsidiaries on a consolidated basis. The Registrant hereby agrees to furnish a copy of any such instrument to the Commission upon request.

12.1	Statements of Computation of Ratio of Earnings to Fixed Charges
12.2	Statements of Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends
23	Consent of PricewaterhouseCoopers LLP with respect to Annual Report on Form 10-K.
24	Powers of Attorney
99.1	Section 906 Certification of Judith A. Johansen
99.2	Section 906 Certification of Richard D. Peach
99.3	Code of Ethics for Principal Officers

---

* Incorporated herein by reference.

(b) Reports on Form 8-K.

On Form 8-K, dated March 6, 2003, under Item 5. Other Events, the Company filed a news release reporting that the WPSC issued an order allowing approximately $9.0 million of the requested $20.0 million general rate increase. Additionally, the WPSC's order disallowed the Company's request for recovery of $60.3 million of excess power costs related to the western power crisis in 2000 and 2001 and $30.7 million of excess power costs resulting from the outage of the Company's Hunter No. 1 generating plant from November 2000 to May 2001.

(c) See (a) 3. above.

(d) See (a) 2. above.

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.

PacifiCorp

By: /s/ JUDITH A. JOHANSEN
Judith A. Johansen
(PRESIDENT AND
CHIEF EXECUTIVE OFFICER)

Date: May 30, 2003

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
*IAN M. RUSSELL Ian M. Russell	Chairman of the Board of Directors	May 30, 2003
/s/ JUDITH A. JOHANSEN Judith A. Johansen	President, Chief Executive Officer and Director	May 30, 2003
/s/ RICHARD D. PEACH Richard D. Peach	Chief Financial Officer and Director	May 30, 2003
Nolan E. Karras	Director	May 30, 2003
William D. Landels		
*ANDREW N. MacRITCHIE Andrew N. MacRitchie		
Michael J. Pittman		
*A. RICHARD WALJE A. Richard Walje		
/s/ MATTHEW R. WRIGHT Matthew R. Wright		
*BARRY G. CUNNINGHAM Barry G. Cunningham		
/s/ ANDREW P. HALLER Andrew P. Haller		
*By: /s/ JUDITH A. JOHANSEN Judith A. Johansen, as Attorney-in-Fact		

CERTIFICATIONS

I, Judith A. Johansen, principal executive officer of PacifiCorp, certify that:

1) I have reviewed this annual report on Form 10-K of PacifiCorp;

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 registrant as of, and for, the periods presented in this annual report;

4) The registrant's other certifying officers 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 registrant and we have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, 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 registrant'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 registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

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

6) The registrant's other certifying officers 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.

/s/ Judith A. Johansen

Judith A. Johansen
President and Chief Executive Officer, PacifiCorp
May 30, 2003

CERTIFICATIONS

I, Richard Peach, principal financial officer of PacifiCorp, certify that:

1) I have reviewed this annual report on Form 10-K of PacifiCorp;

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 registrant as of, and for, the periods presented in this annual report;

4) The registrant's other certifying officers 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 registrant and we have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, 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 registrant'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 registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

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

6) The registrant's other certifying officers 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.

/s/ Richard Peach

Richard D. Peach
Chief Financial Officer, PacifiCorp
May 30, 2003

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2003

OR

☐ 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 1-5152

PacifiCorp
(Exact name of registrant as specified in its charter)

STATE OF OREGON (State or other jurisdiction of incorporation or organization)	**93-0246090** (I.R.S. Employer Identification No.)
825 N.E. Multnomah Street, Suite 2000, Portland, Oregon (Address of principal executive offices)	**97232-4116** (Zip Code)

503-813-5000
(Registrant's telephone number)

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 twelve 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 at least the past 90 days.

YES ☒ NO ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Securities Exchange Act of 1934).

YES ☐ NO ☒

As of November 6, 2003, there were 312,176,089 shares of common stock outstanding. All shares of outstanding common stock are indirectly owned by Scottish Power plc, 1 Atlantic Quay, Glasgow, G2 8SP, Scotland.

PACIFICORP

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

PACIFICORP
CONDENSED CONSOLIDATED STATEMENTS OF INCOME AND RETAINED EARNINGS
(Unaudited)

(Millions of dollars)	Three Months Ended September 30, 2003	Three Months Ended September 30, 2002	Six Months Ended September 30, 2003	Six Months Ended September 30, 2002
Revenues	$ 958.0	$ 943.9	$ 1,852.8	$ 1,829.5
Operating expenses				
Purchased electricity	325.6	358.7	591.6	675.2
Fuel	132.2	133.2	248.9	230.5
Other operations and maintenance	155.0	129.8	305.9	280.1
Depreciation and amortization	106.1	108.5	210.2	214.9
Administrative and general	48.1	61.7	114.1	133.1
Taxes, other than income taxes	24.2	25.3	47.9	48.1
Unrealized loss (gain) on derivative contracts	4.7	(5.3)	3.2	(3.1)
Total	795.9	811.9	1,521.8	1,578.8
Other operating expense	12.8	—	12.8	—
Income from operations	149.3	132.0	318.2	250.7
Interest expense and other (income) expense				
Interest expense	62.5	80.6	123.6	144.6
Interest income	(3.6)	(3.1)	(8.0)	(9.4)
Interest capitalized	(6.5)	(4.4)	(12.1)	(9.9)
Minority interest and other	1.4	5.7	7.3	15.1
Total	53.8	78.8	110.8	140.4
Income from operations before income taxes and cumulative effect of accounting change	95.5	53.2	207.4	110.3
Income tax expense	36.4	21.7	84.8	41.3
Income before cumulative effect of accounting change	59.1	31.5	122.6	69.0
Cumulative effect of accounting change (less applicable income tax benefit: $(0.6)/2003 and $(1.1)/2002) (See Notes 3 and 5)	—	—	(0.9)	(1.9)
Net income	59.1	31.5	121.7	67.1
Preferred dividend requirement	(0.5)	(1.8)	(2.3)	(3.7)
Earnings on common stock	$ 58.6	$ 29.7	$ 119.4	$ 63.4
RETAINED EARNINGS BEGINNING OF PERIOD	$ 326.6	$ 206.8	$ 305.9	$ 173.1
Net income	59.1	31.5	121.7	67.1
Cash dividends declared				
Preferred stock	(0.5)	(1.8)	(2.3)	(3.7)
Common stock	(40.2)	—	(80.3)	—

RETAINED EARNINGS END OF PERIOD	$ 345.0	$ 236.5	$ 345.0	$ 236.5

The accompanying notes are an integral part of these Condensed Consolidated Financial Statements

PACIFICORP
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(Millions of dollars)	Six Months Ended September 30, 2003	2002
Cash flows from operating activities		
Net income	$ 121.7	$ 67.1
Adjustments to reconcile net income to net cash provided by operating activities:		
Cumulative effect of accounting change, net of tax	0.9	1.9
Unrealized loss (gain) on derivative contracts	3.2	(3.1)
Depreciation and amortization	210.2	214.9
Deferred income taxes and investment tax credits - net	24.2	(12.8)
Provision for pension and benefits	(2.5)	(14.3)
Deferred net power costs	(7.2)	(23.2)
Changes in other regulatory assets/liabilities	71.0	71.8
Accounts receivable and prepayments	(33.5)	5.9
Inventories	12.8	(2.8)
Accounts payable and accrued liabilities	(76.2)	(113.0)
Other	11.1	7.7
Net cash provided by operating activities	335.7	200.1
Cash flows from investing activities		
Capital expenditures	(309.9)	(253.1)
Proceeds from sales of assets	1.3	9.8
Proceeds from available for sale securities	64.7	74.6
Purchases of available for sale securities	(63.2)	(75.1)
Other	(5.3)	2.7
Net cash used in investing activities	(312.4)	(241.1)
Cash flows from financing activities		
Changes in short-term debt	65.0	76.5
Proceeds from long-term debt, net of issuance costs	397.0	—
Dividends paid	(83.8)	(3.8)
Repayments of long-term debt	(140.0)	(130.4)
Repayments of preferred securities	(352.0)	—
Redemptions of preferred stock	(7.5)	(7.5)
Other	(0.4)	—
Net cash used in financing activities	(121.7)	(65.2)
Decrease in cash and cash equivalents	(98.4)	(106.1)
Cash and cash equivalents at beginning of period	152.5	157.9
Cash and cash equivalents at end of period	$ 54.1	$ 51.7

The accompanying notes are an integral part of these Condensed Consolidated Financial Statements

PACIFICORP
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

ASSETS

(Millions of dollars)	September 30, 2003	March 31, 2003
Current assets		
Cash and cash equivalents	$ 54.1	$ 152.5
Accounts receivable (less allowance for doubtful accounts: $41.1/September and $36.3/March)	251.1	250.7
Unbilled revenue	135.0	109.2
Amounts due from affiliates	2.7	2.5
Inventories at average cost		
Materials and supplies	98.3	99.4
Fuel	60.1	71.8
Current derivative contract asset	88.4	107.2
Other	25.9	18.9
Total current assets	715.6	812.2
Property, plant and equipment	13,464.7	13,184.3
Construction work in progress	366.0	332.5
Accumulated depreciation and amortization	(4,987.5)	(5,483.2)
Total property, plant and equipment - net	8,843.2	8,033.6
Other assets		
Regulatory assets	1,128.7	1,175.9
Derivative contract regulatory asset	601.7	506.9
Noncurrent derivative contract asset	138.6	122.3
Deferred charges and other	354.1	342.1
Total other assets	2,223.1	2,147.2
Total assets	$ 11,781.9	$ 10,993.0

The accompanying notes are an integral part of these Condensed Consolidated Financial Statements

PACIFICORP
CONDENSED CONSOLIDATED BALANCE SHEETS, continued
(Unaudited)

LIABILITIES AND SHAREHOLDERS' EQUITY

(Millions of dollars)	September 30, 2003	March 31, 2003
Current liabilities		
Long-term debt currently maturing	$ 243.5	$ 136.7
Preferred stock subject to mandatory redemption, currently maturing (See Note 7)	3.8	—
Notes payable and commercial paper	90.0	25.0
Accounts payable	207.9	235.8
Amounts due to affiliates	25.5	39.6
Accrued employee expenses	108.0	137.6
Taxes payable	83.8	66.9
Interest payable	66.6	67.9
Current derivative contract liability	105.5	91.7
Other	111.9	127.3
Total current liabilities	1,046.5	928.5
Deferred credits		
Income taxes	1,498.8	1,480.2
Investment tax credits	87.6	91.4
Regulatory liabilities	815.1	137.0
Noncurrent derivative contract liability	725.2	643.5
Other	703.4	650.1
Total deferred credits	3,830.1	3,002.2
Long-term debt, net of current maturities	3,570.5	3,417.6
Preferred stock subject to mandatory redemption (See Note 7)	56.2	—
Total liabilities	8,503.3	7,348.3
Commitments and contingencies (See Note 8)		
Guaranteed preferred beneficial interests in Company's junior subordinated debentures (See Note 7)	—	341.8
Preferred stock subject to mandatory redemption (See Note 7)	—	66.7
Shareholders' equity		
Preferred stock	41.3	41.3
Common shareholder's capital	2,892.1	2,892.1
Retained earnings	345.0	305.9
Accumulated other comprehensive income (loss):		
Unrealized gain (loss) on available for sale securities, net of tax of $0.9/September and $(1.1)/March	1.6	(1.7)
Minimum pension liability, net of tax of $(0.8)	(1.4)	(1.4)
Total shareholders' equity	3,278.6	3,236.2
Total liabilities and shareholders' equity	$ 11,781.9	$ 10,993.0

The accompanying notes are an integral part of these Condensed Consolidated Financial Statements

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

NOTE 1 - Basis of Presentation and Certain Significant Accounting Policies

The condensed consolidated financial statements of PacifiCorp include its integrated electric utility operations and its wholly owned and majority-owned subsidiaries (together, the "Company"). The subsidiaries of PacifiCorp support its electric utility operations by providing coal mining facilities and services, environmental remediation and, until their securities were redeemed in August 2003, financing. Intercompany transactions and balances have been eliminated upon consolidation.

The accompanying unaudited condensed consolidated financial statements as of September 30, 2003 and for the periods ended September 30, 2003 and 2002, in the opinion of management, include all adjustments, constituting only normal recurring adjustments, necessary for a fair presentation of the financial position, results of operations and cash flows for such periods. The March 31, 2003 condensed consolidated balance sheet data was derived from audited financial statements. Such statements are presented in accordance with the Securities and Exchange Commission's ("SEC") interim reporting requirements, which do not include all the disclosures required by accounting principles generally accepted in the United States of America. Certain information and footnote disclosures made in the Company's last Annual Report on Form 10-K have been condensed in or omitted from the interim statements. A portion of the business of the Company is of a seasonal nature and, therefore, results of operations for the periods ended September 30, 2003 and 2002 are not necessarily indicative of the results for a full year. These condensed consolidated financial statements should be read in conjunction with the financial statements and related notes in the Company's 2003 Annual Report on Form 10-K.

These interim statements have been prepared using accounting policies consistent with those applied at March 31, 2003, except in relation to new accounting standards. Certain amounts have been reclassified to conform to the current method of presentation. These reclassifications had no effect on previously reported consolidated net income.

Stock-based compensation - As permitted by Statement of Financial Accounting Standards ("SFAS") No. 123, *Accounting for Stock-Based Compensation* ("SFAS No. 123"), the Company has elected to account for its stock-based compensation arrangements under the intrinsic value recognition and measurement principles of Accounting Principles Board ("APB") Opinion No. 25, *Accounting for Stock Issued to Employees* ("APB No. 25"), and related interpretations in accounting for employee stock options issued to Company employees. Under APB No. 25, because the exercise price of employee stock options equals the market price of the underlying stock on the date of grant, no compensation expense is recorded. All options are for Scottish Power plc ("ScottishPower") American Depository Shares. Had the Company determined compensation cost based on the fair value at the grant date for all stock options vesting in each period under SFAS No. 123, the Company's net income would have been changed to the pro forma amounts below:

	Three Months Ended September 30,		Six Months Ended September 30,	
(Millions of dollars)	2003	2002	2003	2002
Net income as reported	$ 59.1	$ 31.5	$ 121.7	$ 67.1
Stock-based employee compensation expense	0.2	0.4	0.4	1.0
Pro forma net income	$ 58.9	$ 31.1	$ 121.3	$ 66.1

Unbilled revenues - The Company changed its calculation of unbilled revenues during the three months ended June 30, 2003, which had the effect of increasing revenues by approximately $10.0 million and after-tax net income by approximately $5.7 million for the six months ended September 30, 2003.

NOTE 2 - Accounting for the Effects of Regulation

Regulated utilities have historically applied the provisions of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71"), which is based on the premise that regulators will set rates that allow for the recovery of a utility's costs, including cost of capital. SFAS No. 71 provides that regulatory assets may be capitalized if it is probable that future revenue in an amount at least equal to the capitalized costs will result from the inclusion of that cost in allowable costs for ratemaking purposes. The Company records regulatory assets and liabilities based on management's assessment that it is probable that a cost will be recovered (asset) or that an obligation has been incurred (liability). The final outcome, or additional regulatory actions, could change management's assessment in future periods.

Regulatory assets include the following:

(Millions of dollars)	September 30, 2003	March 31, 2003
Deferred taxes (a)	$ 543.3	$ 550.3
Minimum pension liability offset (b)	234.5	234.5
Deferred net power costs (c)	95.7	137.8
Transition Plan - retirement and severance (d)	49.4	55.1
Demand-side resource	44.0	45.7
Unamortized issuance expense on retired debt (e)	44.2	34.3
Various other	117.6	118.2
Subtotal	1,128.7	1,175.9
Derivative contracts (f)	601.7	506.9
Total	$ 1,730.4	$ 1,682.8

(a) Excludes $87.6 million and $91.4 million as of September 30, 2003 and March 31, 2003, respectively, of investment tax credits.

(b) At the date of the last actuarial evaluations, the Company's retirement plans had assets with a fair value that was less than the accumulated benefit obligation under the plans, primarily due to declines in the equity markets. As a result, the Company recognized a minimum pension liability in the fourth quarter of the year ended March 31, 2003. The liability adjustment was recorded as a noncash increase of $234.5 million to Regulatory assets.

(c) Represents the deferred net power costs that vary from costs included in determining retail rates in Utah, Oregon and Idaho.

(d) Represents the unamortized amount of retirement and severance costs relating to a transition plan that the state commissions allowed to be deferred and amortized.

(e) Represents the unamortized debt expense and redemption premiums on securities retired prior to maturity. During the three months ended September 30, 2003, the Company transferred $11.9 million to regulatory assets in relation to the redemption of First Mortgage Bonds and Preferred Securities. See Note 7.

(f) Represents the current and noncurrent mark-to-market of derivative contracts.

Regulatory liabilities include the following:

(Millions of dollars)	September 30, 2003	March 31, 2003
Asset retirement removal costs - non SFAS No. 143 (a)	$ 665.5	$ —
Centralia gain	57.7	66.5
Deferred taxes	36.9	39.3
Various other	55.0	31.2
Total	$ 815.1	$ 137.0

(a) Represents removal costs recovered in rates that do not qualify as asset retirement obligations under SFAS No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143"). See NOTE 5- Asset Retirement Obligations.

The Company evaluates the recovery of all regulatory assets periodically and as events occur. The evaluation includes the probability of recovery, as well as changes in the regulatory environment. Regulatory and/or legislative actions in Utah, Oregon, Wyoming, Washington, Idaho and California may require the Company to record regulatory asset write-offs and charges for impairment of long-lived assets in future periods.

DEPRECIATION RATE CHANGES

The Company received orders from all state commissions, except California, approving changes in the Company's rates of depreciation. Effective April 1, 2003, the resulting depreciation rate changes reduced total Company annual depreciation expense by approximately $26.0 million, which includes removal costs, and may ultimately result in lower future revenues or offset anticipated price increases.

REGULATORY ACTIONS

Oregon

On August 26, 2003, the Oregon Public Utility Commission (the "OPUC") approved a settlement of the Company's general rate case filed on March 18, 2003. Under the settlement, base rates increased by $8.5 million annually on September 1, 2003 and a $12.0 million offsettable merger credit for the period from January 2004 to December 2004 was eliminated. A nonoffsettable merger credit will be reduced from $6.0 million to $4.0 million, and will be amortized to return the full amount to customers by December 31, 2004.

NOTE 3 - Derivative Instruments

The Company's primary business is to serve its retail customers. The Company's business is exposed to risks relating to, but not limited to, changes in certain commodity prices and counterparty performance. The Company enters into derivative instruments, including electricity, natural gas, oil and coal forward, option and swap contracts, and weather contracts to manage its exposure to commodity price and volume risk and to ensure supply, thereby attempting to minimize variability in net power costs for customers. The Company has policies and procedures to manage the risks inherent in these activities and a risk management committee to monitor compliance with the Company's risk management policies and procedures.

The risk management process established by the Company is designed to identify, assess, monitor and manage each of the various types of risk involved in the Company's business and activities; measure quantitative market risk exposure; and identify qualitative market risk exposure in its businesses. To assist in managing the volatility relating to these exposures, the Company enters into various transactions, including derivative transactions, consistent with the Company's risk management policy. The risk management policy governs energy purchase and sales activities and is designed for hedging the Company's existing energy and asset exposures. The policy also governs the Company's use of derivative instruments, as well as its energy purchase and sales practices, and describes the Company's credit policy and management information systems required to effectively monitor the use of derivatives. The Company's risk management policy provides for the use of only those instruments that have a close volume or price correlation with its portfolio of assets, liabilities or anticipated transactions. The risk management policy includes, as its objective, that such instruments will be primarily used for hedging and not for speculation.

On April 1, 2001, the Company adopted SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS No. 133"), as amended by numerous interpretations of the Derivatives Implementation Group (the "DIG") that are approved by the Financial Accounting Standards Board (the "FASB"). Subsequent revisions were made in SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities*, and SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* ("SFAS No. 149"), both of which have been adopted by the Company. Collectively, these statements are referred to as "SFAS No. 133." Under SFAS No. 133, derivative instruments are recorded on the Condensed Consolidated Balance Sheet as an asset or liability measured at estimated fair value, with changes in fair value recognized currently in earnings unless specific hedge accounting criteria are met. As contracts settle, their impact is recorded in the Condensed Statements of Consolidated Income.

The most recent update, SFAS No. 149, was issued in April 2003. This statement amends and clarifies financial reporting for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. This statement was effective for contracts entered into or modified after June 30, 2003. In applying this statement, the Company began marking to market certain transactions that were entered into after June 30, 2003 that, prior to the implementation of SFAS No. 149, would have been exempted as being normal. The implementation of SFAS No. 149 resulted in a pretax loss of $2.9 million for the three months ended September 30, 2003.

In June 2002, the Company's SFAS No. 133 contract assessments were updated to reflect the revised Issue C15, *Normal Purchase and Normal Sales Exception for Certain Option-Type Contracts and Forward Contracts in Electricity* ("Issue C15"), guidance from the DIG, effective April 1, 2002. The effects of adoption of the revised Issue C15 at April 1, 2002 resulted in a cumulative effect of accounting change adjustment of $2.1 million unfavorable (net of a tax benefit of $1.3 million) on the Company's Condensed Consolidated Statements of Income (Loss) and Retained Earnings.

In October 2001, the DIG issued guidance under Issue C16, *Applying the Normal Purchases and Normal Sales Exception to Contracts that Combine a Forward Contract and a Purchased Option Contract* ("Issue C16"). The effects of adoption of Issue C16 at April 1, 2002 resulted in a cumulative effect of accounting change adjustment of $0.2 million favorable (net of tax of $0.2 million) on the Company's Condensed Consolidated Statements of Income (Loss) and Retained Earnings.

Weather derivatives - To a limited degree, the Company has executed contracts to hedge changes in hydroelectric generation due to variation in streamflows. The Company has also executed contracts to hedge changes in retail electricity demand due to abnormal ambient temperatures. These contracts are not exchange or traded and settlement is based on climatic or other physical variables. Therefore, on a periodic basis, the Company estimates and records a gain or loss in earnings corresponding to the total expected future cash flow from these contracts in accordance with the Emerging Issues Task Force (the "EITF") No. 99-2, *Accounting for Weather Derivatives*. The unrealized loss recorded for these contracts was $1.7 million and $7.4 million for the six months ended September 30, 2003 and 2002, respectively.

The following table summarizes the SFAS No. 133 movements for the six months ended September 30, 2003:

(Millions of dollars)	**Net Asset (Liability)**	**Regulatory Net Asset (Liability)**	**Deferred Tax Asset (Liability)**	**Accumulated Income (Loss)**
Balance at March 31, 2003	$ (505.7)	$ 506.9	$ (0.5)	$ 0.7
Settlements	34.4	(34.3)	—	0.1
Changes in valuation assumptions	(59.6)	59.7	—	0.1
Changes in fair value	(72.8)	69.4	1.3	(2.1)
Balance at September 30, 2003	$ (603.7)	$ 601.7	$ 0.8	$ (1.2)

NOTE 4 – Related-Party Transactions

There are no loans or advances between PacifiCorp and ScottishPower or between PacifiCorp and its immediate corporate parent PacifiCorp Holdings, Inc. ("PHI"). Loans from the Company to ScottishPower or PHI are prohibited under the Public Utility Holding Company Act of 1935. Loans from ScottishPower or PHI to PacifiCorp generally require state regulatory and SEC approval. Affiliate transactions with the Company are subject to certain approval and reporting requirements of the regulatory authorities.

The tables below detail the Company's transactions and balances with unconsolidated related parties.

(Millions of dollars)	September 30, 2003	March 31, 2003
Amounts due from affiliated entities:		
ScottishPower (a)	$ 0.1	$ 0.1
PHI subsidiaries (b)	2.6	2.4
	$ 2.7	$ 2.5
Amounts due to affiliated entities:		
ScottishPower (c)	$ 2.2	$ 2.6
PHI subsidiaries (d)	23.3	37.0
	$ 25.5	$ 39.6

	Three Months Ended September 30,		Six Months Ended September 30,	
(Millions of dollars)	2003	2002	2003	2002
Revenues from affiliated entities:				
PHI subsidiaries (f)	$ 0.8	$ 1.4	$ 1.8	$ 2.5
Expenses incurred from affiliated entities:				
ScottishPower (c)	$ 1.8	$ 2.6	$ 3.7	$ 4.9
PHI subsidiaries (g)	4.3	3.5	8.5	4.1
	$ 6.1	$ 6.1	$ 12.2	$ 9.0
Expenses recharged to affiliated entities:				
ScottishPower (a)	$ 0.1	$ 0.2	$ 0.4	$ 0.3
PHI subsidiaries (b)	1.8	1.9	3.8	3.5
	$ 1.9	$ 2.1	$ 4.2	$ 3.8
Interest expense to affiliated entities:				
PHI subsidiaries (e)	$ —	$ —	$ 0.1	$ —

(a) The Company recharges to ScottishPower payroll costs and related benefits of employees working on international assignment.

(b) Amounts shown pertain to activities of the Company and its subsidiaries with PHI and its subsidiaries. Expenses recharged reflect costs for support services to PHI and its subsidiaries.

(c) These expenses and liabilities primarily represent payroll costs and related benefits of ScottishPower employees working for the Company.

(d) Includes current portion of net income taxes payable to PHI of $23.3 million and $37.0 million at September 30, 2003 and March 31, 2003, respectively. PHI is the tax-paying entity for the Company.

(e) Includes interest on short-term demand loans made to the Company by PacifiCorp Group Holdings Company, in accordance with regulatory authorizations.

(f) These revenues represent wheeling revenues billed to PPM Energy, Inc. ("PPM"), a subsidiary of PHI.

(g) These expenses primarily represent operating lease payments for the West Valley facility, located in Utah and owned by a subsidiary of

PPM, which was only partially operational during the six months ended September 30, 2002.

Interest rates on related-party transactions approximate the lender's short-term borrowing cost or cost of capital as required by the relevant regulatory approval or exemption. The average applicable rates were 1.2% and 1.9% for the six months ended September 30, 2003 and 2002, respectively.

NOTE 5 - Asset Retirement Obligations

In June 2001, the FASB issued SFAS No. 143. The statement requires the fair value of an asset retirement obligation to be recorded as a liability in the period in which the obligation was incurred. At the same time the liability is recorded, the costs of the asset retirement obligation must be recorded as an addition to the carrying amount of the related asset. Over time, the liability is accreted to its present value and the addition to the carrying amount of the asset is depreciated over the asset's useful life. Upon retirement of the asset, the Company will settle the retirement obligation against the recorded balance of the liability. Any difference in the final retirement obligation cost and the liability will result in either a gain or loss. The Company adopted this statement as of April 1, 2003.

The Company had been recording retirement obligations relating to reclamation, closure and removal costs before adoption of the standard. In addition, the Company records removal costs as a part of depreciation expense and accumulated depreciation in accordance with regulatory accounting requirements. As a result of adoption of the standard, the net difference between these previously recorded amounts that qualify as asset retirement obligations and the fair value amounts determined under SFAS No. 143 has been recognized as a noncash cumulative effect of a change in accounting principle, net of related income taxes. The Company recovers asset retirement costs through the ratemaking process and records a Regulatory asset or Regulatory liability on the Consolidated Balance Sheet to account for the difference between asset retirement costs as currently approved in rates and costs under SFAS No. 143.

Upon adoption of SFAS No. 143 on April 1, 2003, the Company recorded an asset retirement obligation liability at its net present value of $196.4 million. The Company also increased net depreciable assets by $37.6 million, removed $163.1 million of costs accrued for final removal from accumulated depreciation and reclamation liabilities, increased regulatory liabilities by $5.8 million for the difference between retirement costs approved by regulators and obligations under SFAS No. 143 and recorded a cumulative pretax effect of a change in accounting principle of $1.5 million. As a result of the regulated environment in which the Company operates, it reclassified to Regulatory liabilities $653.3 million of removal costs recorded in accumulated depreciation that do not qualify as retirement obligations under SFAS No. 143. Accretion and depreciation expense in the first year of adoption are expected to be $8.1 million and $3.3 million, respectively.

The following table describes the changes to the Company's asset retirement obligation liability for the six months ended September 30, 2003:

(Millions of dollars)	
Liability recognized at adoption on April 1, 2003	$ 196.4
Liabilities incurred (a)	4.9
Liabilities settled (b)	(6.7)
Revisions in cash flow (c)	(0.2)
Accretion expense	4.0
Asset retirement obligation at September 30, 2003	$ 198.4

(a) Represents the retirement obligation created in June 2003 when a settlement agreement to decommission the Powerdale hydroelectric plant was signed.

(b) Relates primarily to ongoing reclamation work at the Glenrock coal mine.

(c) Results from changes in the mining plan for the Deer Creek coal mine.

The pro forma asset retirement obligation liability balances that would have been reported assuming SFAS No. 143 had been adopted on April 1, 2001, rather than April 1, 2003, are as follows:

(Millions of dollars)	
Pro forma asset retirement obligation liability at April 1, 2001	$ 207.0
Pro forma asset retirement obligation liability at March 31, 2002	200.8

Due to regulatory accounting treatment, the adoption of SFAS No. 143 would have had no impact on Income before cumulative effect of accounting change for the pro forma periods listed above.

NOTE 6 - Financing Arrangements

At September 30, 2003, the Company had $800.0 million of committed bank revolving credit agreements, including a $300.0 million facility having a three-year term that became effective June 4, 2002 and a $500.0 million facility that became effective June 3, 2003 having a 364-day term plus a one-year term loan option. The interest on advances under these facilities is based on the London Interbank Offered Rate (LIBOR) plus a margin that varies based on the Company's credit ratings. As of September 30, 2003, these facilities were fully available, and there were no borrowings outstanding.

NOTE 7 - Preferred Securities and Long-Term Debt

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity* ("SFAS No. 150"). This statement affects the accounting for certain financial instruments that, under previous guidance, issuers could account for as equity. The new statement requires that those instruments be classified as liabilities. Most of this statement was effective for financial instruments entered into or modified after May 31, 2003, and otherwise was effective at the beginning of the first interim period beginning after June 30, 2003. The Company reclassified 600,000 shares, $100 stated value, of its $7.48 series Preferred stock subject to mandatory redemption to short-term and long-term liabilities on the Company's Condensed Consolidated Balance Sheet, which were $3.8 million and $56.2 million, respectively, at September 30, 2003. Associated dividends declared for the three months ended September 30, 2003 of $1.1 million have been treated as interest expense.

The Company has mandatory redemption requirements on 37,500 shares of its $7.48 series Preferred stock on each June 15 from 2002 through 2006, with a non-cumulative option to redeem 37,500 shares on each June 15 from 2002 through 2006, in each case at $100 per share, plus accrued and unpaid dividends to the date of such redemption. All outstanding shares on June 15, 2007, are subject to mandatory redemption. Holders of Preferred stock subject to mandatory redemption are entitled to certain voting rights.

During July and August 2003, the Company redeemed, prior to maturity, $40.0 million representing all of its 7.25% First Mortgage Bonds due August 1, 2013; $15.5 million representing all of its 7.37% First Mortgage Bonds due August 11, 2023; and $2.0 million representing all of its 7.4% First Mortgage Bonds due July 28, 2023. These retirements were funded initially through short-term debt and subsequently by the long-term financing discussed below.

During August 2003, the Company redeemed, prior to maturity, all of its Series C and D junior subordinated debentures held by the wholly owned subsidiary trusts of the Company (the "Trusts"), resulting in the redemption by the Trusts of the 8,680,000 8.25% Series A Cumulative Quarterly Income Preferred Securities totaling $217.0 million and the 5,400,000 7.70% Series B Preferred Securities totaling $135.0 million. Subsequent to these redemptions, the Trusts were cancelled. Upon redemption, $10.0 million of deferred charges was reclassified to a regulatory asset.

On September 8, 2003, the Company issued $200.0 million of its 4.30% First Mortgage Bonds due September 15, 2008 and $200.0 million of its 5.45% First Mortgage Bonds due September 15, 2013. These bonds contain covenants consistent with the Company's other series of First Mortgage Bonds. The Company used the proceeds for the refinancing of short-term debt incurred to fund the redemptions discussed above.

NOTE 8 - Commitments and Contingencies

The Company follows SFAS No. 5, *Accounting for Contingencies*, to determine accounting and disclosure requirements for contingencies. The Company operates in a highly regulated environment. Governmental bodies such as the Federal Energy Regulatory Commission (the "FERC"), the SEC, the Internal Revenue Service (the "IRS"), the Department of Labor, the United States Environmental Protection Agency (the "EPA") and others have authority over various aspects of the Company's business operations and public reporting. Reserves are established when required in management's judgment, and disclosures regarding litigation, assessments and creditworthiness of customers or counterparties, among others, are made when appropriate. Various specialists inside and outside of the Company perform evaluations of these contingencies.

Litigation

From time to time, the Company and its subsidiaries are parties to various legal claims, actions and complaints, certain of which involve material amounts. Although the Company is unable to predict with certainty whether it will ultimately be successful in these legal proceedings or, if not, what the impact might be, management currently believes that disposition of these matters will not have a material adverse effect on the Company's consolidated financial position or results of operations.

California and Enron reserves

Beginning in summer 2000, market conditions in California resulted in defaults of amounts due to the Company from certain counterparties in California. In addition, in December 2001, Enron Corp. ("Enron") declared bankruptcy and defaulted on certain wholesale contracts. The Company previously provided reserves for its California exposures and its Enron receivable, net of the effect of applying the master netting agreement with Enron, in the aggregate amount of $14.3 million.

FERC issues

California Refund Case - The Company is a party to a FERC proceeding that is investigating potential refunds for energy transactions in the California Independent System Operator and the California Power Exchange markets during past periods of high energy prices. The Company previously established a reserve of $17.7 million for these refunds. The Company's ultimate exposure to refunds is dependent upon any final order issued by the FERC in this proceeding.

Northwest Refund Case - On June 25, 2003, the FERC terminated its proceeding relating to the possibility of requiring refunds for wholesale spot-market bilateral sales in the Pacific Northwest between December 25, 2000 and June 20, 2001. The FERC concluded that ordering refunds would not be an appropriate resolution of the matter. On August 25, 2003, the FERC granted rehearing of its June 25, 2003 order.

Federal Power Act Section 206 Case - On June 26, 2003, the FERC issued a final order denying the Company's request for recovery of excessive prices charged under certain wholesale electricity purchases scheduled for delivery during summer 2002 and dismissing the Company's complaints, under section 206 of the Federal Power Act, against five wholesale power suppliers. On July 3, 2003, the Company filed a petition for review of certain aspects of this order in the Ninth Circuit Court of Appeals. On July 28, 2003, the Company filed its request for rehearing of the FERC's order, which was granted on August 27, 2003.

FERC Show-Cause Orders - In May 2002, the Company, together with other California power market participants, responded to data requests from the FERC regarding trading practices connected with the power crisis during 2000 and 2001. The Company confirmed that it did not engage in any trading practices intended to manipulate the market as described in the FERC's data requests issued in May 2002. On June 25, 2003, the FERC ordered 60 companies (including the Company) to show cause why their behavior during the California energy crisis did not constitute manipulation of the wholesale power market, as defined in the California Independent System Operator and the California Power Exchange tariffs. In setting the cases for hearing, the Commission directed the administrative law judge to hear evidence and render findings and conclusions quantifying the extent of any unjust enrichment that resulted and to recommend monetary or other appropriate remedies. On August 29, 2003, the Company and the FERC staff reached a resolution on the show-cause order. Under the terms of the settlement agreement, the Company denied liability and agreed to pay a nominal amount of $67,745, in exchange for complete and total resolution of the issues raised in the FERC's show-cause order relating to the Company. The FERC must approve the settlement before it becomes binding on the parties.

The BPA Settlement

The Company is a party to lawsuits before the U.S. Court of Appeals for the Ninth Circuit Court challenging the level of the Bonneville Power Administration (the "BPA") exchange benefits payable to residential and small farm customers of investor-owned utilities in the region. These exchange benefits are passed through directly to the Company's residential and small-farm customers in Oregon, Washington and Idaho and do not impact the Company's earnings. Parties to these lawsuits have reached a proposed settlement under which the Company and the other investor-owned utilities will defer, with interest, exchange benefits currently payable during the BPA's fiscal years (October 1 to September 30) 2004-2006 to the BPA's fiscal years 2007-2011. The Company's share of the total benefits to be deferred is between $68.0 million and $94.0 million, of which $11.6 million has already been deferred in the BPA's fiscal year 2003. The Company will also permanently waive its right to $80.0 million in litigation contingency payments if the settlement becomes effective. In exchange for these deferrals and waiver, all lawsuits by the settling parties challenging the investor-owned utilities' exchange benefits will be dismissed. In addition, the settlement modifies the formula for calculating exchange benefits in fiscal years 2007-2011 by substituting an independent forecast of market power prices in place of the BPA's own forecast. A number of parties signed the settlement on October 23, 2003; however, the settlement remains subject to execution by the Company and the other parties to the lawsuits, as well as the approval of the OPUC. The settlement is also subject to conditions that could invalidate the settlement during the 120-day period after the date of its execution on October 23, 2003.

Hydroelectric relicensing

The Company operates the majority of its hydroelectric generating portfolio under long-term licenses from the FERC. These licenses are granted by the FERC for periods of 30 to 50 years. Many of the Company's long-term operating licenses have expired or are expiring in the next few years. Hydroelectric facilities operating under expired licenses may operate under annual licenses granted by the FERC until new operating licenses are issued. Hydroelectric relicensing and the related environmental compliance requirements are subject to a degree of uncertainty. The Company expects that future costs relating to these matters may be significant and consist primarily of additional relicensing costs and capital expenditures. Power generation reductions may also result from additional environmental requirements. As of September 30, 2003, the Company had incurred approximately $100.4 million in costs for ongoing hydroelectric relicensing, which are included in assets on the Company's Condensed Consolidated Balance Sheet. The Company expects that these and future costs will be found to be prudent and recoverable in rates and, as such, will not have a material adverse impact on the Company's consolidated results of operations.

During the six months ended September 30, 2003, the Company entered into a settlement agreement to remove the Powerdale project rather than pursue a new license, based on an analysis of the costs and benefits of relicensing versus decommissioning. Removal of the Powerdale dam and associated project features is projected to cost $4.9 million, with removal to commence in 2010.

The FERC issued final Environmental Impact Statements for both the North Umpqua and Bear River hydroelectric projects in April 2003, which is the final step before receiving new operating licenses. The Environmental Impact Statements are materially consistent with the negotiated settlement agreements for both projects. Settlement agreements are contingent on acceptable orders being issued by the FERC and on obtaining all necessary permits. New licenses are expected to be issued by the FERC by December 2003 for the North Umpqua and Bear River hydroelectric projects. Additionally, in June 2003, the Company submitted a draft license application to interested parties for a 90-day review for the Klamath hydroelectric project and a final license application to the FERC for the Prospect Nos. 1, 2 and 4 hydroelectric projects. The FERC is expected to complete its required analysis over the next two years.

On July 25, 2003, the Company received a new 50-year operating license for its 4.1 megawatt ("MW") Big Fork hydroelectric project located on the Swan River in northwestern Montana.

As part of the general rate case settlement approved by the OPUC on August 26, 2003, the Company was allowed to begin recovery of the relicensing costs associated with the North Umpqua, Bear River and Big Fork hydroelectric projects. Oregon's allocated share of these costs is $15.8 million of the total $56.3 million of costs on a system basis. In July 2003, the Company filed a rate case in Utah, which includes relicensing costs totaling $62.3 million for the costs associated with the North Umpqua, Bear River, Big Fork, American Fork and Powerdale hydroelectric projects. Utah's allocated portion of these costs is $24.4 million. Recovery of these costs in Utah is contingent upon the outcome of the general rate case currently before the Utah Public Service Commission. In May 2003, the Company filed a rate case in Wyoming, which includes relicensing costs totaling $10.3 million for the costs associated with the Bear River hydroelectric project. Wyoming's allocated share of these costs is $1.5 million. Recovery of these costs in Wyoming is contingent upon the outcome of the general rate case currently before the Wyoming Public Service Commission.

Environmental issues

The Company is subject to numerous environmental laws, including the federal Clean Air Act, as enforced by the EPA and various state agencies; the 1990 Clean Air Act Amendments; the Endangered Species Act of 1973, particularly as it relates to certain endangered species of fish; the Comprehensive Environmental Response, Compensation and Liability Act of 1980, relating to environmental cleanups; the Resource Conservation and Recovery Act of 1976; and the Clean Water Act, relating to water quality. These laws could potentially impact future operations. Contingencies identified at September 30, 2003 principally consist of Clean Air Act matters, which are the subject of discussions with the EPA and state regulatory authorities. In addition to these environmental laws, implementation of new mercury maximum control technology requirements, promulgated under the Clean Air Act, is scheduled during the next five years. These requirements may require additional control equipment to be installed by 2008. The Company expects that future costs relating to these matters may be significant and consist primarily of capital expenditures. The Company expects these and future costs will be found to be prudent and recoverable in rates and, as such, will not have a material adverse impact on the Company's consolidated results of operations. The Company is providing information about certain of its generating plants to the EPA in a cooperative effort to seek a mutual, comprehensive solution to air quality issues as they relate to such plants generally. The Company is also discussing air quality issues with state air quality regulators.

Swift power canal

On April 21, 2002, a failure occurred in the Swift power canal on the Lewis River in the state of Washington. The Cowlitz County Public Utility District owns the power canal and associated 70 megawatt ("MW") hydroelectric facility ("Swift No. 2"). The current start-up date estimate for Swift No. 2 is March 1, 2005. The failure impacted, but did not damage, the Company-owned and -operated 240 MW Swift No. 1 hydroelectric facility ("Swift No. 1"), which is upstream of the Swift power canal. The overflow spillway was modified upstream of the Swift No. 2 failure to allow restricted operations of Swift No. 1. Environmental, operations safety and fish mitigation issues remain to be resolved before full use of Swift No. 1 can resume. The current estimate for recommencing full operations at Swift No. 1 is August 1, 2005. The Company continues to seek ways to mitigate any shaping limitations and to recover any business losses. The full impact of the Swift power canal outage and plans for repair of the Swift No. 2 facility are still being determined. The Company is seeking reimbursement from Cowlitz County Public Utility District of the Company's expenditures associated with the Swift No. 2 failure, including canal modifications and energy replacement costs. This event is not expected to have a significant impact on the Company's consolidated financial position or results of operations.

NOTE 9 - Income Taxes

The Company uses an estimated annual effective tax rate for computing the provision for income taxes on an interim basis.

The Company accrued federal and state income tax expense of $84.8 million and $41.3 million, representing effective tax rates of 40.9% and 37.4%, for the six months ended September 30, 2003 and 2002, respectively. The increase in the estimated effective tax rate for the six months ended September 30, 2003 as compared to the six months ended September 30, 2002 is primarily due to the accrual of additional tax contingency reserves and higher levels of pretax income in the current period, which diluted the benefit of certain tax credits.

The Company has established, and periodically reviews, an estimated contingent tax reserve on its consolidated balance sheet to provide for the possibility of adverse outcomes in tax proceedings. During the six months ended September 30, 2003, the Company provided an additional $3.4 million of tax contingency reserve primarily to accrue interest on tax contingencies provided for in prior periods.

During the three months ended September 30, 2003, the Company reached an agreement in principle with the IRS Appeals Division on certain tax issues related to the Company's 1994 through 1998 federal income tax returns. The agreement in principle results in a tax and interest liability of $13.1 million, for which a contingency tax reserve was previously provided. The Company believes that final settlement and payment on agreed issues and other unresolved issues related to the Company's 1994 through 1998 federal income tax returns will not have a material adverse impact on its consolidated financial position or results of operations.

NOTE 10 - Comprehensive Income

The components of comprehensive income are as follows:

(Millions of dollars)	Three Months Ended September 30, 2003	Three Months Ended September 30, 2002	Six Months Ended September 30, 2003	Six Months Ended September 30, 2002
Net income	$ 59.1	$ 31.5	$ 121.7	$ 67.1
Other comprehensive income:				
Unrealized gain (loss) on available-for-sale, securities, net of taxes: $0.4 and $1.9/2003 and $(1.9) and $(1.7)/2002	0.6	(2.4)	3.3	(2.0)
Reclassification of SFAS No. 133 gain in earnings: net of taxes of $14.7/2002	—	24.0	—	24.0
Total comprehensive income	$ 59.7	$ 53.1	$ 125.0	$ 89.1

NOTE 11 - New Accounting Standards

In January 2003, the FASB issued FASB Interpretation No. 46, *Consolidation of Variable-Interest Entities* ("FIN No. 46"), which requires existing unconsolidated variable-interest entities to be consolidated by their primary beneficiaries if the entities do not effectively disperse risks among parties involved. FIN No. 46 applied immediately to variable-interest entities created after January 31, 2003, and applied for periods beginning after June 15, 2003 to variable-interest entities acquired before February 1, 2003. In October 2003, the FASB deferred the effective date of FIN No. 46 until the end of the first interim or annual period beginning after December 15, 2003. The Company is currently evaluating the impact of adopting FIN No. 46 on its consolidated financial position and results of operations.

In May 2003, the EITF issued EITF No. 00-21, *Revenue Arrangements with Multiple Deliverables*. This issue addresses certain aspects of the accounting by a vendor for arrangements under which it will perform multiple revenue-generating activities in different accounting periods. This issue is effective for revenue arrangements entered into in fiscal periods beginning after June 15, 2003. The adoption of this issue had no impact on the Company's consolidated financial position and results of operations.

In May 2003, the EITF issued EITF No. 01-8, *Determining Whether an Arrangement Contains a Lease* ("EITF No. 01-8"). EITF No. 01-8 provides guidance for determining whether an arrangement contains a lease that is within the scope of SFAS No. 13, *Accounting for Leases* ("SFAS No. 13"). The evaluation of whether an arrangement contains a lease within the scope of SFAS No. 13 should be based on the substance of the arrangement. EITF No. 01-8 was effective for the Company on July 1, 2003. The adoption of this issue had no impact on the Company's consolidated financial position and results of operations.

In June 2003, the FASB issued guidance under Issue C20 that amended SFAS No.133, *Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) Regarding Contracts with a Price Adjustment Feature*. This statement amends and clarifies the normal purchases and normal sales exemption for financial reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities. This statement is effective for the Company on October 1, 2003. The Company is currently evaluating the impact of applying this guidance on its consolidated financial position and results of operations.

In July 2003, the EITF issued EITF No. 03-11, *Reporting Gains and Losses on Derivative Instruments that Are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes* ("EITF No. 03-11"). This issue addresses whether realized gains and losses should be shown gross or net in the income statement for contracts that are not held for trading purposes but are derivatives subject to SFAS No. 133. EITF No. 03-11 is effective for all derivative instruments entered into beginning October 1, 2003. The Company currently reports such transactions on a gross basis, which is the basis supported under EITF No. 03-11; therefore, the adoption of EITF No. 03-11 will have no impact on the Company's consolidated financial position and results of operations.

NOTE 12 - Independent Accountants' Review Report

The Company's Quarterly Reports on Form 10-Q are incorporated by reference into various filings under the Securities Act of 1933 (the "Act"). The Company's independent accountants are not subject to the liability provisions of section 11 of the Act for their report on the unaudited condensed consolidated financial information, because such report is not a "report" or a "part" of a registration statement prepared or certified by independent accountants within the meaning of sections 7 and 11 of the Act.

NOTE 13 - Subsequent Events

On October 14, 2003, the Company's Board of Directors declared a dividend on common stock of approximately $0.13 per share totaling $40.1 million, payable on November 25, 2003.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Shareholders of PacifiCorp:

We have reviewed the accompanying Condensed Consolidated Balance Sheet of PacifiCorp and its subsidiaries as of September 30, 2003, and the related Condensed Consolidated Statements of Income and Retained Earnings for each of the three month and six month periods ended September 30, 2003 and 2002 and the Condensed Consolidated Statements of Cash Flows for the six month periods ended September 30, 2003 and 2002. These interim Condensed Consolidated Financial Statements are the responsibility of the Company's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with generally accepted auditing standards, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying interim condensed consolidated financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited, in accordance with auditing standards generally accepted in the United States of America, the Consolidated Balance Sheet as of March 31, 2003, and the related Statements of Consolidated Income, Common Shareholder's Equity and Cash Flows for the year then ended (not presented herein), and in our report dated May 7, 2003, we expressed an unqualified opinion on those Consolidated Financial Statements. In our opinion, the information set forth in the accompanying Condensed Consolidated Balance Sheet as of March 31, 2003, is fairly stated in all material respects in relation to the Consolidated Balance Sheet from which it has been derived.

As discussed in Note 3 to the Condensed Consolidated Financial Statements, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities,* as of July 1, 2003.

As discussed in Note 5 to the Condensed Consolidated Financial Statements, the Company adopted SFAS No. 143, *Accounting for Asset Retirement Obligations,* as of April 1, 2003.

As discussed in Note 7 to the Condensed Consolidated Financial Statements, the Company adopted SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity,* as of July 1, 2003.

PricewaterhouseCoopers LLP
Portland, Oregon

November 5, 2003

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

CRITICAL ACCOUNTING POLICIES

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires Company management to make estimates and assumptions that affect results of operations and the reported amounts of assets and liabilities in the consolidated financial statements. Changes in these estimates and assumptions could have a material impact on the Company's financial position and results of operations. Those policies that management considers critical are Regulation, Revenue Recognition, Contingencies, Asset Retirement Obligations and Pensions and are described in the Company's 2003 Annual Report on Form 10-K under ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

FORWARD-LOOKING STATEMENTS

The information in the tables and text in this document includes certain forward-looking statements that involve a number of risks and uncertainties under the safe-harbor provisions of the Private Securities Litigation Reform Act of 1995 that may influence the financial performance and earnings of the Company. When used in this MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS and elsewhere in this report, the words "estimates," "expects," "anticipates," "forecasts," "plans," "intends" and variations of such words and similar expressions are intended to identify forward-looking statements that involve risks and uncertainties. There can be no assurance the results predicted will be realized. Actual results may vary from those represented by the forecasts, and those variations may be material. The following are among the factors that could cause actual results to differ materially from the forward-looking statements:

- changes in prices and availability of wholesale electricity, natural gas and fuel costs and other changes in operating costs, which could affect the Company's cost recovery;
- changing conditions in wholesale power markets, such as general credit constraints and thin trading volumes, that could make it difficult for the Company to enter into purchase and sale agreements;
- the actions of securities rating agencies, including the determination of whether or when to make changes in the Company's credit ratings and the impact of current or lowered ratings and other financial market conditions on the ability of the Company to obtain needed financing on reasonable terms or at all;
- nonperformance of counterparties;
- the effects of increased competition in energy-related businesses, including new market entrants and the effects of technologies that may be developed in the future;
- attempts by municipalities within the Company's service territory to form public power entities and/or acquire the Company's facilities;
- hydroelectric conditions and natural gas and coal production levels, which could have a significant impact on electric capacity and cost and on the Company's ability to generate electricity;
- changes in weather conditions and other natural disasters that could affect customer demand or electricity supply;
- the impact from the possible formation of a Regional Transmission Organization and the impact from the implementation of the Standard Market Design proposed by the Federal Energy Regulatory Commission (the "FERC");
- the impact of enhanced physical and information security requirements imposed through legislation or regulation;
- the outcome of pending Internal Revenue Service (the "IRS") tax audits and settlement conferences;

- the impact of regional, national and international economic and political conditions, including acts of terrorism, war or similar events;
- employee work-force factors, including strikes, work stoppages, availability of qualified employees or loss of key executives;
- the ability to obtain adequate insurance coverage and the cost of such insurance;
- changes in, and compliance with, environmental and endangered-species laws, regulations, decisions and policies;
- industrial, commercial and residential growth and demographic patterns in the Company's service territories;
- competition and supply in electricity and natural gas markets;
- unscheduled generation outages;
- disruption or failures of transmission or distribution facilities;
- changes in regulatory requirements or other legislation, including industry restructuring and deregulation initiatives;
- the outcome of threatened or pending litigation;
- changes in tax rates and/or policies;
- changes in actuarial assumptions and the return on assets associated with the Company's pension plan, which could impact future funding obligations, costs and pension plan liabilities;
- increasing health care costs associated with employee health insurance premiums and the obligation to provide postretirement health care benefits;
- unanticipated delays or changes in construction costs relating to present or future generating facilities;
- new accounting pronouncements;
- the outcome of general rate cases and other proceedings conducted by regulatory commissions; and
- the cost, feasibility and eventual outcome of hydroelectric facility relicensing proceedings.

Any forward-looking statements issued by the Company should be considered in light of these factors. The Company assumes no obligation to update or revise any forward-looking statements to reflect actual results, changes in assumptions or changes in other factors affecting such forward-looking statements or if the Company later becomes aware that these assumptions are not likely to be achieved.

RESULTS OF OPERATIONS

The Company's earnings contribution on common stock for the six months ended September 30, 2003 was $119.4 million, as compared to $63.4 million for the six months ended September 30, 2002. Retail sales volumes were 4.8% higher in the six months ended September 30, 2003 than the comparable prior year period, driven by higher temperatures in summer 2003 and increases in usage per customer and total customer numbers. Output from the Company's thermal facilities increased by 1,086,000 megawatt-hours ("MWh"), or 4.8%, as a result of improved operating performance and increases from new plant additions. Output from Company-owned hydroelectric facilities was lower by 182,100 MWh, or 10.6%, as a result of unusually dry conditions.

In the six months ended September 30, 2003, western United States electricity market prices were higher than the comparable prior year period driven by a combination of higher northwest natural gas prices and a reduction in hydroelectric generation. As a result of risk management actions previously taken, including use of physical resources and hedging activities, the Company maintained its balanced energy position through the summer peak period and believes that its energy position is balanced for the remainder of fiscal year 2004.

As discussed in **PART II- ITEM 5. OTHER INFORMATION**, the Company has general rate cases pending in Utah, Wyoming and California. These requests total approximately $182.8 million. These increases are sought to recover system investments and rising costs, including insurance premiums, pension expense and health care, along with a return on equity of 11.5% in all cases. These cases should be finalized by March 2004. As with any general rate case, the outcome of these requests is uncertain.

COMPARISON OF THE THREE MONTHS ENDED SEPTEMBER 30, 2003 and 2002

REVENUES

(Millions of dollars)	Three Months Ended September 30, 2003	Three Months Ended September 30, 2002	Change Favorable/(Unfavorable)	% Change Favorable/(Unfavorable)
Residential	$ 241.5	$ 225.9	$ 15.6	6.9%
Commercial	214.6	200.4	14.2	7.1
Industrial	208.6	199.4	9.2	4.6
Other retail revenues	8.8	8.3	0.5	6.0
Retail sales	673.5	634.0	39.5	6.2
Wholesale sales	246.2	260.1	(13.9)	(5.3)
Other revenues	38.3	49.8	(11.5)	(23.1)
Total Revenues	$ 958.0	$ 943.9	$ 14.1	1.5
Energy sales (millions of kWh)				
Residential	3,450	3,192	258	8.1
Commercial	3,981	3,729	252	6.8
Industrial	5,210	5,109	101	2.0
Other	183	177	6	3.4
Retail sales	12,824	12,207	617	5.1
Wholesale sales	5,618	7,516	(1,898)	(25.3)
Total	18,442	19,723	(1,281)	(6.5)
Average residential usage (kWh)	2,608	2,455	153	6.2
Total customers - end of period (in thousands)	1,552	1,526	26	1.7

Residential revenues for the three months ended September 30, 2003 increased $15.6 million, or 6.9%, from the three months ended September 30, 2002 primarily due to increases of $14.2 million from higher average estimated customer usage, including the impact of warmer weather, and $4.2 million relating to growth in the average number of residential customers. These increases were partially offset by a decrease of $2.6 million due to a change in price mix.

Commercial revenues for the three months ended September 30, 2003 increased $14.2 million, or 7.1%, from the three months ended September 30, 2002 primarily due to increases of $10.0 million from higher average estimated customer usage. Growth in the average number of commercial customers increased revenues by $4.3 million.

Industrial revenues for the three months ended September 30, 2003 increased $9.2 million, or 4.6%, from the three months ended September 30, 2002 due to a $16.1 million increase resulting from higher prices, partially offset by a $6.9 million decrease due to lower average estimated customer usage.

Wholesale sales for the three months ended September 30, 2003 decreased $13.9 million, or 5.3%, from the three months ended September 30, 2002 primarily due to a reduction in volumes of 25.3%, the impact of which was $56.6 million. The majority of this reduction was in short-term and spot market sales, which were 38.6% lower than the prior year period. A parallel volume reduction is reflected in the Company's Purchased electricity expense. Offsetting this volume reduction, the Company achieved an increase of 26.6% on prices realized as compared to those in the three months ended September 30, 2002, the impact of which was $42.7 million. The primary factors contributing to higher market electricity prices in the western United States during the three months ended September 30, 2003 were below normal hydroelectric conditions and higher natural gas prices.

Other revenues for the three months ended September 30, 2003 decreased $11.5 million, or 23.1%, from the three months ended September 30, 2002 primarily due to a $20.7 million release of reserves on a power sales contract following a settlement of a dispute with respect to the contract in September 2002 and a decrease in wheeling revenues of $2.3 million. These decreases were partially offset by increases of $4.2 million due to a contract settlement, $3.2 million from the joint use of poles and wires, $2.0 million from the reduction of the Oregon merger credit liability and $2.0 million relating to an alternative form of regulation process in Oregon.

See **PART II - ITEM 5. OTHER INFORMATION** for information regarding recent developments in regulatory issues affecting the Company.

OPERATING EXPENSES

Purchased electricity expense for the three months ended September 30, 2003 decreased $33.1 million, or 9.2%, from the three months ended September 30, 2002. Lower volumes incurred for short-term and spot market purchases, due to a combination of increased thermal generation from Company-owned facilities and a reduction in wholesale activity, reduced volumes by 30.5% with a resulting reduction in Purchased electricity expense of $70.1 million. Partially offsetting this reduction was a 19.9% increase in the average purchase price due to higher market prices resulting from the same factors mentioned above for wholesale sales, the effect of which was an increase in Purchased electricity expense of $40.2 million. Long-term purchase volumes increased Purchased electricity expense by $15.4 million, or 9.3%, primarily from increases on exchange contracts. Wheeling expense decreased $10.3 million as a result of the lower volumes. Unrealized mark-to-market gains on weather derivatives and transactions designated as trading were $0.9 million for the three months ended September 30, 2003, as compared to a $7.4 million loss in the comparable prior year period for a net reduction to Purchased electricity expense of $8.3 million.

Fuel expense for the three months ended September 30, 2003 decreased $1.0 million, or 0.8%, from the three months ended September 30, 2002. Increased thermal generation volumes of 2.2% resulted in increased costs of $2.6 million, of which $2.5 million was due to increases in coal volumes and $0.1 million was due to increases in natural gas volumes. Realized coal prices increased Fuel expense by $0.3 million, but were offset by a 16.8% decrease in realized natural gas prices paid, which resulted in a benefit of $3.8 million. The reduction in realized natural gas prices was a result of lower plant availability in the three months ended September 30, 2002, which resulted in adverse gas balancing costs as compared to the current year period. Due to previous hedging activities, the Company was not required to incur the current higher natural gas market prices.

Other operations and maintenance expense for the three months ended September 30, 2003 increased $25.2 million, or 19.4%, from the three months ended September 30, 2002 primarily due to a $6.8 million increase in employee-related expenses, due in part to higher pension costs; a $4.2 million increase in materials and contract services primarily related to overhauls; and a $4.2 million increase due to contract services related to generation site development. In addition, changes in the level and timing of capitalized costs added $2.8 million to expense, other contract services increased $2.4 million, bad debts increased $1.3 million and rent expense increased $0.8 million.

Depreciation and amortization expense for the three months ended September 30, 2003 decreased $2.4 million, or 2.2%, from the three months ended September 30, 2002 primarily due to a $5.4 million decrease as a result of new depreciation rates approved by regulators as discussed in **PART I - ITEM 1. FINANCIAL STATEMENTS** – NOTE 2 – Accounting for the Effects of Regulation, which was partially offset by the effect on depreciation of increased plant in-service of $2.0 million and increased software development of $1.4 million.

Administrative and general expenses for the three months ended September 30, 2003 decreased $13.6 million, or 22.0%, from the three months ended September 30, 2002 primarily due to decreases of $4.5 million in employee-related expenses, $4.0 million in amortization of regulatory assets as a result of lower average balances, $2.3 million in contract services and a $1.4 million decrease in insurance costs due to lower claims in the current year period and one-time costs recognized in the prior year period.

Taxes, other than income taxes, for the three months ended September 30, 2003 decreased $1.1 million, or 4.3%, from the three months ended September 30, 2002 primarily due to lower property tax expense.

The net Unrealized loss on derivative contracts for the three months ended September 30, 2003 was $4.7 million compared to a gain of $5.3 million for the three months ended September 30, 2002 primarily due to the application of Statement of Financial Accounting Standards ("SFAS") No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* ("SFAS No. 149") in the three months ended September 30, 2003 as compared to favorable price movements in the three months ended September 30, 2002.

Other operating expense for the three months ended September 30, 2003 was $12.8 million primarily due to a $10.8 million expense for changes in regulatory assets and liabilities.

INTEREST EXPENSE AND OTHER (INCOME) EXPENSE

Interest expense decreased $18.1 million, or 22.5%, primarily due to a decrease in interest on regulatory liabilities and lower average debt balances, partially offset by dividends on mandatorily redeemable preferred stock of $1.1 million, which were included in interest expense for the three months ended September 30, 2003 in accordance with SFAS 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity* ("SFAS No. 150").

Interest capitalized increased $2.1 million, or 47.7%, due to higher qualifying construction work-in-progress balances and higher capitalization rates in the current period.

Minority interest and other expense decreased $4.3 million, or 75.4%, primarily due to a $2.5 million decrease in distributions on Preferred Securities, which were redeemed during the three months ended September 30, 2003. In addition, other expenses decreased $2.5 million primarily due to realized gains on the increased cash surrender value of life insurance policies, which was partially offset by a $0.8 million increase in accrued charitable donations.

INCOME TAX EXPENSE

Income tax expense increased $14.7 million primarily due to the higher pretax income in the current period. The estimated effective tax rate for the three months ended September 30, 2003 was 38.1% compared to 40.8% for the three months ended September 30, 2002. The decrease in the estimated effective tax rate is primarily due to higher levels of pretax income in the current period, which diluted the tax effect of the regulatory treatment of depreciation differences.

COMPARISON OF THE SIX MONTHS ENDED SEPTEMBER 30, 2003 and 2002

REVENUES

	Six Months Ended September 30,		Change	% Change
(Millions of dollars)	**2003**	**2002**	**Favorable/(Unfavorable)**	
Residential	$ 468.7	$ 431.0	$ 37.7	8.7%
Commercial	413.8	386.5	27.3	7.1
Industrial	386.0	366.3	19.7	5.4
Other retail revenues	17.5	16.6	0.9	5.4
Retail sales	1,286.0	1,200.4	85.6	7.1
Wholesale sales	499.8	553.6	(53.8)	(9.7)
Other revenues	67.0	75.5	(8.5)	(11.3)
Total Revenues	$ 1,852.8	$ 1,829.5	$ 23.3	1.3
Energy sales (millions of kWh)				
Residential	6,703	6,131	572	9.3
Commercial	7,503	7,109	394	5.5
Industrial	9,886	9,718	168	1.7
Other	341	352	(11)	(3.1)
Retail sales	24,433	23,310	1,123	4.8
Wholesale sales	12,306	17,498	(5,192)	(29.7)
Total	36,739	40,808	(4,069)	(10.0)
Average residential usage (kWh)	5,074	4,722	352	7.5
Total customers - end of period (in thousands)	1,552	1,526	26	1.7

Residential revenues for the six months ended September 30, 2003 increased $37.7 million, or 8.7%, from the six months ended September 30, 2002 primarily due to increases of $33.4 million from higher average estimated customer usage, including a change in the calculation of unbilled revenues and the impact of warmer weather, and

$7.8 million relating to growth in the average number of residential customers. These increases were partially offset by a decrease of $3.4 million due to a change in price mix.

Commercial revenues for the six months ended September 30, 2003 increased $27.3 million, or 7.1%, from the six months ended September 30, 2002 primarily due to increases of $16.1 million from higher average estimated customer usage, including a change in the calculation of unbilled revenues. Growth in the average number of commercial customers increased revenues by $8.1 million, and higher prices increased revenues by $3.2 million.

Industrial revenues for the six months ended September 30, 2003 increased $19.7 million, or 5.4%, from the six months ended September 30, 2002 primarily due to a $24.6 million increase resulting from higher prices, partially offset by a $4.9 million decrease due to lower average estimated customer usage, including a change in the calculation of unbilled revenues.

Wholesale sales for the six months ended September 30, 2003 decreased $53.8 million, or 9.7%, from the six months ended September 30, 2002 primarily due to a reduction in volumes of 29.7%, the impact of which was $119.5 million. The majority of this reduction was in short-term and spot market sales, which were 38.6% lower than the prior year period. A parallel volume reduction is reflected in the Company's Purchased electricity expense. Offsetting this volume reduction, the Company achieved an increase of 28.4% on prices realized as compared to those in the six months ended September 30, 2002, the impact of which was $65.7 million. The primary factors contributing to higher market electricity prices in the western United States during the six months ended September 30, 2003 were an increase in the market price of natural gas and a reduction in hydroelectric generation.

Other revenues for the six months ended September 30, 2003 decreased $8.5 million, or 11.3%, from the six months ended September 30, 2002 primarily due to a $20.7 million release of reserves on a power sales contract following a settlement of a dispute with respect to the contract in September 2002, a $4.6 million decrease in revenue from the conclusion of the amortization of a regulatory liability and a decrease in wheeling revenues of $2.8 million. These decreases were partially offset by increases of $4.9 million from the joint use of poles and wires, $4.5 million relating to an alternative form of regulation process in Oregon, $4.2 million from the reversal of a previously established reserve on power sales contracts, $4.1 million relating to demand-side management and $2.0 million from reduction of the Oregon merger credit liability.

OPERATING EXPENSES

Purchased electricity expense for the six months ended September 30, 2003 decreased $83.6 million, or 12.4%, from the six months ended September 30, 2002. Lower volumes incurred for short-term and spot market purchases, due to a combination of increased thermal generation from Company-owned facilities and a reduction in wholesale activity, reduced volumes by 41.3% with a resulting reduction in Purchased electricity expense of $278.8 million. Partially offsetting this reduction was a 26.1% increase in the average purchase price due to higher market prices resulting from the same factors mentioned above for wholesale sales, the effect of which was an increase in Purchased electricity expense of $130.4 million. Long-term purchase volumes increased Purchased electricity expense by $85.1 million, or 16.9%, primarily from increases on exchange contracts. Wheeling expense decreased $17.2 million as a result of lower volumes. Costs relating to unrealized losses on weather derivatives decreased Purchased electricity expense by $5.7 million as compared to the six months ended September 30, 2002. Other costs, which include demand-side management costs and fees, increased $2.6 million.

Fuel expense for the six months ended September 30, 2003 increased $18.4 million, or 8.0%, from the six months ended September 30, 2002. Increased thermal generation volumes of 4.8% resulted in increased costs of $15.6 million, of which $5.2 million was due to increases in coal volumes and $10.4 million was due to increases in natural gas volumes, primarily due to the impact from the Company's Gadsby peaking plant and the leased West Valley plant, which came on line during the prior year period. Realized coal prices increased $1.3 million, but were offset by a 20.4% decrease in realized natural gas prices paid that resulted in a benefit of $8.0 million. The reduction in realized natural gas prices was as a result of lower plant availability in the six months ended September 30, 2002, which resulted in adverse natural gas balancing costs as compared to the current year period. Due to previous hedging activities, the Company was not required to incur the current higher natural gas market prices. The remaining cost increase of $9.5 million was attributable to the net impact of a regulatory deferral for the Trail Mountain coal mine that reduced fuel costs in the six months ended September 30, 2002.

Other operations and maintenance expense for the six months ended September 30, 2003 increased $25.8 million, or 9.2%, from the six months ended September 30, 2002 primarily due to a $10.0 million increase in employee-related expenses due in part to higher pension costs; a $7.0 million increase due to the level and timing of capitalized costs; a $3.9 million increase in rent expense due to the West Valley plant, which came on-line during the prior year period; a $4.2 million increase in contract services related to generation site development; a $2.4 million increase in materials and contract services, primarily related to overhauls; and a $2.4 million increase in tree-trimming contract services. These increases were partially offset by lower bad debt expense of $6.2 million primarily due to the establishment of a $7.0 million reserve for California exposures in the prior year period.

Depreciation and amortization expense for the six months ended September 30, 2003 decreased $4.7 million, or 2.2%, from the six months ended September 30, 2002 primarily due to an $11.8 million decrease as a result of new depreciation rates approved by regulators as discussed in **PART I - ITEM 1. FINANCIAL STATEMENTS** – NOTE 2 – Accounting for the Effects of Regulation, which was partially offset by the effect on depreciation of increased plant in-service of $4.7 million and increased software development of $2.6 million.

Administrative and general expenses for the six months ended September 30, 2003 decreased $19.0 million, or 14.3%, from the six months ended September 30, 2002 primarily due to a $9.5 million decrease in insurance costs due to lower claims in the current year period and one-time costs recognized in the prior year period, a $6.7 million decrease in amortization on regulatory assets due to lower average asset balances and a $3.2 million decrease in contract services.

The net Unrealized loss on derivative contracts for the six months ended September 30, 2003 was $3.2 million compared to a gain of $3.1 million for the six months ended September 30, 2002 primarily due to losses from the implementation of SFAS No. 149 in the six months ended September 30, 2003.

Other operating expense for the six months ended September 30, 2003 was $12.8 million primarily due to a $10.8 million expense for changes in regulatory assets and liabilities.

INTEREST EXPENSE AND OTHER (INCOME) EXPENSE

Interest expense decreased $21.0 million, or 14.5%, primarily due to a decrease in interest on regulatory liabilities and lower average debt balances. In accordance with SFAS No. 150, dividends on mandatorily redeemable preferred stock of $1.1 million were included in Interest expense for the six months ended September 30, 2003.

Interest income decreased $1.4 million, or 14.9%, primarily due to the recognition of $1.1 million of interest income on a power sales contract settlement in September 2002.

Interest capitalized increased $2.2 million, or 22.2%, due to higher qualifying construction work-in-progress balances and higher capitalization rates in the current period.

Minority interest and other expense decreased $7.8 million, or 51.7%, partially due to a $2.5 million decrease in distributions on Preferred Securities, which were redeemed during the six months ended September 30, 2003. Other expense also decreased due to the reversal in the six months ended September 30, 2002 of a previously recorded gain of $3.4 million as a result of a regulatory order and $3.4 million due to realized gains on the increased cash surrender value of life insurance policies. These decreases were partially offset by a $1.7 million increase in accrued charitable donations.

INCOME TAX EXPENSE

Income tax expense increased $43.5 million principally due to the higher pretax income in the current period. The estimated effective tax rate for the six months ended September 30, 2003 was 40.9% compared to 37.4% for the six months ended September 30, 2002. The increase in the estimated effective tax rate is primarily due to the accrual of additional tax contingency reserves and higher levels of pretax income in the current period, which diluted the benefit of certain tax credits.

CUMULATIVE EFFECT OF ACCOUNTING CHANGE

The Company recorded a $0.9 million after-tax loss from the implementation of SFAS No. 143, *Accounting for Asset Retirement Obligations*, during the six months ended September 30, 2003. The Company recorded a

$1.9 million after-tax loss from the implementation of revised Issue C15 and Issue C16 guidance from the Derivatives Implementation Group during the six months ended September 30, 2002.

LIQUIDITY AND CAPITAL RESOURCES

OPERATING ACTIVITIES

Net cash flows provided by operating activities were $335.7 million for the six months ended September 30, 2003 as compared to $200.2 million for the six months ended September 30, 2002 due primarily to an increase in earnings, decrease in tax payments related to prior period IRS audits, reduced fuel inventory and the timing of collections and payments.

INVESTING ACTIVITIES

Capital spending totaled $309.9 million for the six months ended September 30, 2003 compared to $253.1 million for the six months ended September 30, 2002. The increase was primarily due to expenditures for plant refurbishments, network growth and system upgrades, and information technology.

FINANCING ACTIVITIES

The Company's short-term borrowings and certain other financing arrangements are supported by $800.0 million of revolving credit agreements with one facility for $300.0 million having a three-year term that became effective June 4, 2002 and the other facility for $500.0 million having a 364-day term plus a one-year term loan option that became effective June 3, 2003. The interest on advances under these facilities is based on the London Interbank Offered Rate (LIBOR) plus a margin that varies based on the Company's credit ratings. In addition to these committed credit facilities, the Company had $30.7 million in money market accounts included in Cash and cash equivalents at September 30, 2003 available to meet its liquidity needs.

During July and August 2003, the Company redeemed, prior to maturity, First Mortgage Bonds totaling $57.5 million and Preferred Securities totaling $352.0 million. These retirements were funded initially with short-term debt. On September 8, 2003, the Company issued $200.0 million of its 4.30% First Mortgage Bonds due September 15, 2008 and $200.0 million of its 5.45% First Mortgage Bonds due September 15, 2013.

The Company redeemed $7.5 million of preferred stock during each of the six-month periods ended September 30, 2003 and 2002.

The Company declared and paid dividends of $80.3 million on common stock, and paid dividends of $3.5 million on preferred stock, during the six months ended September 30, 2003. On August 19, 2003, the Company declared dividends of $0.5 million on Preferred stock and $1.1 million on Mandatorily redeemable preferred stock, which are payable on November 15, 2003. The dividends declared on Mandatorily redeemable preferred stock were recorded as interest expense. On October 14, 2003, the Company's Board of Directors declared a dividend on common stock of approximately $0.13 per share totaling $40.1 million payable on November 25, 2003.

Management expects existing funds and cash generated from operations, together with existing credit facilities, to be sufficient to fund liquidity requirements for the next 12 months. However, many participants in the electric utility industry have experienced a period of negative news and ratings downgrades. While the Company to date has been able to fund itself and expects to be able to continue to do so, further negative events by other industry participants may make it more difficult and expensive for the Company to obtain necessary financing or replace financing agreements at their maturity.

CAPITAL EXPENDITURES

The following table shows the Company's estimated capital expenditures for the years ending March 31, 2004 through 2006. The Company's capital expenditure program has been recently revised and the estimates below reflect the outcome of the first of three Requests for Proposal to support the Company's Integrated Resource Plan. Subject to regulatory approvals and other consents, this will result in the construction of the Currant Creek Project, a new 525 megawatt ("MW") natural gas-fired plant located in Juab County, approximately 75 miles south of Salt Lake City, Utah, at a cost of approximately $350.0 million to be incurred generally over three years to 2006.

	Estimated		
	Years Ending March 31,		
Millions of dollars	**2004**	**2005**	**2006**
Distribution and transmission	$336.0	$353.6	$378.2
Generation and mining	313.9	482.6	433.1
Other	99.4	79.5	106.7
Total	$749.3	$915.7	$918.0

In addition to the new generating plant mentioned above, estimated future capital expenditures include upgrades to distribution and transmission lines and existing generation plants, connections for new customers, facilities to accommodate load growth, coal mine investments, air quality and environmental expenditures, hydroelectric relicensing costs and information technology systems. The Company expects that these and future costs will be found to be prudent and recoverable in future rates. All of these expenditures are subject to continuing review and revision by the Company, and actual costs could vary from estimates due to various factors, such as changes in business conditions, revised load-growth estimates, future legislative and regulatory developments and increasing costs in labor, equipment and materials. The estimates of capital expenditures for the years ending March 31, 2004 through 2006 are subject to the potential impact on generation and transmission capacity of future decisions arising from the further stages of the Request for Proposal process to support the Integrated Resource Plan. Additional expenditures may be significant but are likely to be spread over a number of years, and cannot be accurately estimated at this time.

In funding its capital expenditure program, the Company expects to obtain funds required for construction and other purposes from sources similar to those used in the past, including operating cash flows and the issuance of new long-term and short-term debt. In order to maintain an appropriate capital structure and access to the capital markets, the Company may also require additional equity over the next several years through its immediate corporate parent, PacifiCorp Holdings, Inc. However, the amount, type and timing of any financings, if necessary, will depend upon levels of capital expenditures, operating cash flows, returns available, market conditions and regulatory approval, and there can be no assurance that such financings will be available on favorable terms, if at all.

CREDIT RATINGS

The Company's credit ratings at September 30, 2003 were as follows:

	Moody's	**S & P**
Senior secured debt	A3	A
Senior unsecured debt	Baa1	BBB+
Preferred stock	Baa3	BBB
Commercial paper	P-2	A-2
Ratings outlook	Negative	Negative

The Company's credit ratings are unchanged from March 31, 2003. 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.

For a further discussion of the Company's credit ratings, see ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS in the Company's 2003 Annual Report on Form 10-K.

CAPITALIZATION

At September 30, 2003, the Company had $90.0 million of commercial paper outstanding at a weighted average interest rate of 1.2%. These borrowings and other financing arrangements are supported by revolving credit agreements and cash on hand as described above.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

BUSINESS RISK

The Company's business risks relating to Operating, Regulatory, Insurance and Pension continue to be as reported in the Company's 2003 Annual Report on Form 10-K under ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. The Company is further subject to the risks that have been or may in the future be imposed on the market from the FERC proceedings as mentioned under **PART II - ITEM 5. OTHER INFORMATION** – FERC ISSUES below.

Political Risk

The Company's business operations are subject to a multitude of federal and state laws. The U.S. Congress is considering significant energy legislation that would make changes in federal law affecting the Company. This energy legislation is now the subject of a joint conference committee to reconcile the differences between the bills passed by the U.S. House of Representatives and the U.S. Senate. If a comprehensive energy bill is enacted, the bill will likely include direction for the regulation of, as well as financial incentives to invest in, transmission. The competing bills also include similar measures affecting the hydroelectric relicensing process and extension of the renewable energy production tax credit. These and other measures under consideration would likely benefit the Company's efforts to develop, acquire and maintain a low-cost generation portfolio. As part of this legislation, the U.S. Congress may repeal the Public Utility Holding Company Act (the "PUHCA"). At present, the Company is unable to predict how the repeal of the PUHCA would affect the Company, which is a public utility and a subsidiary of a registered holding company. It is possible that new legislation may be enacted or the FERC may adopt new regulations if the PUHCA is repealed. Changes to the Clean Air Act, contemplated by the pending Clear Skies Act, may affect control requirements for several emissions from fossil-fueled generation plants.

The laws of the states in which the Company operates affect the Company's generation, transmission and distribution business. All of the legislatures monitored by the Company have concluded their regular business for their legislative years. The Oregon legislature passed a series of tax changes designed to reduce the state's budget deficit. The Company is not significantly affected by the changes enacted in Oregon, based on a preliminary analysis of the new law. The California legislature failed to pass either of two competing bills designed to revise the state's electric industry restructuring law (AB 1890). The California legislature did pass, and Governor Davis signed into law, a bill exempting the Company from the state's statutory prohibition on the disposal of utility generating assets. This prohibition had been an impediment to the Company's plans to decommission, or otherwise dispose of, several small hydroelectric assets.

In February 2003, the Oregon Public Power Coalition submitted a petition to Multnomah County, Oregon, calling for an election to form a government-owned and -operated electric utility in the county and impose a property tax to perform a feasibility study. On June 12, 2003, the Multnomah County Commission voted to place ballot measures 26-51 and 26-52 on the November 2003 ballot as required by state statute.

On November 4, 2003, Multnomah County voters defeated ballot measures 26-51 and 26-52 to form a government-owned and -operated electric utility. Proponents of the measures may pursue legal challenges to the outcome. State law prohibits proponents from placing a similar measure on the ballot for one year.

The Company serves 68,000 homes and businesses in Multnomah County, which represents approximately 1.9 million MWh, or $108.1 million in annual revenues.

Security Risk

Ongoing threats of terrorism, both domestic and foreign, continue to be a risk to the utility industry, including the Company. The Company has a comprehensive approach to identifying critical assets, evaluating both cyberspace and physical security and retrofitting critical sites with enhanced security controls. In conjunction with the North American Electric Reliability Council's Urgent Action Standard for cyberspace and physical security, the Company is conducting a gap analysis and is implementing necessary changes to standardize security controls to ensure compliance with this standard. The Company continues to monitor the evolution of security standards that may be promulgated by the FERC and the North American Electric Reliability Council.

The Company implemented a program that identified critical business processes and led the Company to develop and verify key business recovery plans across the Company's business.

Market Risk

Coal - The Company operates several thermal generation plants in Utah. A Company mine provides almost 50% of the coal used to fuel these plants. The balance of coal comes from short- and long-term purchases from third parties. Coal production in Utah is expected to decrease in calendar year 2004. This reduction can be primarily attributed to the closing of one unaffiliated mine and the shifting of production from a long-wall to a continuous mine operation at another unaffiliated mine. These reductions may have an impact on long-term coal prices. The Company will continue to evaluate its fueling options. Recovery of all costs incurred to fuel the Company's generating plants will be requested in rate filings with the regulatory commissions.

Natural Gas - In early summer 2003, the FERC announced that it had concerns regarding the economic impact of a major natural gas supply deficiency extending beyond the spot market. While those concerns have somewhat diminished with the increasing natural gas storage levels, the FERC has broadened its focus on natural gas to include an array of policy issues currently facing the natural gas industry and the FERC's regulation of the industry for the future. While the natural gas topics that the FERC is addressing occupy the national interest, these issues and strategy discussions do not materially impact the Company.

Since June 30, 2003, the Company purchased, under fixed-price terms, its calendar year 2006 forecasted natural gas supply needs for the Company's current natural gas-fired electric generation plant. The Company currently supplies four natural gas-fired generating plants that, at capacity, require a maximum of 229,000 MMBtu of natural gas per day. The Company's Integrated Resource Plan has identified the need for additional resources, due to expected load growth, that could increase this requirement to 500,000 MMBtu per day, or more. The Currant Creek Project, which resulted from the Integrated Resource Plan and subsequent Request for Proposal is a natural gas-fired plant. The fuel supply for the Currant Creek Project will be managed by the Company consistent with the corporate fuels strategy, which focuses on the management and mitigation of risks associated with supplying natural gas to fuel generation. The prospective growth of the Company's natural gas requirements points to the need for a prudent, disciplined and well-documented approach to procurement and hedging. The Company has developed a natural gas strategy that addresses hedging the commodity risk (physical availability and price), the transportation risk and the storage risk associated with its forecasted and potentially growing natural gas requirements. The natural gas strategy, combined with the prospect for increasing natural gas requirements, is expected to increase the volume and type of the Company's hedging activity and extend the term of its hedging activity beyond calendar year 2006.

Credit Risk

On July 8, 2003, National Energy & Gas Transmission, Inc. ("NEGT") and Energy Trading Holdings Corporation and its subsidiaries filed petitions for protection under Chapter 11 of the federal bankruptcy code. While PacifiCorp does not have direct exposure to any of the NEGT entities that have filed for bankruptcy protection, the Company, in a joint ownership arrangement with a subsidiary of NEGT, Larkspur Power Corporation ("Larkspur"), that has a 50.0% ownership interest in the Hermiston Generating Company ("HGC"). HGC owns and operates a 452 MW natural gas-fired power plant located in Hermiston, Oregon. Currently, 100.0% of the power generated by this facility is delivered to the Company. Given the current HGC ownership structure, and the fact that NEGT has not included Larkspur in its bankruptcy filing, the Company does not expect any change in the current operating arrangement between itself and HGC. The Company has provided surety to replace expiring letters of credit and other credit support that are part of the facility's financing and other arrangements.

RISK MEASUREMENT

Interest Rate Exposure

The Company's risk to interest rate changes is primarily a noncash fair market value exposure and generally not a cash or current interest expense exposure. This result is due to the size of the Company's fixed-rate, long-term debt portfolio relative to the amount of variable rate debt.

The tests for exposure to interest rate fluctuations discussed below are based on a Value-at-Risk ("VaR") approach using a one-year horizon and a 95.0% confidence level and assuming a one-day holding period in normal market conditions. The VaR model is a risk analysis tool that attempts to measure the potential change in fair value, earnings or cash flow from changes in market conditions and does not purport to represent actual losses (or gains) in fair value that may be incurred by the Company.

The table below shows the potential loss in fair market value of the Company's interest-rate-sensitive positions, as of March 31, 2003 and September 30, 2003, as well as the Company's quarterly high and low potential losses.

				2004 Quarterly		
(Millions of dollars)	Confidence Interval	Time Horizon	March 31, 2003	High	Low	September 30, 2003
Interest-rate-sensitive portfolio - fair market value	95.0%	1 Day	$ (18.2)	$ (33.4)	$ (18.2)	$ (33.4)

The increase in potential loss in fair market value from March 31, 2003 to September 30, 2003 was primarily due to an increase in interest rate volatility.

Commodity Price Exposure

The Company's market risk to commodity price change is primarily related to its fuel and electricity commodities, which are subject to fluctuations due to unpredictable factors, such as weather that impact energy supply and demand. Risk management policy and the risk levels established as part of that policy govern the Company's energy purchase and sales activities. For additional information about on the Company's Risk Management and Measurement, see ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK in the Company's 2003 Annual Report on Form 10-K.

The Company measures the market risk in its electricity and natural gas portfolio daily utilizing a historical VaR approach, as well as other measurements of net position. The Company also monitors its portfolio exposure to market risk in comparison to established thresholds and measures its open positions subject to price risk in terms of volumes at each delivery location for each forward time period. The VaR model is a risk analysis tool that attempts to measure the potential change in fair value, earnings or cash flow from changes in market conditions and does not purport to represent actual losses (or gains) in fair value that may be incurred by the Company.

As of September 30, 2003, the Company's estimated potential five-day unfavorable impact on fair value of the electricity and natural gas commodity portfolio over the next 24 months, as measured by the VaR, was $13.1 million, as compared to $19.9 million as of September 30, 2002. The average daily VaR (five-day holding period and to a 99.0% confidence level) for the quarter ended September 30, 2003 was $12.5 million. The maximum and minimum VaR measured during the quarter ended September 30, 2003 were $14.7 million and $9.8 million, respectively. The Company maintained compliance with its VaR limit procedures during the quarter ended September 30, 2003. Changes in markets inconsistent with historical trends or assumptions used could cause actual results to exceed predicted limits. Market values associated with derivative commodity instruments held for purposes of economic hedging of the Company's energy commodity portfolio risk, but accounted for at fair market value, were not material as of September 30, 2003.

FAIR VALUE OF DERIVATIVES

Statement of Financial Accounting Standards ("SFAS") No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS No. 133"), as amended by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities*, and SFAS No. 149 (collectively SFAS No. 133) requires all derivatives, as defined by the standard, to be measured at fair value, except those that qualify for specific exemption under the standard or associated guidance, such as those defined as normal purchases and normal sales. The numerous updates to SFAS No. 133 continue to alter the definition of a "derivative" and the exemptions. The implementation of SFAS No. 149 in the three months ended September 30, 2003 resulted in a significant increase in the number of contractual arrangements currently marked to market by the Company; however, the overall impact on the Company's consolidated financial statements was insignificant. Although the number of contractual arrangements has increased, the derivatives that are marked to market in accordance with SFAS No. 133 include only certain of the Company's commercial contractual arrangements, as many of these arrangements are outside the scope of SFAS No. 133.

The following table shows the changes in the fair value of energy-related contracts qualifying as derivatives under SFAS No. 133 from April 1, 2003 to September 30, 2003 and quantifies the reasons for the changes.

(Millions of dollars)	
Fair value of contracts outstanding at the beginning of the period	$ (505.7)
Contracts realized or otherwise settled during the period	34.4
Changes in valuation assumptions (a)	(59.6)
Changes in fair values (b)	(72.8)
Fair value of contracts outstanding at the end of the period (c)	$ (603.7)

(a) Reflects changes in the fair value of the mark-to-market values as a result of applying refinements in valuation modeling techniques.

(b) Changes in fair values reflect commodity price risk, which is influenced by contract size, term, location and unique or specific contract terms.

(c) The Company has also recorded $601.7 million in net regulatory assets, as authorized by regulatory orders received, to recover the costs with respect to these contracts.

Short-term contracts are valued based upon quoted market prices. Long-term contracts are valued by separating each contract into its component physical and financial forward, swap and option legs. Forward and swap legs are valued against the appropriate market curve. The option leg is valued using a modified Black-Scholes model or a stochastic simulation (Monte Carlo) approach. Each leg is modeled and valued separately using the appropriate forward market price curve. The forward market price curve is derived using daily market quotes from independent energy brokers. For contracts extending past the period for which independent quotes are available, the forward prices are derived using a fundamentals model (cost-to-build approach) that is updated as warranted to reflect changes in the market at least quarterly and blended with market quotes over an overlap period.

The Company also partially mitigates its exposure to price and volume risk by purchasing weather hedges. These products are designed to protect the Company from the effects of weather on its hydroelectric generation and load forecast. The Company records these instruments in its financial statements at market value in accordance with Emerging Issues Task Force No. 99-2, *Accounting for Weather Derivatives*. At September 30, 2003, the net value of these instruments was a liability of $5.2 million.

The following discloses summarized information with respect to valuation techniques and contractual maturities of the Company's contracts qualifying as derivatives under SFAS No. 133 as of September 30, 2003.

	Fair Value of Contracts at Period-End				
(Millions of dollars)	Maturity less than 1 year	Maturity 2-3 years	Maturity 4-5 years	Maturity in excess of 5 years	Total fair value
Prices based on models and other valuation methods	$ (17.1)	$ (14.2)	$ (78.6)	$ (493.8)	$ (603.7)

ITEM 4. CONTROLS AND PROCEDURES

(a) Management of the Company has evaluated, under the supervision and with the participation of the chief executive officer and chief financial officer, the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this report pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. Based on that evaluation, the chief executive officer and chief financial officer have concluded that the Company's disclosure controls and procedures are effective in ensuring that information required to be disclosed is recorded, processed, summarized and reported in a timely manner.

(b) There has been no change in the Company's internal control over financial reporting that occurred during the last fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 5. OTHER INFORMATION

The Company's 2003 Annual Report on Form 10-K contains information concerning the federal and state regulatory matters in which the Company is involved. See ITEM 1. BUSINESS - REGULATION. Certain developments with respect to those matters are set forth below.

FERC ISSUES

California Refund Case

The Company is a party to a FERC proceeding that is investigating potential refunds for energy transactions in the California Independent System Operator and the California Power Exchange markets during past periods of high energy prices. The Company previously established a reserve of $17.7 million for these refunds. The Company's ultimate level of exposure to refunds is dependent upon any final order issued by the FERC in this proceeding.

Northwest Refund Case

On June 25, 2003, the FERC terminated its proceeding relating to the possibility of requiring refunds for wholesale spot-market bilateral sales in the Pacific Northwest between December 25, 2000 and June 20, 2001. The FERC concluded that ordering refunds would not be an appropriate resolution of the matter. On August 25, 2003, the FERC granted rehearing of its June 25, 2003 order.

Federal Power Act Section 206 Case

On June 26, 2003, the FERC issued a final order denying the Company's request for recovery of excessive prices charged under certain wholesale electricity purchases scheduled for delivery during summer 2002 and dismissing the Company's complaints, under section 206 of the Federal Power Act, against five wholesale power suppliers. On July 3, 2003, the Company filed a petition for review of certain aspects of this order in the Ninth Circuit Court of Appeals. On July 28, 2003, the Company filed its request for rehearing of the FERC's order, which was granted on August 27, 2003.

FERC Show-Cause Orders

In May 2002, the Company, together with other California power market participants, responded to data requests from the FERC regarding trading practices connected with the power crisis during 2000 and 2001. The Company confirmed that it did not engage in any trading practices intended to manipulate the market as described in the FERC's data requests issued in May 2002. On June 25, 2003, the FERC ordered 60 companies (including the Company) to show cause why their behavior during the California energy crisis did not constitute manipulation of the wholesale power market, as defined in the California Independent System Operator and the California Power Exchange tariffs. In setting the cases for hearing, the Commission directed an administrative law judge to hear evidence and render findings and conclusions quantifying the extent of any unjust enrichment that resulted, and to recommend monetary or other appropriate remedies. On August 29, 2003, the Company and the FERC staff reached a resolution on the show-cause order. Under the terms of the settlement agreement, the Company denied liability and agreed to pay a nominal amount of $67,745, in exchange for complete and total resolution of the issues raised in the FERC's show-cause order relating to the Company. The FERC must approve the settlement before it becomes binding on the parties.

REGULATORY ACTIONS

Utah

The Company commenced a general rate case on May 15, 2003 based on financial information for the year ended March 31, 2003 and including known and measurable changes that will occur by January 1, 2004. The initial filing included a projected revenue requirement increase of $125.0 million that serves as a cap on the amount the Company can receive in the case. A subsequent detailed filing was made in July 2003, requesting a revenue increase equal to the cap. The Company supplemented this filing with a filing on September 15, 2003, detailing class cost of service and rate spread and rate design proposals. The Company filed an updated revenue requirement on October 15, 2003 with the total revenue increase unchanged. The Company submitted an updated class cost of service filing on October 31, 2003. If approved, the effective date of the increase is expected to be January 1, 2004, with cash collections beginning April 1, 2004.

During summer 2003, the Company filed and received regulatory approval in Utah on three new residential demand-side management programs: a refrigerator recycling program, an air-conditioning load control program and an incentive program to install evaporative coolers or energy-efficient air-conditioners. The Company filed for a tariff rider to allow it to recover costs incurred through the implementation of all of the programs approved by the Utah Public Service Commission (the "UPSC"). The Company has been deferring the costs of approved programs since August 2001. Following the filing of testimony, tariff proposals and a series of technical conferences, interested parties have approved a stipulation detailing the introduction of a tariff rider mechanism and a self-direction program for large customers. This stipulation was heard and approved by the UPSC on September 23, 2003. By the end of November 2003, the Company will file a proposed collection rate under this newly adopted schedule. It is anticipated that the tariff rider will be introduced in customer bills after April 1, 2004.

Oregon

On August 26, 2003, the Oregon Public Utility Commission (the "OPUC") approved a settlement of the Company's general rate case filed on March 18, 2003. Under the settlement, base rates increased by $8.5 million annually on September 1, 2003 and a $12.0 million offsettable merger credit for the period from January 2004 to December 2004 was eliminated. A nonoffsettable merger credit will be reduced from $6.0 million to $4.0 million, and will be amortized to return the full amount to customers by December 31, 2004.

In November 2000, the Company made a deferred accounting filing to track its excess net power costs. On July 18, 2002, the OPUC approved the filing, finding that the Company had prudently incurred the excess net power costs. The Industrial Customers of Northwest Utilities and the Citizens' Utility Board appealed the OPUC order on March 26, 2003. The Marion County, Oregon circuit court affirmed the OPUC order. The Industrial Customers of Northwest Utilities and the Citizens' Utility Board have appealed the circuit court decision to the Oregon Court of Appeals.

The Company decided to discontinue pursuit of its October 1, 2001 appeals of two OPUC orders issued in conjunction with the deferred accounting application. The orders established the baseline and a mechanism to determine the amount of excess net power costs that are eligible for deferral and eventual recovery. On July 28, 2003, the Oregon Court of Appeals issued an order affirming the OPUC orders. Based upon this order, the Company's judgment is that further efforts to appeal the OPUC orders are unlikely to be successful.

On October 30, 2003, the OPUC approved a settlement of the Company's net power costs for the period September 10, 2001 through May 31, 2002 (the "Bridge Period"). An approved stipulation provided that the Company's net power cost recovery during the Bridge Period would be based on a specified percentage of actual net power costs subject to certain adjustments, with deferred recovery or payment of any undercollection or overcollection. Following an independent audit, the parties to the original stipulation agreed that the Company undercollected Bridge Period net power costs by $300,000. The OPUC approved this $300,000 in net power costs for later collection in rates.

Wyoming

On May 7, 2002, the Company filed a request to recover replacement power costs of $30.7 million, resulting from the outage of the Company's Hunter No. 1 generating plant, and a proposal for recovering deferred net power costs of $60.3 million. In December 2000, the Wyoming Public Service Commission (the "WPSC") authorized the deferral of net power costs. On March 6, 2003, the WPSC denied recovery of the Hunter No. 1 replacement power costs and the deferred net power costs. The Company filed a petition for rehearing of the decision on April 4, 2003. After a public deliberation on May 30, 2003, the WPSC denied the petition, and the order denying rehearing was issued on July 15, 2003. On August 8, 2003, the Company petitioned the Laramie County district court to review the WPSC decision. On September 22, 2003, the district court certified the case to the Wyoming Supreme Court.

On May 27, 2003, the Company filed a general rate case with the WPSC to recover rising costs (including insurance premiums, pension funding and health care costs) and requested an increase in the return on equity to 11.5% to compensate the Company for general risks relating to the western United States utility environment, as well as some additional risks relating to multijurisdictional operations. The Company has requested an annual increase of $41.8 million, or 13.1%, in base rates to take effect in March 2004. Hearings in the case are scheduled to begin on January 16, 2004 with an order expected by the end of March 2004.

On September 26, 2003, the Company filed a request to establish a power cost adjustment mechanism (the "PCAM"). This mechanism will reduce the regulatory lag associated with recovery of net power costs, which are defined as fuel and wheeling expenses and wholesale sales and purchases. The mechanism is proposed to become effective April 1, 2004. The PCAM includes two components: (1) an annual update that recovers forecast net power costs through a surcharge, and (2) a deferral mechanism that shares variations in adjusted actual net power costs from forecasted net power costs between customers and shareholders. Since the base net power cost rate will be established in the current general rate case, the first adjustment to the base net power cost rate under the PCAM would be April 1, 2005, when the new forecast net power cost would go into effect. Also beginning in 2005, the Company would make a filing by July 31 of each year to set the PCAM deferral rate to recover from, or return to, customers any costs deferred during the prior deferral period.

<u>Washington</u>

On April 5, 2002, the Company filed a petition with the Washington Utilities and Transportation Commission (the "WUTC") seeking authority to begin deferring net power costs in excess of those included in rates as of June 1, 2002 for later recovery in rates, either through a power cost adjustment mechanism or a limited rate adjustment. Under the rate plan approved by the WUTC in August 2000 at the conclusion of the Company's last general rate case in Washington, there were limitations on the Company's ability to request changes to general rates before January 2006. On October 18, 2002, the Company filed testimony and supporting documents, requesting deferral and recovery of excess net power costs estimated at the time to be $17.5 million, including carrying charges, or, alternatively, to allow the Company to file a general rate case, which was restricted through December 2005. Through March 31, 2003, the deferral was expected to total $12.2 million. Hearings were held March 20-24, 2003, and a decision was issued on July 15, 2003. This decision did not allow for the deferral and recovery of excess power costs, but does allow the Company to file a general rate case any time before July 2005 that addresses the level of prices needed to cover all ongoing costs to serve Washington customers. On August 14, 2003, the Public Counsel section of the state attorney general's office filed a court action in Thurston County superior court requesting review of the WUTC's decision to allow the Company to file a general rate case that would allow a change in rate base prior to January 1, 2006. A status conference in that proceeding is scheduled for November 7, 2003.

On October 13, 2003, the Company filed petitions with the WUTC for accounting orders to allow deferral and amortization of the Trail Mountain coal mine closure costs and environmental remediation costs. These filings were made in response to the stipulation approved in the last general rate proceeding in Washington requiring that items treated as regulatory assets under authorizations from other states that are proposed for inclusion in Washington at the end of the rate plan period be supported by accounting authorizations in Washington.

<u>Idaho</u>

On July 11, 2003, the Company filed an application for approval of a renewable energy tariff. Under the proposed tariff, residential and nonresidential customers can purchase newly developed wind, geothermal and solar power energy in fixed increments. On August 28, 2003, the Idaho Public Utilities Commission approved the application as filed.

California

On June 19, 2003, the Company and the California Public Utilities Commission's ("CPUC") Office of Ratepayer Advocates executed a settlement agreement addressing revenue requirements in the Company's pending general rate case. On July 7, 2003, an all-party settlement was filed addressing revenue allocation and rate design. Hearings were held in June and July to consider the respective settlement agreements and to receive evidence and exhibits into the record. On September 9, 2003, an administrative law judge issued a draft order approving the settlement and establishing a 30-day comment period. The matter is currently scheduled for consideration at the CPUC's November 13, 2003 business meeting. If the CPUC approves the draft order on November 13, 2003, the likely effective date would be December 1, 2003. If the draft order is approved, the Company would be allowed to recover approximately \$2.8 million annually in addition to the \$4.7 million collected annually through the interim increase approved by the CPUC in June 2002.

Affiliated Interest Filings

On September 30, 2003, the Company made compliance filings for a cross-charge policy agreement governing the allocation of costs incurred by the Company and by Scottish Power UK plc, a subsidiary of Scottish Power plc, on behalf of each other. Filings were submitted to Utah, Oregon, Wyoming, Washington and Idaho. The agreement establishes a process for directly assigning or allocating costs between the Company and Scottish Power UK plc for common corporate functions. These charges to the Company are estimated to be approximately \$20 million annually.

PROPOSED ASSET DISPOSITION

In July 1998, the Company announced its intention to sell its California service territory, including its electric distribution assets, to Nor-Cal Electric Authority ("Nor-Cal"). In June 2002, the California county of Siskiyou filed a validation action in California superior court, challenging the authority of Nor-Cal to enter into such a transaction and alleging certain conflicts of interest between Nor-Cal and its advisors. On August 7, 2003, the Company announced that it was concluding talks with Nor-Cal and ending all efforts to sell the Company's California service area.

INTEGRATED RESOURCE PLAN

The Company's Integrated Resource Plan was filed with the relevant state commissions on January 24, 2003. The Integrated Resource Plan is a regulatory requirement in all states in which the Company operates, with the exception of Wyoming. The Integrated Resource Plan has been acknowledged in Utah, Oregon, Washington and Idaho, and the Company filed for an exemption in California.

The Company has segregated the Integrated Resource Plan supply-side action items into a series of three separate Requests for Proposal, each of which focuses on a specific category of supply-side resources and provides for the staged procurement of resources in future years to achieve load/resource balance.

The first of these three Requests for Proposal (RFP 2003A) was issued on June 6, 2003. RFP 2003A requested east side seasonal resources of 225 MW for the summer period (June through September) in years 2004-2007; resources of 200 MW for delivery starting by June 1, 2005; and resources of 570 MW for delivery starting by June 1, 2007. No seasonal supply resources have been procured to date although negotiations continue. The Currant Creek Project was demonstrated to be the most economical resource choice for a flexible resource capable of being available by June 2005. The Currant Creek Project is a 525 MW natural gas-fired combined-cycle combustion turbine generation project located approximately 75 miles south of Salt Lake City, Utah. The Currant Creek Project will be constructed in two phases with two 140 MW (280 MW total) simple-cycle combustion turbines being installed during calendar year 2005.Two heat-recovery steam generators and a steam generation turbine will be added in calendar year 2006 to bring the plant output to a total of 525 MW. In addition, the Company requested a resource capable of being available by June 2007. Evaluation of responses to the Company's request for a 570 MW, or more, resource capable of being available by June 2007 continues. This may result in a long-term power purchase agreement, a facility lease or investment in an additional generation plant.

The second Request for Proposal (RFP 2003B) is expected to be issued in December 2003 and will request approximately 1,100 MW of renewable resources for the Company's entire service territory. The third Request for Proposal (RFP2004A) is expected to be issued in early calendar year 2004 and will request additional resources to serve the Company's eastern service territory in Utah, Wyoming and Idaho. The expected total cycle time for each Request for Proposal process is approximately six to eight months.

In addition to the three supply-side Requests for Proposal, the Company issued a separate Request for Proposal for the demand-side resources called for in the Integrated Resource Plan. The demand-side Request for Proposal requested 100 MW or more of conservation to be obtained over the next 10 years and load control proposals specifically addressing peak load. The demand-side Request for Proposal was issued on June 26, 2003, with responses due on August 18, 2003. Analysis of initial responses has been completed and a short-list of bidders has been selected for further evaluation.

The effects of a recently updated load forecast may result in demand-side and supply-side resources being procured or constructed that are in excess of that originally published in the Integrated Resource Plan. An update to the Integrated Resource Plan has been filed with the regulatory commissions in the states the Company serves.

MULTI-STATE PROCESS

The Company is involved in a collaborative process with the six states it serves to develop mutually acceptable solutions to the issues faced by the Company and the states, as a result of the Company's multistate operations. These issues pertain to the inconsistent allocation of some of the cost of the Company's existing investments and the recovery of the cost of future investments. Between April 2002 and July 2003, the Company and key parties from Utah, Oregon, Wyoming, Washington and Idaho, along with a key monitoring contact from California, analyzed over 50 options to address these issues, which were narrowed to two possibilities. Both sought to clarify roles and responsibilities, including cost allocations for future generation resources and provide states with the ability to independently implement state energy policy objectives, and achieve permanent consensus on each state's responsibility for the costs and entitlement to the benefits of the Company's existing assets. Following the July 2003 meeting, the Company undertook extensive analytical work to develop a single proposal that would best balance the needs of the Company and requirements of the states in addressing the positions, issues and concerns raised and discussed during the course of the collaborative and individual state meetings. This work culminated in a regulatory filing on September 30, 2003 in the states of Utah, Oregon, Wyoming and Idaho. Similar filings in Washington and California will follow in coordination with rate case activity. The states are now working to set regulatory process schedules in preparation for the hearings in the near future.

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Exhibits.

2.1(a)* Agreement and Plan of Merger, dated as of December 6, 1998, by and among Scottish Power plc, NA General Partnership, Scottish Power NA 1 Limited and Scottish Power NA 2 Limited (Exhibit 1 to the Form 6-K, dated December 11, 1998, filed by Scottish Power plc, File No. 1-14676).

2.1(b)* Amended and Restated Agreement and Plan of Merger, dated as of December 6, 1998, as amended as of January 29, 1999 and February 9, 1999, and amended and restated as of February 23, 1999, by and among New Scottish Power plc, Scottish Power plc, NA General Partnership and PacifiCorp (Exhibit (2)b, Form 10-K for year ended December 31, 1998, File No. 1-5152).

3.1* Third Restated Articles of Incorporation of the Company (Exhibit (3)b, Form 10-K for the year ended December 31, 1996, File No. 1-5152).

3.2* Bylaws of the Company effective November 29, 1999 (Exhibit (3)b, Form 10-K for the year ended March 31, 2000, File No. 1-5152).

4.1* Mortgage and Deed of Trust, dated as of January 9, 1989, between the Company and Morgan Guaranty Trust Company of New York (The Chase Manhattan Bank, successor), Trustee, Ex. 4-E, Form 8-B, File No. 1-5152 as supplemented and modified by 16 Supplemental Indentures as follows:

Exhibit Number	File Type	File Date	File Number
(4)(b)			33-31861
(4)(a)	8-K	January 9, 1990	1-5152
4(a)	8-K	September 11, 1991	1-5152
4(a)	8-K	January 7, 1992	1-5152
4(a)	10-Q	Quarter ended March 31, 1992	1-5152
4(a)	10-Q	Quarter ended September 30, 1992	1-5152
4(a)	8-K	April 1, 1993	1-5152
4(a)	10-Q	Quarter ended September 30, 1992	1-5152
4(a)	10-Q	Quarter ended September 30, 1993	1-5152
(4)b	10-Q	Quarter ended June 30, 1994	1-5152
(4)b	10-K	Quarter ended December 31, 1994	1-5152
(4)b	10-K	Quarter ended December 31, 1995	1-5152
(4)b	10-K	Quarter ended December 31, 1996	1-5152
99(a)	8-K	November 21, 2001	1-5152
4.1	10-Q	Quarter ended June 30, 2003	1-5152
99	8-K	September 8, 2003	1-5152

4.2* Third Restated Articles of Incorporation and Bylaws. See 3.1 and 3.2 above.
12.1 Statements of Computation of Ratio of Earnings to Fixed Charges
12.2 Statements of Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends
15 Letter regarding unaudited interim financial information
31.1 Principal Executive Officer Certification Pursuant to Sarbanes-Oxley Act of 2002, Section 302
31.2 Principal Financial Officer Certification Pursuant to Sarbanes-Oxley Act of 2002, Section 302
32.1 Principal Executive Officer Certification Pursuant to Sarbanes-Oxley Act of 2002, Section 906
32.2 Principal Financial Officer Certification Pursuant to Sarbanes-Oxley Act of 2002, Section 906

* Incorporated herein by reference.

(b) Reports on Form 8-K.

On Form 8-K, dated August 7, 2003, under Item 5. Other Events, the Company announced that it was concluding its talks with Nor-Cal and ending all efforts to sell the Company's California service area to Nor-Cal.

On Form 8-K, dated August 27, 2003, under Item 5. Other Events, the Company announced that the OPUC had granted approximately $8.5 million of additional annual revenues, the removal of merger credits of approximately $12.0 million and an additional $5.0 million in revenues in the current fiscal year due to allowing implementation of the new rates five months earlier than scheduled.

On Form 8-K, dated September 8, 2003, under Item 5. Other Events, the Company announced that it had issued $200.0 million of its 4.30% First Mortgage Bonds due September 15, 2008 and $200.0 million of its 5.45% First Mortgage Bonds due September 15, 2013.

SIGNATURE

Pursuant to the requirements 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.

PACIFICORP

Date: November 5, 2003

By: /s/ RICHARD D. PEACH

Richard D. Peach
Chief Financial Officer

Exhibit No. ___(RAL-1T)
Docket No. _______
Witness: Randy A. Landolt

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Application of PACIFICORP for an Order Approving the Sale of its Interest in the Skookumchuck Hydroelectric Plant and for EWG Determinations

Docket No. _________

PACIFICORP

DIRECT TESTIMONY OF RANDY A. LANDOLT

Q. Please state your name, business address and present position with PacifiCorp.

A. My name is Randy A. Landolt and my business address is Suite 1500, Lloyd Center Tower, 825 NE Multnomah Street, Portland, Oregon. My present position at PacifiCorp is Managing Director, Hydro Resources.

Qualifications

Q. Briefly describe your educational and professional background.

A. I graduated in 1973 from Oregon State University with a Bachelor of Science Degree in Civil Engineering. Following graduation, I briefly performed land development work before joining PacifiCorp as an Assistant Design Engineer of generation, transmission and distribution infrastructure. Most of my career has been associated with the engineering and Federal Energy Regulatory Commission ("FERC") regulation of hydroelectric facilities.

Q. What are your responsibilities as Managing Director, Hydro Facilities?

A. I am currently responsible for the operations and maintenance, engineering, construction, and regulatory/environmental compliance for PacifiCorp's portfolio of 51 hydroelectric projects.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I describe the contemplated sale of the Skookumchuck Dam and related assets (the "Skookumchuck Project" or "Project") and the reasons for the proposed sale. In addition, I briefly address PacifiCorp's request that the Commission find that allowing the Project to become an "eligible facility" under section 32 of the Public Utility Holding Company Act of 1935 ("PUHCA") will benefit consumers, is in the public interest and does not violate State law. These findings are necessary for FERC to authorize the purchaser to operate the Project as an exempt wholesale generator.

Description of the Transaction

Q. Please describe the assets proposed for sale.

A. The primary asset is the Skookumchuck Dam which is an earthfill structure 190 feet high and 1340 feet in length. Other assets included in the sale are 1,653 acres of land beneath and adjacent to the four-mile long reservoir created by the dam, the powerhouse at the base of the dam housing a 1 MW hydroelectric generating unit, and miscellaneous small buildings and operations and maintenance equipment. All assets included in the sale are specifically identified in the Skookumchuck Facilities Purchase and Sale Agreement dated November 25, 2003 (the "Sale Agreement"). The Sale Agreement is identified as Exhibit No.___(RAL-2). *See* Sale Agreement, Schedules 2.1(a) through 2.1(e). All of the facilities included in the Sale Agreement are located in Thurston County, Washington, twelve miles northeast of Centralia, Washington.

Q. Who currently owns the sale assets?

A. The Skookumchuck Project is owned as tenants in common by PacifiCorp and six other public and private owners: Puget Sound Energy, Inc. ("Puget"); Public Utility District No. 1 of Snohomish County, Washington; City of Tacoma, Washington; Avista Corporation; City of Seattle, Washington; and Public Utility District No. 1 of Grays Harbor County, Washington (collectively, the "Owners"). These same entities owned the 1,340 MW coal-fired Centralia Steam Plant until that plant was sold in May 2000. PacifiCorp has a 47.5 percent ownership share in the Skookumchuck Project, the same ownership share the Company had in the Centralia Steam Plant.

Q. Please describe the purchaser.

A. The purchaser is 2677588 Washington LLC ("Washington LLC" or the "Buyer"), a limited liability company formed under Washington law by TransAlta USA, Inc. ("TransAlta"). TransAlta is a Delaware corporation with headquarters in Centralia, Washington. TransAlta is the indirect owner of both the Centralia Steam Plant and the Centralia Coal Mine.

Q. When and why was the Skookumchuck Dam constructed?

A. The construction of the dam was completed in 1973. The sole purpose of the dam was to store portions of the natural flow of the Skookumchuck River for release in a controlled manner to meet the cooling water requirements of the Centralia Steam Plant. Water from the reservoir is released into the natural channel of the river and then diverted at the Centralia Steam Plant Pumping Station located approximately 2 miles downstream of the dam.

Q. Please explain the development of hydropower generation at the Skookumchuck Dam.

A. The Owners considered construction of a hydroelectric facility during the late 1980s. The Skookumchuck Dam had the potential to develop upwards of 10 MW of hydroelectric capacity if the management of the stored water in the Skookumchuck Reservoir were oriented toward power production. However, the needs of the Centralia Steam Plant have had priority over maximum hydroelectric development at the dam. The Owners therefore chose to develop a smaller hydroelectric project. The hydroelectric facilities were constructed in 1991 and were sized at 1 MW in order not to conflict with the water cooling needs of the Centralia Steam Plant.

Q. What arrangements are in place for disposition of the energy produced by the hydroelectric facility?

A. The Project output is and always has been sold to Puget, which owns and operates the adjacent electrical transmission and distribution system. The wholesale purchase agreement with Puget expired several years ago and sales since then have been made without a contract. Decisions regarding future Project sales will be made by Washington LLC.

Q. Please describe governmental regulation of the Project.

A. The addition of the hydroelectric facilities to the Project required the Owners to file an Application for Exemption from licensing with the FERC. An exemption from licensing was available under 16 U.S.C. §2705(d) because the Project was under 5 MW in capacity. The Skookumchuck Project is exempt from routine annual inspections by the FERC, but is under the FERC's jurisdiction relative to dam safety issues.

Q. What are the basic terms of the sale to Washington LLC?

A. The base sale price is $7,570,373.16, which was calculated by multiplying PacifiCorp's net book value for the Project as of September 30, 2003 by 2.105. The multiplier grosses up PacifiCorp's net book value to incorporate the other Owners' 52.5 percent interest in the Project. The base sale price will be adjusted for changes in net book value from September 30, 2003 to the Closing Date of the transaction.

The Owners are selling to Washington LLC all of their interests in the Skookumchuck Dam, 1,653 acres of real property underlying and adjacent to the reservoir, all relevant easements, rights of way, licenses, franchises, and water rights appurtenant to the real property or associated with operation of the hydroelectric facility.

Washington LLC will also acquire the powerhouse structure, equipment utilized to operate the Skookumchuck Dam and hydroelectric generating facilities, outbuildings, and specifically identified vehicles. *See* Sale Agreement, Schedules 1.1(a), (b), and (c). Washington LLC will continue operating under current fish and wildlife agreements and licenses. Assigned contracts and licenses are listed in the Sale Agreement, Schedules 2.1(d) and (e), respectively.

Washington LLC will assume all liabilities associated with the Skookumchuck Project including the obligation to maintain the flow regimes below the Project and provide the required services associated with the Centralia Steam Electric Generating Project Fish and Wildlife Agreement dated May 29, 1998. *See* Sale Agreement, Section 2.6.

Washington LLC will also assume the Owners' rights and obligations under the Project Safety Program. The Safety Program, described in detail in Exhibit A of the Sale Agreement, is a dam safety/stability program addressing the identification of the appropriate Maximum Credible Earthquake (MCE) to be used for stability analysis, the liquefaction potential of foundation materials beneath the downstream shell of the dam and an examination of the current Probable Maximum Flood (PMF) inflow curve calculations with regard to the most recent storm of record that occurred in February 1996.

Puget will retain its 12 kV electric distribution line that crosses the real property that is subject to the sale. *See* Sale Agreement, Schedule 2.2(b).

Additional details of the transaction are specifically described in the Sale Agreement, Exhibit No.___(RAL-2).

Q. Please identify the costs associated with operating the Skookumchuck Project.

A. The average annual operating cost from 2000 through 2003 has been approximately $320,000. These costs include labor costs for the single part-time Project operator, security and periodic maintenance support and approximately $134,000 associated with the adjacent Washington State Department of Fisheries steelhead rearing facility that is physically and contractually associated with the Skookumchuck Project. The balance of the expenses are for engineering and regulatory activity support.

Costs have risen in recent years due to increased Safety Program expenses and the need for increased security in compliance with the Project's "Level 1 Security Risk" classification, as established by the FERC. Project costs are more specifically addressed in the testimony of PacifiCorp witness Craig Johnson.

Q Please identify Exhibit No.___(RAL-3), the Skookumchuck Dam Management Agreement.

A. The Skookumchuck Dam Management Agreement is an agreement entered into between the Owners and TransAlta Centralia Generation LLC governing how the Skookumchuck Dam will be managed and how the parties will bear the costs of management. Under this Agreement, TransAlta (through its indirect wholly-owned subsidiary, TransAlta Centralia Generation LLC) agreed to pay up to $300,000 of the annual Project costs for the first two years after acquiring the Centralia Steam Plant. Since May 2002, there has been no cap on Project costs and TransAlta has deposited payments into an escrow account for the eventual offset of Project costs. These Project costs will be paid to the Owners in addition to the sale price.

Q. What has been the generation output experience from the Project?

A. Over the last eight years, PacifiCorp's share of the Project output has averaged 3,013 MWh/year. The last four years' experience has been particularly low, averaging approximately 1,000 MWh per year. This change in generation level is due primarily to changes to the operating schedule for the unit. The Skookumchuck Project experienced the failure of a circuit board in the control and communications module about the same time as the Centralia Steam Plant was sold to TransAlta. The failure of this component resulted in the shutdown of the generating unit, and resolution of the problem was delayed due to limited staff availability. The ability to operate the generating unit with this component out of service was subsequently confirmed by PacifiCorp engineering staff. The Skookumchuck plant operator is currently operating the generating unit in a manual mode during the hours he is present on site each day.

Q. What are the key incentives for the Owners to sell the Skookumchuck Project at this time?

A. The key factors are as follows:

- The facilities represented "core business" assets to each of the Owners only as long as they had an ownership interest in the Centralia Steam Plant.
- The energy generated by the hydroelectric facilities has negligible value compared to the $7.57 million net book value.
- It is likely that FERC will mandate dam modifications to meet stability criteria. The cost of these modifications is estimated to be $5 million to $7 million.
- Unless TransAlta is willing to continue its commitment to shoulder Project expenses under the current Skookumchuck Dam Management Agreement, there is

no ongoing assurance that TransAlta will compensate the Owners for ongoing operation and maintenance costs or for other operational liabilities.

- TransAlta is currently motivated to own the Skookumchuck Project and control stream flows to meet Centralia Steam Plant cooling water requirements.

Q. Does the proposed sale benefit PacifiCorp's customers?

A. Yes, positive benefits for customers will be realized if the sale takes place. Absent the ownership of the Centralia Steam Plant, the continued ownership of the Skookumchuck Project does not provide positive benefits to the Company's customers or shareholders. In addition, the following facts support selling the Project:

- The Project is clearly uneconomic as a stand-alone hydroelectric facility and the energy output is insignificant in the Company's generation portfolio.
- The Project is not a source of power for PacifiCorp customers as the Project output is sold to Puget.
- The facilities are over one hour travel time from PacifiCorp's nearest operation center at the Lewis River, 10 miles east of Woodland, Washington, making it difficult to effectively manage the Project.
- The Project diverts critical operating and capital funds and management attention away from the core generating assets of the Company.
- But for the sale, PacifiCorp would retain economic responsibility for its share of routine expense, capital costs and any capital modifications to the dam that may be required to meet federal seismic criteria for stability.
- A Flood Control Committee formed by Lewis and Grays Harbor Counties, Washington and the cities of Centralia, Chehalis and Aberdeen, Washington (the

"Committee") to develop a flood control plan has indicated that if they decide to pursue acquiring the Project for flood control purposes, they will not be in a position to offer net book value.

Given the positive aspects of selling the Skookumchuck Project and the net book value price, the proposed sale would be beneficial to both PacifiCorp's customers and its shareholders.

Q. When the Centralia Steam Plant was sold in 2000, why was the Skookumchuck Project retained by the Owners?

A. In July 1998, the Centralia Steam Plant Owners received an inquiry from the Committee expressing an interest in acquiring the Skookumchuck Dam and reservoir. The Committee had been working with the U.S. Army Corps of Engineers to develop a comprehensive flood control plan for the basin. In June 1999, a Memorandum of Understanding ("MOU") between the Owners and the Committee was signed reflecting the Committee's intent to purchase the facilities. This MOU expired in December 1999, but the Owners understood that the Committee's intent to acquire the facilities had not changed. This desire by the Committee to purchase the facilities and the Committee's stated intent to operate the facilities in a manner that would not be in conflict with the continued operation of the Centralia Steam Plant caused the Owners to withhold the Skookumchuck Project from the sale of the Centralia Steam Plant.

Q. How did the new owners of the Centralia Steam Plant address operation of the Skookumchuck Project?

A. The Centralia Steam Plant sale was completed on May 4, 2000 and the parties then entered into the Skookumchuck Dam Management Agreement. As I explained above, under this Agreement, TransAlta (through its indirect wholly-owned subsidiary, TransAlta Centralia Generation LLC) agreed to reimburse the Skookumchuck Project Owners for all expenses related to the Project up to a cap of $300,000 per calendar year for a period of two years. The Owners and TransAlta Centralia Generation LLC also executed a Water Flow Agreement reflecting the need to coordinate the operation of the Project with the cooling water requirements of TransAlta's Centralia Steam Plant. *See* Sale Agreement, Section 2.7. The Skookumchuck Dam Management Agreement also provided TransAlta with an option to purchase the Skookumchuck Project at PacifiCorp's net book value multiplied by 2.105 between May 5, 2002 and May 5, 2003 if a sale to the local governmental consortium had not taken place. The 2.105 multiplier was explained on page 4 of my testimony.

Q. Why was the sale to the Committee not completed?

A. There were several reasons. Following the expiration of the Committee-Owners MOU, the consortium continued to work with the Corps of Engineers to conduct stability/safety drilling tests and studies on the dam and to evaluate the ability to modify the dam, which would be a requirement of the flood control project. Concurrently, the Skookumchuck Dam was also due for stability/safety studies required by the FERC, and the FERC agreed to use the Corps' field results instead of requiring the Owners to conduct duplicate drilling tests and studies. Once the Corps' studies were complete, it was unclear whether the structure met safety and stability criteria. The FERC commissioned an independent consultant to analyze the drilling test data and studies.

In March 2003, PacifiCorp received notification from FERC to conduct additional seismic drilling, at an estimated cost of $130,000, to determine the liquefaction potential of the dam under critical seismic load conditions. This additional field work was completed in January 2004 and the ensuing analysis is scheduled to be submitted to the FERC by March 31, 2004.

In addition, the Committee has been unable to secure governmental appropriations for the flood control project. Even if such a funding source materialized, the Committee has indicated that it would not pay for any remediation costs to bring the Project up to current seismic standards, and would only be willing to pay approximately 1/3 of the net book value of the Project, an offer that the Owners are not willing to accept.

Q. Why was TransAlta the only purchaser considered?

A. The dam was originally constructed to provide an assured water cooling source for the Centralia Steam Plant. This original purpose still has value to TransAlta, the owner and operator of the Centralia Steam Plant, but does not afford the same value to anyone else. For this reason, TransAlta included in the Skookumchuck Dam Management Agreement a right of first refusal for the purchase of the facilities at a price of net book value. In addition, TransAlta has expressed a willingness to meet the stability/safety requirements that may be imposed on the Skookumchuck Dam. *See* Sale Agreement, Sections 1.1(o), 2.6 and 5.3(a)(iv).

Q. Does TransAlta intend to operate the Project as an exempt wholesale generator ("EWG") under PUHCA?

A. Yes, that is the stated intention of TransAlta. In order to secure EWG status, we must ask the Commission to find that allowing the Project to be an "eligible facility" under PUHCA: (a) will benefit customers, (b) is in the public interest and (c) does not violate Washington law. Section III.B and Section IV of PacifiCorp's Application describe the specific approvals requested of the Commission. We ask the Commission to consider the EWG issues on an expedited basis. The Owners and TransAlta could move up the Closing Date if EWG findings are secured early from each state in which the Project was included in rate base, thus allowing TransAlta to accelerate its EWG filing with FERC.

Q. Does this conclude your direct testimony?

A. Yes.

Landolt
Exhibit (RAL-2)

Exhibit No.___(RAL-2)
Docket No.__________
Witness: Randy A. Landolt

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Application of PACIFICORP for an Order Approving the Sale of its Interest in the Skookumchuck Hydroelectric Plant and for EWG Determinations	Docket No. __________

PACIFICORP

EXHIBIT OF RANDY A. LANDOLT

Purchase and Sale Agreement and Exhibits

February 2004

SKOOKUMCHUCK FACILITIES PURCHASE AND SALE AGREEMENT

******

PACIFICORP;
PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY, WASHINGTON; PUGET SOUND ENERGY, INC.;
CITY OF TACOMA, WASHINGTON; AVISTA CORPORATION;
CITY OF SEATTLE, WASHINGTON; and
PUBLIC UTILITY DISTRICT NO. 1 OF GRAYS HARBOR COUNTY, WASHINGTON

As Sellers

AND

2677588 Washington LLC

As Buyer

Execution Copy

SKOOKUMCHUCK FACILITIES PURCHASE AND SALE AGREEMENT

TABLE OF CONTENTS

Page

LIST OF SCHEDULES

LIST OF EXHIBITS

SKOOKUMCHUCK FACILITIES PURCHASE AND SALE AGREEMENT

This SKOOKUMCHUCK FACILITIES PURCHASE AND SALE AGREEMENT (the "Agreement") is made and entered into as of the 25 day of November, 2003 by and among PACIFICORP ("PacifiCorp"); PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY, WASHINGTON ("Snohomish PUD"); PUGET SOUND ENERGY, INC. ("PSE"); CITY OF TACOMA, WASHINGTON ("Tacoma"); AVISTA CORPORATION ("Avista"); CITY OF SEATTLE, WASHINGTON ("Seattle"); AND PUBLIC UTILITY DISTRICT NO. 1 OF GRAYS HARBOR COUNTY, WASHINGTON ("Grays Harbor PUD") (each a "Seller" and collectively "Sellers"), and 2677588 WASHINGTON LLC, a Washington limited liability company or its nominee ("Buyer"), with reference to the following facts:

A. Sellers are engaged in the business of generating, transmitting and distributing electric energy and in connection therewith own as tenants in common the Skookumchuck Dam located along the Skookumchuck River near Centralia, Washington (the "Dam"). The Skookumchuck Facilities impound a reservoir on the Skookumchuck River (the "Reservoir").

B. Buyer desires to purchase from Sellers, and Sellers desires to sell to Buyer, the interests in the LLC to which Sellers will contribute the Dam, related real property and other assets associated therewith (collectively, the "Facilities") upon the terms and subject to the conditions of this Agreement.

NOW, THEREFORE, in consideration of the foregoing recitals and the agreements contained herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto, intending to be legally bound, do hereby agree as follows:

ARTICLE I
DEFINITIONS

Section 1.1 Certain Defined Terms. For purposes of this Agreement, the following terms shall have the following meanings:

(a) "Affiliate" of a specified Person shall mean any corporation, partnership, sole proprietorship or other Person which directly or indirectly through one or more intermediaries controls, is controlled by or is under common control with the Person specified. The term "control" means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a Person.

(b) "Assigned Contracts" shall mean all of Sellers' rights, title and interest in and to all written contracts and agreements specifically and exclusively relating to the Facilities to which Sellers are a party at the Closing. The Assigned Contracts shall also include, without limitation, engineering or construction contracts relating to engineering or construction work-in-progress at the Facilities; equipment leases (whether operating or capital leases) and installment purchase contracts; contracts or arrangements binding on the Facilities which restrict the nature of the business activities in which the Facilities may engage; and leases with respect to which Sellers are lessor or sublessor.

(c) "Business Day" means a day that is not a Saturday, a Sunday or a day on which banking institutions in the State of Washington are not required to be open.

(d) "Environmental Law" shall mean all applicable Laws and Licenses for or relating to: (i) air emissions, hazardous materials, storage, use and release to the environment of Hazardous Materials, generation, treatment, storage, and disposal of hazardous wastes, wastewater discharges and similar environmental matters, and (ii) the protection and enhancement of the environment (including without limitation the National Environmental Policy Act of 1969, 42 U.S.C. Section 4321 et seq.: Endangered Species Act of 1973, as amended, 16 U.S.C. Section 1531 et seq.; Migratory Bird Treaty Act, 16 U.S.C. Sections 703-712; Magnuson Stevens Fisheries Conservation and Management Act, 16 U.S.C. Section 1801 et seq.; the Washington State Environmental Policy Act of 1971, Chapter 43.21C RCW; Federal Water Pollution Control Act of 1972, 33 U.S.C. Section 1251 et seq.; and state Laws addressing species, impacts to water quality and wetlands).

(e) "Governmental Body" means any federal, state, local, municipal, or other government; any governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, police, regulatory or taxing authority or power; and any court or governmental tribunal; including without limitation FERC, the Securities Exchange Commission, the U.S. Department of Fish and Wildlife, the Washington Department of Fish and Wildlife, the U.S. Army Corps of Engineers and each State PUC; but does not include any Seller, Buyer, Buyer Affiliate, or any of their respective successors in interest or any owner or operator of the Facilities (if otherwise a Governmental Body) acting in their role as owner or operator.

(f) "Hazardous Materials" means any chemicals, materials, substances, or items in any form, whether solid, liquid, gaseous, semisolid, or any combination thereof, whether waste materials, raw materials, chemicals, finished products, by-products, or any other materials or articles, which are listed as hazardous, toxic or dangerous under Environmental Law, including without limitation, petroleum products, asbestos, urea formaldehyde foam insulation, lead-containing paints or coatings and "hazardous debris," "hazardous substances" and "hazardous wastes" as defined by WAC 173-303-040.

(g) "Knowledge" of a party shall mean with respect to such party, the extent of the actual knowledge of the Persons listed on Schedule 1.1(g) with respect to such party, with consultation of documents and Persons under their supervision in the ordinary course of their duties but without further inquiry of other Persons. Actual knowledge of any individual Seller shall not be imputed to any other individual Seller.

(h) "LLC" shall mean "Skookumchuck Dam, LLC," a Washington limited liability company to be formed for purposes of the LLC Transaction.

(i) "Laws" shall mean all statutes, rules, regulations, ordinances, orders, common law and their legal and equitable principles, and codes of federal, foreign, state and local governmental and regulatory authorities.

(j) "Licenses" shall mean registrations, licenses, permits, authorizations and other consents or approvals of Governmental Bodies.

(k) "Material Adverse Effect": (a) When used with respect to the LLC Interests, means a material adverse effect on the value or transferability of the LLC Interests, (b) when used with respect to the Assets or Facilities, means a material adverse effect on the Assets or Facilities and on the operation thereof, taken as a whole; (c) when used with respect to any portion of the Assets or Facilities, means a material adverse effect on such portion of the Assets or Facilities and on the operation thereof, taken as a whole; and (d) when used with respect to a Person, such as a Seller or Buyer, means a material adverse effect on the business, condition (financial or otherwise) and results of operations of such Person taken as a whole (including any subsidiaries of such entity) or on the ability of such Person to consummate the transactions contemplated hereby.

(l) "Person" means any individual, corporation (including any non-profit corporation), general or limited partnership, limited liability company, joint venture, estate, trust, association, organization, labor union, or other entity or Governmental Body.

(m) "PUHCA" means the Public Utility Holding Company Act of 1935, as amended, and the rules and regulations promulgated thereunder.

(n) "Release" means any release, spill, emission, leaking, pumping, emptying, dumping, injection, abandonment, deposit, disposal, discharge, dispersal, leaching, or migration of Hazardous Materials (including, without limitation, the abandonment or discarding of Hazardous Materials in barrels, drums, or other containers) into or within the environment, including, without limitation, the migration of Hazardous Materials into, under, on, through, soil, subsurface strata, surface water, groundwater, drinking water supply, any sediments associated with any water bodies, or any other environmental medium, regardless of where such migration originates.

(o) "Safety Program" means the design and implementation of the seismic drilling program contemplated by the Federal Energy Regulatory Commission's ("FERC") letters of March 19, 2003, July 31, 2003 and October 7, 2003 and Sellers' May 1, 2003 and July 30, 2003 letters to FERC which are attached hereto as Exhibit A and as may be further modified pursuant to Section 5.1(b)(ii).

(p) "State PUC" means any state commission with jurisdiction over the rates and charges of one or more Sellers.

(q) "Taxes" shall mean (i) all federal, state, county and local sales, use, real and personal property, recordation and transfer taxes, (ii) all business and occupation taxes, and (iii) any interest, penalties and additions to tax attributable to any of the foregoing, but shall not include income and other taxes described in Section 2.2(c).

(r) "Washington Ruling" shall mean a ruling letter to be issued by the Washington State Department of Revenue in response to the request to be filed by Buyer no earlier than 45 days prior to the Closing seeking confirmation that no Washington State sales or use tax will be due in respect of (i) the transfer of the Facilities by Sellers to the LLC, and (ii) the transfer of the LLC Interests by Sellers to Buyer.

Section 1.2 Index of Other Defined Terms. In addition to those terms defined above, the following terms shall have the respective meanings given thereto in the Sections indicated below:

Defined Term	Section
AAA	13.9(a)
Agreement	Preamble
Allocation Schedule	2.3
Approvals	8.4
Appurtenant Rights	2.1(b)
Assets	2.1
Buyer	Preamble
Buyer Affiliate	2.5
Chargeable Costs	5.3(a)
Charter Documents	3.2(a)
Claim Notice	12.6
Closing	10.2
Closing Date	10.2
Dam	Recital A
Deductible Amount	12.3(b)(ii)
Distribution Line	2.2(b)
Distribution Line Easement	Schedule 3.7
Equipment	2.1(c)
Escrow Agent	10.3
Excluded Assets	2.2
Facilities	Recital B
Facilities Purchase Price	2.3(a)
FERC	1.1(o)
Indemnitee	12.5
Indemnitor	12.5(a)
LLC Interests	2.1
LLC Transaction	10.1
Losses	12.3(a)
Management Agreement	5.3(a)
Net Book Value	2.3(a)
New Exception	5.4
O&M Costs	5.3(a)
O&M Costs Forecast	5.3(a)(v)
Owned Real Property	2.1(a)
Permitted Encumbrances	3.7
Reservoir	Recital A
Rules	13.9(a)
Sellers	Preamble

ARTICLE II
BASIC TRANSACTIONS

Section 2.1 Purchased Assets. On the terms and subject to the conditions contained in this Agreement, at the Closing Buyer shall, or shall cause the applicable Buyer Affiliate to, purchase, and Sellers shall sell, convey, assign, transfer and deliver to Buyer, or the applicable Buyer Affiliate, all of Sellers' rights, title and interest in the LLC (the "LLC Interests") after Sellers have contributed, conveyed, assigned, transferred and delivered to the LLC the following assets that (except to the extent otherwise noted) are used in the operations of the Facilities (the "Assets"), but excluding all Excluded Assets (as defined in Section 2.2):

(a) All of Sellers' rights, title and interest in and to the real property owned in fee (the "Owned Real Property") that is identified on Schedule 2.1(a), together with all buildings, fixtures and improvements located thereon (including all construction work-in-progress), reserving to PSE the Distribution Line described on Schedule 2.2(b).

(b) All of Sellers' easements, rights of way, licenses, franchises, water rights (including, without limitation, perfected, certificated, or otherwise, to divert, impound, consume or otherwise use waters of the State of Washington) and similar real property rights appurtenant to their ownership of the Owned Real Property or associated with their operation of the Facilities (collectively, the "Appurtenant Rights"), including, without limitation, those identified on Schedule 2.1(b).

(c) The fixed or mobile machinery and equipment, as well as similar items of tangible personal property, including, without limitation those items listed on Schedule 2.1(c) (collectively "Equipment") that are used, owned or leased by Sellers as of the Closing Date, and are used primarily in connection with the ownership or operation of the Facilities and its related support facilities (including Assets temporarily off-site for repair or other purposes), but excluding the Distribution Line described on Schedule 2.2(b).

(d) All of Sellers' rights, title and interest in and to and obligations arising under the Assigned Contracts including, without limitation, those identified on Schedule 2.1(d).

(e) All of Sellers' rights, title and interest in and to and obligations arising under all of the Licenses in favor of Sellers or any Sellers' Affiliates as of Closing that relate to or are necessary for or used in connection with the operation of the Facilities as heretofore operated by Sellers, all of such Licenses being included on Schedule 2.1(e), except for and to the extent that such Licenses relate to Excluded Assets; provided that such Licenses shall be included within the Assets only to the extent they relate exclusively to the Facilities and are lawfully transferable to the LLC.

(f) All of Sellers' rights, title and interest in and to all of the books, records, plans, sepias, drawings, instruction manuals and similar items, whether in written or electronic form, to the extent they relate to the Facilities or the operation thereof, and other procedural manuals of Sellers related primarily to the operation of the Facilities, subject to the rights of Sellers to make copies of and make non-exclusive use of the same and except to the extent such materials are subject to confidentiality or non-disclosure agreements in favor of third parties whose consent to transfer is not obtained.

(g) All of Sellers' rights, title and interest, if any, in and to unexpired warranties as of the Closing that are transferable to the LLC wholly owned by Buyer which Sellers have received from third parties which relate specifically to the Facilities, including, without limitation, warranties set forth in any equipment purchase agreement, construction agreement, lease agreement, consulting agreement or agreement for architectural or engineering services, it being understood that nothing in this paragraph shall be construed as a representation by Sellers that any such unexpired warranty remains enforceable.

(h) All of Sellers' rights, if any, to create, claim, obtain, register or otherwise hold any right to climate change, greenhouse gas or other renewable energy or emission credits or offsets relating to the Assets or their operation with respect to any period of time.

(i) Claims, choses in action, rights of recovery, rights of set-off, rights to refunds and similar rights of any kind in favor of any one or all of Sellers relating to or arising out of the period prior to Closing related to Washington State sales taxes included in the Chargeable Costs, whether such refund is received as a payment or as a credit against future Washington State sales taxes.

(j) Any of the foregoing owned or otherwise held by an Affiliate of a Seller.

Section 2.2 <u>Excluded Assets</u>. The Assets shall not include any of the assets, properties, rights, Licenses, or contracts of Sellers not specifically enumerated in Section 2.1 above, all such other assets, properties, rights, Licenses, and contracts collectively constituting "<u>Excluded Assets</u>," including, without limitation, the following specifically enumerated Excluded Assets:

(a) The fixtures, equipment and other personal property located at the Facilities comprising or constituting a part of the proprietary or specialized communications systems used by any or all of Sellers to communicate between and among their facilities or to transmit voltage and other control data and information utilized in any or all of Sellers' transmission and distribution systems.

(b) The distribution line (the "<u>Distribution Line</u>") described on <u>Schedule 2.2(b)</u> and the Distribution Line Easement described on <u>Schedule 3.7</u>.

(c) Claims, choses in action, rights of recovery, rights of set-off, rights to refunds and similar rights of any kind in favor of any one or all of Sellers relating to or arising out of the period prior to Closing, including, but not limited to, any refund related to real estate taxes paid prior to the Closing, whether such refund is received as a payment or as a credit against future real estate or other taxes, excluding Washington State sales taxes included in the Chargeable Costs.

(d) Subject to the provisions of Section 2.4, all privileged or proprietary (to any or all of Sellers) materials, documents, information, media, methods, and processes owned by or licensed to any or all of Sellers and any and all rights to use same, including, without limitation, intangible assets of an intellectual property nature such as trademarks, service marks and trade names (whether or not registered), computer software that is proprietary to any or all of Sellers, or the use of which under the pertinent license therefor is limited to operation by any or all of Sellers or their Affiliates or on equipment owned by any or all of Sellers or their Affiliates, all promotional or marketing materials (including all marketing computer software), and any and all trade names under which Sellers or the Facilities prior to Closing have done business or offered programs, and all abbreviations and variations thereof.

(e) The rights of any or all of Sellers under any insurance policy (it being understood, however, that Sellers will have no obligation to take any action under any such policy to seek any recovery except at the reasonable request, and at the sole expense, of Buyer or to continue any such policies in force except to the extent expressly set forth herein).

(f) Any and all rights respecting computer and data processing hardware or firmware that is proprietary to any or all of Sellers and any computer and data processing hardware or firmware, whether or not located at the Facilities, that is part of a computer system the central processing unit of which is not located at the Facilities.

(g) Any and all data and information pertaining to customers of Sellers or their Affiliates, whether or not located at the Facilities.

(h) Miscellaneous assets, if any, identified by category on Schedule 2.2(h), which assets may have been utilized by Sellers in the ownership and operation of the Facilities but which are not intended to be included in the Assets and which are not otherwise enumerated above.

(i) Subject to Section 5.3 respecting certain expenses incurred in connection with the transactions contemplated hereby, any of Sellers' or their Affiliates' liabilities or obligations with respect to franchise taxes and with respect to foreign, federal, state or local taxes imposed upon or measured, in whole or in part, by the income for any period of Sellers or any member of any combined or consolidated group of companies of which any of Sellers are, or were at any time, a part, or with respect to interest, penalties or additions to any of such taxes, and any income, franchise, tax recapture, transfer tax, sales tax or use tax that may arise upon consummation of the transactions contemplated hereby and be due from or payable by Sellers, it being understood that neither the LLC nor Buyer shall be deemed to be Sellers' transferee with respect to any such tax liability.

Sellers may remove at any time or from time to time, up to 90 days following the Closing, any and all of the Excluded Assets from the Facilities (at Sellers' expense, but without charge by Buyer for storage), *provided* that Sellers shall do so in a manner that does not unduly or unnecessarily disrupt Buyer's normal business activities at the Facilities, and *provided further* that Excluded Assets may be retained at the Facilities pursuant to easements, licenses or similar arrangements retained by Sellers and described above or otherwise in the Schedules to this Agreement.

Section 2.3 Facilities Purchase Price.

(a) The Facilities purchase price shall be $7,570,373.16, which is PacifiCorp's net book value for the Facilities as of September 30, 2003 multiplied by 2.105 (as contemplated by Section 1.3(b) of the Management Agreement) ("Net Book Value"), adjusted for changes in such Net Book Value of the Facilities from September 30, 2003 to the Closing Date (the "Facilities Purchase Price").

(b) The adjustment described in Section 2.3(a) above shall be determined in accordance with U.S. GAAP and FERC accounting guidelines. The Facilities Purchase Price as so adjusted shall be communicated by written notice to Buyer not less than ten (10) Business Days prior to the Closing. Buyer shall, or shall cause one or more Buyer Affiliates to, pay to Sellers the Facilities Purchase Price in cash at the Closing by wire transfer of immediately available funds in U.S. dollars to an account specified in writing by Sellers to Buyer. Sellers shall give Buyer written notice of the account for the wire transfer not later than the tenth (10^{th}) Business Day prior to the Closing Date.

(c) PacifiCorp and Buyer agree that for all purposes, except Washington property taxes and Washington sales taxes, the Facilities Purchase Price shall be allocated among the Assets in proportion to the Net Book Value as adjusted under this Section 2.3.

Section 2.4 License of Non-Transferred Intangible Assets. Although trade names of Sellers are Excluded Assets, such names appear on certain of the Assets, such as certain fixtures and Equipment, and on supplies, materials, stationery and similar consumable items which may be on hand at the Facilities at the Closing. Notwithstanding that such names are Excluded Assets, the LLC, Buyer and any Buyer Affiliates shall be entitled to use such consumable items for a period of three (3) months following the Closing and shall have up to six (6) months following the Closing to remove such names from fixed Assets, *provided* that none of such parties shall send correspondence or other materials to third parties on any stationery that contains a trade name or trademark of Sellers or any Affiliates of Sellers.

Section 2.5 Assignment of Rights and Obligations to Buyer Affiliate. For purposes of this Agreement, the term "Buyer Affiliate" shall refer to any Affiliate of Buyer to which any of Buyer's rights and obligations hereunder are assigned in compliance with the requirements of this Section. Notwithstanding any contrary provisions contained herein, the parties hereto agree that, prior to and after the Closing, Buyer, in its sole discretion, may assign any or all of its rights and obligations arising under this Agreement or any other agreement contemplated hereby to one or more Buyer Affiliates, *provided* that no such assignment shall relieve Buyer of any obligation or liability to Sellers hereunder or any other agreement contemplated hereby.

Section 2.6 Assumption of Liabilities. Buyer agrees to assume all liabilities related to the Facilities including, but not limited to, the Assigned Contracts and the Safety Program after Closing; *provided, however,* that the obligations set forth on Schedule 2.6 are not to be assumed by Buyer and are to be released or otherwise discharged by Closing by Sellers pursuant to the terms and conditions of this Agreement.

Section 2.7 Water Flow Agreement. The Water Flow Agreement between Sellers and TransAlta Centralia Generation LLC dated May 4, 2000 is hereby extended to the Closing Date or date of termination of this Agreement.

ARTICLE III
REPRESENTATIONS AND WARRANTIES OF SELLERS

Sellers hereby represent and warrant to Buyer, as of the date hereof, as follows, except as set forth in Schedules numbered in relation to the Sections set forth below:

Section 3.1 Authority and Enforceability. The execution, delivery and performance of this Agreement and all other agreements contemplated hereby and the consummation of the transactions contemplated hereby and thereby have been duly authorized by the board of directors or other applicable governing body of each Seller; no other corporate act or corporate proceeding on the part of any Seller is necessary to authorize this Agreement or any other agreement contemplated hereby or the transactions contemplated hereby and thereby. This Agreement has been and other agreements contemplated hereby will be, as of the Closing duly executed and delivered by each of Sellers, and this Agreement constitutes and such other agreements when executed and delivered will constitute, a valid and binding obligation of Sellers, enforceable against Sellers in accordance with its terms, except as it may be limited by bankruptcy, insolvency, reorganization, moratorium or other similar Laws now or hereafter in effect relating to creditors' rights generally and that the remedy of specific performance and injunctive and other forms of equitable relief may be subject to equitable defenses and to the discretion of the court before which any proceeding may be brought.

Section 3.2 No Breach or Conflict. Subject to the provisions of Sections 3.3(a) and 3.3(b) below regarding private party and governmental consents, and except for any regulatory or licensing Laws applicable to the businesses and assets represented by the Facilities, the execution, delivery and performance by Sellers of this Agreement and any other agreements contemplated hereby do not:

(a) conflict with or result in a breach of any of the provisions of the Articles of Incorporation or Bylaws or similar charter documents (the "Charter Documents") of Sellers;

(b) contravene any Law presently in effect or cause the suspension or revocation of any License presently in effect, which affects or binds Sellers or any of their properties, except where such contravention, suspension or revocation will not have a Material Adverse Effect (as defined below) on the LLC Interests or the Assets and will not affect the validity or enforceability of this Agreement or any other agreement contemplated hereby or the validity of the transactions contemplated hereby and thereby; or

(c) conflict with or result in a breach of or a default (with or without notice or lapse of time or both) under any material agreement or instrument to which Sellers are a party or by which they or any of their properties may be affected or bound, the effect of which conflict, breach, or default, either individually or in the aggregate, would be a Material Adverse Effect on the Assets or the LLC Interests.

Section 3.3 Approvals.

(a) Except as set forth on Schedule 3.3(a), the execution, delivery and performance by Sellers of this Agreement and any other agreements contemplated hereby (including the assignment of the non-governmental Assigned Contracts) do not require the authorization, consent or approval of any non-governmental third party of such a nature that the failure to obtain the same would have a Material Adverse Effect on the LLC Interests, the Assets or the Facilities substantially as they have heretofore operated.

(b) Except as set forth on Schedule 3.3(b), the execution, delivery and performance by Sellers of this Agreement and any other agreements contemplated hereby (including the assignment of any Assigned Contracts to which a Governmental Body is a party) do not require the authorization, consent, approval, certification, license or order of, or any filing, with, any court or Governmental Body of such a nature that the failure to obtain the same would have a Material Adverse Effect on the LLC Interests or the Assets.

Section 3.4 Licenses. Except as set forth on Schedule 3.4, all Licenses necessary for the operation of the Facilities at the location and in the manner presently operated, related thereto in any material respect or required in order to consummate or perform the transactions contemplated under this Agreement are set forth on Schedule 2.1(e). Except as identified on Schedule 3.4, all such Licenses are valid and in full force and effect and not subject to termination for default by notice or passage of time or both.

Section 3.5 Compliance with Law. Except as set forth on Schedule 3.5, and except for the matters that are the subject of Sections 3.4 and 3.6 and the Schedules, if any, related thereto, to Sellers' Knowledge, Sellers are in compliance in all material respects with all pertinent Laws and Licenses related to the ownership and operation of the LLC Interests or the Assets, other than violations that would not, individually or in the aggregate, have a Material Adverse Effect on the ownership, use or operation of the LLC Interests or the Assets or on the ability of Sellers to execute and deliver this Agreement or any other agreements contemplated hereby and consummate the transactions contemplated hereby and thereby.

Section 3.6 Hazardous Materials. To Sellers' Knowledge, except as disclosed on Schedule 3.6:

(a) There has not been a Release of Hazardous Material on or otherwise affecting the Assets (other than Releases involving de minimis quantities of Hazardous Materials) that: (i) constitutes an unremedied material violation of any Environmental Law by Sellers or by any third party if the effect of such violation by such third party imposes a current remediation obligation on the part of Sellers; (ii) currently imposes any material release-reporting obligations on Sellers under any Environmental Law that have not been or are not being complied with; or (iii) currently imposes any material clean-up or remediation obligations of Sellers under any Environmental Law.

(b) Sellers, during at least the last three (3) years, have complied, and currently are in compliance, in all material respects, with all Environmental Laws that govern the Assets;

(c) Sellers have all material Licenses required under Environmental Laws for its operation of the Assets, are in compliance in all material respects with all such Licenses and during the three (3) year period preceding the date of this Agreement have not received any notice that: (i) any such existing Licensing will be revoked; or (ii) any pending application for any new such License or renewal of any existing Licensing will be denied;

(d) Sellers have not received any currently outstanding written notice of any material proceedings, action, or other claim or liability arising under any Environmental Laws (including, without limitation, notice of potentially responsible party status under the Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. §§ 9601 et seq. or any state counterpart) from any Person or Governmental Body regarding the Assets; and

(e) No portion of the Assets has ever contained an underground storage tank, surface impoundment or similar device used for the management of wastewater, or other waste management unit dedicated to the disposal, treatment, or long-term (greater than 90 days) storage of Hazardous Materials.

Section 3.7 Title to Assets. Sellers have good, valid and marketable title to the LLC Interests and all tangible real and personal property included in the Assets to be sold, conveyed, assigned, transferred and delivered to the LLC, Buyer or a Buyer Affiliate, as the case may be, by Sellers, free and clear of all liens, charges, claims, pledges, security interests, equities, licenses and encumbrances of any nature whatsoever, except for those created or allowed to be suffered by Buyer or such Buyer Affiliate and except for the following: (i) the lien of current taxes not delinquent, (ii) liens and encumbrances listed on Schedule 3.7 (the "Permitted Encumbrances"), (iii) such consents, authorizations approvals and Licenses referred to in Sections 3.3(a), 3.3(b) and 3.4, (iv) liens, charges, claims, pledges, security, interests, equities and encumbrances which will be discharged or released either prior to, or substantially simultaneously with, the Closing Date (and which Sellers will cause to be discharged or released), and (v) the matters contained in the Assigned Contracts set forth on Schedule 2.1(d) and the Licenses set forth on Schedule 2.1(e).

Section 3.8 Contracts. Except for such matters which individually and in the aggregate do not have a Material Adverse Effect on the LLC Interests or the Assets, or except as otherwise disclosed on Schedule 3.8, to Sellers' Knowledge (a) there is no liability to any third party by reason of the default by Sellers under any Assigned Contract, (b) Sellers have not received notice that any Person intends to cancel or terminate any Assigned Contract nor are they otherwise subject to termination for default by notice or passage of time or both, and (c) all of the Assigned Contracts are in full force and effect; *provided* that notwithstanding clauses (a), (b) and (c) of this Section 3.8, Sellers make no separate representation or warranty under this Section respecting compliance with the provisions of Laws generally, Hazardous Materials, title to or condition of property, Licenses, environmental conditions or Environmental Laws.

Section 3.9 Litigation. Except for (a) ordinary, routine and non-material claims and litigation incidental to the businesses represented by the Assets (including, without limitation, actions for negligence, workers' compensation claims and the like), (b) Governmental Body inspections and reviews customarily made of businesses such as those operated from the Facilities, (c) non-material proceedings before any Governmental Body, (d) proceedings before any Governmental Body that are contemplated by this Agreement (as set forth on Schedule 3.3(b)), and (e) as set forth on Schedule 3.9, there are no actions, suits, claims or proceedings pending, or to Sellers' Knowledge, threatened against or affecting the LLC Interests or the Assets or relating to the operations of the Assets, at law or in equity, or before or by any Governmental Body.

Section 3.10 Brokers. No broker, finder, or investment banker is entitled to any brokerage, finder's or other fee or commission in connection with this Agreement or the transactions contemplated hereby based upon any agreements or arrangements or commitments written or oral, made by or on behalf of Sellers.

Section 3.11 Assets Used in the Operation of the Facilities. Except as delineated on Schedule 3.11, and except for the Excluded Assets, there are no material assets or properties that are used in the conduct of the operations of the Facilities that are owned by Sellers or that individually or in the aggregate are reasonably necessary for the operation of the Facilities as currently operated by Sellers that are not included in the Assets.

Section 3.12 Option Rights. Except as delineated on Schedule 3.12, none of the Persons constituting Sellers, nor to Sellers' Knowledge any other Person, retains any rights of first refusal, option rights or other similar rights to purchase all or any portion of the LLC Interests or the Assets in connection with a contribution of the Assets to the LLC or a sale of the LLC Interests to Buyer pursuant to this Agreement.

Section 3.13 LLC Interests. The LLC Interests that Sellers will transfer to Buyer at the Closing constitute Sellers' entire interest in the LLC and the Assets.

Section 3.14 Liability. Prior to the Closing, the LLC has no direct or indirect liability, indebtedness, obligation, commitment, expense, claim, deficiency, liability for Taxes, guaranty or endorsement of any type, whether accrued, absolute, contingent, matured, unmatured, due or to become due or otherwise.

Section 3.15 Liabilities. Except as otherwise disclosed in this Agreement or on the Schedules attached hereto, to Sellers' Knowledge, there are no other material liabilities associated with the Facilities.

Section 3.16 Appurtenant Rights. Except as disclosed on Schedule 2.2(b), no Seller has any Appurtenant Rights associated with the Facilities that are not being conveyed hereunder or have not been previously conveyed to Buyer or an Affiliate of Buyer. Sellers have at all times taken all reasonable measures, and shall continue to do so through the Closing, to protect and maintain the Appurtenant Rights associated with the Facilities.

Section 3.17 Disregarded Entity. The LLC is and has at all times before and at Closing been a disregarded entity for federal income tax purposes and all applicable state income tax purposes.

Section 3.18 Regulatory Status. Neither Avista nor PSE is, as of the date of this Agreement, a registered holding company under PUHCA or an Affiliate of such a company, and PacifiCorp has received (or will receive as of the Closing) all SEC approvals, if any, required under PUHCA to consummate the transactions contemplated by this Agreement.

ARTICLE IV
REPRESENTATIONS AND WARRANTIES OF BUYER

Buyer hereby represents and warrants to Sellers, as of the date hereof, as follows, except as set forth in Schedules numbered in relation to the Sections set forth below:

Section 4.1 Organization and Corporate Power. Buyer is a limited liability company duly incorporated and validly existing under the Laws of, and is authorized to exercise its limited liability company powers, rights and privileges and is in good standing in, the State of Washington and has full corporate power to carry on its business as presently conducted and to own or lease and operate its properties and assets now owned or leased and operated by it and to perform the transactions on its part contemplated by this Agreement and all other agreements contemplated hereby.

Section 4.2 Authority and Enforceability. The execution, delivery and performance of this Agreement and any other agreements contemplated hereby and the consummation of the transactions contemplated hereby and thereby have been duly authorized by the management committee or other applicable governing body of Buyer; no other corporate act or corporate proceeding on the part of Buyer is necessary to authorize this Agreement, any other agreement contemplated hereby, or the transactions contemplated hereby and thereby. This Agreement has been, and other agreements contemplated hereby will be, as of the Closing, duly executed and delivered by Buyer, and this Agreement constitutes, and such other agreements when executed and delivered will constitute, a valid and binding obligation of Buyer, enforceable against Buyer, in accordance with its terms, except as it may be limited by bankruptcy, insolvency, reorganization, moratorium or other similar Laws now or hereafter in effect relating to creditors' rights generally and that the remedy of specific performance and injunctive and other forms of equitable relief may be subject to equitable defenses and to the discretion of the court before which any proceeding may be brought.

Section 4.3 No Breach or Conflict. Subject to the provisions of Sections 4.4(a) and 4.4(b) below regarding private party and governmental consents, and except for any regulatory or licensing Laws applicable to the businesses and assets represented by the Facilities, the execution, delivery and performance by Buyer and any Buyer Affiliate of this Agreement and any other agreements contemplated hereby do not:

(a) conflict with or result in a breach of any of the provisions of the Charter Documents of Buyer or any Buyer Affiliate;

(b) contravene any Law presently in effect or cause the suspension or revocation of any License presently in effect, which affects or binds Buyer or any Buyer Affiliate or any of their material properties; or

(c) conflict with or result in a breach of or default under any material agreement or instrument to which Buyer or any Buyer Affiliate is a party or by which it or they or any of their properties may be affected or bound.

Section 4.4 Approvals.

(a) Except as set forth on Schedule 4.4(a), the execution, delivery and performance by Buyer and any Buyer Affiliate of this Agreement and any other agreement contemplated hereby do not require the authorization, consent or approval of any non-governmental third party.

(b) Except as set forth on Schedule 4.4(b), the execution, delivery and performance by Buyer and any Buyer Affiliate of this Agreement and any other agreement contemplated hereby do not require the authorization, consent, approval, certification, license or order of, or any filing with, any court or Governmental Body, to consummate the transactions contemplated hereby and to permit Buyer to acquire the LLC Interests and the LLC to acquire the Assets.

Section 4.5 Litigation. Except as set forth on Schedule 4.5, there are no actions, suits, claims or proceedings pending, or to Buyer's Knowledge, threatened against Buyer or any Buyer Affiliate likely to impair the consummation of the transactions contemplated hereby or otherwise material to such transactions or to Buyer or any Buyer Affiliate, and Buyer is not aware of facts likely to give rise to such litigation.

Section 4.6 Brokers. No broker, finder, or investment banker is entitled to any brokerage, finder's or other fee or commission in connection with this Agreement or the transactions contemplated hereby based upon any agreements or arrangements or commitments, written or oral, made by or on behalf of Buyer.

Section 4.7 Exculpation. BUYER AGREES THAT EXCEPT FOR THE REPRESENTATIONS AND WARRANTIES EXPRESSLY SET FORTH IN THIS AGREEMENT, (i) THE ASSETS ARE BEING SOLD ON AN "AS IS" "WHERE IS" BASIS AND IN "WITH ALL FAULTS" CONDITION, (ii) WITHOUT LIMITING THE GENERALITY OF THE FOREGOING, SELLERS MAKE NO WRITTEN OR ORAL REPRESENTATION OR WARRANTY, EITHER EXPRESS OR IMPLIED, WITH RESPECT TO THE FITNESS, CONDITION, MERCHANTABILITY, OR SUITABILITY OF THE ASSETS FOR ANY PARTICULAR PURPOSE OR THE OPERATION OF THE ASSETS BY BUYER, AND (iii) BUYER WAIVES ALL RIGHTS TO CONTRIBUTION, OFFSETS AND DAMAGES WHICH IN ANY MANNER RELATE TO THE COMPLIANCE OF THE FACILITIES WITH ANY LAWS.

Section 4.8 Financing. Buyer has liquid capital or committed sources therefor sufficient to permit it and the pertinent Buyer Affiliates, if any, and the LLC to perform timely its or their obligations hereunder and under any other agreements contemplated hereby.

Section 4.9 No Knowledge of Sellers' Breach. Buyer has no Knowledge of any breach of any representation or warranty by Sellers or of any other condition or circumstance that would excuse Buyer from its timely performance of its obligation hereunder. Buyer shall notify Sellers as promptly as practicable if any such information comes to its attention prior to Closing.

Section 4.10 Qualified for Licenses. To Buyer's Knowledge, Buyer and any pertinent Buyer Affiliate and the LLC are, or by Closing will be, qualified to obtain any Licenses necessary for the operation by Buyer, such Buyer Affiliate or the LLC of the Facilities as of the Closing in substantially the same manner as the Facilities are presently operated by Sellers.

Section 4.11 Buyer Affiliate.

(a) As of the Closing, each Buyer Affiliate will be an entity duly organized, validly existing and in good standing under the Laws of its state of organization. Each Buyer Affiliate will at the Closing have all requisite power and authority to carry on its business as then conducted and to own or lease and operate its properties and assets then owned or leased and operated by it and to perform the transactions on its part contemplated by this Agreement and all other agreements contemplated hereby.

(b) The governing body of each Buyer Affiliate and, if required, its shareholders or other owners, will have, by the date of the Closing, duly and effectively authorized (i) the purchase of the LLC Interests to be purchased by such Buyer Affiliate, and (ii) the execution, delivery and performance of this Agreement and any other agreements contemplated hereby and thereby to which such Buyer Affiliate is a party. No other organizational act or proceeding on the part of any Buyer Affiliate, its governing body or its shareholders or other owners will be necessary to authorize this Agreement or other agreement contemplated hereby and thereby or the transactions contemplated hereby and thereby.

(c) This Agreement and all other agreements contemplated hereby and thereby to which any Buyer Affiliate is a party will, as of the Closing, be duly executed and delivered by each such Buyer Affiliate, and each such agreement, when executed and delivered will constitute, a valid and binding obligation of such Buyer Affiliate, enforceable against such Buyer Affiliate in accordance with its terms, except as it may be limited by bankruptcy, insolvency, reorganization, moratorium or other similar Laws now or hereafter in effect relating to creditors' rights generally and that the remedy of specific performance and injunctive and other forms of equitable relief may be subject to equitable defenses and to the discretion of the court before which any proceeding may be brought.

ARTICLE V
COVENANTS OF EACH PARTY

Section 5.1 Efforts to Close.

(a) Reasonable Efforts. Subject to the terms and conditions herein provided including, without limitation, Articles 8 and 9 hereof, each of the parties hereto agrees to take all reasonable actions and to do all reasonable things necessary, proper or advisable under applicable Laws to consummate and make effective, as soon as reasonably practicable, the transactions contemplated hereby, including the satisfaction of all conditions thereto set forth herein. Such action shall also include, without limitation, exerting their reasonable efforts to obtain the consents, authorizations and approvals of all private parties and Governmental Bodies whose consent is reasonably necessary to effectuate the transactions contemplated hereby, and effecting all other necessary registrations and filings. Sellers shall cooperate with Buyer's efforts to obtain the requisite Licenses and regulatory consents, provided Sellers shall not be obligated to incur any liabilities or assume any obligations in connection therewith. Other than Buyer's and Sellers' obligations under Section 5.3, no party shall have any liability to the other parties if, after using its reasonable commercial efforts, it is unable to obtain any consents, authorizations or approvals necessary for such party to consummate the transactions contemplated hereby. As used herein, the terms "reasonable efforts" or "reasonable actions" do not include the provision of any consideration to any third party, the commencement of litigation or the suffering of any economic detriment to a party's ongoing operations for the procurement of any such consent, authorization or approval except for the costs of gathering and supplying data or other information or making any filings, the fees and expenses of counsel and consultants and the customary fees and charges of Governmental Bodies. Furthermore, Sellers and Buyer shall execute and deliver such other agreements, documents and instruments as are required to be delivered by such party prior to Closing to effectuate the transactions contemplated by this Agreement.

(b) Control Over Proceedings.

(i) All analyses, appearances, presentations, memoranda, briefs, arguments, opinions and proposals made or submitted by or on behalf of any party before any Governmental Body (other than any governing board or other governing body of any of the publicly owned utility Sellers) in connection with the approval of the transactions contemplated hereby, or any other matter before any Governmental Body relating to the LLC Interests or the Assets shall be subject to the joint review of Buyer and Sellers, it being the intent that the parties will consult and cooperate with one another, and consider in good faith the views of one another, in connection with any such analysis, appearance, presentation, memorandum, brief, argument, opinion and proposal; *provided* that nothing will prevent a party from responding to a subpoena or other legal process as required by Law or submitting factual information in response to a request therefor. Each party will promptly provide the others with copies of all written communications from Governmental Bodies relating to the approval or disapproval of the transactions contemplated by this Agreement. Nothing in this Agreement shall limit Buyer's ability to intervene in regulatory proceedings related to the LLC Interests or the Assets.

(ii) Notwithstanding the foregoing, Sellers shall not make any change in the Safety Program, which is attached hereto as Exhibit A, without Buyer's prior written consent (which Buyer shall not unreasonably withhold, condition or delay). If Sellers wish to make a change in the Safety Program, they shall first propose the change to Buyer in writing. Buyer shall have ten (10) Business Days in which to disapprove of the proposed change by written notice to Sellers explaining Buyer's reasons for disapproving. If Buyer has not disapproved of the change within the ten (10) Business Day period, it shall be deemed approved.

(iii) Notwithstanding the foregoing, to the extent that FERC requires a change in the Safety Program and such change was not sought by Sellers, Sellers shall have the right to implement such change in compliance with directives from FERC, *provided however*, Sellers shall promptly notify Buyer of such directives and shall allow Buyer to participate in any communication or proceedings related to the implementation of such change.

Section 5.2 Post-Closing Cooperation. After the Closing, upon prior reasonable written request, each party shall cooperate with the other parties in furnishing records, information, testimony and other assistance in connection with any inquiries, actions, audits, proceedings or disputes involving any of the parties hereto (other than in connection with disputes between the parties hereto) and based upon contracts, arrangements or acts of Sellers which were in effect or occurred on or prior to Closing and which relate to the LLC Interests or the Assets, including, without limitation, arranging discussions with (and the calling as witness of) officers, directors, employees, agents, and representatives of the LLC, Buyer and any Buyer Affiliates. The requesting party shall in each instance be responsible for payment of any costs and expenses reasonably incurred by any other party in affording such cooperation, including any out-of-pocket expenses reasonably incurred by such party to third parties; *provided, however*, that in no event shall the costs and expenses for which any such requesting party shall be liable include any wages or other benefits paid or provided by any such cooperating party to its officers, directors or employees.

Section 5.3 Expenses. Whether or not the transactions contemplated hereby are consummated, except as otherwise provided in this Agreement, all costs and expenses incurred in connection with this Agreement and the transactions contemplated hereby or thereby shall be paid by the party incurring such expenses except as follows:

(a) O&M Costs. The "O&M Costs" shall be equal to 100% of the Chargeable Costs incurred on or after May 4, 2002 until the Closing. "Chargeable Costs" shall have the same meaning given to that term in the Management Agreement between Sellers and TransAlta Centralia Generation LLC, dated May 4, 2000, which is hereby extended to the Closing Date or date of termination of this Agreement (the "Management Agreement"); *provided, however*, (i) Chargeable Costs shall also include Sellers' costs associated with the Safety Program to the extent such costs are incurred while the Management Agreement remains in effect, and (ii) except as otherwise provided in Section 5.3(a)(ii), the $300,000 annual cap on Chargeable Costs contemplated in Section 4.2 of the Management Agreement shall cease to apply effective on and after May 4, 2002.

(i) O&M Costs Payment Due at Execution. Unless otherwise agreed to by PacifiCorp and Buyer in writing, on the execution date of this Agreement Buyer shall, or shall cause one or more Buyer Affiliates to, pay to PacifiCorp $477,067.46 (which is the total amount of the O&M Costs from May 4, 2002 to September 30, 2003) in cash by wire transfer of immediately available funds in U.S. dollars to an account specified in writing by PacifiCorp to Buyer. PacifiCorp shall give Buyer written notice of the account for the wire transfer not later than the tenth (10^{th}) Business Day prior to the execution date of this Agreement.

(ii) O&M Costs Payment Due at Closing or Termination. PacifiCorp will inform Buyer in writing, at least ten (10) Business Days prior to the Closing Date, or within ten (10) Business Days following the date of termination of this Agreement, as the case may be, of the amount of O&M Costs PacifiCorp has incurred and received invoices for after September 30, 2003 that are not included in the O&M Costs payment due at execution under Section 5.3(a)(i). Buyer shall, or shall cause one or more Buyer Affiliates to, pay to PacifiCorp such amount in cash by wire transfer of immediately available funds in U.S. dollars not later than the Closing Date, or ten (10) Business Days following Buyer's receipt of PacifiCorp's notice of the amount due after termination, as the case may be, to an account specified in writing by PacifiCorp to Buyer. PacifiCorp shall give Buyer written notice of the account for the wire transfer not later than the tenth (10^{th}) Business Day prior to the Closing Date, or concurrently with PacifiCorp's notice of the amount due after termination, as the case may be. Notwithstanding the foregoing, if this Agreement is terminated by Buyer or Sellers pursuant to Section 11.1(b); by Buyer pursuant to Section 11.1(c); by Buyer pursuant to Section 11.1(d)(ii)(B); or by Buyer pursuant to Section 5.4, 8.6(b), 8.7(a) or 8.7(b); then the $300,000 annual cap on Chargeable Costs contemplated in Section 4.2 of the Management Agreement shall be reinstated effective September 30, 2003.

(iii) O&M Costs Payment Due Post-Closing or Post-Termination. PacifiCorp will inform Buyer in writing, within 90 days after the Closing Date or date of termination of this Agreement, of the amount of O&M Costs PacifiCorp has incurred prior to the Closing Date or date of termination, and received invoices for prior to or after the Closing Date or date of termination, as the case may be, that are not included in the O&M Costs payment due at Closing or termination under Section 5.3(a)(ii). Buyer shall, or shall cause one or more Buyer Affiliates to, pay to PacifiCorp such amount in cash by wire transfer of immediately available funds in U.S. dollars not later than the tenth (10^{th}) Business Day after Buyer's receipt of PacifiCorp's notice of the amount due, to an account specified in writing by PacifiCorp to Buyer. PacifiCorp shall give Buyer written notice of the account for the wire transfer not later than the tenth (10^{th}) Business Day prior to the Closing Date, or concurrently with PacifiCorp's notice of the amount due after termination, as the case may be. The payment schedule set out in Sections 5.3(a)(ii) and 5.3(a)(iii) is in lieu of the monthly invoicing and payment schedule contemplated by Sections 4.1 and 4.2 of the Management Agreement.

(iv) Safety Program. In order to comply with the Safety Program, Sellers have determined to initiate actions necessary to implement the Safety Program. Until the Closing Date or date of termination of this Agreement, PacifiCorp will use commercially reasonable efforts to negotiate and implement a reasonable Safety Program for the Facilities. Sellers will inform and consult with Buyer during the Safety Program on all matters related to the Safety Program including, costs and projected costs associated with the Safety Program, the schedule for the Safety Program, the scope of the Safety Program and correspondence with FERC.

(v) O&M Costs Forecast. PacifiCorp shall make reasonable efforts to keep Buyer promptly informed about O&M Costs and shall provide Buyer with a three (3) month forecast of O&M Costs expenditures updated on a monthly basis between execution of this Agreement and the Closing Date ("O&M Costs Forecast"). The first such three (3) month O&M Costs Forecast is attached hereto as Exhibit B. The O&M Costs Forecast shall include as a line item Sellers' costs for designing and implementing the Safety Program during the period covered by the O&M Costs Forecast. Sellers shall not make O&M Costs expenditures in excess of 110% of the total amounts and schedules set forth in the O&M Costs Forecast without Buyer's prior written consent (which Buyer shall not unreasonably withhold, condition or delay). Buyer shall have the right to audit the O&M Costs Forecast and associated invoices, which right shall not be exercised more than once every six (6) months plus one audit prior to each payment contemplated by this Section 5.3(a).

(b) Costs associated with a preliminary title report and a title insurance policy shall be borne by Sellers up to the costs that would have been incurred had the title policy been standard coverage policies of title insurance, and the remaining costs, if any, including costs for extended coverage, any endorsements and any survey shall be borne by Buyer.

(c) Recording costs and charges respecting the transfer of the real property to the LLC (and escrow fees) will be borne one-half by Buyer and one-half by Sellers.

(d) All fees and charges of Governmental Bodies shall be borne by the party incurring the fee or charge, except that all fees and charges of Governmental Bodies in connection with the transfer, issuance or authorization of any License shall be borne by Buyer.

(e) All liabilities or obligations for Taxes in the nature of sales or use taxes or real estate excise taxes incurred as a result of the contribution of the Assets to the LLC or the sale of the LLC Interests hereunder to Buyer shall be borne by Buyer.

(f) Each party will bear its own expenses in preparing regulatory filings and seeking required consents and approvals.

(g) All costs of any "Phase I" and "Phase II" (if recommended by the Phase I) environmental site assessments to be conducted by Buyer's representatives and any additional environmental investigations shall be borne by Buyer.

All such charges and expenses shall be promptly settled between the parties at the Closing or upon termination or expiration of further proceedings under this Agreement, or with respect to such charges and expenses not determined as of such time, as soon thereafter as is reasonably practicable.

Section 5.4 New Exceptions to Title. The Parties acknowledge receipt of a Commitment for Title Insurance issued by Stewart Title Guaranty Company (the "Title Insurer")(Commitment No. 108490-BJ) dated July 15, 2003 (the "Title Report"). The Parties anticipate that after the date of this Agreement, the Title Insurer may issue a supplemental title report or reports (each, a "Supplemental Report") with respect to the Owned Real Property. If a Supplemental Report discloses an exception to title that is not a Permitted Encumbrance and is not a monetary lien or an interest of Washington Irrigation and Development Company that is to be satisfied or removed by Sellers on or before the Closing Date (a "New Exception"), Buyer shall have 30 days after receipt of the Supplemental Report in which to notify Sellers in writing of Buyer's disapproval of any New Exception shown in the Supplemental Report. If Buyer fails to so notify Seller of its disapproval of any New Exception within such period, such exception shall be deemed a Permitted Encumbrance and set forth on Schedule 3.7. If Buyer notifies Seller of it disapproval of one or more New Exceptions, Seller shall have sixty (60) days to (i) remove the disapproved exception(s) and proceed to Closing; or (ii) refuse to remove the disapproved exception(s), in which case Buyer may elect to waive its objection and proceed to Closing or, if such exception would adversely affect the operation of the Facilities after Closing for their intended purposes, terminate this Agreement without liability to either Buyer or Sellers. This Section 5.4 sets forth Buyer's exclusive remedy with respect to any New Exception to title.

ARTICLE VI
ADDITIONAL COVENANTS OF SELLERS

Sellers hereby additionally covenant, promise and agree as follows:

Section 6.1 Access. PacifiCorp, on behalf of Sellers, will afford Buyer, and the counsel, accountants and other representatives of Buyer, reasonable access, throughout the period from the date hereof to the Closing Date or date of termination of this Agreement, to the Assets and the managerial and technical personnel associated therewith and all the properties, books, contracts, commitments, and records included in the Assets which Sellers have in their possession or to which they have access in order to facilitate transition planning. Such access shall be afforded to Buyer after no less than 24 hours' prior written notice, during normal business hours and only in such manner as not to disturb or interfere with the normal operation of Sellers. PacifiCorp's covenants under this Section are made with the understanding that Buyer shall use all such information in compliance with all Laws. Notwithstanding the foregoing, Buyer acknowledges and agrees that Buyer's access to the books and records of the Assets shall not include access to, and PacifiCorp shall not have any obligation to deliver to Buyer, any information concerning any alleged dispute or any pending litigation, investigation or proceeding involving Sellers or their Affiliates that is protected by or subject to the attorney-client privilege, or the disclosure of which is restricted by an agreement entered into in connection with such dispute, litigation, investigation or proceeding or an order entered by any court.

Section 6.2 Updating. Sellers shall notify Buyer of any changes or additions to any of Sellers' Schedules to this Agreement with respect to the Assets by the delivery of updates thereof, if any, as of a reasonably current date prior to the Closing. No such updates made pursuant to this Section shall be deemed to cure an inaccuracy of any representation or warranty made in this Agreement as of the date hereof, unless Buyer specifically agrees thereto in writing nor shall any such notification be considered to constitute or give rise to a waiver by Buyer of any condition set forth in this Agreement. Without limiting the generality of the foregoing, Sellers shall notify Buyer promptly of the occurrence of any material casualty, physical damages, destruction or physical loss respecting, or, to Sellers' Knowledge, material adverse change in the physical condition of, the Facilities, not including ordinary wear and tear and routine maintenance. Sellers will promptly report to Buyer with respect to matters and events that, to Sellers' Knowledge, could have a Material Adverse Effect on the LLC Interests or the Assets and shall timely provide Buyer with copies of relevant documents and notices. Sellers shall consult and cooperate with Buyer in good faith in regard to such matters and events and incorporate Buyer's suggestions where they deem reasonably appropriate.

Section 6.3 Conduct Pending Closing. Prior to consummation of the transactions contemplated hereby or the termination or expiration of this Agreement pursuant to its terms, unless Buyer shall otherwise consent in writing, which consent shall not be unreasonably withheld or delayed, and except for actions taken pursuant to Assigned Contracts, or which are required by Law, License or arise from or are related to the anticipated transfer of the Assets or as otherwise contemplated by this Agreement or disclosed on Schedule 6.3 or another Schedule to this Agreement, Sellers shall:

(a) Operate and maintain the Assets in a workmanlike manner and only in the usual and ordinary course, materially consistent with practices followed prior to the execution of this Agreement;

(b) Except as required by their terms, not amend, terminate, renew, or renegotiate any existing material Assigned Contract or enter into any new Assigned Contract, except in the ordinary course of business and consistent with practices of the recent past, or default (or take or omit to take any action that, with or without the giving of notice or passage of time, would constitute a default) in any of their obligations under any such contracts;

(c) Not (i) sell, lease, transfer or dispose of, or make any contract for the sale, lease, transfer or disposition of, the LLC Interests or any assets or properties which would be included in the Assets, other than sales in the ordinary course of business which would not individually, or in the aggregate, have a Material Adverse Effect upon the operations or value of the Facilities or the LLC Interests; (ii) incur, assume, guaranty, or otherwise become liable in respect of any indebtedness for money borrowed which would result in the LLC or Buyer assuming such liability hereunder after the Closing; (iii) delay the payment and discharge of any liability because of the transactions contemplated hereby; or (iv) encumber or voluntarily subject to any lien any Asset or LLC Interest (except for Permitted Encumbrances); or (v) sell, lease, transfer or dispose of, to any Seller or any Affiliate of any Seller, any LLC Interest or any assets or properties which would be included in the Assets, or remove any such assets or property to or for the benefit of any Seller or any Affiliate of any Seller;

(d) Maintain in force and effect the material property and liability insurance policies related to the Assets;

(e) Subject to Section 6.2, not take any action which would cause any of Sellers' representations and warranties set forth in Article 3 to be materially false as of the Closing;

Provided that nothing in this Section shall (i) obligate Sellers to make expenditures other than in the ordinary course of business and consistent with good utility practices (including, without limitation, compliance with Laws, Licenses and Assigned Contracts) of the recent past or to otherwise suffer any economic detriment, (ii) preclude Sellers from paying, prepaying or otherwise satisfying any liability, (iii) preclude Sellers from incurring any liabilities or obligations to any third party in connection with obtaining such party's consent to any transaction contemplated by this Agreement or any other agreement contemplated hereby, or (iv) preclude Sellers from instituting or completing any program designed to promote compliance or comply with Laws or other good business practices respecting the Facilities.

Section 6.4 State PUC Determinations. Each of Avista, PacifiCorp and PSE shall seek a specific determination that allowing the Facilities to be an "eligible facility" within the meaning of Section 32(a)(2) of PUHCA will (a) benefit consumers, (b) is in the public interest, and (c) does not violate state Laws, from (x) each State PUC with jurisdiction over any of such Seller's rates or charges for, or in connection with, the construction of the Facilities, or for electric energy produced by the Facilities (other than any portion of a rate or charge which represents recovery of the cost of a wholesale rate or charge for electric energy produced by the Facilities) that was in effect as of October 25, 1992, and (y) if such Seller is an Affiliate of a registered holding company under PUHCA, any other State PUC having jurisdiction over the rates and charges of the registered holding company's Affiliates.

Section 6.5 Disregarded Entity Documentation. Sellers shall, promptly and timely after the Closing, deliver to Buyer a copy of the notification received from the Internal Revenue Service approving the classification of the LLC as a disregarded entity, as contemplated in Section 3.17.

ARTICLE VII
ADDITIONAL COVENANTS OF BUYER

Section 7.1 Resale Certificate. Buyer agrees, and will cause each Buyer Affiliate, to furnish to Sellers any resale certificate or certificates or other similar documents reasonably requested by Sellers to comply with pertinent sales and use tax Laws.

Section 7.2 Conduct Pending Closing. Prior to consummation of the transactions contemplated hereby or the termination or expiration of this Agreement pursuant to its terms, unless Sellers shall otherwise consent in writing, which consent shall not be unreasonably withheld or delayed, and except for actions which are required by Law or arise from or are related to the anticipated transfer of the LLC Interests and the Assets, Buyer shall not take any action which would cause any of Buyer's representations and warranties set forth in Article 4 to be materially false as of the Closing.

Section 7.3 EWG Application. Buyer shall, either prior to the Closing, concurrently with the Closing or promptly and timely after the Closing (as appropriate), file with FERC with respect to the LLC Interests and the Assets (i) an exempt wholesale generator application, and (ii) a qualifying facility self certification; *provided, however*, Closing shall not await any decision or further action by FERC.

ARTICLE VIII
BUYER'S CONDITIONS TO CLOSING

The obligations of Buyer to consummate the transactions contemplated with respect to the LLC Interests and the Facilities shall be subject to fulfillment at or prior to the Closing of the following conditions, unless Buyer waives in writing such fulfillment.

Section 8.1 Performance of Agreement. Except for such matters which individually and in the aggregate do not have a Material Adverse Effect on the Facilities or on the Assets or the LLC Interests, Sellers shall have performed in all material respects their agreements and obligations contained in this Agreement required to be performed on or prior to the Closing.

Section 8.2 Accuracy of Representations and Warranties. The representations and warranties of Sellers set forth in Article 3 of this Agreement shall be true in all material respects as to the Assets or the LLC Interests in question and as of the date of this Agreement (unless the inaccuracy or inaccuracies which would otherwise result in a failure of this condition have been cured as of the Closing) and as of the Closing (as updated by the revising of Schedules contemplated by Section 6.2) as if made as of such time, provided that any such update shall not have disclosed any change in the physical condition, ownership, or transferability of the Assets or the LLC Interests that would have a Material Adverse Effect on the Assets or the LLC Interests.

Section 8.3 Officers' Certificate. Buyer shall have received from Sellers an officers' certificate, executed on behalf of each Seller by its chief executive officer, president, vice president, chief financial officer or treasurer (in his or her capacity as such) dated the Closing Date and stating that to the Knowledge of such individual, the conditions in Sections 8.1 and 8.2 above have been met with respect to such Seller.

Section 8.4 Approvals. All approvals, consents, authorizations and waivers from Governmental Bodies (as delineated on Schedules 3.3(b) and 4.4(b)) and all approvals, consents, authorizations and waivers from other third parties (collectively "Approvals") required for Sellers to transfer the Assets to the LLC and for Buyer to purchase the LLC Interests and operate the Facilities materially in accordance with the manner in which they were operated by Sellers prior to the Closing, shall have been obtained and (if Buyer is affected by any such approval) shall be in form and substance (including the regulatory treatment and financial impacts thereof on Buyer) satisfactory to Buyer in its reasonable discretion.

Section 8.5 No Restraint. There shall be no:

(a) Injunction, restraining order or order of any nature issued by any court of competent jurisdiction or Governmental Body which directs that the transactions contemplated hereby shall not be consummated as herein provided or compels or would compel Buyer to dispose of or discontinue, or materially restrict the operations of, the Facilities or any significant portion of the Assets with respect thereto or the LLC Interests as a result of the consummation of the transactions contemplated hereby;

(b) Suit, action or other proceeding by any Governmental Body pending or threatened (pursuant to a written notification), wherein such complainant seeks the restraint or prohibition of the consummation of the transactions contemplated hereby or seeks to compel, or such complainant's actions would compel, Buyer to dispose of or discontinue, or materially restrict the operations of, the Facilities or any significant portion of the Assets or the LLC Interests as a result of the consummation of the transactions contemplated hereby; or

(c) Action taken, or Law enacted, promulgated or deemed applicable to the transactions contemplated hereby, by any Governmental Body which would render the purchase and sale of the LLC Interests illegal or which would threaten the imposition of any penalty or material economic detriment upon Buyer if such purchase and sale were consummated;

Provided that the parties shall use their reasonable efforts to litigate against, and to obtain the lifting of, any such injunction, restraining or other order, restraint, prohibition, action, suit, Law or penalty.

Section 8.6 Title Insurance.

(a) Title Policy. The commitment by the Title Insurer (or an Affiliate thereof) or other title company mutually acceptable to the parties to issue at regular rates an ALTA owner's, or lessee's, as the case may be, extended coverage policy of title insurance (1990 Form B) in the coverage amount of $3,800,000.00 (the "Title Policy"), with the general survey and creditors' rights exceptions removed, showing title to such interests in such real property vested in the LLC. Such Title Policy shall show title vested in the LLC, subject only to the Permitted Encumbrances.

(b) Evidence of Commitment. The commitment of the Title Insurer to issue the Title Policy shall be evidenced either by the issuance thereof at the Closing or by the Title Insurer's delivery of written commitments or binders, dated as of the Closing, to issue such Title Policy within a reasonable time after the Closing Date, subject to actual transfer of the real property in question. If the Title Insurer is unwilling to issue any such Title Policy, it shall be required to provide Buyer and Sellers, in writing, notice setting forth the reason(s) for such unwillingness as soon as practicable. Sellers shall have the right to seek to cure any defect which is the reason for such unwillingness, and to extend the Closing and the Termination Date, if necessary, for a period of up to ten (10) Business Days to provide to Sellers the opportunity to cure. In the event that, despite Sellers' efforts to cure, the Title Insurer remains unwilling to issue any such Title Policy on the Closing Date (as may be extended as provided herein), then Buyer, at its option, may terminate this Agreement. Notwithstanding the foregoing, Buyer or the pertinent Buyer Affiliate may accept such title to any such property interests as Sellers may be able to convey, and such title insurance with respect to the same as the Title Insurer is willing to issue, in which case such interests shall be conveyed as part of the Assets without reduction of the Facilities Purchase Price or any credit or allowance against the same and without any other liability on the part of Sellers.

Section 8.7 Casualty; Condemnation.

(a) Casualty. If any part of the Facilities is damaged or destroyed (whether by fire, theft, vandalism or other casualty) in whole or in part prior to the Closing, and the Net Book Value of the damaged or destroyed Assets or the cost of repair of the Assets that were damaged or destroyed is less than 15 percent of the aggregate Facilities Purchase Price, Sellers shall, at their option, either (i) reduce the Facilities Purchase Price by the lesser of the Net Book Value of the Assets damaged or destroyed (such value to be determined as of the date immediately prior to such damage or destruction), or the estimated cost to repair or restore the same, (ii) upon the Closing, transfer the proceeds or the rights to the proceeds of applicable insurance to Buyer, provided that the proceeds or the rights to the proceeds are obtainable without delay and are sufficient to fully restore the damaged or destroyed Assets, or (iii) repair or restore such damaged or destroyed Assets and, at Sellers' election, delay the Closing and the Termination Date for a reasonable time necessary to accomplish the same. If any part of the Assets related to the Facilities are damaged or destroyed (whether by fire, theft, vandalism or other cause or casualty) in whole or in part prior to the Closing and the lesser of the Net Book Value of such Assets or the cost of repair is greater than 15 percent of the aggregate Facilities Purchase Price, then Buyer may elect to terminate this Agreement or require Sellers upon the Closing to transfer the proceeds (or the right to the proceeds) of applicable insurance to Buyer and Buyer may restore or repair the Assets.

(b) Condemnation. From the date hereof until the Closing, in the event that any material portion of the Facilities becomes subject to or is threatened with any condemnation or eminent domain proceedings, then Buyer, at its option, may, (i) if such condemnation, if successful, would not practically preclude the operation of the balance of the Facilities for the purposes for which it was intended, elect to terminate this Agreement with respect only to that part which is condemned or threatened to be condemned with a reduction in the Facilities Purchase Price determined as provided in Section 8.7(a) above, or (ii) if such condemnation, if successful, would practically preclude the operation of the balance of the Facilities for purposes for which it is intended, elect to terminate this Agreement.

Section 8.8 Receipt of Other Documents. Buyer shall have received the following:

(a) Copies of all current Licenses relevant to operation of the Facilities and all third party and Governmental Body consents, permits and authorizations that Sellers have received in connection with this Agreement and any other agreement contemplated hereby and the transactions contemplated hereby and thereby to occur at the Closing; and

(b) All other documents, instruments and writings required to be delivered to Buyer at or prior to Closing pursuant to the Agreement and such other certificates of authority and documents as Buyer reasonably requests.

Section 8.9 All Sellers. All of the Persons constituting Sellers shall have delivered all documents, instruments and writings required to be delivered to Buyer at or prior to Closing pursuant to this Agreement and none of the Persons constituting Sellers shall have retained any rights, title or interest in any of the Assets or the LLC Interests except for the Excluded Assets.

Section 8.10 Material Adverse Effect. There shall not have been an impairment of any Asset or the LLC Interests, as a result of a degradation of its physical condition, a change in Law, a change to, modification in or amendment to (by order or otherwise) any License, or a provision of any Approval that could reasonably be expected to have a Material Adverse Effect on the LLC Interests or Buyer's ability to operate the Facilities.

Section 8.11 LLC Contribution. Sellers shall have contributed, transferred, conveyed and assigned all rights, title and interest in the Assets to the LLC in a manner and in form and substance reasonably satisfactory to Buyer.

ARTICLE IX
SELLERS' CONDITIONS TO CLOSING

The obligations of Sellers to consummate the transactions contemplated hereby with respect to the LLC Interests and the Facilities shall be subject to the fulfillment at or prior to the Closing of the following conditions, unless Sellers waive in writing such fulfillment.

Section 9.1 Performance of Agreement. Buyer shall have performed in all material respects its agreements and obligations contained in this Agreement required to be performed on or prior to the Closing.

Section 9.2 Accuracy of Representations and Warranties. The representations and warranties of Buyer set forth in Article 4 of this Agreement shall be true in all material respects as of the date of this Agreement (unless the inaccuracy or inaccuracies which would otherwise result in a failure of this condition have been cured by the Closing) and as of the Closing as if made as of such time.

Section 9.3 Officers' Certificate. Sellers shall have received from Buyer an officers' certificate, executed on Buyer's behalf by its chief executive officer, president, chief financial officer or treasurer (in his or her capacity as such) dated the Closing Date and stating that to the Knowledge of such individual, the conditions in Sections 9.1 and 9.2 above have been met.

Section 9.4 Approvals. All approvals, consents, authorizations and waivers from Governmental Bodies as delineated on Schedule 3.3(b) shall have been obtained in form and substance (including the regulatory treatment and financial impacts thereof) satisfactory to each Seller affected by any such approval in its reasonable discretion. All approvals, consents, authorizations and waivers from other third parties required for Sellers to transfer the Assets to the LLC and for Buyer to purchase the LLC Interests shall have been obtained.

Section 9.5 No Restraint. There shall be no:

(a) Injunction, restraining order or order of any nature issued by any court of competent jurisdiction or Governmental Body which directs that the transactions contemplated hereby shall not be consummated as herein provided;

(b) Suit, action or other proceeding by any Governmental Body pending or threatened (pursuant to a written notification), wherein such complainant seeks the restraint or prohibition of the consummation of the transactions contemplated hereby or otherwise constrains consummation of such transactions on the terms contemplated herein; or

(c) Action taken, or Law enacted, promulgated or deemed applicable to the transactions contemplated hereby, by any Governmental Body which would render the purchase and sale of the LLC Interests, the Facilities and related Assets illegal or which would threaten the imposition of any penalty or material economic detriment upon Sellers if such transactions were consummated;

Provided that the parties will use their reasonable efforts to litigate against, and to obtain the lifting of, any such injunction, restraining or other order, restraint, prohibition, action, suit, Law or penalty.

Section 9.6 Receipt of Other Documents. Sellers shall have received the following:

(a) Copies of all current Licenses of Buyer and each pertinent Buyer Affiliate relevant to operation of the Facilities and all third party and Governmental Body consents, permits and authorizations that Buyer and each pertinent Buyer Affiliate has received in connection with this Agreement and any other agreements contemplated hereby; and

(b) All other documents, instruments and writings required to be delivered to Sellers at or prior to Closing pursuant to this Agreement and such other certificates of authority and documents as Sellers reasonably request.

ARTICLE X
CLOSING

Section 10.1 LLC Transaction. If, as of the first day that the Closing may occur pursuant to Section 10.2, the Washington Ruling has been issued, immediately prior to the Closing Sellers shall, and shall cause the LLC to, take all actions necessary to consummate, and shall consummate, the transactions described in the Washington Ruling in order to allow Buyer to obtain the Washington State sales tax benefits contemplated thereby (collectively, the "LLC Transaction"). Without limiting the generality of the foregoing, the parties agree that immediately prior to the Closing, all of the Assets will be contributed by Sellers to the LLC in exchange for all the membership interests in the LLC. If at such time the Washington Ruling has not issued, the parties shall promptly negotiate in good faith amendments to this Agreement that will provide for the conveyance of the Assets by Sellers directly to Buyer with such amended Agreement being substantially in the form of this Agreement. The parties will endeavor to execute such amended Agreement prior to the last date the Closing may occur pursuant to Section 10.2. In no event, however, shall the failure of the Washington Ruling to timely issue or the failure of the parties to amend this Agreement be a condition to Closing hereunder.

Section 10.2 Closing. Subject to the terms and conditions hereof, the consummation of the transactions contemplated hereby (the "Closing") shall occur at the offices of Stoel Rives LLC in Seattle, Washington, or a mutually agreeable place or places within five (5) Business Days after all of the conditions set forth in Article 8 and Article 9 hereof have been satisfied or waived or at such other time as the parties may agree, but in no event later than the Termination Date set forth in Section 11.1(d). The date on which the Closing actually occurs is referred to herein as the "Closing Date." The Closing shall be effective for all purposes at 11:59 p.m., Pacific Time, on the Closing Date. At the Closing and subject to the terms and conditions of this Agreement, the following will occur:

(a) Deliveries by Sellers. Sellers shall deliver to the LLC such instruments of transfer and conveyance properly executed and acknowledged by Sellers in customary form mutually agreed to by Sellers and Buyer necessary to transfer to and vest in the LLC all of

Sellers' rights, title and interest in and to the Assets or which may be required by the Title Insurer, including, without limitation:

(i) Bills of sale and assignment in respect of the Assets;

(ii) Special Warranty Deeds in the form attached as Exhibit C, properly executed and acknowledged by Sellers with respect to each of the Owned Real Property included in the Assets, and related excise tax affidavits executed by both Sellers and Buyer (provided that Seller shall not be required to deliver Statutory Warranty Deeds or Statutory Bargain and Sale Deeds);

(iii) Assignment and assumption agreements properly executed and acknowledged by Sellers with respect to each Assigned Contract included in the Assets;

(iv) Instruments of transfer, sufficient to transfer personal property interests that are included in the Assets but not otherwise transferred by the bills of sale and assignment referred to in clause (i) above, properly executed and acknowledged in the form customarily used in commercial transactions in Washington; and

(v) Possession of the Assets which shall include, without limitation, keys, codes, passcodes and/or combinations to all locks and vehicles.

(b) Sellers shall deliver to Buyer an assignment of all of the interests in the LLC.

(c) Sellers shall deliver to Buyer a copy of Form 8832 as filed with the Internal Revenue Service (regarding the classification of the LLC as a disregarded entity), as contemplated in Section 3.17.

(d) Deliveries by Buyer. Buyer shall, or shall cause Buyer Affiliates to, deliver to Sellers immediately available funds, by way of wire transfer to an account or account designated by Sellers, in an aggregate amount equal to the Facilities Purchase Price and such instruments of assumption properly executed and acknowledged by Buyer and the pertinent Buyer Affiliates in customary form mutually agreed to by Buyer and Sellers necessary for Buyer to assume the liabilities described in Section 2.6, including, without limitation:

(i) Assignment and assumption agreements properly executed and acknowledged by Buyer and the pertinent Buyer Affiliates with respect to each Assigned Contract included in the Assets; and

(ii) An assumption agreement or assumption agreements in favor of Sellers.

Section 10.3 Escrow. If either Buyer or Sellers desire to consummate the Closing through an escrow, an escrow shall be opened with, and the escrow agent shall be, the Title Insurer or an Affiliate thereof (the "Escrow Agent"), by depositing a fully executed copy of this Agreement with the Escrow Agent to serve as escrow instructions. This Agreement shall be considered the primary escrow instructions between the parties, but the parties shall execute such additional standard escrow instructions as the Escrow Agent shall require in order to clarify the duties and responsibilities of the Escrow Agent. In addition, prior to the Closing the parties shall provide the Escrow Agent with an estimated closing statement setting forth the parties' best estimate of all of the closing costs to be paid by the parties. Within 30 days after the Closing Date, Escrow Agent shall prepare a final closing statement reflecting the actual final closing costs and provide it to Buyers and Sellers for review. Any adjustments required pursuant to the final closing statement shall be paid by the owing party within 45 days after the Closing Date. In the event of any conflict between this Agreement and such additional standard escrow instructions, this Agreement shall prevail. If the Closing is to be consummated through the Escrow Agent, the parties shall deliver the funds, instruments of sale, assignment, conveyance and assumption called for by Section 10.2 to the Escrow Agent, and on the Closing Date, the Escrow Agent shall close the escrow by:

(a) Causing the deeds for the Owned Real Property and any other documents which the parties may mutually designate to be recorded in the official records of the appropriate counties in which the pertinent Assets are located;

(b) Delivering to Sellers by wire transfer of immediately available funds, to an account or accounts designated by Sellers, the amounts called for in Section 10.2; and

(c) Delivering to Buyer or Sellers, as the case may be, the other instruments referred to in Section 10.2.

Section 10.4 Prorations. Items of expense and income (if any) affecting the Assets that are customarily prorated, including, without limitation, real and personal property taxes and assessments, utility charges, charges arising under leases, insurance premiums, and the like, shall be prorated between Sellers and Buyer and the pertinent Buyer Affiliates as of the Closing Date.

ARTICLE XI
TERMINATION

Section 11.1 Termination. In addition to any other rights of termination set forth in this Agreement, any transactions contemplated hereby that have not been consummated may be terminated:

(a) At any time, by mutual written consent of Sellers and Buyer; or

(b) By either Buyer or Sellers, as the case may be, upon 30 days' written notice given any time after (i) the issuance of an order by a Governmental Body in a manner that fails to meet the conditions of the terminating party set forth in Sections 8.4 or 9.4, as the case may be, or (ii) 270 days have elapsed from the filing after the date hereof of all applications for approval of this Agreement and the transactions contemplated hereby by Governmental Bodies and a final order has not been obtained with respect to each such application, it being understood that such 270-day period shall not include any period after such order during which applications for rehearing or modification or judicial appeals or remedies are pending; or

(c) By one party upon written notice to the other if there has been a material default or breach under this Agreement by another party which is not cured by the earlier of the

Closing Date or the date 30 days after receipt by the other party of written notice from the terminating party specifying with particularity such breach or default; or

(d) By either Buyer or Sellers upon written notice to the other party, if (i) the Closing shall not have occurred by the Termination Date; or (ii) (A) in the case of termination by Sellers, the conditions set forth in Article 9 for the Closing cannot reasonably be met by the Termination Date and (B) in the case of termination by Buyer, the conditions set forth in Article 8 for the Closing cannot reasonably be met by the Termination Date, unless in either of the cases described in clauses (A) or (B), the failure of the condition is the result of the material breach of this Agreement by the party seeking to terminate. The Termination Date for the Closing shall be the date that is twelve (12) months from the date hereof. Such date, or such later date as may be specifically provided for in this Agreement (including any date arising under operation of Sections 8.6 and 8.7(a) hereof) or agreed upon by the parties, is herein referred to as the "Termination Date." Each party's right of termination hereunder is in addition to any other rights it may have hereunder or otherwise; or

(e) By Buyer, upon written notice to Sellers not later than ten (10) Business Days prior to the Closing Date, if Buyer has reasonably determined that the Safety Program will result in required seismic or other safety modifications to the Facilities that exceed $14,000,000. Such written notice will include a reasonably detailed explanation as to why Buyer believes costs of seismic or other safety modifications will exceed $14,000,000, together with supporting evidence (including copies of consultants reports) for that conclusion. The parties shall, within 30 days after the date of such notice, meet in good faith to discuss Buyer's notice. If Buyer has properly given notice, does not waive the objection and the parties do not, for any reason, enter into a written modification within the 30 day period, Buyer may elect to terminate this Agreement upon written notice to Sellers within five (5) days after the end of such period. If Buyer terminates pursuant to this provision, Sellers shall have no further obligation to Buyer for maintenance or operation of the Facilities.

Section 11.2 Effect of Termination. If there has been a termination pursuant to Section 11.1 or pursuant to any other provisions of this Agreement, then this Agreement shall be deemed terminated, and all further obligations of the parties hereunder shall terminate, except that the obligations set forth in Section 5.3 and in Articles 12 and 13.9 shall survive. In the event of such termination of this Agreement, there shall be no liability for damages on the part of a party to another under and by reason of this Agreement or the transactions contemplated hereby except as set forth in Article 12 and except for intentionally fraudulent acts by a party, the remedies for which shall not be limited by the provisions of this Agreement. The foregoing provisions shall not, however, limit or restrict the availability of specific performance or other injunctive or equitable relief to the extent that specific performance or such other relief would otherwise be available to a party hereunder.

Section 11.3 Modification of Terms. In the event any Governmental Body entertains, as an alternative to approval of this Agreement and any other agreement contemplated hereby, any proposal of one or more third parties to acquire the Facilities from Sellers on terms and conditions that include a higher purchase price than the Facilities Purchase Price set forth herein, and such terms and conditions are acceptable to Sellers, then and in that event, subject to such restrictions and requirements as such Governmental Body may impose upon Sellers, Sellers shall exercise their best efforts to afford to Buyer the right to enter into appropriate amendments and modifications of this Agreement to match such proposed alternate terms and conditions. Buyer shall be entitled to exercise such right by delivery of written notice thereof to Sellers within three (3) Business Days after its receipt of written notice from Sellers that, in Sellers' good faith belief, the proposals of such third party or parties makes it unlikely that such Governmental Body will approve this Agreement and the transactions contemplated hereby in a timely fashion and that the alternate terms and conditions are acceptable to Sellers. If such right is not exercised and such Governmental Body proceeds to decline to grant its approval, the termination provisions of Section 11.1 shall apply.

ARTICLE XII
SURVIVAL AND REMEDIES; INDEMNIFICATION

Section 12.1 Survival. Except as may be otherwise expressly set forth in this Agreement, the representations, warranties, covenants and agreements of Buyer and Sellers set forth in this Agreement, or in any writing required to be delivered in connection with this Agreement, shall survive the Closing Date.

Section 12.2 Exclusive Remedy. Absent intentional fraud or unless otherwise specifically provided herein, the sole exclusive remedy for damages of a party hereto for any breach of the representations, warranties, covenants and agreements of the other party contained in this Agreement shall be the remedies contained in this Article 12.

Section 12.3 Indemnity by Sellers.

(a) Sellers shall indemnify and hold harmless the LLC (from and after the Closing), Buyer, each Buyer Affiliate, and each Affiliate of Buyer or any Buyer Affiliate from and against any and all claims, demands, suits, losses, liabilities, damages and expenses, including reasonable attorneys' fees and costs of investigation, litigation, settlement and judgment, and including any costs and expenses incurred by any such Indemnitee as a result or arising out of any obligation or election (whether arising out of or in connection with any Law, any contract, any Charter Document, or otherwise) of any such Indemnitee to indemnify its directors, officers, attorneys, employees, subcontractors, agents and assigns (collectively "Losses"), which they or any of them may sustain or suffer or to which they or any of them may become subject as a result of:

(i) The inaccuracy of any representation or the breach of any warranty made by Sellers in this Agreement; and

(ii) The nonperformance or breach of any covenant or agreement made or undertaken by Sellers in this Agreement.

(b) The indemnification obligations of Sellers provided above shall, in addition to the qualifications and conditions set forth in Sections 12.5 and 12.6, be subject to the following qualifications with respect to claims of indemnity for Losses:

(i) Written notice to Sellers of such claim specifying the basis thereof must be made, or an action at law or in equity with respect to such claim must be served, before the second (2nd) anniversary of the earlier to occur of the Closing Date or the date on which this Agreement is terminated, as the case may be;

(ii) If the Closing occurs, the LLC, Buyer, Buyer Affiliates and their respective Affiliates shall be entitled only to recover the amount by which the aggregate Losses sustained or suffered by them exceed $500,000 (the "Deductible Amount"), *provided, however*, that individual claims of $5,000 or less shall not be aggregated for purposes of calculating either the Deductible Amount or the excess of Losses over the Deductible Amount and Buyer shall be entitled to recover on a dollar for dollar basis all claims for Losses covered under insurance maintained by Sellers; and

(iii) If the Closing occurs, in no event shall Sellers and their Affiliates be liable to the LLC, Buyer, Buyer Affiliates and their respective Affiliates for Losses in the nature of consequential damages, incidental damages, indirect damages, punitive damages, special damages, lost profits, damage to reputation or the like, but such damages shall be limited to out-of-pocket Losses and diminution in value; *provided, however*, that damages for all Losses shall be limited to an aggregate limit under this Agreement equal to the Facilities Purchase Price.

(c) The liability of Sellers under this Agreement shall be several and not joint or collective and no individual Seller shall be jointly or severally liable for the acts, omissions or obligations of any other Seller.

Section 12.4 Indemnity by Buyer.

(a) Buyer shall indemnify and hold harmless Sellers and each of them, and each Affiliate of Sellers or any of them, from and against any and all Losses which they or any of them may sustain or suffer or to which they may become subject as a result of:

(i) The inaccuracy of any representation or the breach of any warranty made by Buyer in this Agreement;

(ii) The nonperformance or breach of any covenant or agreement made or undertaken by Buyer in this Agreement; and

(iii) If the Closing occurs, the failure of the LLC or Buyer to pay, discharge or perform as and when due.

(b) The indemnification obligations of Buyer provided above shall, in addition to the qualifications and conditions set forth in Sections 12.5 and 12.6, be subject to the following qualifications:

(i) Sellers and their Affiliates shall not be entitled to indemnity for Losses unless written notice to Buyer of such claim specifying the basis thereof is made, or an action at law or in equity with respect to such claim is served, before the second (2nd) anniversary of the earlier to occur of the Closing Date or the date on which this Agreement is terminated, as the case may be;

(ii) If the Closing occurs, Sellers and their Affiliates shall be entitled only to recover the amount by which the aggregate Losses suffered or sustained by them exceed the Deductible Amount, *provided, however*, that individual claims of $5,000 or less shall not be aggregated for purposes of calculating either the Deductible Amount or the excess of Losses over the Deductible Amount; and

(iii) If the Closing occurs, in no event shall the LLC, Buyer and its Affiliates be liable to Sellers or their respective Affiliates for Losses in the nature of consequential damages, incidental damages, indirect damages, punitive damages, special damages, lost profits, damage to reputation or the like, but such damages shall be limited to out-of-pocket Losses and diminution in value; *provided, however*, that all Losses shall be limited to an aggregate limit under this Agreement equal to the Facilities Purchase Price.

Section 12.5 Further Qualifications Respecting Indemnification. The right of a party (an "Indemnitee") to indemnity hereunder shall be subject to the following additional qualifications:

(a) The Indemnitee shall promptly upon its discovery of facts or circumstances giving rise to a claim for indemnification, including receipt by it of notice of any demand, assertion, claim, action or proceeding, judicial, governmental or otherwise, by any third party (such third party actions being collectively referred to herein as "Third Party Claims"), give notice thereof to the indemnifying party (the "Indemnitor"), such notice in any event to be given within 60 days from the date the Indemnitee obtains actual knowledge of the basis or alleged basis for the right of indemnity or such shorter period as may be necessary to avoid material prejudice to the Indemnitor *provided, however*, the failure to provide or timely provide the Indemnitor with notice of any Third Party Claim shall only affect the Indemnitee's rights to indemnification to the extent that the Indemnitor is materially prejudiced as a result of the Indemnitee's failure to give timely notice of such Third Party Claim; and

(b) In computing Losses, such amounts shall be computed net of any related recoveries to which the Indemnitee is entitled under insurance policies, or other related payments received or receivable from third parties, and net of any tax benefits actually received by the Indemnitee or for which it is eligible, taking into account the income tax treatment of the receipt of indemnification.

Section 12.6 Procedures Respecting Third Party Claims. In providing notice to the Indemnitor of any Third Party Claim (the "Claim Notice"), the Indemnitee shall provide the Indemnitor with a copy of such Third Party Claim or other documents received and shall otherwise make available to the Indemnitor all relevant information material to the defense of such claim and within the Indemnitee's possession. The Indemnitor shall have the right, by notice given to the Indemnitee within 15 days after the date of the Claim Notice, to assume and control the defense of the Third Party Claim that is the subject of such Claim Notice, including the employment of counsel selected by the Indemnitor after consultation with the Indemnitee, and the Indemnitor shall pay all expenses of, and the Indemnitee shall cooperate fully with the Indemnitor in connection with, the conduct of such defense. The Indemnitee shall have the right to employ separate counsel in any such proceeding and to participate in (but not control) the defense of such Third Party Claim, but the fees and expenses of such counsel shall be borne by the Indemnitee unless the Indemnitor shall agree otherwise; *provided, however*, if the named parties to any such proceeding (including any impleaded parties) include both the Indemnitee and the Indemnitor, the Indemnitor requires that the same counsel represent both the Indemnitee and the Indemnitor, and representation of both parties by the same counsel would be inappropriate due to actual or potential differing interests between them, then the Indemnitee shall have the right to retain its own counsel at the cost and expense of the Indemnitor. If the Indemnitor shall have failed to assume the defense of any Third Party Claim in accordance with the provisions of this Section, then the Indemnitee shall have the absolute right to control the defense of such Third Party Claim, and, if and when it is finally determined that the Indemnitee is entitled to indemnification from the Indemnitor hereunder, the fees and expenses of Indemnitee's counsel shall be borne by the Indemnitor, provided that the Indemnitor shall be entitled, at its expense, to participate in (but not control) such defense. The Indemnitor shall have the right to settle or compromise any such Third Party Claim for which it is providing indemnity so long as such settlement does not impose any obligations on the Indemnitee (except with respect to providing releases of the third party). The Indemnitor shall not be liable for any settlement effected by the Indemnitee without the Indemnitor's consent except where the Indemnitee has assumed the defense because Indemnitor has failed or refused to do so. The Indemnitor may assume and control, or bear the costs, of any such defense subject to its reservation of a right to contest the Indemnitee's right to indemnification hereunder, provided that it gives the Indemnitee notice of such reservation within 15 days of the date of the Claim Notice.

ARTICLE XIII
GENERAL PROVISIONS

Section 13.1 Notices. All notices, requests, demands, waivers, consents and other communications hereunder shall be in writing, shall be delivered either in person, by telegraphic, facsimile or other electronic means, by overnight air courier or by mail, and shall be deemed to have been duly given and to have become effective (a) upon receipt if delivered in person or by telegraphic, facsimile or other electronic means, (b) one (1) Business Day after having been delivered to an air courier for overnight delivery or (c) three (3) Business Days after having been deposited in the U.S. mail as certified or registered mail, return receipt requested, all fees prepaid, directed to the parties or their permitted assignees at the following addresses (or at such other address as shall be given in writing by a party hereto):

If to Sellers, addressed to:

Jeffery B. Erb
Assistant General Counsel
PacifiCorp
825 NE Multnomah
Portland, OR 97232
Facsimile: (503) 813-7252

with a copy to:

William H. Holmes
Stoel Rives LLP
900 SW Fifth Avenue
Portland, OR 97204
Facsimile: (503) 220-2480

If to Buyer or any Buyer Affiliate, addressed to:

2677588 Washington LLC
913 Big Hanaford Road
Centralia, WA 98531
Attn: Charles Bates, Secretary
Facsimile: (360) 807-8051

with a copy to:

TransAlta Corporation
Box 1900, Station "M"
110 - 12th Avenue SW
Calgary, AB Canada T2P 2M1
Attn: Executive Vice President, Legal
Facsimile: (403) 267-7255

and:

Joel H. Mack
Latham & Watkins LLP
701 B Street
Suite 2100
San Diego, CA 92101
Facsimile: (619) 696-7419

Section 13.2 Attorneys' Fees. Subject to the provisions of Section 13.9, in any litigation or other proceeding relating to this Agreement, the prevailing party shall be entitled to recover its costs and reasonable attorneys' fees.

Section 13.3 Successors and Assigns. Except as provided in Section 2.5, the rights under this Agreement shall not be assignable or transferable nor the duties delegable by any party without the prior written consent of the other; and nothing contained in this Agreement, express or implied, is intended to confer upon any Person, other than the parties hereto, their permitted successors-in-interest and permitted assignees and any Person who or which is an intended beneficiary of the indemnities provided herein, any rights or remedies under or by reason of this Agreement unless so stated to the contrary. Notwithstanding the foregoing, Buyer may grant to its lenders a security interest in its rights under this Agreement; provided that neither the grant of any such interest, nor the foreclosure of any such interest, shall in any way release, reduce or diminish the obligations of Buyer to Sellers hereunder, and Sellers shall enter into a consent to assignment with such lenders reasonably acceptable to Sellers.

Section 13.4 Counterparts. This Agreement may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

Section 13.5 Captions and Paragraph Headings. Captions and paragraph headings used herein are for convenience only and are not a part of this Agreement and shall not be used in construing it.

Section 13.6 Entirety of Agreement; Amendments. This Agreement (including the Schedules and Exhibits hereto), and the other documents and instruments specifically provided for in this Agreement, including but not limited to the Confidentiality Agreement, contain the entire understanding between the parties concerning the subject matter of this Agreement and such other documents and instruments and, except as expressly provided for herein, supersede all prior understandings and agreements, whether oral or written, between them with respect to the subject matter hereof and thereof. There are no representations, warranties, agreements, arrangements or understandings, oral or written, between the parties hereto relating to the subject matter of this Agreement and such other documents and instruments which are not fully expressed herein or therein. This Agreement may be amended or modified only by an agreement in writing signed by each of the parties hereto. All Exhibits and Schedules attached to or delivered in connection with this Agreement are integral parts of this Agreement as if fully set forth herein.

Section 13.7 Construction. This Agreement and any documents or instruments delivered pursuant hereto shall be construed without regard to the identity of the Person who drafted the various provisions of the same. Each and every provision of this Agreement and such other documents and instruments shall be construed as though the parties participated equally in the drafting of the same. Consequently, the parties acknowledge and agree that any rule of construction that a document is to be construed against the drafting party shall not be applicable either to this Agreement or such other documents and instruments. Whenever in this Agreement the context so suggests, references to the masculine shall be deemed to include the feminine, references to the singular shall be deemed to include the plural, and references to "or" shall be deemed to be disjunctive but not necessarily exclusive.

Section 13.8 Waiver. The failure of a party to insist, in any one or more instances, on performance of any of the terms, covenants and conditions of this Agreement shall not be construed as a waiver or relinquishment of any rights granted hereunder or of the future performance of any such term, covenant or condition, but the obligations of the parties with respect thereto shall continue in full force and effect. No waiver of any provision or condition of this Agreement by a party shall be valid unless in writing signed by such party or operational by the terms of this Agreement. A waiver by any party of the performance of any covenant, condition, representation or warranty of any other party shall not invalidate this Agreement, nor shall such waiver be construed as a waiver of any other covenant, condition, representation or warranty. A waiver by any party of the time for performing any act shall not constitute a waiver of the time for performing any other act or the time for performing an identical act required to be performed at a later time.

Section 13.9 Arbitration.

(a) Agreement to Arbitrate. Any controversy or claim arising out of or relating to this Agreement, or the breach or alleged breach hereof, shall, upon demand of either Sellers or Buyer, be submitted to arbitration in the manner hereinafter provided. Sellers and Buyer will make every reasonable effort to resolve any such controversy or claim without resort to arbitration. But in the event the parties are unable to effect a satisfactory resolution between themselves, such controversy shall be submitted to arbitration in accordance with the terms and provisions of this Section 13.9 and in accordance with the then current Commercial Arbitration Rules (hereinafter the "Rules") of the American Arbitration Association (or any successor organization) (hereinafter the "AAA"). Any such arbitration shall take place in Seattle, Washington and shall be administered by the AAA. Sellers shall, for purposes of this Agreement, be deemed a single party in any such proceeding. In the event of any conflict between the terms and provisions of this Section and the Rules, the terms and provisions of this Section shall prevail.

(b) Submission to Arbitration. A party desiring to submit to arbitration any such controversy shall send a written arbitration demand to the AAA and to the opposing party. The demand shall set forth a clear and complete statement of the nature of the claim, its basis, and the remedy sought, including the amount of damages, if any. The opposing party may, within 30 days of receiving the arbitration demand, assert a counterclaim or set-off. The counterclaim or set-off, which shall be sent to the AAA and the opposing party, shall include a clear and complete statement of the nature of the counterclaim or set-off, its basis, and the remedy sought, including the amount of damages, if any.

(c) Selection of Arbitration Panel. The dispute shall be decided by a panel of three neutral arbitrators selected as follows. The AAA shall submit to the parties, within ten (10) days after receipt of an arbitration demand, a list of eleven potential arbitrators consisting of retired federal or state court judges; provided that none of the potential arbitrators shall have (or have ever had) any material affiliation of any kind with any party or with legal counsel for any party. Each party shall, within five days, strike four, three, two, one or none of the arbitrators, rank the remaining arbitrators in order of preference (with "1" designating the most preferred, "2" the next most preferred and so forth) and so advise the AAA in writing. The AAA shall appoint the arbitrators with the best combined preference ranking on both lists and designate the most preferred arbitrator as presiding officer (in each case, selecting by lot, if necessary, in the event of a tie).

(d) Prehearing Discovery. There shall be no prehearing discovery except as follows. Subject to the authority of the presiding officer of the arbitration panel to modify the provisions of this paragraph before the arbitration hearing upon a showing of exceptional circumstances, each party (i) shall propound to the other no more than 20 requests for production of documents, including subparts, and (ii) shall take no more than two (2) discovery depositions. Such discovery shall be conducted in accordance with the provisions and procedures of the Federal Rules of Civil Procedure. No interrogatories or requests for admission shall be permitted. Disputes concerning discovery obligations or protection of discovery materials shall be determined by the presiding officer of the arbitration panel. The foregoing limitations shall not be deemed to limit a party's right to subpoena witnesses or the production of documents at the arbitration hearing, nor to limit a party's right to depose witnesses that are not subject to subpoena to testify in person at the arbitration hearing; *provided, however*, that the presiding officer of the arbitration panel may, upon motion, place reasonable limits upon the number and length of such testimonial depositions.

(e) Arbitration Hearing. The presiding officer of the arbitration panel shall designate the place and time of the hearing. The hearing shall be scheduled to begin within ninety (90) days after the filing of the arbitration demand (unless extended by the arbitration panel on a showing of exceptional circumstances) and shall be conducted as expeditiously as possible. In all events, the issues being arbitrated, which shall be limited to those issues identified in the initial claim and counter-claim submitted to the arbitration panel pursuant to Subsection (b) above, shall be submitted for decision within 30 days after the beginning of the arbitration hearing. At least 30 days prior to the beginning of the arbitration hearing, each party shall provide the other party and the arbitration panel with written notice of the identity of each witness (other than rebuttal witnesses) it intends to call to testify at the hearing, together with a detailed written outline of the substance of the anticipated testimony of each such witness. The arbitration panel shall not permit any witness to testify that was not so identified prior to the hearing and shall limit the testimony of each such witness to the matters disclosed in such outline. Subject to the foregoing, the parties shall have the right to attend the hearing, to be represented by counsel, to present documentary evidence and witnesses, to cross-examine opposing witnesses and to subpoena witnesses. The Federal Rules of Evidence shall apply and the panel shall determine the competency, relevance, and materiality of evidence as appropriate. The panel shall recognize privileges available under applicable Law. A stenographic record shall be made of the arbitration proceedings.

(f) Award. The panel's award shall be made by majority vote of the panel. An award in writing signed by at least two of the panel's arbitrators shall set forth the panel's findings of fact and conclusions of Law. The award shall be filed with the AAA and mailed to the parties no later than 30 days after the last day of testimony at the arbitration hearing. The panel shall have authority to issue any lawful relief that is just and equitable, except consequential damages, incidental damages, indirect damages, punitive damages, special damages, lost profits, diminution in value, damage to reputation or the like. The award shall state that it dissolves and supersedes any provisional remedies entered pursuant to Subsection (g) below.

(g) Provisional Remedies. Pending the selection of the arbitration panel, upon request of a party, the AAA may appoint a retired judge to serve as a provisional arbitrator to rule on any motion for preliminary relief. Any preliminary relief ordered by the provisional arbitrator may be immediately entered in any federal or state court having jurisdiction thereof even though the decision on the underlying dispute may still be pending. Once constituted, the arbitration panel may, upon request of a party, issue a superseding order to modify or reverse such preliminary relief or may itself order preliminary relief pending a full hearing on the merits of the underlying dispute. Any such initial or superseding order of preliminary relief may be immediately entered in any federal or state court having jurisdiction thereof even though the decision on the underlying dispute may still be pending. Such relief may be granted by the appointed arbitrator or the arbitration panel only after notice to and opportunity to be heard by the opposing party. Such awards of preliminary relief shall be in writing and, if ordered by a panel of three arbitrators, must be signed by at least two of the panel members.

(h) Entry of Award by Court. The arbitration panel's arbitration award shall be final. The parties agree and consent that judgment upon the arbitration award may be entered in any federal or state court having jurisdiction thereof.

(i) Costs and Attorneys' Fees. The prevailing party shall be entitled to recover its costs and reasonable attorneys' fees, and the party losing the arbitration shall pay all expenses and fees of the AAA, all costs of the stenographic record, all expenses of witnesses or proofs that may have been produced at the direction of the arbitrators, and the fees, costs, and expenses of the arbitrators. The arbitration panel shall designate the prevailing party for these purposes.

Section 13.10 Governing Law. This Agreement shall be governed in all respects, including validity, interpretation and effect, by the Laws of the State of Washington applicable to contracts made and to be performed wholly within the State of Washington, provided that federal Law, including the Federal Arbitration Act, shall govern all issues concerning the validity, enforceability and interpretation of the arbitration provision set forth in Section 13.9 hereof. Any judicial action or proceeding arising under this Agreement shall be adjudicated in Seattle, Washington.

Section 13.11 Severability. Whenever possible, each provision of this Agreement shall be interpreted in such manner as to be valid, binding and enforceable under applicable Law, but if any provision of this Agreement is held to be invalid, void (or voidable) or unenforceable under applicable Law, such provision shall be ineffective only to the extent held to be invalid, void (or voidable) or unenforceable, without affecting the remainder of such provision or the remaining provisions of this Agreement.

Section 13.12 Consents Not Unreasonably Withheld. Wherever the consent or approval of any party is required under this Agreement, such consent or approval shall not be unreasonably withheld or delayed, unless such consent or approval is to be given by such party at the sole or absolute discretion of such party or is otherwise similarly qualified.

Section 13.13 Time Is of the Essence. Time is hereby expressly made of the essence with respect to each and every term and provision of this Agreement. The parties acknowledge that each will be relying upon the timely performance by the others of their obligations hereunder as a material inducement to each party's execution of this Agreement.

Section 13.14 Liability. The liability of Sellers under this Agreement shall be several and not joint or collective and no individual Seller shall be jointly or severally liable for the acts, omissions or obligations of any other Seller.

Section 13.15 Execution. This Agreement may be executed in counterpart and executed signature pages delivered by facsimile.

ARTICLE XIV
AGENCY

Section 14.1 Agency. Each Seller hereby appoints PacifiCorp as its sole agent for purposes of this Agreement. If, however, this Agreement is amended or modified in any way, such agency shall no longer be valid and all such amendments or modifications must be approved in writing by each Seller individually. Buyer may rely on such agency, and shall have no obligation to provide any notices or undertake any other action with respect to any other Seller except upon amendment or modification of this Agreement.

SIGNATURE PAGE FOLLOWS

IN WITNESS WHEREOF, the parties have duly executed this Agreement as of the date first above written.

BUYER:

2677588 WASHINGTON LLC

By:______________________________
Name:
Title:

By:______________________________
Name:
Title:

SELLERS:

PACIFICORP

By:______________________________
Name: Judith A. Johansen
Title: President & Chief Executive Officer

PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY, WASHINGTON

By:______________________________
Name:
Title:

PUGET SOUND ENERGY, INC.

By:______________________________
Name:
Title:

CITY OF TACOMA, WASHINGTON

By:______________________________
Name:
Title:

AVISTA CORPORATION

By:______________________________
Name:
Title:

CITY OF SEATTLE, WASHINGTON

By:______________________________
Name:
Title:

PUBLIC UTILITY DISTRICT NO. 1 OF GRAYS HARBOR COUNTY, WASHINGTON

By:______________________________
Name:
Title:

TRANSALTA CENTRALIA GENERATION LLC

By:______________________________
Name:
Title:

TransAlta Centralia Generation LLC executes this Agreement for purposes of the agreements contained in Sections 2.7 and 5.3(a) of this Agreement.

IN WITNESS WHEREOF, the parties have duly executed this Agreement as of the date first above written.

BUYER:

2677588 WASHINGTON LLC

By:____________________
Name:
Title:

By:____________________
Name:
Title:

SELLERS:

PACIFICORP

By:____________________
Name:
Title:

PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY, WASHINGTON

By: Edward D. Hansen
Name: Edward Hansen
Title: General Manager

PUGET SOUND ENERGY, INC.

By:____________________
Name:
Title:

CITY OF TACOMA, WASHINGTON

By:____________________
Name:
Title:

AVISTA CORPORATION

By:____________________
Name:
Title:

CITY OF SEATTLE, WASHINGTON

By:____________________
Name:
Title:

PUBLIC UTILITY DISTRICT NO. 1 OF GRAYS HARBOR COUNTY, WASHINGTON

By:____________________
Name:
Title:

TRANSALTA CENTRALIA GENERATION LLC

By:____________________
Name:
Title:

TransAlta Centralia Generation LLC executes this Agreement for purposes of the agreements contained in Sections 2.7 and 5.3(a) of this Agreement.

IN WITNESS WHEREOF, the parties have duly executed this Agreement as of the date first above written.

BUYER:

2677588 WASHINGTON LLC

By:______________________________
Name:
Title:

By:______________________________
Name:
Title:

SELLERS:

PACIFICORP

By:______________________________
Name:
Title:

CITY OF SEATTLE, WASHINGTON

By:______________________________
Name:
Title:

PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY, WASHINGTON

By:______________________________
Name:
Title:

PUBLIC UTILITY DISTRICT NO. 1 OF GRAYS HARBOR COUNTY, WASHINGTON

By:______________________________
Name:
Title:

PUGET SOUND ENERGY, INC.

By:______________________________
Name:
Title:

CITY OF TACOMA, WASHINGTON

By: Mark Crisson
Name: Mark Crisson
Title: Director of Utilities

TRANSALTA CENTRALIA GENERATION LLC

By:______________________________
Name:
Title:

AVISTA CORPORATION

By:______________________________
Name:
Title:

TransAlta Centralia Generation LLC executes this Agreement for purposes of the agreements contained in Sections 2.7 and 5.3(a) of this Agreement.

Approved As To Form & Legality:

B. S. Karavites
S[illegible] City Attorney

IN WITNESS WHEREOF, the parties have duly executed this Agreement as of the date first above written.

BUYER:

2677588 WASHINGTON LLC

By:______________________________
Name:
Title:

By:______________________________
Name:
Title:

SELLERS:

PACIFICORP

By:______________________________
Name:
Title:

CITY OF SEATTLE, WASHINGTON

By:______________________________
Name:
Title:

PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY, WASHINGTON

By:______________________________
Name:
Title:

PUBLIC UTILITY DISTRICT NO. 1 OF GRAYS HARBOR COUNTY, WASHINGTON

By:______________________________
Name:
Title:

PUGET SOUND ENERGY, INC.

By: Eric M Markell
Name: ERIC M. MARKELL
Title: SR Vice President

CITY OF TACOMA, WASHINGTON

By:______________________________
Name:
Title:

TRANSALTA CENTRALIA GENERATION LLC

By:______________________________
Name:
Title:

TransAlta Centralia Generation LLC executes this Agreement for purposes of the agreements contained in Sections 2.7 and 5.3(a) of this Agreement.

AVISTA CORPORATION

By:______________________________
Name:
Title:

IN WITNESS WHEREOF, the parties have duly executed this Agreement as of the date first above written.

BUYER:

2677588 WASHINGTON LLC

By:____________________________
Name:
Title:

By:____________________________
Name:
Title:

SELLERS:

PACIFICORP

By:____________________________
Name:
Title:

PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY, WASHINGTON

By:____________________________
Name:
Title:

PUGET SOUND ENERGY, INC.

By:____________________________
Name:
Title:

CITY OF TACOMA, WASHINGTON

By:____________________________
Name:
Title:

AVISTA CORPORATION

By:____________________________
Name: Gary G. Ely
Title: Chairman, President & CEO

CITY OF SEATTLE, WASHINGTON

By:____________________________
Name:
Title:

PUBLIC UTILITY DISTRICT NO. 1 OF GRAYS HARBOR COUNTY, WASHINGTON

By:____________________________
Name:
Title:

TRANSALTA CENTRALIA GENERATION LLC

By:____________________________
Name:
Title:

TransAlta Centralia Generation LLC executes this Agreement for purposes of the agreements contained in Sections 2.7 and 5.3(a) of this Agreement.

IN WITNESS WHEREOF, the parties have duly executed this Agreement as of the date first above written.

BUYER:

2677588 WASHINGTON LLC

By: [signature]
Name: Charles Bates
Title: Secretary

By:______________________________
Name:
Title:

SELLERS:

PACIFICORP

By:______________________________
Name:
Title:

PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY, WASHINGTON

By:______________________________
Name:
Title:

PUGET SOUND ENERGY, INC.

By:______________________________
Name:
Title:

CITY OF TACOMA, WASHINGTON

By:______________________________
Name:
Title:

AVISTA CORPORATION

By:______________________________
Name:
Title:

CITY OF SEATTLE, WASHINGTON

By:______________________________
Name:
Title:

PUBLIC UTILITY DISTRICT NO. 1 OF GRAYS HARBOR COUNTY, WASHINGTON

By:______________________________
Name:
Title:

TRANSALTA CENTRALIA GENERATION LLC

By: [signature]
Name: Charles Bates
Title: Secretary

By:______________________________
Name:
Title:

TransAlta Centralia Generation LLC executes this Agreement for purposes of the agreements contained in Sections 2.7 and 5.3(a) of this Agreement.

IN WITNESS WHEREOF, the parties have duly executed this Agreement as of the date first above written.

BUYER:

2677588 WASHINGTON LLC

By:____________________
Name:
Title:

By: Alison T. Love
Name: Alison T. Love
Title:

SELLERS:

PACIFICORP

By:____________________
Name:
Title:

PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY, WASHINGTON

By:____________________
Name:
Title:

PUGET SOUND ENERGY, INC.

By:____________________
Name:
Title:

CITY OF TACOMA, WASHINGTON

By:____________________
Name:
Title:

AVISTA CORPORATION

By:____________________
Name:
Title:

CITY OF SEATTLE, WASHINGTON

By:____________________
Name:
Title:

PUBLIC UTILITY DISTRICT NO. 1 OF GRAYS HARBOR COUNTY, WASHINGTON

By:____________________
Name:
Title:

TRANSALTA CENTRALIA GENERATION LLC

By:____________________
Name:
Title:

By: Alison T Love
Name: Alison T. Love
Title:

TransAlta Centralia Generation LLC executes this Agreement for purposes of the agreements contained in Sections 2.7 and 5.3(a) of this Agreement.

IN WITNESS WHEREOF, the parties have duly executed this Agreement as of the date first above written.

BUYER:

2677588 WASHINGTON LLC

By:______________________________
Name:
Title:

By:______________________________
Name:
Title:

SELLERS:

PACIFICORP

By:______________________________
Name:
Title:

PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY, WASHINGTON

By:______________________________
Name:
Title:

PUGET SOUND ENERGY, INC.

By:______________________________
Name:
Title:

CITY OF TACOMA, WASHINGTON

By:______________________________
Name:
Title:

AVISTA CORPORATION

By:______________________________
Name:
Title:

CITY OF SEATTLE, WASHINGTON

By:______________________________
Name:
Title:

PUBLIC UTILITY DISTRICT NO. 1 OF GRAYS HARBOR COUNTY, WASHINGTON

By: Richard D Lovely
Name: Richard D Lovely
Title: General Manager

TRANSALTA CENTRALIA GENERATION LLC

By:______________________________
Name:
Title:

TransAlta Centralia Generation LLC executes this Agreement for purposes of the agreements contained in Sections 2.7 and 5.3(a) of this Agreement.

EXHIBIT A

FEDERAL ENERGY REGULATORY COMMISSION
Office of Energy Projects
Division of Dam Safety and Inspections
Portland Regional Office
101 S.W. Main Street, Suite #905
Portland, Oregon 97204

MAR 19 2003

In reply refer to:
P-4441-WA
NATDAM-WA00153

Mr. Randy A. Londolt
Director, Hydro Resources
PacifiCorp
825 NE Multnomah, Suite 1500
Portland, OR 97232

Dear Mr. Landolt:

We have completed our review of the January 15, 2002 Fourth Part 12 Independent Consultant's Safety Inspection Report (2002 Report) for the Skookumchuck Project, FERC No. 4441. The following information was also reviewed in conjunction with the 2002 Report:

- Results of soil tests conducted by Shannon & Wilson and included in four letter reports (dated July 8, 1969, August 8, 1969, August 12, 1969, and September 11, 1969) to Bechtel Corporation;

- Report titled "Construction Report for Water Supply Facilities, Skookumchuck Dam, Pumping Plant", prepared by Bechtel Corporation, for Pacific Power & Light Company and the Washington Water Power Company, and dated August 1971;

- April 3, 2002 letter from Mr. Richard Gorny (Independent Consultant) of Black & Veatch regarding: (a) Material Properties; and (b) 1990 Displacement Analysis Results. Mr. Gorny also included some material regarding 'Liquefied and Non-Liquefied Gravel case Histories' based on information included in a paper titled "A Practical Perspective on Liquefaction of Gravels", by J. E. Valera, M. L. Traubenik, J. A. Egan, and J. Y. Kanshiro, ASCE Special Publication on Ground Failure Under Seismic Conditions, 1994;

- April 30, 2002 letter report from Shannon & Wilson titled "Re-evaluation of Field Data, Skookumchuck Dam, Thurston County, Washington";

○ May 23, 2002 letter report from Mr. Gorny providing dam displacement analyses and stability analyses loading diagrams;

○ <u>Becker Hammer Exploration Study, Final Submittal</u>, December 2000 (Becker Hammer Study, transmitted by PacifiCorp March 12, 2001 letter) prepared by Shannon and Wilson;

○ <u>Liquefaction Potential Evaluation Study, November 2001</u> (Liquefaction Study, submitted by PacifiCorp January 24, 2002 letter) prepared by Shannon and Wilson;

○ <u>Seismic Ground Motion Study for Skookumchuck Dam, March 2001</u> (Seismic Study, transmitted by PacifiCorp March 23, 2001 letter) prepared by Shannon and Wilson;

○ <u>Skookumchuck Dam Modification Project Geotechnical Report</u>, February 2001 (Geotechnical Study, transmitted by PacifiCorp March 23, 2001 letter) prepared by Shannon and Wilson;

○ <u>Skookumchuck Embankment Seismic Analytic Study</u>, January 2002 (Analytic Study, transmitted by PacifiCorp February 5, 2002 letter) prepared by Shannon and Wilson.

Our review of the seismic stability of the dam was coordinated with our consultant Dr. I.M. Idriss. A copy of his September 20, 2002 letter report is enclosed. We have reviewed his report and concur with his findings and have incorporated them into the body of this letter.

We have the following comments on the above submittals:

1. Your consultant concluded that the MCE for the project was due to an event occurring on the Cascadia Subduction Zone fault (CSZ), and the 1988 Supplement to the 1985 Part12 Report characterized the maximum magnitude for the CSZ of M=8.0 to 8.5. The peak horizontal ground acceleration was 0.25g and was developed using the attenuation model by Heaton and Hartzell (1986). We do not concur that this ground motion represents the maximum earthquake for this source.

The May 1999 "Report On Seismic Hazard Evaluation For The Pacificorp Merwin and Yale Dams, Southwest Washington," by Golder Associates, Inc., included a seismic evaluation of the CSZ. Based on Golders findings, the appropriate magnitude for an event occurring on the CSZ would be $M_w = 9.0$, and because the CSZ has a fairly high recurrence interval and slip rate, about 300 years and 4 cm/yr, respectively, the 84th percentile ground motions should be used. This finding is consistent with Dr. I.M. Idriss' report. Using a distance of 68km, the PGA at Skookumchuck would be 0.41g for a M_w 9.0 event occurring on the CSZ.

The 1988 Part 12 D Supplement considered subduction zone events which may occur on the CSZ; however, deep intraplate events or those that may occur on the Juan de Fuca Plate were not mentioned . The Golder Report evaluated intraplate events and the estimated magnitude was 7.5. Although the size of these events are slightly smaller than the MCE, the ground motions for these events should be considered in a reevaluation of seismicity for Skookumchuck dam. Since the recurrence interval for these events is short, the 84th percentile ground motions should be determined.

2. In addition to the CSZ, the Seismic Study identified the Legislature fault as a possible seismic source. In the 2002 Report, your consultant reported that the USGS is scheduled to perform studies to evaluate the seismogenic nature of this fault in 2002, and recommended no action until the studies are completed. We do not concur. The Legislature fault should be considered as a potential seismic source. Dr. I. M. Idriss's September 23, 2002 letter report (enclosed) includes an evaluation of the Legislature fault based on a discussion with Dr. E. Weaver of the USGS. We have reviewed Dr. Idriss' comments and concur with them. The seismicity at Skookumchuck dam should be revised considering the recommendations contained in Dr. Idriss' report.

3. When Skookumchuck Dam was constructed, the question of liquefaction was considered - records and photos indicate the naturally dense gravelly alluvium was left in place beneath the downstream shell on the north side of the embankment while the less dense alluvium was excavated out. In September 2000, Becker Hammer borings were conducted to further evaluate the liquefaction potential in this area. Based on the Becker Hammer data, the Liquefaction Study considered that discontinuous zones of liquefaction occurs in the downstream berm with these zones possibly extending upstream to the core. We recognized that this assumption is conservative considering the gradations and that construction exploration Borings AH-1 and AH- 6 indicated refusal and N_{60}=300, respectively, in the thin layer of alluvium left beneath the downstream shell. Further, we noted that boring SB-02 was not used in the liquefaction analysis since the soils were non-liquefiable or the potentially liquefiable soils were above the groundwater table.

In the April 2001 Journal of Geotechnical and Geoenvironmental Engineering by Youd and Idriss, Liquefaction Resistance of Soils: Summary Report From The 1996 NCEER and 1998 NCEER/NSF Workshops On Evaluation Of Liquefaction Resistance Of Soils, it was reported that although SPT blow counts can be roughly estimated from BPT measurements, there can be considerable uncertainty for calculating liquefaction resistance because of data scatter in the range of greatest importance, 0-30 blow counts. Based on review of the data for borings BD-1 thru BD-4, we noted that the blow counts were all below 26. Since the available subsurface information does not provide sufficient information to dismiss or confirm liquefaction or address the upstream extent of liquefaction beneath the dam, we agree with your consultant that additional explorations are needed beneath the downstream shell to further explore the presence of liquefiable materials. A plan and schedule to accomplish this work must be submitted for our review.

4. In the May 23, 2002 letter report, dam displacement was estimated to be between 5 and 40 cm using Makdisi and Seed's Simplified Method and a PGA=0.46g. Pending the outcome of the upcoming field investigations, the current estimate may be adequate or it may be necessary to conduct a post-earthquake deformation analysis using residual shear strengths for the zones where liquefaction is triggered. In addition, it may be necessary to calculate the response of Skookumchuck Dam using a non-linear 2-dimensional dynamic analysis procedure.

5. It was reported that a new PMF study had been commissioned by the Corps of Engineers and when completed, it would be reviewed and presented in an addendum to the 2002 Report. We concur with your consultants' recommendation to submit this study as an addendum to the Part 12 report. We noted that the 9,020 cfs flood of record occurred on February 8, 1996; however, the consultant did not state that the current PMF inflow curve was checked in relation to this recent flood of record. This should be done for the PMF, and for the new PMF commissioned by the Corps.

The 2002 Report does not satisfy the requirements of Part 12 D of the Commission's Regulations. You must provide this office, within 45 days of the date of this letter, three copies of a plan and schedule for submitting a supplement which addresses the items discussed above.

If you have any questions, please contact Messrs. William Lagnion or Edward Perez of this office at (503) 944-6748 or (503) 944-6750, respectively.

Sincerely,

Harry T. Hall, P.E.
Regional Engineer

Enclosure

I. M. IDRISS
CONSULTING GEOTECHNICAL ENGINEER
P. O. BOX 330, DAVIS, CA 95617-0330
Tel: (530) 758-5739 Fax: (530) 758-1104 e-mail: imidriss@aol.com

September 20, 2002

Mr. Constantine G. Tjoumas, P. E.
Director, Division of Dam Safety and Inspections
Office of Hydropower Licensing
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

__Subject__: Seismic Stability Issues
Skookumchuck Dam – Lewis County, Washington

Dear Mr. Tjoumas:

INTRODUCTORY REMARKS

As requested by Mr. William Allerton, I attended a meeting on March 14, 2002, at FERC's Office in Portland, Oregon, to review the work completed to date regarding seismic stability issues of the Skookumchuck Dam in Lewis County, Washington. The general location of the dam is depicted in Fig. 1.

The following documents were provided to me after the March 14 meeting:

1. Results of soil tests conducted by Shannon & Wilson and included in four letter reports to Bechtel Corporation; the letters are dated July 8, 1969, August 8, 1969, August 12, 1969, and September 11, 1969, respectively.

2. Report titled "Construction Report for Water Supply Facilities, Skookumchuck Dam, Pumping Plant", prepared by Bechtel Corporation, for Pacific Power & Light Company and the Washington Water Power Company, and dated August 1971.

3. Report titled "Supplement to December 1985 Dam Safety Investigation, Skookumchuck Dam, FERC No. 4441", prepared by Bechtel Civil & Minerals, Inc., for Pacific Power & Light Company, and dated April 1988.

4. Report titled "Additional Information to the April 1988 Supplement to December 1985 Dam Safety Investigation, Skookumchuck Dam, FERC No. 4441", prepared by Bechtel Corporation, for Pacific Power & Light Company, and dated October 1990.

5. A pdf (Adobe Acrobat format) file of the report titled "Becker Hammer Exploration Study, Skookumchuck Dam Site, Lewis County, Washington", prepared by Shannon & Wilson, Inc., Seattle, Washington, for the Seattle District of the U.S. Army Corps of Engineers, and dated December 2000.

6. A pdf file of the report titled "Seismic Ground Motion Study for Skookumchuck Dam, Lewis County, Washington", prepared by Shannon & Wilson, Inc., Seattle, for the Seattle District of the U.S. Army Corps of Engineers, and dated March 2001.

7. A pdf file of the report titled "Liquefaction Potential Evaluation for the Skookumchuck Dam Site, Thurston County, Washington", prepared by Shannon & Wilson, Inc., Seattle, for the Seattle District of the U.S. Army Corps of Engineers, and dated November 2001.

8. A pdf file of the report titled "Skookumchuck Embankment, Seismic Analytical Study, Skookumchuck Dam, Thurston County, Washington", prepared by Shannon & Wilson, Inc., Seattle, for the Seattle District of the U.S. Army Corps of Engineers, and dated January 2002.

9. Mr. R. H. Gorny of Black & Veatch sent me a letter on April 3, 2002, which included copies of above items No. 3 and 4, and discussions (based on the contents of these two items) regarding: (a) Material Properties; and (b) 1990 Displacement Analysis Results. Mr. Gorny also included some material regarding 'Liquefied and Non-Liquefied Gravel case Histories' based on information included a paper titled "A Practical Perspective on Liquefaction of Gravels", by J. E. Valera, M. L. Traubenik, J. A. Egan, and J. Y. Kanshiro, ASCE Special Publication on Ground Failure Under Seismic Conditions, 1994. The material and discussions provided by Mr. Gorny were very helpful in expediting my review.

A conference call was held on April 25, 2002 to discuss the additional work being completed by Shannon & Wilson for the U.S. Army Corps of Engineers and to finalize the date of the next meeting, which was set for May 17 in Portland.

10. At the May 17 meeting, I was provided with a copy of the letter report by Shannon & Wilson titled "Re-Evaluation of Field Data, Skookumchuck Dam, Thurston County, Washington", and dated April 30, 2002.

GENERAL OBSERVATIONS

The review of the above documents and the discussions at the two meetings provide the following observations at this time:

- As is common in the North Western Part of the USA, the seismic sources of concern consist of crustal sources and the subduction source. For this site, the Legislature Fault appears to be the controlling crustal source. Based on a telephone conversation with Dr. Weaver of the USGS in Seattle, it appears that this fault has a length of 50 to 60 km, its ground surface projection is about 9.3 km from the dam site, the rupture surface would have a width of about 15 to 20 km, the upper 5 to 8 km could be considered non-seismogenic, and that the slip rate of this fault is very low (<< 1 mm/year). Based on these considerations, the maximum earthquake to be assigned to this source would be a magnitude 7 (using the equations of Wells & Coppersmith for length of 55 km and width of 17.5 km) occurring at a closest distance of 10.6 km (considering a horizontal distance of 9.3 km and a depth of 5 km) from the dam site. Because the fault has a very low degree of fault activity, the median estimates of the earthquake ground motions would be appropriate. Dr. Weaver also suggested that events on this fault are likely to be mostly strike slip, but that they may have a thrust component. Accordingly, it was agreed that a weight of 2/3 would be assigned to a strike slip mechanism and a weight of 1/3 would be assigned to a thrust mechanism.

- The subduction events considered in the report by Shannon & Wilson (item No. 6 above), are those that may occur on the Cascadia Subduction Zone (CSZ) or those that may occur on the Juan de Fuca Plate. For the deterministic estimate of earthquake ground motions Shannon & Wilson only considered the event on the CSZ ($\boldsymbol{M} = 9$ at a distance of 68 km). It is necessary that estimates for a magnitude 7½ earthquake occurring on the Juan de Fuca Plate be also included. The recurrence interval for these events is relatively short (on the order of a few hundred years, as summarized in item 6 above). Therefore, the 84th percentile estimates of earthquake ground motions need to be considered.

- Concern of liquefaction being triggered during future earthquakes is only in the alluvial soils, and not of the silt or the gravels.

- Shannon & Wilson (items No. 7, 8 & 10 above) considered that liquefaction would be triggered in a layer below the embankment extending from a short distance downstream of the toe of the downstream-berm almost all the way to the core trench. This assumption is certainly conservative, but the available subsurface information from investigations carried out prior to and during construction do not provide sufficient information to either fully dismiss this possibility or to confirm it. The most recent subsurface investigation concentrated on the downstream end of the downstream berm, and, therefore, does not provide any additional input regarding the extent of possible liquefaction beneath the embankment. Accordingly, it was agreed at the May 17, 2002 meeting that additional drilling would be conducted beneath the embankment to delineate the presence of potentially liquefiable soils.

- Estimates of the deformations of the embankment following the occurrence of the postulated earthquakes will be needed. If it is eventually judged that liquefaction is unlikely to be triggered under the entire embankment, then a simplified Newmark-type deformation analysis will probably be adequate to judge the performance of this dam. If, on the other hand, it is concluded that a major portion of the foundation layer is likely to liquefy, then a more detailed nonlinear deformation analysis may be required.

It is essential that all the available information be integrated and synthesized to fully evaluate the potential behavior of the Skookumchuck Dam during future earthquakes. It is hoped that Shannon & Wilson will complete such an effort, which will include the results of the soon to be completed drilling.

Respectively submitted,

I. M. Idriss

Enclosures: Figure 1

825 N.E. Multnomah, Suite 1500
Portland, Oregon 97232
(503) 813-5000

PACIFICORP
PACIFIC POWER UTAH POWER

May 1, 2003

Harry T. Hall, P.E.
Regional Engineer
Federal Energy Regulatory Commission
101 SW Main, Suite 905
Portland, Oregon 97204

Subject: Skookumchuck Hydroelectric Project, FERC No. 4441
Fourth Part 12 Consultant's Safety and Inspection Report
Plan and Schedule to Submit Supplemental Reports

Dear Mr. Hall:

Your letter dated March 19, 2003 included review comments and requested a plan and schedule to provide supplemental information to the Fourth Part 12 Consultant's Safety Inspection Report (CSIR) for the Skookumchuck dam in Washington. Your review was coordinated with your consultant, Dr. I. M. Idriss, and a copy of his letter report dated September 20, 2002 was included with your comments. In accordance with your request, PacifiCorp's plan and schedule to provide the five items described in your letter are as follows:

1 PacifiCorp will conduct a new seismic hazard evaluation to determine the MCE and associated ground motions for the Skookumchuck dam. This evaluation will include the Cascadia Subduction Zone (CSZ), deep intraplate events such as those that may occur on the Juan de Fuca Plate, and the Legislative fault (crustal event) as potential seismic sources. Since the recurrence interval of the CSZ and deep intra-plate events is short, the 84^{th} percentile ground motions will be determined for these events. The new seismic hazard evaluation will be completed and submitted to the Commission by December 31, 2003.

2 In accordance with the information provided by Dr. Idriss in his September 20, 2002 letter, PacifiCorp will incorporate the Legislative fault in the seismic hazard evaluation. The information provided by Dr. Idriss will be used to characterize this fault and because this fault has a very low degree of fault activity, the median estimates of ground motions will be determined. The new seismic hazard evaluation will be completed and submitted to the Commission by December 31, 2003.

3 PacifiCorp will conduct a drilling and testing program that includes three additional boreholes to be located on 100-foot centers where the berm intersects the toe of the embankment slope. Standard penetration testing, shear wave velocity and permeability testing will be performed in all the boreholes. Laboratory testing will include gradation tests on all of the samples. Drawings and the specifications for the drilling program will be submitted to the Commission for review by July 31, 2003. Upon the Commission's authorization, drilling work will commence no later than October 31, 2003. The results of the drilling program and an evaluation of liquefaction potential based on information from the new borings and gradation tests will be provided to the Commission no later than March 31, 2004. If a wide variety of conditions are encountered during the drilling operation, PacifiCorp may elect to add additional borings to better define the subsurface conditions.

4 If appropriate, pending the outcome of the field investigations proposed in Item 3, PacifiCorp will conduct a post-earthquake deformation analysis using residual shear strengths for the zones where liquefaction may be triggered. Also, if appropriate, PacifiCorp will calculate the response of Skookumchuck Dam using a non-linear 2-dimensional dynamic analysis procedure. A plan and schedule for each of these activities will be developed accordingly.

5 The U.S. Army Corps of Engineers (COE) completed the PMF study work. The previous PMF studies were based on HMR 43, and PacifiCorp considers the Corps of Engineers PMF study to be the most valid to date. This study incorporates the more recent HMR 57 and the February 8, 1996 flood of record as a calibration point. The results indicate a peak inflow of 32,500 cfs and a peak outflow of 30,600 cfs. The peak reservoir elevation resulting from the PMF is 492.68 feet leaving a freeboard of 4.32 feet. A study performed for PacifiCorp by Bechtel Civil & Mineral, Inc. in 1987 estimated a maximum reservoir wave run-up of 3.8 feet, 0.52 feet lower than the available freeboard of 4.32 feet during the PMF. PacifiCorp's independent consultant is reviewing the new PMF study and PacifiCorp will provide this PMF study along with the Consultant's comments to the Commission by December 31, 2003.

As the Commission is aware, PacifiCorp has held discussions with TransAlta Centralia Generation LLC (TransAlta) regarding the sale of Skookumchuck dam and related assets. PacifiCorp and TransAlta expect to sign a letter of agreement in principle within two weeks to extend the expiration date for the existing right of first refusal to purchase Skookumchuck dam and related assets through June 2003. This extension will allow TransAlta the time necessary to complete various due diligence activities needed to prepare for closure of the sale. PacifiCorp will sustain the activities relative to the addendum to the 2002 Part 12 Report noted above until, and unless, subsequent license exemption transfer or surrender would alter the ownership or jurisdictional status of the project.

The original and two copies of this letter are enclosed. If you have questions or need further information, please contact Mildred Thompson at (503) 813-6664.

Sincerely,

RAL cs

R.A. Landolt
Managing Director, Hydro Resources

MT
RAL:MT:hb

Cc: Washington Department of Ecology, Dam Safety Team

bc: Fields/Strande - Merwin, Kirschenman, Leis, Raeburn, Snyder, Sturtevant, Thompson/FERCEASE, File: Skookumchuck, FERC, Part 12, Compliance

In House Part 12 Supplemental Information Follow-up Task Schedule

Item Number	Description	Responsible Party	Due Date
Items 1 & 2	Submit new seismic hazard evaluation to FERC	Kirschenman, Raeburn, Thompson	December 31, 2003
Item 3	Submit additional drilling program drawings and specs to FERC	Kirschenman, Raeburn, Thompson	July 31, 2003
Item 3	Commence drilling program with FERC approval	Kirschenman, Raeburn	NLT October 31, 2003
Item 3	Provide drilling program results to FERC	Kirschenman, Raeburn, Thompson	NLT March 31, 2004
Item 4	Develop plan & Schedule for deformation analysis as necessary	Kirschenman, Raeburn	TBD
Item 5	Provide new PMF to FERC	Kirschenman, Raeburn, Thompson	December 31, 2003

825 N.E. Multnomah St.
Portland, OR 97232

PACIFICORP

July 30, 2003

Harry T. Hall, P.E.
Regional Engineer
Federal Energy Regulatory Commission
101 SW Main, Suite 905
Portland, Oregon 97204

**Subject: Skookumchuck Hydroelectric Project, FERC No. 4441
Fourth Part 12 Consultant's Safety and Inspection Report
Subsurface Investigation – Drilling Program**

Dear Mr. Hall:

Our letter dated May 1, 2003 included PacifiCorp's plan and schedules to submit supplemental reports to the fourth Skookumchuck Part 12 Consultant's Safety and Inspection Report. Item 3, of our May 1st letter contained a proposed plan and schedule for a drilling and testing program for three additional boreholes along the toe of the embankment slope of Skookumchuck Dam. Drawings and specifications for the additional drilling program are included in the attached, Skookumchuck Subsurface Investigation - Drilling Program, July 2003 for the Commission's review.

Upon the Commission's authorization, drilling work will mobilize and commence by October 30, 2003. As we indicated in our May 1st letter, results of the drilling program and an evaluation of liquefaction potential based on information from the new borings and gradation tests will be provided to the Commission no later than March 31, 2004. If a wide variety of conditions are encountered during the drilling operation, PacifiCorp may elect to add additional borings to better define the subsurface conditions.

The original and two copies of this letter and three copies of its attachment are enclosed. If you have questions or need further information, please contact Mildred Thompson at (503) 813-6664.

Sincerely,

R.A. Landolt
Managing Director, Hydro Resources

RAL:MT:js
Attachment: (Skookumchuck Subsurface Exploration – Drilling Program, July 2003)

C: Washington Department of Ecology, Dam Safety Team*
(With Attachment*)

bc: Fields/Strande - Merwin, Kirschenman*, Leis, Raeburn, Snyder, Sturtevant, Thompson*/FERCEASE, File*: Skookumchuck, FERC, Part 12, Compliance

1.0 Subsurface Investigation

1.1 General

This investigation is to determine the in situ properties and liquefaction potential of the alluvial materials left in place beneath the downstream shell of Skookumchuck Dam during construction. Standard penetration tests, downhole shear wave velocity measurements, and falling head permeability testing will be performed in each borehole.

1.1.1 Scope of Work

Scope of Work shall include furnishing labor, equipment, materials, tools, supervision, testing, and other services required to perform subsurface investigations, laboratory testing, and other services as specified herein. The Scope of Work includes the following items:

Ensuring that all Contractor personnel utilize necessary safety equipment including hard hats, safety glasses, hearing protection, and steel toe boots.

Surveying the location and elevation of all investigation locations.

Performing all exploratory borings, designated BV-1, BV-2, and BV-3, and backfilling as required.

Sampling soil by split barrel methods at required intervals, at changes in stratum, or as required by the Company.

Providing all materials required to protect and preserve soil samples from damage, freezing, or loss of moisture.

Transporting all samples to the laboratory for testing.

Performing laboratory tests as required by the Company and preparing test reports.

Performing falling head permeability tests in boreholes as directed by the Company.

Installing casing for downhole shear wave velocity testing to be performed by others.

1.1.2 Items Furnished by Others and Interfaces

Items furnished by others and not in this Scope of Work include the following:

Downhole shear wave velocity testing.

At the Contractor's option, the Contractor can provide the downhole sheer wave testing as an optional item as described in Section 2.0 of this specification. The Contractor's proposal for this optional item shall include the names and qualifications of Subcontractors, if any, to be utilized in performing the testing work. The Company retains the option to accept or reject the Contractor's proposal.

1.1.3 Performance and Design Requirements

Performance and design requirements for the subsurface investigations are indicated in Article 1.1.7.

1.1.4 Codes and Standards

Work performed under these specifications shall be done in accordance with the following codes and standards. Unless otherwise specified, the applicable governing edition and addenda to be used for all references to codes or standards specified herein shall be interpreted to be the jurisdictionally approved edition and addenda. If a code or standard is not jurisdictionally mandated, then the current edition and addenda in effect at the date of this document shall apply. These references shall govern the work except where they conflict with the Company's specifications. In case of conflict, the latter shall govern to the extent of such difference.

Work	In Accordance With
Auger borings	ASTM D1452
Split barrel sampling	ASTM D1586
Rotary wash borings	US Army Corps of Engineers, Engineering Manual, EM 1110-2-1907, Chapter 4

1.1.5 Materials

The following materials shall be used:

General	
Component	**Material**
Bentonite for drilling fluid	Naturally occurring, high yield sodium montmorillonite powder containing no polymer additives or chemical treatments
Revert® for drilling fluid	Biodegradable drilling fluid
Hole plug	Naturally occurring, high yield sodium montmorillonite graded chips
High solids bentonite grout	Naturally occurring, high yield sodium montmorillonite grout with a high solids content
Cement	ASTM C150, Type I
Concrete	Ready-mix for aboveground and flush mounted covers, and guard posts; 5,000 psi (34,474 kPa) concrete for aircraft rated covers
3 inch Polyvinyl chloride (PVC)	PVC that is National Sanitation Foundation (NSF) tested and approved, Schedule 40
Water	Clean, potable, and free from oil, acids, organic materials, or other deleterious substances

1.1.6 Approved Manufacturers of Components

For the following components, only the listed manufacturers are recognized as maintaining the level of quality of workmanship required by these specifications. If the Contractor wants to propose a nonlisted manufacturer that is considered to provide an equivalent level of quality, this manufacturer must be identified and supporting testimony provided. Acceptance of the manufacturer as a substitute is at the discretion of the Company.

Component	Manufacturer
Biodegradable drilling fluid	Johnson, "Revert"
High solids bentonite grout	Baroid Drilling Fluids, Inc., "Aqua-Grout Catalyst/Benseal"
Hole plug	Baroid Drilling Fluids, Inc.

1.1.7 Services

The following articles cover the services included in the Scope of Work. Services are divided into Field Services and Laboratory Testing Services.

1.1.7.1 Field Services. The following items detail the Scope of Work for Field Services to be performed by the Contractor. Depths of individual borings shall be approximately 80 feet. The estimated quantities for bidding are provided in ??????????.

Drilling	
Auger Drilling	Contractor selected
Rotary wash drilling	Contractor selected, 6.5 inch diameter maximum
Sampling	
Sampling frequency	At 5 foot (1.5 m) intervals between Elevation 390 (~ ground surface) and 350, and 2.5 foot intervals from Elevation 350 to refusal on bedrock (~ Elevation 310).
Sampling methods	2 inch (50 mm) split barrel sampling.
Abandonment and Backfilling of Borings	
Boring abandonment	High solids bentonite grout with cuttings
Backfill boring with	High solids bentonite grout with cuttings
Downhole Shear Wave Velocity Casing Installation	3 inch PVC, flush joint.
Testing	
Falling head permeability testing	By Contractor
Downhole shear wave testing	By Others (Refer to Article 1.1.2.)

Auger drilling may be used from Elevation 390 to Elevation 350, but rotary wash boring is required between Elevation 350 and refusal on bedrock. Previous investigations indicate the bedrock is at Elevation 310 +/-.

1.1.7.2 Laboratory Testing Services. The following testing shall be conducted in accordance with the specified source. This testing is to be considered part of the defined Scope of Work, and all associated costs are the responsibility of the Contractor unless specifically identified as Company-conducted.

Tests	In Accordance With	Conducted By
Atterberg limits	ASTM D4318	Contractor
Grain size analysis	ASTM D422 with sample preparation by ASTM D2217 (wet preparation method), Procedure B	Contractor
Moisture content	ASTM D2216	Contractor
Specific gravity	ASTM D854	Contractor
Specific gravity of coarse grained soils	ASTM C136	Contractor

1.1.8 Technical Attachments

The following attachments are located at the end of this Section. The information contained in these documents constitutes requirements under the defined Scope of Work.

Document Number/Description	Title	Revision
Figure 1	Site Location Map	0
Figure 2	Dam Plan/Drilling Area	0
Figure 3	Boring Location Plan	0

1.2 Products

1.2.1 General

This article describes the labor, equipment, materials, tools, supervision, and services required to perform the subsurface investigation. The purpose of the subsurface investigation is to obtain geotechnical information used to support permitting, design, and construction. Geotechnical information obtained from investigations includes the description and classification of subsurface materials, engineering properties of subsurface materials, subsurface stratigraphy, presence or absence of groundwater, and the identification of potential geologic hazards.

The Contractor shall have all necessary permits, licenses, and insurance coverage required to perform the work. The Contractor shall provide the Company with a current insurance certificate with required coverage before mobilizing.

The location, number, types of investigation techniques, and required depth of investigations used in a subsurface investigation are dependent upon the scope of the investigation, geologic setting, and layout of project structures.

The Contractor shall be responsible for locating all underground utilities at each investigation location. No work shall begin until all utility services have been notified, utility locations have been marked at each investigation location, and the Company has issued an authorization to proceed.

The Company will have representatives in the field during the subsurface exploration program. They will observe the services performed to determine, in general, if the services are proceeding in accordance with the intent of the requirements herein. They may request adjustments in the services as required. The Company's field representatives, as required, will approve boring locations; maintain a log of each boring, select intervals for falling head permeability testing, authorize changes in the services to be performed; and oversee the performance of the services.

The Contractor shall add to or deduct from the depth and number of the borings indicated on the drawings as directed by the Company during the course of the work. The Contractor shall also add to or deduct from the number of each type of laboratory test as directed by the Company during the course of the work. Such changes will be determined by the Company, and changes in price due to changes in quantities will be calculated using unit prices.

The Contractor shall provide, on each drilling rig, a 20 pound (9.1 kg) ABC type fire extinguisher and one first aid kit equipped with an eyewash bottle.

The Contractor shall be held responsible for any damage to existing structures or property resulting from his operations and shall repair or replace any such damaged structures or property to the satisfaction of the property owner at no additional cost to the Company.

The Contractor shall be responsible for all damages to streets, roads, curbs, sidewalks, highways, shoulders, ditches, embankments, culverts, bridges, or other public or private property that may be used to transport equipment, materials, or personnel to or from the site and investigation locations, as required. The Contractor shall make satisfactory and acceptable arrangements with the responsible individuals having jurisdiction over the damaged property concerning its repair or replacement.

Access for the services will be provided by the Company and will be available so that services can proceed as scheduled; however, the Contractor shall have written notification from the Company to proceed before entering areas where the services will be performed. The Contractor shall become familiar with the site prior to bidding the work.

All Contractor personnel engaged in the field investigation services shall be trained for such activity, when required. Training shall include, but not be limited to, review of the proper use of personal protective equipment, safe operating procedures, and emergency response.

1.2.2 Drawings. Drawings indicating the location plan of the borings are included with these technical specifications in Article 1.1.8.

1.2.3 Materials
All materials required for the subsurface investigation shall be furnished by the Contractor and work shall be performed in accordance with the codes and standards specified herein.

The materials shall be new and undamaged and shall conform to the requirements specified in this specification.

1.2.4 Equipment. Equipment shall be in good operating condition and shall operate at the capacity specified or required to perform the work required for the subsurface investigation. Equipment shall be acceptable to the Company.

No payment will be made for mobilization costs for equipment brought to the site to replace equipment that breaks down, does not perform satisfactorily, or is found to be unsuitable for site conditions.

The Contractor shall provide the Company with all calibration information for calibrated equipment.

1.2.5 Water. The Contractor shall furnish all water required for drilling and other work, as required. No separate payment will be made for water or for time spent getting water. All water used shall be free from oil, acids, organic materials, or other deleterious substances. In addition, clean water shall be used for mixing grout for backfilling borings. Contractor shall obtain permission and pay all costs associated with using water from fire hydrants.

Potable water shall be used for all drilling and piezometer installation.

1.2.6 Discharge Water. Discharge water from the boring operations shall be conveyed to natural drainage by piping or ditches acceptable to the Company. The Contractor shall ensure that discharging of water shall be in accordance with all federal, state, and local requirements. At the conclusion of the work, the Contractor shall repair all erosion damage caused by the discharge water and restore ditches and other drainage facilities to their original condition.

1.2.7 Electrical Power. The Contractor shall furnish all electrical power required for drilling and other work. No separate payment will be made for providing electrical power.

1.3 Execution

All borings shall be drilled vertically unless directed otherwise by the Company or specified herein. The borings shall be kept straight and plumb within limits that will permit satisfactory installation of casings, as required. Should the boring prove unsatisfactory at any time prior to acceptance, the boring shall be considered abandoned with the requirements of Article 1.3.3, Abandonment of Boring/Piezometers.

Cuttings generated during advancement of the borings shall be spread evenly on the ground surface in the vicinity of the piezometer or boring in a manner that will not damage the area or be unsightly, unless directed otherwise by the Company. Water from the boring operations shall be discharged in accordance with Article 1.2.6, Discharge Water.

Sampling shall be performed in accordance with the requirements of Article 1.3.2, Sampling Method and Frequency. The borehole shall be cleaned prior to collecting samples.

Borings shall be left open for 24 hours after completion to allow the Company to obtain a water level, unless directed otherwise by the Company. After the 24 hour water level reading, or when directed by the Company, the Contractor shall install casing for downhole shear wave testing.

1.3.1 Rotary Wash Drilling. When required, rotary wash drilling shall include earth drilling with or without sampling as directed by the Company. Rotary wash borings shall have the minimum diameter specified in Article 1.1.7.1 and shall be of sufficient size to accommodate sampling equipment and down hole shear wave casing installation. Unless otherwise permitted by the Company, rotary wash borings shall be performed in accordance with Article 1.1.4.

In silty formations that might be disturbed by conventional side discharging bits, the hole shall be prepared for sampling equipment with a bit equipped with baffles to deflect the drilling fluid upward.

Drilling mud or temporary casing shall be provided by the Contractor if required to maintain an open hole.

Drilling mud shall consist of a mixture of high-swelling bentonite and water, or biodegradable drilling fluid as specified in Article 1.1.6 (or acceptable equivalent approved by the Company) and water, of sufficient viscosity to prevent penetration of the mud into the soil during sampling operations. Chemical additives for adjusting viscosity may be used if permitted by the Company. When piezometers are to be installed, high-swelling bentonite shall not be used.

If required for borehole stability and approved by the Company, temporary casing may be used by the Contractor. Temporary casing required to advance the boring in soil or rock shall be acceptable to the Company. The casing shall be steel pipe of the size to facilitate all required operations and may be either new material or used material in good condition.

Temporary casing shall remain in the boring until its removal is authorized by the Company. The Contractor may be required to move off any boring after drilling and casing placement are completed and then return to the boring to remove all temporary casing and backfill the boring as specified.

All temporary casing shall be pulled prior to or during backfilling to ensure complete backfilling of the hole in a manner acceptable to the Company. No payment will be made for temporary casings left in place because of the impracticability of removal.

1.3.2 Sampling Method and Frequency

When required by the Company, sampling shall consist of split barrel samples at the depths listed in Article 1.1.7.1.

The water level in each boring shall be maintained whenever drilling equipment is retracted in preparation for sampling to avoid unbalanced hydrostatic pressure that might wash in material from the sides and bottom of the boring or make the boring unstable.

The 2 inch (50 mm) diameter split barrel samples shall be obtained and resistance to soil penetration shall be measured using the split barrel sampler in accordance with Article 1.1.4. Penetration resistance (blow count) for each 6 inch (150 mm) increment shall be required.

The coupling head for the split barrel sampler shall be provided with a ball check valve and shall have open vents. The sampler shall also be equipped with a spring type sample retainer or an acceptable equivalent approved by the Company. The Contractor shall have a minimum of two complete split barrel samplers on the drill rig. The barrel for the sampler shall be at least 18 inches (457 mm) in length to allow for 18 inch (457 mm) long samples.

The Contractor shall break down all split barrel samplers after collecting a sample. Sample jars for split barrel samples submitted for physical analysis shall be supplied by the Contractor and shall not be larger than 2-3/8 inches (60 mm) in diameter. Sample jars for split barrel samples shall be moistureproof and vaporproof wide-mouth glass jars with self-sealing screw covers. Sample jars will be labeled by the Company. The Contractor shall supply labels with space for the job name, boring number, interval sampled, and blow count in 6 inch (150 mm) increments.

The Contractor may use sealable plastic bags in place of glass jars for storage of samples if approval is obtained from the Company before the start of work.

If the Company is away during sampling, the Contractor, under the direction of the Company, shall place the sample in a sample jar or plastic bag and label the sample jar or plastic bag in the manner directed by the Company. The sample jar or plastic bag should then be placed in its appropriate location for the Company to check at a later time.

1.3.3 Abandonment of Boring

Any boring that does not meet the depth, alignment, plumbness, or other requirements, or any boring on which the Contractor stops work before completion will be considered an abandoned boring. A new boring shall be started in the immediate vicinity at a location designated by the Company after the location of utilities has been established by the Contractor. No payment will be made for any work on an abandoned boring. An abandoned boring shall be backfilled and sealed with cement-bentonite grout, high solids bentonite grout, or cuttings as required in Article 1.1.7.1 or as approved by the Company.

Any newly installed piezometer that does not meet construction quality, accuracy of piezometer screen placement, or other requirements, or any piezometer on which the Contractor stops work before completion, will be considered an abandoned piezometer. No payment will be made for any work on an abandoned piezometer. Piezometer abandonment shall meet all regulations of the state where the services are performed and/or requirements of the Company and be in accordance with Article 1.3.4, Grout. A new piezometer shall be installed in the immediate vicinity at a location designated by the Company after the location of utilities has been established by the Contractor.

1.3.4 Grout

The cement-bentonite or high solids bentonite grout used to backfill borings not completed. The cement-bentonite or high solids bentonite grout seal shall be brought to the ground surface, or as required by the Company.

When required, the cement-bentonite grout slurry shall weigh between 12 and 14 pounds per gallon (1.44 and 1.68 kg/L) and consist of 95 percent (by weight) cement with 5 percent sodium bentonite mixed with no more than 6 gallons (23 L) of water per 94 pound (42.6 kg) sack of cement. Cement shall conform to Article 1.1.5. The grout shall be thoroughly mixed and shall be used before any stiffening occurs. The Contractor shall supply a balance to measure the weight of the grout.

When required, the high solids bentonite grout shall be as specified in Article 1.1.6, or an acceptable equivalent approved by the Company. The high solids bentonite grout shall be thoroughly mixed according to the manufacturer's specifications. The bentonite grout shall weigh between 9.0 and 9.5 pounds per gallon (1.08 and 1.14 kg/L), unless otherwise directed by the Company. The Contractor shall supply a balance to measure the weight of the grout.

Grout shall be placed by the tremie method. The tremie method shall consist of pumping the slurry down the boring or annular space outside the piezometer casing through a pipe. The bottom of the pipe shall be placed near the bottom of the zone to be grouted and shall be raised as the grout is placed, always keeping the bottom of the tremie pipe below the top of the grout. The tremie pipe tip shall be equipped with baffles to discharge the grout upward. The tremie pipe tip shall be placed as close as possible to the top of the silica sand filter or seal. The tremie pipe tip shall be kept at least 5 feet (1.5 m) below the grout surface during grout placement. Before grouting is completed, the Company will weigh the grout exiting the borehole to ensure that the correct mixture has been brought to the surface. Pumps, piping, and other materials for mixing and pumping grout shall be provided by the Contractor.

When allowed in Article 1.1.7.1, borings may be backfilled with cuttings.

1.3.5 Downhole Shear Wave Casing Installation

The Contractor shall furnish all labor, materials, and equipment for completing the installation of casing for downhole shear wave testing. Casing shall be installed in accordance with Article 1.1.4 and as described below. Materials required for construction of the permanent casing shall be as required in Article 1.1.7.1.

Permanent Schedule 40 PVC casing, with a minimum inside diameter of 3 inches (75 mm), shall be installed to the completed depth of each boring. PVC pipe sections shall be joined using watertight, flush-threaded joints that are acceptable to the Company. A watertight bottom cap shall be provided to seal the bottom of the casing.

In accordance with the requirements in Article 1.1.4, the maximum boring diameter shall be 6.5 inches (162.5 mm). The annulus outside the casing shall be backfilled with cement bentonite grout using the tremie method in accordance with Article 1.3.4, Grout. The grout shall have a similar density to the in situ material, and shall consist of 1 pound bentonite (not synthetic materials), 1 pound of Portland Cement, and 6.25 pounds of water.

Bentonite drilling mud shall not be used to advance a borehole unless approved by the Company. A biodegradable synthetic drilling fluid acceptable to the Company may be used; the manufacturer's directions shall be carefully followed.

1.3.6 Falling Head Permeability Testing

The Contractor shall provide a suitable pump, water meter, water level indicator, necessary pipe and connections, and all other equipment and supplies required to perform falling head tests.

In general, the tests will be conducted between Elevation 350 and rock. The Contractor shall record the test results on a form acceptable to the Company. Based upon inspection of the samples, the purchaser will select intervals for testing. The hole will be cleaned out from the bottom of the casing to the top of the next sample interval, and the test will be performed.

The casing will be filled with water and the time to drop 10 feet, or the drop in 5 minutes will be monitored. If the casing can not be filled, the flow into the casing will be recorded.

1.3.7 Cleanup

As work at each boring location concludes, the Contractor shall remove all equipment, tools, material, and supplies and shall leave the site clean and clear of all debris generated by his work. All earth cuttings, drilling fluid, and discharge water from piezometer development shall be spread evenly on the ground around the piezometer or boring so as not to damage the area or be unsightly, unless directed otherwise by the Company.

1.3.8 Restoration of Damaged Property
The Contractor shall conduct all services in a manner to prevent any destruction, scarring, or defacing of the worksite. At the completion of services, the Contractor shall restore each location to its original condition.

The Contractor shall, at his own expense, restore all property damaged while accessing the drill sites and performing services.

The restoration work shall include, but not be limited to, the repair of fences and roads and the leveling of ruts produced by driving to the investigation locations.

1.3.9 Surveying
All locations of subsurface investigations shall be surveyed and staked. All surveying shall be performed by a land surveyor registered in the state in which the work is being performed.

The Contractor shall use the Company designated elevation datum and coordinate system to locate the subsurface investigations. The Contractor shall not start work at any location until the location has been staked, the surface elevation has been determined, clearance for underground utilities has been received, the location has been reviewed by the Company, and authorization to proceed has been issued. Subsurface investigations shall be located as indicated on the drawing included in these specifications.

The acceptable tolerance for elevation shall be 0.1 foot (30.5 mm) and for location shall be 1.0 foot (0.3 m). Locations shall not be moved more than 15 feet (4.6 m) from the planned location without Company's approval.

1.3.10 Laboratory Tests
Unless otherwise permitted by the Company, each laboratory test shall be performed as specified in the laboratory test standards specified herein. Test results shall be reported on forms suitable for reproduction and shall be acceptable to the Company.

Samples to be tested will be selected by the Company after completion of the drilling. The Contractor shall be responsible for delivering the test samples to the laboratory.

1.3.10.1 Atterberg Limits. When required, Atterberg limits shall be as specified in Article 1.1.7.2. The liquid limit shall be determined by securing the results of at least three trials. The test report shall include initial moisture content.

1.3.10.2 Grain Size Analysis. When required, grain size analysis shall be as specified in Article 1.1.7.2. This test is a complete sieve analysis, not just a measurement of the percent finer than the No. 200 sieve. This test does not include a hydrometer analysis. If the Company requires hydrometer analyses, they will be requested separately. Reports of the results of this test shall include data and a graph of the data.

1.3.10.3 Moisture Content. When required, moisture content determination shall be as specified in Article 1.1.7.2; no exceptions cited.

1.3.10.4 Specific Gravity. When required, the specific gravity of the soils shall be determined as specified in Article 1.1.7.2; no exceptions cited.

1.3.10.5 Specific Gravity of Coarse Grained Soils. Specific gravity determination for gravel and larger grained soils shall be as specified in Article 1.1.7.2.

1.3.11 Quantities Measurement
Quantities of work completed by the Contractor will be measured and paid for as specified herein. All work not specifically set forth as a pay item shall be considered a subsidiary obligation of the Contractor, and all associated costs shall be included in the unit prices.

1.3.11.1 Mobilization and Demobilization. When required, the initial mobilization of drill rig(s), bulldozers, backhoes, cone penetrometer rig(s), crosshole testing equipment, refraction survey equipment, and associated equipment as required in Article 1.1.5 and demobilization of same shall be made in the amount of the appropriate unit price stated herein, per drill rig, bulldozer, backhoe, cone penetrometer rig, crosshole testing equipment, or refraction survey equipment. If additional mobilization is initiated by a written request from the Company, additional payment for delivery to and removal from the site of all materials, tools, and drilling and sampling equipment will be made, for each item, in the amount of the appropriate unit price stated in this proposal.

The mobilization unit prices are to be for the complete mobilization and demobilization.

No payment will be made for mobilization costs for equipment brought to the site to replace equipment that breaks down, does not perform satisfactorily, or is found to be unsuited to site conditions. No payment will be made for mobilization costs for additional equipment the Contractor chooses to mobilize because of conditions brought about by adverse weather.

1.3.11.2 Drilling and Sampling. The unit price for drilling borings and securing samples shall include the costs of all labor, materials, and equipment required, including all costs of labor, materials, and equipment required for the boring and sampling services.

The unit price for borings shall include the costs of making borings and supplying water and all other appurtenant drilling costs, including moving equipment between piezometer and boring locations. Payment for borings will be made on the basis of actual footage of boring advanced, measured from the ground surface to the depth authorized by the Company.

The unit price for temporary casings shall include the cost of supplying, installing, and removing all temporary casings. No payments shall be made for temporary casings left in place because of impracticability of removal. Payment for temporary casings shall be made on the basis of actual footage installed, measured from the ground surface to the depth authorized by the Company.

The unit price for 2 inch (50 mm) diameter split barrel sampling shall include the costs of cleaning the bottom of the boring before sampling, making standard penetration tests with 2 inch (50 mm) samplers, recovering representative samples of soil from the sampler, opening samplers, and all other appurtenant costs, including the cost of containers and labels for samples, and placing samples in containers as needed. Payment for split barrel sampling shall be made on the basis of the actual number of sampling attempts authorized by the Company. No payment will be made for split barrel sample attempts where there is no recovery due to careless handling or sampling procedures used by the Contractor, as judged by the Company.

The unit price for grout sealing borings shall include the cost of all labor, materials, and equipment as required by the Company. Payment for grout sealing will be made on the basis of the actual footage of the boring grouted. If the boring has collapsed before backfilling, the quantity shall be measured from the ground surface to the depth of collapse as determined by the Company.

The unit price for sealing borings with granular bentonite below the bottom of piezometers shall include the cost of all labor, materials, and equipment as required by the Company. Payment for sealing will be made on the basis of the actual footage of the boring sealed.

1.3.11.3 Surveying. The unit price for surveying shall include the cost of all labor, materials, and equipment required to survey and stake the location and elevation at all borings, piezometers, and test pits, including tying the survey to a known bench mark or state plane coordinate system. The surveying unit price shall also include the cost of providing the survey results in a letter report and an electronic AutoCAD file. Payment will be made on the basis of the number of borings, piezometers, and test pits surveyed.

1.3.11.4 Falling Head Permeability Testing. The unit price for packer testing shall include all labor, materials, and equipment required to perform the testing and record the data during the tests. Payment for falling head testing will be made on the basis of the number of tests performed, including setup time.

1.3.11.5 Permanent Casing Installation for Downhole Shear Wave Velocity Testing. Payment for permanent casing installation for downhole shear wave velocity testing shall include the costs of all labor, materials, and equipment required for installing and grouting the casing. Payment shall be made on the basis of actual footage of casing installed, measured from the ground surface to the depth authorized by the Company.

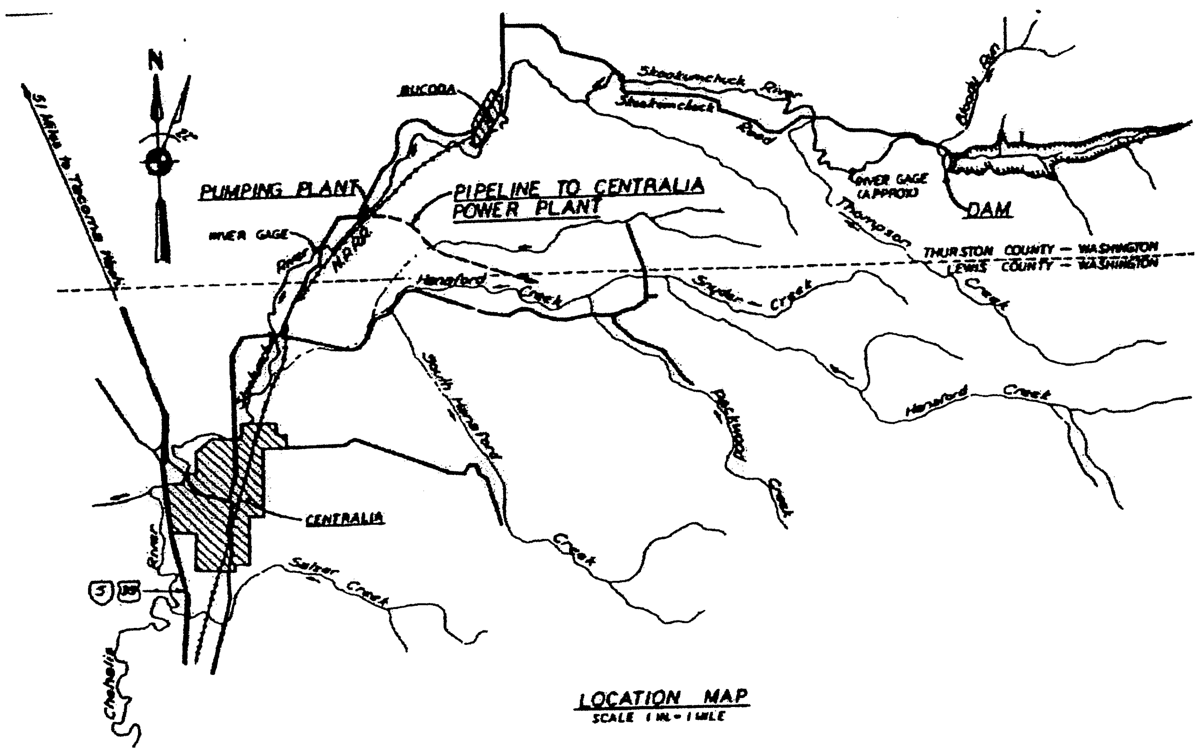
1.3.11.6 Laboratory Tests. The unit price for each laboratory test shall include all costs of labor, materials, and equipment for performing the tests and presenting five copies of the results.

1.3.11.7 Standby Time/Downtime. Standby time shall be time when the Contractor could be working, but the Company has directed the Contractor to discontinue working and to remain onsite and be prepared to resume services when directed by the Company. Downtime shall be time when services cannot be performed due to failure of the Contractor's equipment or other factors caused by the Contractor that prevent services from being performed. Standby time will be paid only if service stoppages directed by the Company exceed downtime caused by the Contractor. The Company will keep a record of both standby time and downtime. Payment will be based on the actual amount of standby time in excess of downtime. Work stoppage caused by inclement weather does not constitute standby time or downtime.

1.4 Schedule

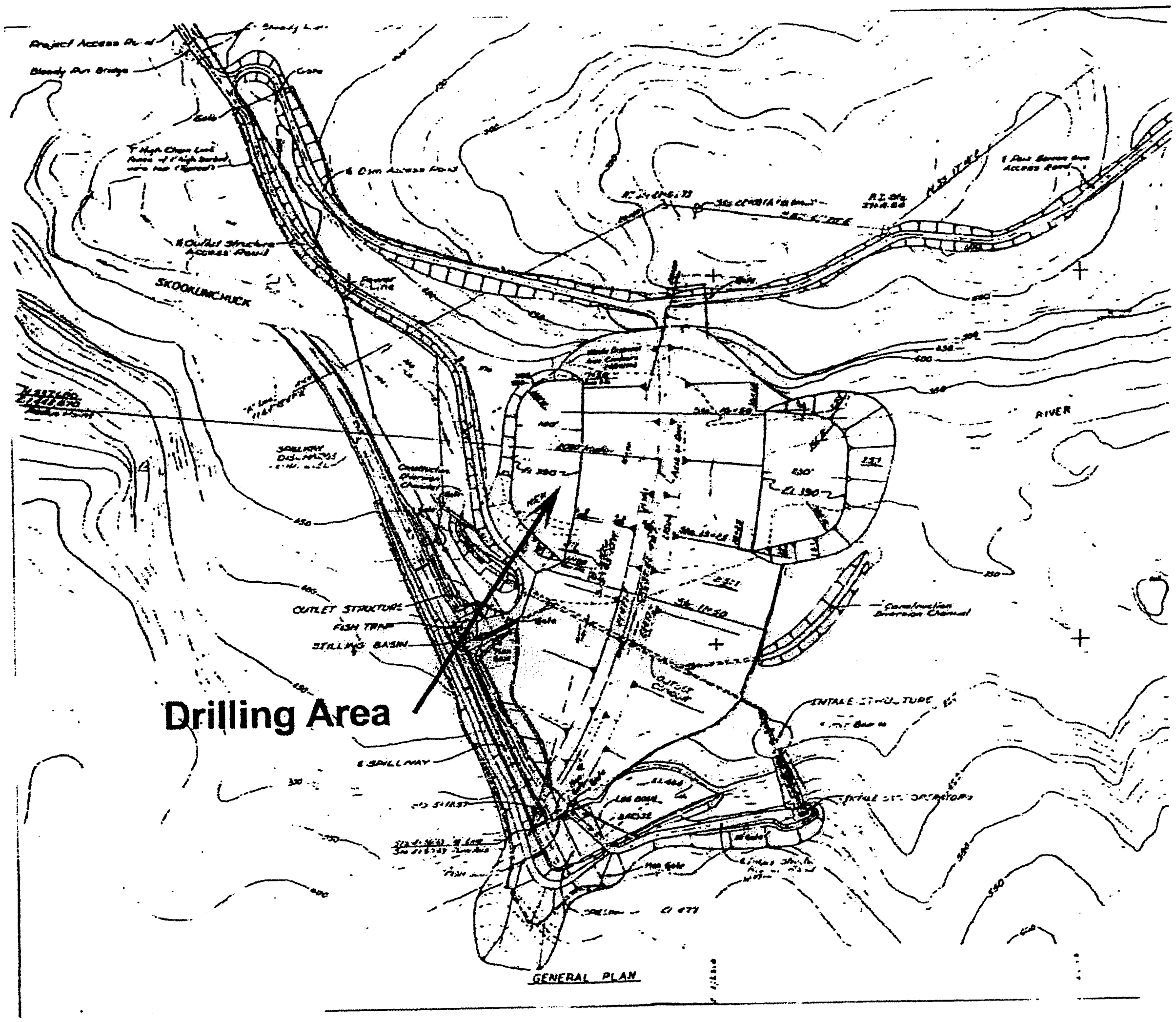
The Field Services and Laboratory Testing Services shall be performed within the following completion dates.

Activity	Completion Date
Award Work	October 23, 2003
Mobilize Drilling Contractor	October 30, 2003
Conduct Drilling Work	November 20, 2003
Conduct Laboratory Testing	December 25, 2003



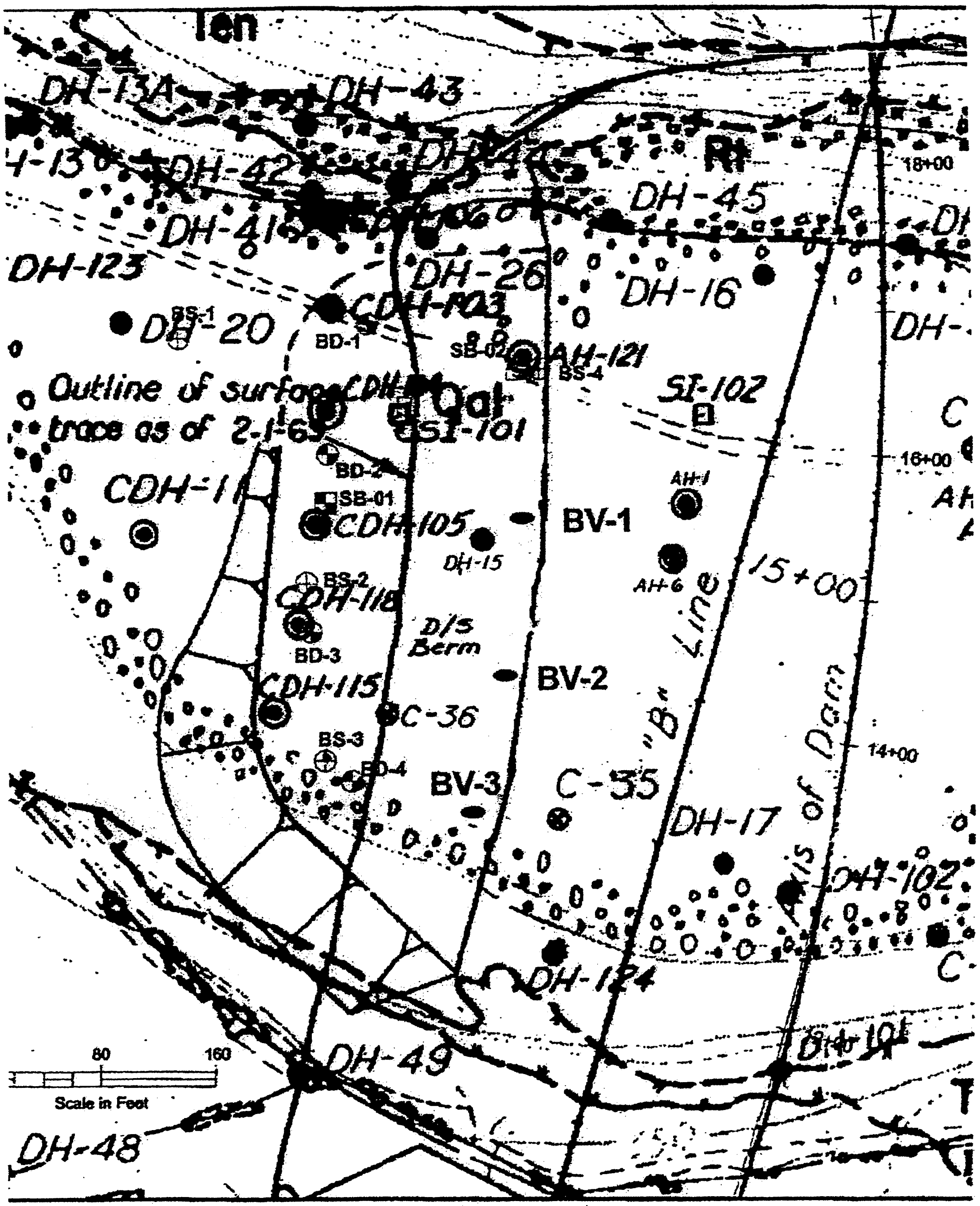
Skookumchuck Dam
Subsurface Investigations

Figure 1
Site Location Map
Rev. 0



Skookumchuck Dam
Subsurface Investigations

Figure 2
Dam Plan/Drilling Area
Rev. 0



Proposed 2003 Boring

2.0 Downhole Shear Wave Velocity Test

2.1 General

The intent of this testing is to determine the variation in compression (P-wave) and shear wave (S-wave) velocity with depth using downhole seismic test procedures. The boreholes and casing will be installed by others.

2.1.1 Field Procedures

A three component downhole geophone shall be used to record the seismic signals. Seismic signals shall be created by two sources. A sledge hammer and plate shall be used for as the P-wave source, and a vehicle weighted plank and sledge hammer shall be used as the shear wave source. To take advantage of the S-wave polarization, both sides of the weighted plank shall be struck, and the waveforms recorded separately.

P and S wave data shall be collected on 2.5 foot intervals. The recording device shall have at least 24 channels. Signal stacking shall be used to enhance the measurement of polarized signals and reduce ambient vibration interference.

2.1.2 Report

A report providing P and S wave velocity at each test depth shall be provided in tabulated and graphical form. A description of field procedures and data reduction methodology shall be provided.

2.2 Schedule

The downhole shear wave velocity testing shall be performed within the following completion dates.

Activity	Completion Date
Award Work	October 23, 2003
Boreholes and Casing Installed by Others	November 20, 2003
Conduct Downhole Shear Wave Velocity Tests	December 25, 2003

FEDERAL ENERGY REGULATORY COMMISSION
Office of Energy Projects
Division of Dam Safety and Inspections
Portland Regional Office
101 S.W. Main Street, Suite #905
Portland, Oregon 97204

Copied 8/11/03 CS:hb
Fields – Merwin
Scibelli - Merwin
Strande – Merwin
Thompson/FERCEASE – 1500 LCT
File/Skookumchuck, Compliance,
FERC, Part 12 plan & schedule,
Acknowledgment

JUL 31 2003

In reply refer to:
P-4441-WA
NATDAM-WA00153

Mr. Randy A. Landolt
Director, Hydro Resources
PacifiCorp
825 NE Multnomah, Suite 1500
Portland, OR 97232

Dear Mr. Landolt:

This is to acknowledge your May 1, 2003 letter, in response to our March 19, 2003 letter, proposing a plan and schedule for providing supplemental information to the January 15, 2002 Fourth Independent Consultant's Safety Inspection Report for the Skookumchuck Project, FERC No. 4441. We have the following comments on the items addressed in your May 1 letter:

- Items 1 and 2 - You proposed to conduct a new seismic hazard evaluation, which would include the Cascadia Subduction Zone, deep intraplate events, and the Legislature fault. Further, the information provided in Dr. I. M. Idriss' September 20, 2002 letter report would be incorporated into the evaluation and the evaluation submitted to this office by December 31, 2003. This is acceptable.

- Item 3 - You proposed to submit plans and specifications for the Skookumchuck Dam drilling/explorations program by July 31, 2003; begin the drilling/explorations by October 31, 2003; and submit the exploration results and a liquefaction evaluation by March 31, 2004. This is acceptable. In addition to the plans and specifications, a Quality Control and Inspection Program, including a soil erosion and sediment control plan, should be submitted. By June 13, 2003 letter, Mr. Roger L. Raeburn, Manager, Hydro Plant Engineering, forwarded drawings showing the existing and proposed drill hole locations. We have reviewed this information; the proposed locations of the three new drill holes are acceptable. We concur that, as information is learned from the initial advancement of the borings, additional borings may be needed.

Critical Energy Infrastructure Information
-Do Not Release-

o Item 4 - Based on the results obtained from the drilling/explorations program addressed in Item 3, you indicated that a post-earthquake deformation analysis may be performed and, if appropriate, a non-linear 2-dimensional dynamic analysis would be performed. This is acceptable. If these analyses are considered necessary, the plan and schedule for the work must be submitted to this office for our review.

o Item 5 - You stated that your consultant will review the recently completed U.S. Army Corps of Engineers' Skookumchuck Dam PMF study, and that copies of the PMF study and your consultant's comments thereon will be submitted by December 31, 2003. This is acceptable.

As a reminder, all of the above discussed submittals should be made in triplicate to this office. If you have any questions, please contact Messrs. William Lagnion or Edward Perez of this office at (503) 522-2748 or (503) 552-2750, respectively.

Sincerely,

Harry T. Hall, P.E.
Regional Engineer

FEDERAL ENERGY REGULATORY COMMISSION
Office of Energy Projects
Division of Dam Safety and Inspections
Portland Regional Office
101 S.W. Main Street, Suite #905
Portland, Oregon 97204

Copied 10-10-03 CS:hb
Fields - Merwin
Kirschenman - 1500 LCT
Leis - 1500 LCT
O'Connor - 1500 LCT
Raeburn - 1500 LCT
Snyder - 1500 LCT
Strande - 1500 LCT
Sturtevant - 1500 LCT
Thompson/FERCEASE - 1500 LCT
File: Skookumchuck, Compliance, FERC, Part 12 D Report 2002-Plan and Schedule response, Instrumentation Maintenance

2003

In reply refer to:
P-4441-WA
NATDAM-WA00153

Mr. Randy A. Landolt
Director, Hydro Resources
PacifiCorp
825 NE Multnomah, Suite 1500
Portland, OR 97232

Dear Mr. Landolt:

This is to acknowledge your July 30, 2003 letter providing plans and specifications for the drilling program regarding the January 15, 2002 Fourth Independent Consultant's Safety Inspection Report for the Skookumchuck Project, FERC No. 4441. We have the following comments:

(1) As requested in our July 31, 2003 letter, a Quality Control and Inspection Program (QCIP), including a sediment and erosion control plan (SECP), should be submitted. Your July 30 letter did not provide a QCIP or SECP. Section 1.2.6 - Discharge Water, states that drilling discharge water will be sent to ditches. Discharge water and cuttings from drilling activities should be contained within the area of drilling in a manner that will not cause adverse environmental impacts.

(2) Section 1.1.4 – SPT sampling should be performed in accordance with ASTM D 6066, "Standard Practice for Determining the Normalized Penetration Resistance of Sands for Evaluation of Liquefaction Potential", in addition to ASTM 1586, "Standard Test Method for Penetration Test and Split-Barrel Sampling of Soils". However, you are required to perform continuous SPTs below Elevation 350 as stated in Item 6, below.

(3) Section 1.1.1 - Scope of Work, should include the installation of open tube piezometers in two of the borings for the purpose of measuring static water level readings and falling head permeability tests if appropriate. Tip installation elevations of the piezometers should be chosen on the basis of conditions encountered during drilling operations.

(4) Section 1.3.1 - Rotary Wash Drilling, states that casing may be used to maintain an open boring. This section should state that if casing is used, it should not be advanced within 2.5 feet of the current standard penetration testing (SPT) interval in conformance with ASTM D 6066 section 11.2.2.

(5) The type of hammer used to advance SPTs should be provided along with the appropriate calibration data. Calibration data should be provided with the information requested in Item 7, below. In addition, a liner should be used in the SPT sampler (creating a constant 1 3/8" ID) to eliminate the need to apply a correction factor in the normalization of N values.

(6) Section 1.1.7.1 – SPTs may be performed on 5-foot intervals from the ground surface to approximate Elev. 350 as indicated. SPTs should then be performed continuously from Elev. 350 to refusal on bedrock, instead of 2.5-foot intervals as stated.

(7) A copy of the field boring logs, backfill records, and piezometer/casing installation records should be mailed or faxed to this office within 10 days upon completion of drilling activities. Field boring logs should include recovery, and details of casing advancement if used.

Once the above comments are incorporated, the plans and specifications will be acceptable. No work may proceed until a QCIP and SECP for the work is filed with and approved by this office. **Please provide the QCIP and SECP as soon as possible so that we can continue our review and that you may meet the current construction schedule.**

You are reminded that, as licensee, it is your responsibility to ensure that construction practices are such that erosion and other potential environmental impacts during and after the proposed work are minimized, and that all deleterious material and fluids are kept out of the river. In addition, you must notify this office as soon as possible if there are any developments that might affect the integrity of the Skookumchuck Dam.

As a reminder, all of the above discussed submittals should be made in triplicate to this office. If you have any questions, please contact Messrs. William Lagnion or Edward Perez of this office at (503) 522-2748 or (503) 552-2750, respectively.

Sincerely,

Harry T. Hall, P.E.
Regional Engineer

EXHIBIT B

SKOOKUMCHUCK FORECAST - November 2003 to January 2004

	2004 - Estimated Budget Calendar Year						Assigned PM
Description of Work	Labor	Emp Exp	Materials	Contracts	Other	TOTAL	
Fish Hatchery				138,000	8,500	146,500	Lesko
Security				130,600		130,600	Fields
Wildlife Management Plan	6,000	240	14,400	39,000	-	59,640	Naylor
Hydrologic Data - USGS Data				17,500		17,500	Bornemeier
Routine Operating Expenses	16,900	500	2,200	-	5,300	24,900	Fields
FERC Issues	700	46		23,000		23,746	Thompson
Skookumchuck Stability Analysis Drilling Program	9,600			100,000		109,600	Raeburn
Skookumchuck Weyerhaeuser Easement Payment					3,000	3,000	
Annual Revenue from Generation Sales						-	
	33,200	786	16,600	448,100	13,800	512,486	

LABOR

Description of Work	Nov-03	Dec-03	Jan-04	Feb-04	TOTAL
Fish Hatchery	-	-	-	-	-
Security	-	-	-	-	-
Wildlife Management Plan	500	500	500	500	2,000
Hydrologic Data - USGS Data	-	-	-	-	-
Routine Operating Expenses	1,407	1,407	1,407	1,407	5,628
FERC Issues	-	-	-	-	-
Skookumchuck Stability Analysis Drilling Program	3,000	2,000	2,000	1,300	8,300
Skookumchuck Weyerhaeuser Easement Payment	-	-	-	-	-
Annual Revenue from Generation Sales	-	-	-		-
TOTAL	$ 4,907	$ 3,907	$ 3,907	$ 3,207	$ 15,928

EMPLOYEE EXPENSES

Description of Work	Nov-03	Dec-03	Jan-04	Feb-04	TOTAL
Fish Hatchery	-	-	-	-	-
Security	-	-	-	-	-
Wildlife Management Plan	20	20	20	20	80
Hydrologic Data - USGS Data	-	-	-	-	-
Routine Operating Expenses	30	30	30	30	120
FERC Issues	-	-	-	-	-
Skookumchuck Stability Analysis Drilling Program	-	-	-	-	-
Skookumchuck Weyerhaeuser Easement Payment	-	-	-	-	-
Annual Revenue from Generation Sales	-	-	-		-
TOTAL	$ 50	$ 50	$ 50	$ 50	$ 200

MATERIALS

Description of Work	Nov-03	Dec-03	Jan-04	Feb-04	TOTAL
Fish Hatchery	-	-	-	-	-
Security	-	-	-	-	-
Wildlife Management Plan	1,200	1,200	1,200	1,200	4,800
Hydrologic Data - USGS Data	-	-	-	-	-
Routine Operating Expenses	110	110	110	110	440
FERC Issues	-	-	-	-	-
Skookumchuck Stability Analysis Drilling Program	-	-	-	-	-
Skookumchuck Weyerhaeuser Easement Payment	-	-	-	-	-
Annual Revenue from Generation Sales	-	-	-		-
TOTAL	$ 1,310	$ 1,310	$ 1,310	$ 1,310	$ 5,240

CONTRACTS

Description of Work	Nov-03	Dec-03	Jan-04	Feb-04	TOTAL
Fish Hatchery	34,294	-	-	34,294	68,588
Security	10,800	10,800	10,800	10,800	43,200
Wildlife Management Plan	4,000	1,500	1,500	4,000	11,000
Hydrologic Data - USGS Data	-	-	-	-	-
Routine Operating Expenses	-	-	-	-	-
FERC Issues	-	-	-	-	-
Skookumchuck Stability Analysis Drilling Program	15,000	25,000	20,000	10,000	70,000
Skookumchuck Weyerhaeuser Easement Payment	3,000	-	-	-	3,000
Annual Revenue from Generation Sales	-	-	-		-
TOTAL	$ 67,094	$ 37,300	$ 32,300	$ 59,094	$ 195,788

OTHER

Description of Work	Nov-03	Dec-03	Jan-04	Feb-04	TOTAL
Fish Hatchery	-	-	-	-	-
Security	-	-	-	-	-
Wildlife Management Plan	-	-	-	-	-
Hydrologic Data - USGS Data	-	-	-	-	-
Routine Operating Expenses	442	442	442	442	1,768
FERC Issues	-	-	-	-	-
Skookumchuck Stability Analysis Drilling Program	-	-	-	-	-
Skookumchuck Weyerhaeuser Easement Payment	-	-	-	-	-
Annual Revenue from Generation Sales	(2,000)	-	-	(1,500)	(3,500)
TOTAL	$ (1,558)	$ 442	$ 442	$ (1,058)	$ (1,732)

TOTAL FORECAST

Description of Work	Nov-03	Dec-03	Jan-04	Feb-04	TOTAL
Fish Hatchery	34,294	-	-	34,294	68,588
Security	10,800	10,800	10,800	10,800	43,200
Wildlife Management Plan	5,720	3,220	3,220	5,720	17,880
Hydrologic Data - USGS Data	-	-	-	-	-
Routine Operating Expenses	1,989	1,989	1,989	1,989	7,956
FERC Issues	-	-	-	-	-
Skookumchuck Stability Analysis Drilling Program	18,000	27,000	22,000	11,300	78,300
Skookumchuck Weyerhaeuser Easement Payment	3,000	-	-	-	3,000
Annual Revenue from Generation Sales	(2,000)	-	-	(1,500)	(3,500)
TOTAL	71,803	43,009	38,009	62,603	$ 215,424

Routine Operating Expenses	Avg Mo
Electricity	400
Telephone	42
Vehicle Maintenance	80
Maintenance (Not including Res Part-time Labor)	1,467
TOTAL	1,989

EXHIBIT C

After Recording Return to:

____

____

____

Attn: ______________________

SPACE ABOVE LINE FOR RECORDER'S USE ONLY

Title of Document:	Special Warranty Deed
Grantors:	Pacificorp, an Oregon corporation (formerly known as Pacific Power & Light Company); Avista Corporation, a Washington corporation (formerly known as the Washington Water Power Company) See page 2 for complete names of all Grantors
Grantee:	Skookumchuck LLC, a Washington limited liability company
Abbreviated Legal Description:	Ptn Sec 7, 11, 14, 15, 16, 17 & 18, T15N, R1E, and Ptn Sec 12 & 13, T15N, R1W Complete legal description is on <u>Exhibit A</u> of this document
Assessor's Tax Parcel Account Nos.:	11512310400(TCA-540); 11512340100(TCA-540) 11513100000(TCA-561); 11513120000(TCA-561) 11513210000(TCA-561); 11513310000(TCA-540) Additional tax parcel account numbers are on <u>Exhibit B</u> of this document

EXHIBIT C

SPECIAL WARRANTY DEED

The Grantors, Pacificorp, an Oregon corporation (formerly known as Pacific Power & Light Company); Avista Corporation, a Washington corporation (formerly known as the Washington Water Power Company); The City of Seattle, a municipal corporation; The City of Tacoma, a municipal corporation; Public Utility District No. 1 of Snohomish County, a municipal corporation; Puget Sound Energy, Inc., a Washington corporation (formerly known as Puget Sound Power & Light Company); Public Utility District No. 1 of Grays Harbor County, a municipal corporation; and _______ Avista Corporation, a Washington corporation (non-utility) (collectively herein, the "**Grantors**") for good and valuable consideration, in hand paid, do hereby bargain, sell and convey to Skookumchuck LLC, a Washington limited liability company, the Grantee, the following-described real property situated in the County of Thurston, State of Washington:

See Exhibit A attached hereto and incorporated herein by this reference.

This conveyance is subject to taxes and assessments, general and special, not yet due and payable; and all agreements, easements, reservations, restrictions, covenants and conditions listed on Exhibit C attached hereto and incorporated herein by this reference.

The Grantors, for themselves and for their successors in interest, do by these presents expressly limit the covenants of this Deed to those herein expressed, exclude all covenants arising or to arise by statutory or other implication, and do hereby covenant that against all persons whomsoever lawfully claiming or to claim by, through or under the Grantors, and not otherwise, they will warrant and defend the title to the above-described real property.

EXHIBIT C

DATED: ________________, 2003.

PACIFICORP, an Oregon corporation

By:________________________________
Printed Name:__________________
Title:__________________________

AVISTA CORPORATION, a Washington corporation

By:________________________________
Printed Name:__________________
Title:__________________________

THE CITY OF SEATTLE, a municipal corporation

By:________________________________
Printed Name:__________________
Title:__________________________

THE CITY OF TACOMA, a municipal corporation

By:________________________________
Printed Name:__________________
Title:__________________________

EXHIBIT C

PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY, a municipal corporation

By:________________________________
Printed Name:____________________
Title:____________________________

PUGET SOUND ENERGY, INC., a Washington corporation

By:________________________________
Printed Name:____________________
Title:____________________________

PUBLIC UTILITY DISTRICT NO. 1 OF GRAYS HARBOR COUNTY, a municipal corporation

By:________________________________
Printed Name:____________________
Title:____________________________

AVISTA CORPORATION,
a Washington corporation (non-utility)

By:________________________________
Printed Name:____________________
Title:____________________________

EXHIBIT C

STATE OF ______________)
) ss.
COUNTY OF ____________)

On this ___ day of _________, 2003, before me personally appeared ___________________, to me personally known to be the _____________ of PACIFICORP, the Oregon corporation that executed the within and foregoing instrument, and acknowledged said instrument to be the free and voluntary act and deed of said corporation, for the uses and purposes therein mentioned, and on oath stated that (s)he was authorized to execute said instrument and that the seal affixed, if any, is the corporate seal of said corporation.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal the day and year first above written.

Signature:_________________________

Name (Print):______________________

NOTARY PUBLIC in and for the State of
__________, residing at_____________
My appointment expires:______________

STATE OF ______________)
) ss.
COUNTY OF ____________)

On this ___ day of _________, 2003, before me personally appeared ___________________, to me personally known to be the _____________ of AVISTA CORPORATION, the Washington corporation that executed the within and foregoing instrument, and acknowledged said instrument to be the free and voluntary act and deed of said corporation, for the uses and purposes therein mentioned, and on oath stated that (s)he was authorized to execute said instrument and that the seal affixed, if any, is the corporate seal of said corporation.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal the day and year first above written.

Signature:_________________________

Name (Print):______________________

NOTARY PUBLIC in and for the State of
__________, residing at_____________
My appointment expires:______________

EXHIBIT C

STATE OF ______________)
) ss.
COUNTY OF _____________)

On this ___ day of _________, 2003, before me personally appeared ____________________, to me personally known to be the _____________ of THE CITY OF SEATTLE, the municipal corporation that executed the within and foregoing instrument, and acknowledged said instrument to be the free and voluntary act and deed of said corporation, for the uses and purposes therein mentioned, and on oath stated that (s)he was authorized to execute said instrument and that the seal affixed, if any, is the corporate seal of said municipal corporation.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal the day and year first above written.

Signature:_________________________

Name (Print):______________________

NOTARY PUBLIC in and for the State of
___________, residing at______________
My appointment expires:_______________

STATE OF ______________)
) ss.
COUNTY OF _____________)

On this ___ day of _________, 2003, before me personally appeared ____________________, to me personally known to be the _____________ of THE CITY OF TACOMA, the municipal corporation that executed the within and foregoing instrument, and acknowledged said instrument to be the free and voluntary act and deed of said corporation, for the uses and purposes therein mentioned, and on oath stated that (s)he was authorized to execute said instrument and that the seal affixed, if any, is the corporate seal of said municipal corporation.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal the day and year first above written.

Signature:_________________________
Name (Print):______________________

NOTARY PUBLIC in and for the State of
___________, residing at______________
My appointment expires:_______________

EXHIBIT C

STATE OF _______________)
) ss.
COUNTY OF _____________)

On this ___ day of _________, 2003, before me personally appeared ____________________, to me personally known to be the _____________ of PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY, the municipal corporation that executed the within and foregoing instrument, and acknowledged said instrument to be the free and voluntary act and deed of said corporation, for the uses and purposes therein mentioned, and on oath stated that (s)he was authorized to execute said instrument and that the seal affixed, if any, is the corporate seal of said municipal corporation.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal the day and year first above written.

Signature:___________________________

Name (Print):________________________

NOTARY PUBLIC in and for the State of
___________, residing at______________
My appointment expires:______________

STATE OF _______________)
) ss.
COUNTY OF _____________)

On this ___ day of _________, 2003, before me personally appeared ____________________, to me personally known to be the _____________ of PUGET SOUND ENERGY, INC., the Washington corporation that executed the within and foregoing instrument, and acknowledged said instrument to be the free and voluntary act and deed of said corporation, for the uses and purposes therein mentioned, and on oath stated that (s)he was authorized to execute said instrument and that the seal affixed, if any, is the corporate seal of said corporation.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal the day and year first above written.

Signature:___________________________

Name (Print):________________________

NOTARY PUBLIC in and for the State of
___________, residing at______________

EXHIBIT C

My appointment expires:_______________

STATE OF _______________)
) ss.
COUNTY OF _____________)

On this ___ day of _________, 2003, before me personally appeared ____________________, to me personally known to be the ______________ of PUBLIC UTILITY DISTRICT NO. 1 OF GRAYS HARBOR COUNTY, the municipal corporation that executed the within and foregoing instrument, and acknowledged said instrument to be the free and voluntary act and deed of said corporation, for the uses and purposes therein mentioned, and on oath stated that (s)he was authorized to execute said instrument and that the seal affixed, if any, is the corporate seal of said municipal corporation.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal the day and year first above written.

Signature:___________________________

Name (Print):________________________

NOTARY PUBLIC in and for the State of ___________, residing at_______________
My appointment expires:_______________

STATE OF _______________)
) ss.
COUNTY OF _____________)

On this ___ day of _________, 2003, before me personally appeared ____________________, to me personally known to be the ______________ of ___________________, the ______________ corporation that executed the within and foregoing instrument, and acknowledged said instrument to be the free and voluntary act and deed of said corporation, for the uses and purposes therein mentioned, and on oath stated that (s)he was authorized to execute said instrument and that the seal affixed, if any, is the corporate seal of said corporation.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal the day and year first above written.

Signature:___________________________

Name (Print):________________________

NOTARY PUBLIC in and for the State of

EXHIBIT C

___________, residing at______________
My appointment expires:_______________

EXHIBIT A

(Complete legal description)

IN THE COUNTY OF THURSTON, STATE OF WASHINGTON

TOWNSHIP FIFTEEN (15) NORTH, RANGE ONE (1) EAST OF THE WILLAMETTE MERIDIAN

PARCEL 1 - SECTIONS ELEVEN (11), FOURTEEN (14), FIFTEEN (15), SIXTEEN (16) AND SEVENTEEN (17)

BEGINNING AT A POINT ON THE EAST-WEST LINE BETWEEN SECTIONS 11 AND 14 THAT IS NORTH 87° 00' 05" WEST 182.27 FEET FROM THE SOUTHEAST CORNER OF SAID SECTION 11; THENCE ALONG THE FOLLOWING COURSES AND DISTANCES IN SAID SECTION 11:

NORTH 53° 49' 14" EAST 100.09 FEET; NORTH 65° 55' 35" WEST 359.73 FEET; SOUTH 43° 16' 54" WEST 220.51 FEET; SOUTH 60° 49' 42" WEST 45.76 FEET, MORE OR LESS, TO A POINT ON THE SOUTH LINE OF SAID SECTION 11; THENCE ALONG THE FOLLOWING COURSES AND DISTANCES IN SAID SECTION 14:

SOUTH 60° 49' 42" WEST 255.90 FEET; SOUTH 71° 30' 17" WEST 338.46 FEET; NORTH 51° 54' 39" WEST 271.89 FEET; NORTH 83° 20' 37" WEST 254.24 FEET; NORTH 76° 03' 51" WEST 356.87 FEET; SOUTH 70° 40' 57" WEST 436.45 FEET; SOUTH 59° 49' 51" WEST 255.72 FEET; SOUTH 47° 47' 22" WEST 236.45 FEET; SOUTH 58° 20' 37" WEST 81.47 FEET; SOUTH 75° 59' 05" WEST 82.72 FEET; SOUTH 88° 24' 10" WEST 73.99 FEET; NORTH 73° 22' 49" WEST 69.10 FEET; NORTH 64° 51' 36" WEST 98.73 FEET; NORTH 53° 03' 31" WEST 177.29 FEET; NORTH 88° 20' 53" WEST 49.75 FEET; NORTH 70° 36' 08" WEST 92.49 FEET; NORTH 58° 47' 11" WEST 78.31 FEET; NORTH 46° 41' 53" WEST 221.29 FEET; SOUTH 74° 41' 45" WEST 662.79 FEET; NORTH 86° 11' 28" WEST 186.15 FEET; SOUTH 78° 26' 42" WEST 242.55 FEET; NORTH 87° 59' 29" WEST 494.18 FEET, MORE OR LESS, TO A POINT ON THE NORTH-SOUTH SECTION LINE COMMON TO SECTIONS 14 AND 15 THAT IS SOUTH 01° 52' 20" WEST 493.39 FEET FROM THE NORTHWEST CORNER OF SAID SECTION 14; THENCE ALONG THE FOLLOWING COURSES AND DISTANCES IN SAID SECTION 15:

NORTH 87° 59' 29" WEST 327.43 FEET; NORTH 74° 02' 53" WEST 400.22 FEET; NORTH 88° 45' 51" WEST 575.91 FEET; SOUTH 76° 33' 47" WEST 492.55 FEET; SOUTH 16° 25' 23" WEST 164.36 FEET; SOUTH 59° 05' 01" WEST 329.19 FEET; NORTH 76° 22' 18" WEST 407.09 FEET; SOUTH 32° 14' 15" WEST 423.58 FEET; NORTH 89° 33' 35" WEST 156.21 FEET; NORTH 33° 49' 33" WEST 186.80 FEET; SOUTH 62° 47' 03" WEST

257.36 FEET; SOUTH 82° 05' 25" WEST 287.38 FEET; SOUTH 34° 00' 02" WEST 263.98 FEET; NORTH 52° 43' 21" WEST 152.81 FEET; SOUTH 86° 35' 42" WEST 664.04 FEET; SOUTH 25° 15' 30" WEST 378.46 FEET; NORTH 85° 32' 51" WEST 369.85 FEET; SOUTH 69° 45' 16" WEST 285.24 FEET; NORTH 88° 02' 05" WEST 120.15 FEET, MORE OR LESS, TO A POINT ON THE NORTH-SOUTH SECTION LINE COMMON TO SECTIONS 15 AND 16 THAT IS SOUTH 02° 26' 44" EAST 1,846.54 FEET FROM THE NORTHWEST CORNER OF SAID SECTION 15; THENCE ALONG THE FOLLOWING COURSES AND DISTANCES IN SAID SECTION 16:

NORTH 88° 02' 05" WEST 144.02 FEET; NORTH 62° 20' 54" WEST 244.42 FEET; NORTH 40° 31' 43" WEST 215.43 FEET; NORTH 82° 23' 41" WEST 161.01 FEET; SOUTH 83° 11' 32" WEST 349.15 FEET; SOUTH 88° 51' 12" WEST 334.53 FEET; SOUTH 76° 46' 31" WEST 564.62 FEET; NORTH 80° 09' 45" WEST 693.06 FEET; SOUTH 85° 54' 49" WEST 391.76 FEET; NORTH 73° 54' 40" WEST 592.15 FEET; NORTH 20° 12' 38" EAST 239.00 FEET; NORTH 06° 58' 06" EAST 165.47 FEET; SOUTH 74° 49' 49" WEST 104.10 FEET; SOUTH 62° 14' 25" WEST 776.84 FEET; NORTH 87° 28' 02" WEST 220.95 FEET; SOUTH 80° 53' 35" WEST 766.03 FEET; NORTH 85° 36' 44" WEST 46.89 FEET, MORE OR LESS, TO A POINT ON THE NORTH-SOUTH SECTION LINE COMMON TO SECTIONS 16 AND 17 THAT IS SOUTH 02° 20' 51" EAST 1,836.31 FEET FROM THE NORTHWEST CORNER OF SAID SECTION 16; THENCE ALONG THE FOLLOWING COURSES AND DISTANCES IN SECTION 17:

NORTH 85° 36' 44" WEST 132.92 FEET; NORTH 02° 21' 01" EAST 128.11 FEET; NORTH 23° 07' 41" WEST 325.96 FEET; NORTH 03° 45' 27" EAST 318.32 FEET; NORTH 85° 40' 34" WEST 162.58 FEET; SOUTH 28° 26' 02" WEST 320.98 FEET; SOUTH 03° 48' 36" WEST 182.46 FEET; SOUTH 22° 25' 40" EAST 232.05 FEET; NORTH 80° 33' 24" WEST 258.57 FEET; NORTH 65° 21' 10" WEST 287.74 FEET; SOUTH 69° 12' 12" WEST 394.31 FEET; NORTH 35° 32' 27" WEST 752.13 FEET; SOUTH 66° 44' 11" WEST 199.85 FEET; NORTH 79° 30' 27" WEST 173.22 FEET; NORTH 66° 00' 29" WEST 114.86 FEET; NORTH 77° 32' 52" WEST 350.23 FEET; SOUTH 62° 54' 49" WEST 169.14 FEET; SOUTH 33° 05' 59" WEST 584.71 FEET; SOUTH 74° 11' 20" WEST 845.70 FEET; NORTH 72° 17' 34" WEST 1,186.61 FEET; NORTH 47° 40' 31" WEST 156.06 FEET, MORE OR LESS, TO A POINT ON THE WEST LINE OF SAID SECTION 17 THAT IS SOUTH 00° 19' 55" WEST 1,415.45 FEET FROM THE NORTHWEST CORNER OF SAID SECTION, THENCE SOUTHERLY, ALONG THE WEST LINE OF SAID SECTION TO THE SOUTHWEST CORNER OF THE NORTHWEST QUARTER OF THE SOUTHWEST QUARTER OF SAID SECTION; THENCE EASTERLY, ALONG THE SOUTH LINE OF THE NORTH HALF OF THE SOUTH HALF OF SAID SECTION, 402.17 FEET TO A POINT; THENCE ALONG THE FOLLOWING COURSES AND DISTANCES IN SECTION 17:

NORTH 79° 25' 38" EAST 846.57 FEET; SOUTH 51° 56' 54" EAST 123.58 FEET; SOUTH 85° 51' 31" EAST 166.81 FEET; NORTH 02° 52' 28" WEST 272.18 FEET; NORTH 62° 14' 10" EAST 317.25 FEET; SOUTH 52° 28' 44" EAST 313.04 FEET; NORTH 65° 55' 38" EAST 105.35 FEET; NORTH 87° 57' 47" EAST 703.00 FEET; SOUTH 83° 31' 25" EAST 427.31 FEET; NORTH 58° 18' 40" EAST 460.38 FEET; SOUTH 39° 38' 57" EAST 360.74 FEET; SOUTH 87° 17' 54" EAST 129.02 FEET; SOUTH 46° 56' 40" EAST 474.08

FEET; NORTH 71° 34' 04" EAST 236.69 FEET; SOUTH 88° 48' 09" EAST 232.44 FEET; NORTH 71° 34' 25" EAST 453.41 FEET, MORE OR LESS, TO A POINT ON THE NORTH-SOUTH SECTION LINE COMMON TO SECTIONS 16 AND 17 THAT IS SOUTH 02° 20' 51" EAST 3,799.98 FEET FROM THE NORTHEAST CORNER OF SAID SECTION 17; THENCE ALONG THE FOLLOWING COURSES AND DISTANCES IN SECTION 16;

NORTH 71° 34' 25" EAST 66.25 FEET; NORTH 72° 01' 00" EAST 240.65 FEET; SOUTH 77° 56' 16" EAST 429.48 FEET; SOUTH 54° 48' 47" EAST 311.98 FEET; SOUTH 81° 21' 40" EAST 307.40 FEET; SOUTH 44° 57' 41" EAST 665.70 FEET; NORTH 50° 01' 56" EAST 508.54 FEET; SOUTH 86° 38' 08" EAST 146.78 FEET; NORTH 50° 50' 53" EAST 174.84 FEET; SOUTH 88° 33' 23" EAST 113.41 FEET; SOUTH 33° 23' 03" EAST 200.31 FEET; NORTH 42° 52' 15" EAST 187.86 FEET; SOUTH 65° 02' 35" EAST 250.65 FEET; SOUTH 39° 05' 42" EAST 698.82 FEET; NORTH 49° 22' 24" EAST 225.54 FEET; NORTH 01° 07' 02" WEST 507.66 FEET; NORTH 16° 09' 36" WEST 362.05 FEET; NORTH 04° 44' 27" WEST 217.89 FEET; NORTH 52° 03' 43" EAST 115.97 FEET; NORTH 81° 08' 00" EAST 455.98 FEET; NORTH 89° 02' 56" EAST 367.24 FEET; NORTH 39° 54' 40" EAST 320.69 FEET; SOUTH 37° 54' 29" EAST 342.62 FEET; NORTH 68° 50' 52" EAST 439.91 FEET, MORE OR LESS, TO A POINT ON THE NORTH-SOUTH SECTION LINE BETWEEN SECTIONS 15 AND 16 THAT IS SOUTH 02° 26' 44" EAST 2,979.49 FEET FROM THE NORTHEAST CORNER OF SAID SECTION 16; THENCE ALONG THE FOLLOWING COURSES AND DISTANCES IN SECTION 15:

NORTH 68° 50' 52" EAST 147.51 FEET; SOUTH 58° 22' 18" EAST 221.38 FEET; SOUTH 85° 10' 21" EAST 505.81 FEET; NORTH 20° 22' 33" EAST 180.03 FEET; SOUTH 80° 21' 39" EAST 478.83 FEET; NORTH 11° 20' 03" EAST 230.24 FEET; NORTH 68° 10' 44" EAST 275.97 FEET; NORTH 89° 30' 09" EAST 272.44 FEET; SOUTH 75° 41' 41" EAST 43.02 FEET; NORTH 78° 37' 48" EAST 506.93 FEET; NORTH 83° 20' 25" EAST 448.82 FEET; NORTH 46° 04' 37" EAST 296.71 FEET; NORTH 79° 33' 02" EAST 637.43 FEET; NORTH 51° 46' 37" EAST 551.52 FEET; NORTH 81° 28' 02 EAST 606.99 FEET; NORTH 75° 18' 13" EAST 290.80 FEET; SOUTH 85° 56' 25" EAST 134.60 FEET; NORTH 48° 23' 08" EAST 68.60 FEET, MORE OR LESS, TO A POINT ON THE NORTH-SOUTH SECTION LINE COMMON TO SECTIONS 14 AND 15 THAT IS SOUTH 01° 52' 20" WEST 1,452.35 FEET FROM THE NORTHEAST CORNER OF SAID SECTION 15; THENCE ALONG THE FOLLOWING COURSES AND DISTANCES IN SECTION 14:

NORTH 48° 23' 08" EAST 71.61 FEET; SOUTH 70° 59' 32" EAST 304.30 FEET; NORTH 68° 24' 16" EAST 286.10 FEET; NORTH 79° 00'16" EAST 559.39 FEET; SOUTH 89° 13' 50" EAST 538.86 FEET; NORTH 61° 44' 25" EAST 315.72 FEET; SOUTH 85° 02' 10" EAST 1,180.34 FEET; NORTH 61° 30' 30" EAST 819.09 FEET; NORTH 71° 29' 01" EAST 761.67 FEET; NORTH 53° 49' 14" EAST 601.16 FEET, MORE OR LESS, TO A POINT ON THE EAST-WEST SECTION LINE BETWEEN SECTIONS 11 AND 14 THAT IS NORTH 87° 00' 05" WEST 182.27 FEET FROM THE NORTHEAST CORNER OF SAID SECTION 14, AND THE POINT OF BEGINNING FOR THIS DESCRIPTION.

<u>PARCEL 2</u> - SECTION EIGHTEEN (18)

EXHIBIT C

THOSE PORTIONS OF THE NORTH HALF AND THE NORTH HALF OF THE SOUTHEAST QUARTER OF SAID SECTION 18 LYING SOUTHERLY OF THE FOLLOWING DESCRIBED LINE:

BEGINNING AT A POINT ON THE EAST LINE OF SAID SECTION 18 THAT IS SOUTH 00° 19' 55" WEST 1,415.45 FEET FROM THE NORTHEAST CORNER OF SAID SECTION; THENCE NORTH 47° 40' 31" WEST 951.19 FEET; THENCE NORTH 71° 15' 47" WEST 1,858.15 FEET; THENCE SOUTH 73° 14' 02" WEST 1,096.69 FEET; THENCE SOUTH 61° 46' 54" WEST 317.30 FEET; THENCE SOUTH 87° 40' 58" WEST 89.00 FEET, MORE OR LESS, TO A POINT ON THE NORTHEASTERLY LINE OF THAT CERTAIN TRACT CONVEYED BY SCOTT PAPER COMPANY TO HENRY W. TURNER AND EVELYN TURNER BY DEED DATED MAY 22, 1958 AND RECORDED JUNE 3, 1958 UNDER AUDITOR'S FILE NO. 597416; THENCE NORTHWESTERLY, ALONG SAID NORTHEASTERLY LINE OF SAID TURNER TRACT, TO THE NORTH LINE OF SAID SECTION 18; THENCE WESTERLY, ALONG SAID NORTH LINE OF SAID SECTION, TO THE NORTHWEST CORNER THEREOF;

AND LYING NORTHERLY OF THE FOLLOWING DESCRIBED LINE:

BEGINNING AT A POINT ON THE EAST LINE OF SAID SECTION 18 THAT IS SOUTH 00° 19' 55" WEST 3,759.54 FEET FROM THE NORTHEAST CORNER OF SAID SECTION; THENCE NORTH 68° 11' 24" WEST 614.59 FEET; THENCE NORTH 44° 33' 55" WEST 1,275.23 FEET; THENCE NORTH 32° 13' 14" WEST 827.33 FEET; THENCE NORTH 86° 47' 55" WEST 1,202.47 FEET; THENCE SOUTH 34° 42' 19" WEST 811.72 FEET; THENCE NORTH 14° 23' 23" WEST 79.18 FEET, MORE OR LESS, TO A POINT ON THE SOUTHEASTERLY LINE OF THAT CERTAIN TRACT CONVEYED BY SCOTT PAPER COMPANY TO HENRY W. TURNER AND EVELYN TURNER BY DEED DATED MAY 22, 1958 AND RECORDED JUNE 3, 1958 UNDER AUDITOR'S FILE NO. 597416; THENCE SOUTHWESTERLY, ALONG SAID SOUTHEASTERLY LINE OF SAID TURNER TRACT TO ITS INTERSECTION WITH THE EAST-WEST CENTERLINE OF SAID SECTION 18; THENCE WESTERLY, ALONG SAID EAST-WEST CENTERLINE, TO THE WEST QUARTER CORNER OF SAID SECTION 18.

EXCEPTING THEREFROM THAT PORTION OF THE NORTHWEST QUARTER OF SAID SECTION 18 CONTAINED IN THAT CERTAIN TRACT CONVEYED BY SCOTT PAPER COMPANY TO HENRY W. TURNER AND EVELYN TURNER BY DEED DATED MAY 22, 1958 AND RECORDED JUNE 3, 1958 UNDER AUDITOR'S FILE NO. 597416, AND

EXCEPT THAT PORTION CONVEYED TO THURSTON COUNTY FOR COUNTY ROAD KNOWN AS JOHNSON CREEK ROAD SE BY INSTRUMENT RECORDED JANUARY 12, 1972 UNDER AUDITOR'S FILE NO. 857989, AND

EXCEPT THAT PORTION CONVEYED TO THE STATE OF WASHINGTON, DEPARTMENT OF GAME BY INSTRUMENT RECORDED AUGUST 18, 1972 UNDER AUDITOR'S FILE NO. 872705, AND

EXHIBIT C

EXCEPT THAT PORTION CONVEYED TO THE STATE OF WASHINGTON BY INSTRUMENT RECORDED APRIL 24, 1979 UNDER AUDITOR'S FILE NO. 1074923.

TOGETHER WITH THAT PORTION OF VACATED ROADWAY, IF ANY, THAT WOULD ATTACH TO BY OPERATION OF LAW AS DISCLOSED BY RESOLUTION 7312 AS RECORDED JULY 27, 1982 UNDER AUDITOR'S FILE NO. 8207270131.

PARCEL 3 - SECTIONS SEVEN (7) AND EIGHTEEN (18)

THAT PORTION OF GOVERNMENT LOT 4 OF SAID SECTION 7 AND THOSE PORTIONS OF THE NORTHEAST QUARTER OF THE NORTHWEST QUARTER, GOVERNMENT LOTS 1 AND 2, THE SOUTHEAST QUARTER OF THE NORTHWEST QUARTER, THE NORTHEAST QUARTER OF THE SOUTHWEST QUARTER AND OF GOVERNMENT LOT 3 OF SAID SECTION 18, DESCRIBED AS FOLLOWS:
BEGINNING AT THE SOUTHWEST CORNER OF SAID SECTION 7; THENCE NORTH 00° 18' 39" EAST, ALONG THE WEST LINE OF SAID SECTION, 122.21 FEET; THENCE SOUTH 78° 10' 12" EAST 528.20 FEET; THENCE SOUTH 61° 28' 14" EAST 362.28 FEET; THENCE SOUTH 15° 42' 23" EAST 390.98 FEET; THENCE SOUTH 09° 50' 00" EAST 575.00 FEET, MORE OR LESS, TO THE LINE OF ORDINARY HIGH WATER OF THE LEFT BANK OF SKOOKUMCHUCK RIVER; THENCE NORTHEASTERLY, ALONG SAID LINE OF ORDINARY HIGH WATER, 1,270.00 FEET, MORE OR LESS, TO A POINT DESCRIBED AS 747.00 FEET SOUTH AND 2,215.25 FEET EAST OF THE NORTHWEST CORNER OF SAID SECTION 18; THENCE SOUTH 07° 22' 35" WEST 434.30 FEET; THENCE SOUTH 34° 14' 22" WEST 298.32 FEET; THENCE SOUTH 33° 36' 51" WEST 327.28 FEET; THENCE SOUTH 46° 55' 48" EAST 32.33 FEET; THENCE SOUTH 46° 10' 44" WEST 222.71 FEET; THENCE SOUTH 19° 03' 38" WEST 142.48 FEET; THENCE SOUTH 36° 18' 34" WEST 426.57 FEET; THENCE SOUTH 03° 39' 39" WEST 300.86 FEET; THENCE SOUTH 42° 49' 24" WEST 597.78 FEET; THENCE NORTH 79° 22' 14" WEST 189.91 FEET; THENCE NORTH 56° 47' 53" WEST 186.23 FEET; THENCE NORTH 38° 24' 23" WEST 720.00 FEET, MORE OR LESS, TO SAID LINE OF ORDINARY HIGH WATER; THENCE SOUTHWESTERLY, ALONG SAID LINE OF ORDINARY HIGH WATER, 350.00 FEET, MORE OR LESS, TO THE WEST LINE OF SAID SECTION 18; THENCE NORTH 00° 06' 58" WEST, ALONG SAID WEST LINE, 2,748.00 FEET, MORE OR LESS, TO THE POINT OF BEGINNING.
EXCEPTING THEREFROM THAT PORTION CONVEYED TO THE STATE OF WASHINGTON, DEPARTMENT OF GAME BY INSTRUMENT RECORDED AUGUST 18, 1972 UNDER AUDITOR'S FILE NO. 872705.

TOWNSHIP FIFTEEN (15) NORTH, RANGE ONE (1) WEST OF THE WILLAMETTE MERIDIAN

PARCEL 4 - SECTION TWELVE (12)

THE SOUTH HALF OF THE SOUTHEAST QUARTER, THE SOUTHEAST QUARTER OF THE NORTHEAST QUARTER OF THE SOUTHWEST QUARTER, THE EAST HALF OF THE SOUTHEAST QUARTER OF THE SOUTHWEST QUARTER, AND THAT PORTION OF THE WEST HALF OF THE SOUTHEAST QUARTER OF THE SOUTHWEST QUARTER BOUNDED ON THE EAST BY THE EAST LINE OF SAID WEST HALF OF THE SOUTHEAST QUARTER OF THE SOUTHWEST QUARTER AND BOUNDED ON THE SOUTHERLY SIDE BY THE NORTHEASTERLY RIGHT OF WAY LINE OF THE TROLLER (SKOOKUMCHUCK) COUNTY ROAD AND BOUNDED ON THE NORTHWESTERLY SIDE BY A LINE THAT IS PARALLEL WITH AND 37.50 FEET NORTHWESTERLY OF THE CENTER SURVEY LINE OF THAT CERTAIN RIGHT OF WAY GRANTED TO PACIFIC NORTHWEST PIPELINE CORPORATION BY INSTRUMENT DATED FEBRUARY 24, 1956 AND RECORDED FEBRUARY 28, 1956 UNDER AUDITOR'S FILE NO. 557791B, ALL IN SAID SECTION 12.

EXCEPTING THEREFROM COUNTY ROAD KNOWN AS TROLLER ROAD, AND EXCEPT ANY OTHER COUNTY ROADS.

PARCEL 5 - SECTION THIRTEEN (13)

THE SOUTH HALF, THE NORTHEAST QUARTER, AND THE EAST HALF OF THE NORTHWEST QUARTER OF SAID SECTION 13.

EXCEPTING THEREFROM COUNTY ROAD KNOWN AS TROLLER ROAD, AND EXCEPT ANY OTHER COUNTY ROADS.

IN THE COUNTY OF THURSTON, STATE OF WASHINGTON

EXHIBIT C

EXHIBIT B

(Additional tax parcel account numbers)

1151332000(TCA-540)	1151341000(TCA-540)
1151342000(TCA-540)	21507330100(TCA-540)
21511440200(TCA-320)	21514110100(TCA-540)
21514120100(TCA-540)	21515110000(TCA-320)
21515310000(TCA-320)	21516200000(TCA-320)
21516230100(TCA-320)	21517110000(TCA-540)
21518120100(TCA-540)	21518210000(TCA-540)

EXHIBIT C

[INSERT PERMITTED ENCUMBRANCES LISTED ON SCHEDULE 3.7 AT CLOSING]

Landolt
Exhibit (RAL-3)

Exhibit No.___(RAL-3)
Docket No.________
Witness: Randy A. Landolt

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Application of PACIFICORP for an Order Approving the Sale of its Interest in the Skookumchuck Hydroelectric Plant and for EWG Determinations	Docket No. ________

PACIFICORP

EXHIBIT OF RANDY A. LANDOLT

Dam Management Agreement

February 2004

SKOOKUMCHUCK DAM MANAGEMENT AGREEMENT

THIS SKOOKUMCHUCK DAM MANAGEMENT AGREEMENT (the "Agreement") is made as of May ___, 2000 (the "Effective Date"), by, on the one hand, PacifiCorp, Public Utilities District No. 1 of Snohomish County, Washington; Puget Sound Energy, Inc.; City of Tacoma, Washington; Avista Corporation; City of Seattle, Washington; and Public Utility District No. 1 of Grays Harbor County, Washington (each a "Dam Owner" and collectively the "Dam Owners") and, on the other hand, TransAlta Centralia Generation LLC, a Washington limited liability company ("Plant Owner") (each a "Party" and collectively, the "Parties"), with reference to the following:

RECITALS

A. Dam Owners are the owners of the Skookumchuck Dam and the real property identified on Exhibit A (collectively, the "Dam") along the Skookumchuck River near Centralia, Washington. The Skookumchuck Dam impounds a reservoir on the Skookumchuck River (the "Reservoir").

B. Pursuant to that certain Centralia Plant Purchase and Sale Agreement, dated as of May 7, 1999 (the "Purchase and Sale Agreement") by, on the one hand, the Dam Owners and, on the other hand, TECWA Power, Inc., a Washington corporation (the "Buyer"), the Dam Owners have agreed to convey the Centralia Steam Electric Generating Plant and related assets located near Centralia, Washington (the "Plant") to the Plant Owner and subsequently to assign the membership interests in the Plant Owner to the Buyer.

C. The Parties wish to enter into this Agreement to govern how the Dam will be managed and how the Parties will bear the costs of management.

NOW, THEREFORE, in consideration of the premises and mutual agreements set forth in this Agreement and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties, intending to be legally bound, agree as follows:

AGREEMENT

1. Term.

1.1 Initial Term. Unless terminated sooner under Section 7 or extended as provided in Section 1.2, this Agreement shall take effect on the Effective Date and shall remain in effect until the second anniversary of the Effective Date (the "Term").

1.2 Extension of Term. Notwithstanding Section 1.1, the Parties may extend the Term from year to year, by written agreement, if the Dam Owners have not sold the Dam on or before the second anniversary of the Effective Date. The Parties shall begin to negotiate in good faith at least thirty (30) days before the second anniversary of the Effective Date either an extension or amendment of this Agreement, or a new agreement.

1.3 Right of First Refusal: Option to Purchase.

a. During the Term, if the Dam Owners wish to convey the Dam to any party other than Lewis County, Washington (or an agency of Lewis County or an entity created by or for the benefit of Lewis County), the Army Corps of Engineers or the City of Centralia, they shall give the Plant Owner prior written notice of the terms and conditions of the proposed transfer. Plant Owner shall have thirty (30) days from the receipt of such notice in which to accept the offered terms and conditions. If the Plant Owner accepts the proposed terms and conditions, it shall acquire the Dam in accordance with those terms and conditions within sixty (60) days of its acceptance. If the Plant Owner rejects the proposed terms and conditions, or if the Plant Owner does not accept the proposed terms and conditions within the thirty (30) day period, the Dam Owners may proceed to transfer the Dam for a price no lower than, and otherwise on terms and conditions not materially more favorable than. those offered to the Plant Owner.

b. If the Dam Owners have not sold the Dam on or before the second anniversary of the Effective Date. , the Plant Owner shall have the option to purchase the Dam on terms to be agreed by the Parties in their reasonable discretion, at PacifiCorp's net book value multiplied by 2.105 (the "Dam Purchase Price"). This option shall expire on the third (3^{rd}) anniversary of the Effective Date. Plant Owner may exercise this option at any time after the second anniversary of the Effective Date by giving written notice to the Dam Owners. If the Plant Owner exercises this option, the Parties shall close the sale of the Dam within sixty (60) days after the Plant Owner's exercise of the option. At the closing, (a) Plant Owner's delivery of the Dam Purchase Price shall be conditioned on the Dam Owner's conveyance of the Dam to the Plant Owner, (b) Dam Owner's conveyance of the Dam shall be conditioned on the Plant Owner's payment of the Dam Purchase Price to the Dam Owners in immediately available funds, and (c) the performance of each Party shall be conditioned on the receipt of any necessary third party consents.

1.4 Plant Owner's Right to Inspect the Dam. During the Term, Plant Owner and its agents or representatives may inspect the Dam during regular business hours at the Plant Owner's sole risk and expense. Plant Owner shall give PacifiCorp at least ten (10) days' prior written notice before commencing any inspection of the Dam. Upon reasonable notice to PacifiCorp, the Plant Owner may, during PacifiCorp's regular business hours, examine PacifiCorp's records pertaining to the condition of the Dam. Plant Owner and its agents or representatives shall keep confidential any information obtained from its inspection of the Dam or examination of records, except with PacifiCorp's prior written consent.

2. Dam Owners' Designation of Agent. The Dam Owners hereby designate PacifiCorp as their agent for the purposes of discharging their obligations as Dam Owners, including carrying out this Agreement on behalf of the Dam Owners.

3. Management Duties. During the Term, PacifiCorp shall employ one (1) part-time employee at the Dam (the "On Site Employee") to perform onsite management, including the

maintenance of the Dam in accordance with good utility practice. PacifiCorp shall supervise the employee and provide the management, materials, and equipment necessary to operate and maintain the Dam in such a manner in compliance with all applicable legal obligations, including the Centralia Steam Electric Generating Project Fish and Wildlife Agreement dated May 29, 1998 (the "DF&W Agreement") and applicable law. To the extent that items of equipment ordinarily used in the operation and maintenance of the Dam have been conveyed to Plant Owner under the Purchase and Sale Agreement, Plant Owner shall make such equipment available to PacifiCorp at no charge and at PacifiCorp's sole risk and liability solely for the purpose of carrying out the Dam Owners' duties under this Agreement.

4. Costs.

4.1 Monthly Invoice for Costs. On or before the twentieth (20th) day of each calendar month, PacifiCorp shall invoice Plant Owner for all costs incurred by PacifiCorp during the previous calendar month to perform PacifiCorp's duties under this Agreement (except for direct costs and overhead costs for the On-Site Employee) ("Chargeable Costs"). Chargeable Costs shall include but not be limited to the costs of (a) operating and maintaining the Dam and the Reservoir in compliance with applicable law (including dam safety, measuring and monitoring costs); (b) complying with the DF&W Agreement (including paying fees); (c) controlling and removing debris in the Reservoir, (d) purchasing and storing necessary equipment and materials used in performing the Dam Owners' duties under this Agreement, plus PacifiCorp's standard overhead relating to equipment and materials (including without limitation shipping and insurance and warehouse restocking charges), (e) transportation of any personnel (other than the On-Site Employee), materials or equipment used by PacifiCorp to carry out its duties under this Agreement (which costs shall be equal to the internal allocated transportation costs PacifiCorp uses for its own accounting purposes), and (f) PacifiCorp's direct and overhead costs attributable to required supervision and management of the On Site Employee. To manage Chargeable Costs, PacifiCorp shall use reasonable efforts to keep the Plant Owner informed of operations and maintenance activities at the Dam and shall give the Plant Owner a reasonable opportunity to perform for its own account any of the maintenance or operations tasks that would otherwise be performed by PacifiCorp or a third party contractor.

4.2 Payment. Plant Owner shall pay all invoices issued by PacifiCorp under this Agreement within forty-five (45) days of receipt; provided, however, that Plant Owner shall not be required to pay an invoice to the extent that payment would cause the Plant Owner to pay more than US$300,000 under this Agreement in any calendar year (which amount shall be prorated for any partial calendar year). Any amount of Chargeable Costs that exceeds US$300,000 (or the prorated portion thereof) shall not rollover to any subsequent calendar year.

4.3 Sharing of Unreimbursed Costs. Any Chargeable Costs or other costs that are not reimbursed by the Plant Owner under this Agreement are "Unreimbursed Costs." The Dam Owners shall share Unreimbursed Costs in accordance with the percentage shares set forth on Exhibit B. On or before the twentieth (20th) day of each calendar month, PacifiCorp shall invoice each Dam Owner for any Unreimbursed Costs incurred by PacifiCorp during the preceding calendar month. If the Plant Owner fails to pay an invoice under this Agreement for more than forty-five (45) days after the date on which the payment is due, PacifiCorp may include the unpaid amount as Unreimbursed Costs in its next invoice to the Dam Owners, subject to subsequent crediting upon receipt of the Plant Owner's payment. Payment is due no later than thirty (30) days after receipt of the invoice.

4.4 Records. PacifiCorp shall maintain reasonably detailed records of the costs incurred and invoiced by it under this Agreement. The Plant Owner or the Dam Owners collectively may, upon reasonable notice to PacifiCorp given not more than once per year, examine these records during PacifiCorp's regular business hours to verify the costs invoiced by PacifiCorp.

4.5 Late Payments. Late payments shall accrue simple interest from the due date until the date full payment is received by PacifiCorp at the interest rate of 1½% per month (18% per year) or the highest rate permitted by law, whichever is lower.

4.6 Disputed Invoices. If the recipient of an invoice disputes any charges included in an invoice delivered by PacifiCorp under this Agreement, the recipient shall nonetheless pay the undisputed amount included in the invoice. The recipient shall include with any partial payment a written description of the reasons for the dispute. PacifiCorp shall respond to the recipient's written protest within fifteen (15) days of receipt. Any payment resulting from the settlement of a disputed portion of an invoice will include interest at the rate specified in Section 4.5. Any invoice that has not been disputed within one (1) year of the date on which it was received by a Party shall be conclusive and not subject to adjustment.

5. Liability.

5.1 Limitation. NO PARTY WILL HAVE ANY LIABILITY TO ANY OTHER PARTY, WHETHER BASED ON CONTRACT, WARRANTY, TORT, STRICT LIABILITY, OR ANY OTHER THEORY, FOR ANY LOST PROFITS, LOST REVENUES, LOST USE OF FACILITIES, LOST DATA, OR ANY INDIRECT, INCIDENTAL, CONSEQUENTIAL, SPECIAL, EXEMPLARY, OR PUNITIVE DAMAGES.

5.2 Allocation Among Dam Owners. The Dam Owners will share any liability incurred with respect to the management and operation of the Dam in accordance with their percentage interests as set forth on Exhibit B.

6. Force Majeure. A Party shall be excused from performing any obligation or undertaking imposed upon it by this Agreement (other than the duty to make payments when due) in the event and/or for so long as the performance of such obligation or undertaking is prevented, delayed, retarded or hindered by (a) fire or explosion; (b) earthquake, flood, action of the elements or any other act of God; (c) war, invasion, insurrection, riot, mob violence, sabotage or malicious mischief; (d) strike, lockout, or other action of any labor union; (e) condemnation, requisition, law, order of government or civil or military or naval authority; (f) drought or other physical impairment of water supply or sources; (g) a law, statute, code, ordinance, order, award,

judgment, decree, injunction, rule, or regulation; or (h) any other external cause (excluding financial inability) not within the reasonable control of such Party.

7. Termination and Survival.

7.1 Termination. If the Dam Owners, on the one hand, or the Plant Owner, on the other, fail to perform their respective obligations under this Agreement, and the failure is not: (1) excused under Section 6 above, or (2) cured within thirty (30) days' of written notice from the non-defaulting Party of the failure, then the non-defaulting Party shall have the right to terminate this Agreement by providing written notice to the other Party. This Agreement shall also terminate upon the closure of the Plant and the Mine, and shall terminate, unless renewed or extended or provided in Section 1.2, upon the second anniversary of the Effective Date. This Agreement shall terminate upon sale or other transfer of the Dam to any third party.

7.2 Survival. All payment obligations and liabilities incurred before the termination or expiration of this Agreement shall survive its termination or expiration.

7.3 Cumulative Remedies. A Party's right to terminate under this Section 7 is in addition to any other remedies that a Party may have at law or in equity against a defaulting Party.

8. Waiver of Headwater Benefits. In consideration of the reimbursement obligations of the Plant Owner hereto, the Dam owners hereby release the Plant Owner and Mine Owner from any and all liabilities or obligations respecting headwater benefits, if any, due to the Dam Owners under applicable law, respecting any period in which this Agreement is in effect.

9. Notices. All notices, requests, demands, waivers, consents and other communications hereunder shall be in writing, shall be delivered either in person, by telegraphic, facsimile or other electronic means, by overnight air courier or by mail, and shall be deemed to have been duly given and to have become effective (a) upon receipt if delivered in person or by telegraphic, facsimile or other electronic means (b) one (1) Business Day after having been delivered to an air courier for overnight delivery or (c) three (3) Business Days after having been deposited in the U.S. mails as certified or registered mail, return receipt requested, all fees prepaid, directed to the parties or their permitted assignees at the following addresses (or at such other address as shall be given in writing by a Party hereto):

If to Dam Owners, addressed to:

Senior Vice President
Power Supply
PacifiCorp
One Utah Center, 23rd Floor
Salt Lake City, Utah 94140

with a copy to:

George M. Galloway
Stoel Rives LLP
900 SW Fifth Avenue
Portland, Oregon 97204
Facsimile: (503) 220-2480

If to Plant Owner, addressed to:

TransAlta Centralia Generation LLC
913 Big Hanaford Road
Centralia, Washington 98531

with a copy to:

TECWA Power, Inc.
110 12th Avenue SW
Calgary, Alberta
Canada T2P 2M1
Attn: General Counsel
Facsimile: (403) 267-3734

and a copy to:

Joel H. Mack
Latham & Watkins
701 B Street, Suite 2100
San Diego, California
Facsimile: (619) 696-7419

10. Successors and Assigns. Except as provided in Section 7.1, the provisions of this Agreement shall bind and inure to the benefit of all successors and other parties now having or obtaining any beneficial interest in the Parcels.

11. General Interpretation. This Agreement shall be governed by, and construed in accordance with, the laws of the State of Washington. If any term, provision or condition contained in this Agreement (or the application of any such term, provision, or condition) shall to any extent be invalid or unenforceable, the remainder of this Agreement shall be valid and enforceable to the fullest extent permitted by law. When the context in which the words are used herein indicates that such is the intent, words in the singular shall include the plural and vice versa, and all pronouns and any variations thereof shall be deemed to refer to all genders. The captions of the Sections in this Agreement are for convenience of reference only and shall not be considered or referred to in resolving questions of interpretation or construction.

12. Warranty of Authority. Each Person signing this Agreement represents and warrants that he or she has been duly authorized to enter into this Agreement by the entity on whose behalf it is indicated that the Person is signing.

[Signature Pages Follow]

IN WITNESS WHEREOF, the Parties have executed this Agreement the day and year first above written.

TRANSALTA CENTRALIA GENERATION LLC,
a Washington limited liability company

By: TECWA Power, Inc.
a Washington corporation,
its sole member

By: ______________________
Name:
Title:

PACIFICORP

By: ______________________
Name:
Title:

PUBLIC UTILITIES DISTRICT NO. 1 OF SNOHOMISH COUNTY, WASHINGTON

By: ______________________
Name:
Title:

PUGET SOUND ENERGY, INC.

By: ______________________
Name:
Title:

CITY OF TACOMA, WASHINGTON

By: ______________________
Name:
Title:

AVISTA CORPORATION

By: ______________________

Name:

Title:

CITY OF SEATTLE, WASHINGTON

By: ______________________

Name:

Title:

PUBLIC UTILITY DISTRICT NO. 1 OF GRAYS HARBOR COUNTY, WASHINGTON

By: ______________________

Name:

Title:

EXHIBIT A

Real Property

The real property located in Thurston County and described in the following Correction Deeds and Bills of Sale dated April 2, 1986, from Washington Irrigation & Development Company, as grantor, subject to all matters disclosed of record.

Grantee	Thurston County Auditor's Number	Vol/Page	Recording Date
PacifiCorp	8604160017	1406/843	4/16/86
City of Tacoma	8604160012	1406/788	4/16/86
City of Seattle	8604160013	1406/807	4/16/86
Puget Sound Power & Light Company	8604160014	1406/816	4/16/86
The Washington Water Power Company	8604160015	1406/825	4/16/86
Portland General Electric Company	8604160016	1406/834	4/16/86
Public utility District No. 1 of Snohomish County	8604160018	1406/852	4/16/86
Public Utility District No. 1 of Grays Ha	8604160019	1406/861	4/16/86

8604160017

13
OK

CORRECTION DEED AND BILL OF SALE

The Grantor, WASHINGTON IRRIGATION & DEVELOPMENT COMPANY, a corporation, in consideration of Ten Dollars and other consideration in hand paid, bargains, sells and conveys to PACIFICORP, a Maine corporation, doing business as PACIFIC POWER & LIGHT COMPANY, Grantee, a Forty-Seven and Five Tenths Percent (47.5%) undivided interest, as a tenant in common with Grantor and others, in and to the real estate situated in the County of Thurston, State of Washington, as described in Exhibit A attached hereto and by this reference made a part hereof; and in and to the structures, equipment and facilities now or hereafter constructed and installed in or on said real estate; SUBJECT TO rights of the City of Centralia as set forth in that certain letter agreement dated May 26, 1967 between Pacific Power & Light Company and the City of Centralia, also SUBJECT TO the easements, rights of way, restrictions, reservations and other encumbrances of record, including but not limited to an Easement for Access Roads, dated March 7, 1974, granted by Washington Irrigation & Development Company to Weyerhaeuser Company, recorded in Volume 666, Page 213, Records of Thurston County, Washington, an Easement for Access Roads, dated May 17, 1974, granted by Washington Irrigation & Development Company to Scott Paper Company, recorded in Volume 904, Page 578, Records of Thurston County, Washington, and an Easement for Access Roads, dated November 18, 1975, granted by Washington Irrigation & Development Company to the State of Washington, recorded in Volume 716 of Deeds, Page 366, Records of Thurston County, Washington.

8604160017

As condition of the making and acceptance of this conveyance:

Real Estate Sales Tax Paid None
Receipt No. 148922 Date 4-16-86
Lorris G. Hunter, Thurston County Treas.
By Don Drury Deputy

INDEXED

PD-26-WA-93

VOL 1406 PAGE 843
1406 843

(a) Grantor covenants with Grantee, and the Grantee covenants with Grantor and with all other tenants in common thereof, that so long as the Centralia Thermal Plant is used or useful for the generation of electric energy, said real estate shall be used only for the purposes of constructing and operating thereon the Skookumchuck Reservoir and associated facilities used or useful in connection with said Centralia Thermal Plant, or for such other purpose as may be mutually agreed upon by all of said tenants in common; and

(b) Grantee, for itself, its successors and assigns, hereby accepts title to said real estate and any improvements now or hereafter constructed thereon as a tenant in common with Grantor and others who may now hold or hereafter acquire interests as tenants in common in said real estate, and AGREES that, for the period commencing with the date hereof and continuing so long as the Centralia Thermal Plant is used or useful for the generation of electric energy: (1) the interest hereby conveyed shall be held in such tenancy in common; (2) Grantee waives the right to partition of the Skookumchuck Reservoir and associated facilities or the real estate hereby conveyed whether by partition in kind or by sale and division of the proceeds thereof; (3) Grantee will not resort to any action at law or in equity to partition the Skookumchuck Reservoir and associated facilities or said real estate; (4) Grantee waives the benefit of all such laws as may now or hereafter authorize such partition; (5) the covenants herein made and restrictions set forth in this conveyance shall be binding upon Grantee, its successors and assigns, shall be an attribute of the title herein conveyed to Grantee, and shall be and remain covenants running with the real estate hereby conveyed; (6) Grantee recognizes and represents to the Grantor and others who may now or hereafter acquire interests in said real estate as tenants in common, that the

MICROFILMED

8604160017

common ownership created hereby and the reservations, conditions, restrictions, waivers and covenants herein set forth are for the mutual benefit of Grantor, others who may now or hereafter acquire interests in said real estate as tenants in common and the Grantee and its successors and assigns, and that such benefit is best realized by insuring to each tenant in common the value of ownership, use and operation of the Centralia Thermal Plant and the Skookumchuck Reservoir and associated facilities during such period; and (7) said reservations, conditions, restrictions, waivers and covenants are reasonably related to a proper purpose to be accomplished, and that said period is therefore reasonable when so considered.

(c) Grantor covenants with Grantee that Grantor shall likewise by bound by all of the terms, conditions, restrictions, waivers and covenants hereof with respect to any interest retained by Grantor in said real estate and improvements thereon; and Grantor further covenants that any further conveyances of any interest in said real estate shall include all of the same terms, conditions, restrictions, waivers and convenants as contained herein.

This Correction Deed and Bill of Sale is filed to correct certain errors in the legal description contained in that certain Deed and Bill of Sale executed on November 16, 1984 from Grantor to Grantee.

DATED this 2nd day of April, 1986.

WASHINGTON IRRIGATION & DEVELOPMENT COMPANY

By: Lloyd H. Meyer
President

Attest: Edward J. Leary
Secretary

FILED

8604160017

STATE OF WASHINGTON)
) ss.
County of)

On this 2nd day of April, 1986, before me, the undersigned, a Notary Public in and for the State of Washington, duly commissioned and sworn, personally appeared Lloyd V. Meyers and Edward J. Leahy to me known to be the — President and — Secretary, respectively, of WASHINGTON IRRIGATION & DEVELOPMENT COMPANY, the corporation that executed the foregoing instrument, and acknowledged the said instrument to be the free and voluntary act and deed of said corporation, for the uses and purposes therein mentioned, and on oath stated that they were authorized to execute the said instrument and that the seal affixed (if any) is the corporate seal of said corporation.

WITNESS my hand and official seal hereto affixed the day and year first above written.

(SEAL)

Donna Ashley
Notary Public in and for the State of Washington, residing at Spokane

MICROFILMED

VOL 1406 PAGE 848

8604160017

EXHIBIT "A" TO DEED

from

WASHINGTON IRRIGATION & DEVELOPMENT COMPANY

to

PACIFICORP dba PACIFIC POWER & LIGHT COMPANY

dated March 27, 1986

County of Thurston, State of Washington

Township Fifteen (15) North, Range One (1) East of the Willamette Meridian.

Parcel 1 - Sections Eleven (11), Fourteen (14), Fifteen (15), Sixteen (16) and Seventeen (17)

Beginning at a point on the east-west line between Sections 11 and 14 which bears North 87° 00' 05" West 18[illegible] feet from the southeast corner of said Section 11, thence along the following courses and distances in said Section 11:

North 53° 49' 14" East 100.09 feet; North 65° 55' 35" West 359.73 feet; South 43° 16' 54" West 220.51 feet; South 60° 49' 42" West 45.76 feet, more or less,

to a point on the south line of said Section 11, thence along the following courses and distances in said Section 14:

South 60° 49' 42" West 255.90 feet; South 71° 30' 17" West 338.46 feet; North 51° 56' 39" West 271.89 feet; North 83° 20' 37" West 256.24 feet; North 76° 03' 51" West 356.87 feet; South 70° 40' 57" West 436.45 feet; South 59° 49' 51" West 255.72 feet; South 47° 47' 22" West 236.45 feet; South 58° 20' 37" West 81.47 feet; South 75° 59' 05" West 82.72 feet; South 88° 24' 10" West 73.99 feet; North 78° 22' 49" West 69.10 feet; North 64° 51' 36" West 98.13 feet; North 53° 03' 31" West 177.29 feet; North 88° 20' 53" West 49.75 feet; North 70° 36' 08" West 92.49 feet; North 58° 47' 11" West 78.31 feet; North 46° 41' 53" West 221.29 feet; South 74° 41' 45" West 662.79 feet; North 86° 11' 28" West 186.15 feet; South 78° 26' 42" West 242.55 feet; North 87° 59' 29" West 494.18 feet more or less,

to a point on the north-south Section line common to Sections 14 and 15 which is South 01° 52' 20" West 493.39 feet from the northwest corner of said Section 14, thence along the following courses and distances in said Section 15:

North 87° 59' 29" West 327.43 feet; North 74° 02' 53" West 400.22 feet; North 88° 45' 51" West 575.91 feet; South 76° 33' 47" West 492.55 feet; South 16° 25' 23" West 164.36 feet; South 59° 05' 01" West 329.19 feet; North 76° 22' 18" West 407.09 feet; South 32° 14' 15" West 423.58 feet; North 89° 33' 35" West 156.21 feet; North 33° 49' 33" West 186.80 feet; South 62° 47' 03" West 257.36 feet; South 82° 05' 25" West 287.[illegible] feet; South 34° 00' 02" West 263.98 feet; North 52° 43' 21" West 152.81 feet; South 86° 35' 42" West [illegible]54.04 feet; South 25° 15' 30" West 378.46 feet; North [illegible]5° 32' 51" West 369.85 feet; South 69° 45' 16" West 285.24 feet; North 88° 02' 05" West 120.15 feet more or less.

APR 16 9 40 AM '86

VOL 1406 PAGE 847

to a point on the north-south section line common to Sections 15 and 16 which is South 02° 26' 44" East 1,846.54 feet from the northwest corner of said Section 15, thence along the following courses and distances in said Section 16:

North 88° 02' 05" West 144.02 feet; North 62° 20' 56" West 264.42 feet; North 40° 31' 43" West 215.43 feet; North 82° 23' 41" West 161.01 feet; South 83° 11' 32" West 349.15 feet; South 88° 51' 12" West 334.53 feet; South 76° 46' 31" West 564.62 feet; North 80° 09' 45" West 693.06 feet; South 83° 54' 49" West 391.76 feet; North 73° 54' 40" West 592.15 feet; North 20° 12' 38" East 239.00 feet; North 06° 58' 06" East 165.47 feet; South 76° 49' 49" West 104.10 feet; South 62° 14' 25" West 776.84 feet; North 87° 28' 02" West 220.95 feet; South 80° 53' 35" West 766.03 feet; North 85° 36' 44" West 46.89 feet more or less,

to a point on the north-south section line common to Sections 16 and 17 which is South 02° 20' 51" East 1,836.31 feet from the northwest corner of said Section 16, thence along the following courses and distances in Section 17:

North 85° 36' 44" West 132.92 feet; North 02° 21' 01" East 128.11 feet; North 23° 07' 41" West 325.96 feet; North 03° 45' 27" East 318.32 feet; North 85° 40' 34" West 162.58 feet; South 28° 26' 02" West 320.98 feet; South 03° 48' 36" West 182.46 feet; South 22° 25' 40" East 232.05 feet; North 80° 33' 74" West 258.57 feet; North 65° 21' 10" West 287.74 feet; South 69° 12' 12" West 394.31 feet; North 35° 32' 27" West 752.13 feet; South 66° 44' 11" West 199.83 feet; North 73° 30' 27" West 173.22 feet; North 66° 00' 29" West 114.86 feet; North 77° 32' 52" West 350.23 feet; South 62° 54' 49" West 169.14 feet; South 33° 05' 59" West 584.71 feet; South 74° 11' 20" West 845.70 feet; North 72° 17' 34" West 1,186.61 feet; North 47° 40' 31" West 156.06 feet more or less,

to a point on the west line of said Section 17 which is South 00° 19' 55" West 1,415.45 feet from the northwest corner of said section, thence northerly along the west line of said section to the southwest corner of the northwest quarter of the southwest quarter (NW1/4SW1/4) of said section, thence easterly along the south line of the north half of the south half (N1/2S1/2) of said section 402.17 feet to a point, thence along the following courses and distances in Section 17:

North 79° 25' 38" East 846.57 feet; South 51° 56' 54" East 123.58 feet; South 85° 51' 31" East 166.81 feet; North 02° 52' 28" West 272.18 feet; North 62° 14' 10" East 317.5 feet; South 52° 28' 44" East 113.04 feet; North 65° 53' 38" East 105.35 feet; North 87° 57' 47" East 703.00 feet; South 83° 31' 25" East 427.31 feet; North 58° 18' 40" East 460.38 feet; South 39° 38' 57" East 340.74 feet; South 87° 17' 54" East 129.02 feet; South 46° 56' 40" East 474.08 feet; North 71° 34' 04" East 236.69 feet; South 88° 48' 09" East 232.44 feet; North 71° 34' 25" East 653.41 feet more or less,

to a point on the north-south section line common to Sections 16 and 17 which is South 02° 20' 51" East 3,799.98 feet from the northeast corner of said Section 17, thence along the following courses and distances in Section 16:

MICROFILMED

8604160017

North 71° 34' 25" East 66.25 feet; North 72° 01' 00" East 240.65 feet; South 77° 56' 16" East 429.48 feet; South 54° 48' 47" East 311.95 feet; South 81° 21' 40" East 307.40 feet; South 64° 57' 41" East 665.70 feet; North 50° 01' 58" East 508.54 feet; South 86° 38' 08" East 146.78 feet; North 50° 50' 53" East 174.84 feet; South 88° 33' 23" East 113.41 feet; South 33° 23' 03" East 200.31 feet; North 42° 52' 15" East 187.86 feet; South 65° 02' 35" East 230.65 feet; South 39° 05' 42" East 698.82 feet; North 49° 22' 24" East 225.54 feet; North 01° 07' 02" West 507.66 feet; North 16° 09' 36" West 362.05 feet; North 04° 44' 27" West 217.89 feet; North 52° 03' 43" East 115.97 feet; North 81° 08' 00" East 455.98 feet; North 69° 02' 56" East 367.24 feet; North 39° 54' 40" East 320.69 feet; South 37° 54' 29" East 342.52 feet; North 68° 50' 52" East 439.91 feet more or less,

to a point on the north-south section line between Sections 15 and 16 which is South 02° 26' 44" East 2,979.49 feet from the northeast corner of said Section 16, thence along the following courses and distances in Section 15:

North 68° 50' 52" East 147.51 feet; South 58° 22' 18" East 221.38 feet; South 85° 10' 21" East 505.81 feet; North 20° 22' 33" East 180.03 feet; South 80° 21' 39" East 478.53 feet; North 11° 20' 03" East 230.34 feet; North 68° 10' 46" East 275.97 feet; North 89° 30' 09" East 272.44 feet; South 75° 41' 41" East 43.02 feet; North 78° 37' 48" East 506.93 feet; North 83° 20' 25" East 448.82 feet; North 46° 04' 37" East 256.71 feet; North 79° 33' 02" East 637.43 feet; North 51° 46' 37" East 551.52 feet; North 81° 28' 02" East 604.99 feet; North 75° 18' 13" East 290.80 feet; South 83° 50' 25" East 134.60 feet; North 48° 23' 00" East 68.60 feet more or less,

to a point on the northsouth section line common to Sections 14 and 15 which is South 01° 52' 20" West 1,452.35 feet from the northeast corner of said Section 15, thence along the following courses and distances in Section 14:

North 48° 13' 08" East 71.61 feet; South 70° 59' 32" East 304.30 feet; North 68° 24' 16" East 286.10 feet; North 79° 00' 16" East 559.39 feet; South 89° 13' 50" East 538.86 feet; North 61° 44' 25" East 315.72 feet; South 85° 02' 10" East 1,180.34 feet; North 61° 30' 30" East 819.09 feet; North 71° 29' 01" East 751.67 feet; North 53° 49' 14" East 601.16 feet more or less,

to a point on the east-west section line between Sections 11 and 14 which is North 87° 00' 05" West 182.27 feet from the northeast corner of said Section 14, and the point of beginning for this description.

NOTE: All courses shown in the foregoing description are based on the State of Washington Coordinate System (South Zone).

TOGETHER WITH an easement as granted in that certain deed recorded November 25, 1970, in Volume 525, page 303, Deed Records of Thurston County under Auditor's File No. 833263 for the temporary overflow of reservoir waters on any lands owned by WEYERHAEUSER COMPANY, a Washington corporation, in said certain deed within the Southeast Quarter of the Southeast Quarter of Section 11, all of Section 12, the North Half of Section 13, the North Half of Section 14, the North Half of Section 15, and the North three-fourths of Section 17, in Township 15 North, Range 1 East of the Willamette Meridian; PROVIDED, HOWEVER, that in the event of such overflow, Grantee shall pay for any damage to land, timber and improvements occasioned by such overflow.

MICROFILMED

VOL 1406 PAGE 849

ALSO TOGETHER WITH an easement contained in that certain Warranty Deed recorded December 14, 1970 in Volume 528, page 792, Deed Records of Thurston County, under Auditor's File No. 834257 for the temporary and intermittent overflow of the reservoir waters, upon and over the adjoining lands of Grantor therein: provided that, in the event of any such overflow, the Grantee herein shall be responsible for payment of any damage to growing timber, improvements or personal property, including rock inventories upon such adjoining lands of such Grantor, and shall be responsible for payment of compensatory damages resulting from any temporary interruption of quarry operations, if any, upon such adjoining lands of such Grantor, occasioned by such overflow.

Parcel 2 - Section Eighteen (18)

Those portions of the North Half and the North Half of the Southeast Quarter of said Section 18 lying southerly of the following described line:

Beginning at a point on the east line of said Section 18 which bears South 00° 19' 55" West 1,415.45 feet from the northeast corner of said section; thence North 47° 40' 31" West 951.19 feet; thence North 71° 15' 47" West 1,858.15 feet; thence South 73° 14' 02" West 1,096.69 feet; thence South 61° 46' 54" West 317.30 feet; thence South 87° 40' 58" West 89.00 feet, more or less, to a point on the northeasterly line of that certain tract conveyed by Scott Paper Company to Henry W. Turner and Evelyn Turner by deed dated May 22, 1958 and recorded in the Deed Records of said Thurston County under Auditor's File No. 597416; thence northwesterly along said northeasterly line of said Turner tract to the north line of said Section 18; thence westerly along said north line of said section to the northwest corner thereof;

and lying northerly of the following described line:

Beginning at a point on the east line of said Section 18 which bears South 00° 19' 55" West 3,759.54 feet from the northeast corner of said section; thence North 68° 11' 24" West 614.59 feet; thence North 44° 33' 55" West 1,275.23 feet; thence North 32° 13' 14" West 827.33 feet; thence North 86° 47' 55" West 1,202.47 feet; thence South 34° 42' 19" West 811.72 feet; thence North 14° 23' 23" West 79.18 feet, more or less, to a point on the southeasterly line of the aforementioned Turner tract; thence southwesterly along said southeasterly line of said Turner tract to its intersection with the east-west centerline of said Section 18; thence westerly along said east-west centerline to the west quarter corner of said Section 18;

EXCEPTING THEREFROM, so much of the Northwest Quarter of said Section 18 as was conveyed by Scott Paper Company to Henry W. Turner and Evelyn Turner by said deed dated May 22, 1958.

FURTHER EXCEPTING THEREFROM, those portions conveyed under Auditor's File Nos. 857989, 872705 and 1074923.

TOGETHER WITH that portion of vacated roadway, if any, that would attach to the said Parcel 2 by operation of law as disclosed by Resolution 7312 under Auditor's File No. 8207270131.

Parcel 3 - Sections Seven (7) and Eighteen (18)

That part of Lot 4 of said Section 7 and those portions of the Northeast Quarter of the Northwest Quarter, Government Lots 1 and 2, the Southeast Quarter of said Northwest Quarter, the Northeast Quarter of the Southwest Quarter and of Government Lot 3 of said Section 18 described as follows:

Beginning at the southwest corner of said Section 7; running thence North 00° 18' 39" East along the west line of said section 122.21 feet; thence South 78° 10' 12" East

MICROFILMED

528.20 feet; thence South 61° 28' 14" East 362.28 feet; thence South 15° 42' 23" East 390.98 feet; thence South 09° 50' 00" East 575.00 feet, more or less, to the line of ordinary high water of the left bank of Skookumchuck River; thence northeasterly along said line of ordinary high water 1,270.00 feet, more or less, to a point described as 747.00 feet south and 2,215.25 feet east of the northwest corner of said Section 18; thence South 07° 22' 35" West 434.30 feet; thence South 34° 14' 22" West 298.32 feet; thence South 33° 36' 51" West 327.28 feet; thence South 46° 55' 48" East 22.33 feet; thence South 46° 10' 44" West 222.71 feet; thence South 19° 03' 38" West 142.48 feet; thence South 36° 18' 34" West 426.57 feet; thence South 03° 39' 39" West 300.86 feet; thence South 42° 49' 24" West 597.78 feet; thence North 79° 22' 14" West 189.91 feet; thence North 56° 47' 53" West 186.23 feet; thence North 38° 24' 23" West 720.00 feet, more or less, to said line of ordinary high water; thence southwesterly along said line of ordinary high water 350.00 feet, more or less, to the west line of said Section 18; thence North 00° 06' 58" West along said west line 2,748.00 feet, more or less, to the point of beginning;

EXCEPT that certain tract of real property conveyed to the State of Washington by Deed dated August 2, 1972 and recorded August 18, 1972 in Deed Records of Thurston County under Auditor's File No. 872705.

Township Fifteen (15) North, Range One (1) West of the Willamette Meridian.

Parcel 4 - Section Twelve (12)

The South Half of the Southeast Quarter, the Southeast Quarter of the Northeast Quarter of the Southwest Quarter, the East Half of the Southeast Quarter of the Southwest Quarter, and that portion of the West Half of the Southeast Quarter of the Southwest Quarter bounded on the east by the east line of said West Half of the Southeast Quarter of the Southwest Quarter and bounded on the southerly side by the northeasterly right of way line of the Troller (Skookumchuck) County Road and bounded on the northwesterly side by a line which is parallel with and 37.50 feet northwesterly of the center survey line of that certain right of way granted to Pacific Northwest Pipeline Corporation by instrument dated February 24, 1956 and recorded File No. 557791-8, all in said Section 12, EXCEPTING therefrom county road known as Troller Road and EXCEPT any other county roads.

Parcel 5 - Section Thirteen (13)

The South Half, the Northeast Quarter, and the East Half of the Northwest Quarter of said Section 13 EXCEPTING therefrom county road known as Troller Road and EXCEPT any other county roads.

APR 16 9 40 AM '86
REQUE: [illegible]
SAM [illegible] AUDITOR
DEPUTY

8604160012

13
OK

CORRECTION DEED AND BILL OF SALE

The Grantor, WASHINGTON IRRIGATION & DEVELOPMENT COMPANY, a corporation, in consideration of Ten Dollars and other consideration in hand paid, bargains, sells and conveys to the CITY OF TACOMA, a municipal corporation of the State of Washington, Grantee, an Eight Percent (8%) undivided interest, as a tenant in common with Grantor and others, in and to the real estate situated in the County of Thurston, State of Washington, as described in Exhibit A attached hereto and by this reference made a part hereof; and in and to the structures, equipment and facilities now or hereafter constructed and installed in or on said real estate; SUBJECT TO rights of the City of Centralia as set forth in that certain letter agreement dated May 26, 1967 between Pacific Power & Light Company and the City of Centralia, also SUBJECT TO the easements, rights of way, restrictions, reservations and other encumbrances of record, including but not limited to an Easement for Access Roads, dated March 7, 1974, granted by Washington Irrigation & Development Company to Weyerhaeuser Company, recorded in Volume 666, Page 213, Records of Thurston County, Washington, an Easement for Access Roads, dated May 17, 1974, granted by Washington Irrigation & Development Company to Scott Paper Company, recorded in Volume 904, Page 578, Records of Thurston County, Washington, and an Easement for Access Roads, dated November 18, 1975, granted by Washington Irrigation & Development Company to the State of Washington, recorded in Volume 716 of Deeds, Page 366, Records of Thurston County, Washington.

8604160012

As condition of the making and acceptance of this conveyance:

(a) Grantor covenants with Grantee, and the Grantee covenants with Grantor and with all other tenants in common thereof, that so long as the

MICROFILMED

Real Estate Sales Tax Paid None
Receipt No. 148927 Date 4-16-86
Harris G. Hunter, Thurston County Treas.
[signature] Deputy

VOL 1408 PAGE 78[illegible]

PD-26-WA-93

8604160013

13

CORRECTION DEED AND BILL OF SALE

8604160013

The Grantor, WASHINGTON IRRIGATION & DEVELOPMENT COMPANY, a corporation, in consideration of Ten Dollars and other consideration in hand paid, bargains, sells and conveys to the CITY OF SEATTLE, a municipal corporation of the State of Washington, Grantee, an Eight Percent (8%) undivided interest, as a tenant in common with Grantor and others, in and to the real estate situated in the County of Thurston, State of Washington, as described in Exhibit A attached hereto and by this reference made a part hereof; and in and to the structures, equipment and facilities now or hereafter constructed and installed in or on said real estate; SUBJECT TO rights of the City of Centralia as set forth in that certain letter agreement dated May 26, 1967 between Pacific Power & Light Company and the City of Centralia, also SUBJECT TO the easements, rights of way, restrictions, reservations and other encumbrances of record, including but not limited to an Easement for Access Roads, dated March 7, 1974, granted by Washington Irrigation & Development Company to Weyerhaeuser Company, recorded in Volume 666, Page 213, Records of Thurston County, Washington, an Easement for Access Roads, dated May 17, 1974, granted by Washington Irrigation & Development Company to Scott Paper Company, recorded in Volume 934, Page 578, Records of Thurston County, Washington, and an Easement for Access Roads, dated November 18, 1975, granted by Washington Irrigation & Development Company to the State of Washington, recorded in Volume 716 of Deeds, Page 366, Records of Thurston County, Washington.

As condition of the making and acceptance of this conveyance:

(a) Grantor covenants with Grantee, and the Grantee covenants with Grantor and with all other tenants in common thereof, that so long as the

Real Estate Sales Tax Paid
Receipt No. 148923 Date 4-16-86
Harris G. Hunter, Thurston County Treas.
By ______ Deputy

VOL 1408 PAGE 807

PD-26-WA-93

MICROFILMED

8604160014

13 CK

CORRECTION DEED AND BILL OF SALE

The Grantor, WASHINGTON IRRIGATION & DEVELOPMENT COMPANY, a corporation, in consideration of Ten Dollars and other consideration in hand paid, bargains, sells and conveys to PUGET SOUND POWER & LIGHT COMPANY, a Washington corporation, Grantee, a Seven Percent (7%) undivided interest, as a tenant in common with Grantor and others, in and to the real estate situated in the County of Thurston, State of Washington, as described in Exhibit A attached hereto and by this reference made a part hereof; and in and to the structures, equipment and facilities now or hereafter constructed and installed in or on said real estate; SUBJECT TO rights of the City of Centralia as set forth in that certain letter agreement dated May 26, 1967 between Pacific Power & Light Company and the City of Centralia, also SUBJECT TO the easements, rights of way, restrictions, reservations and other encumbrances of record, including but not limited to an Easement for Access Roads, dated March 7, 1974, granted by Washington Irrigation & Development Company to Weyerhaeuser Company, recorded in Volume 666, Page 213, Records of Thurston County, Washington, an Easement for Access Roads, dated May 17, 1974, granted by Washington Irrigation & Development Company to Scott Paper Company, recorded in Volume 904, Page 578, Records of Thurston County, Washington, and an Easement for Access Roads, dated November 18, 1975, granted by Washington Irrigation & Development Company to the State of Washington, recorded in Volume 716 of Deeds, Page 366, Records of Thurston County, Washington.

As condition of the making and acceptance of this conveyance:

(a) Grantor covenants with Grantee, and the Grantee covenants with Grantor and with all other tenants in common thereof, that so long as the

Real Estate Sales Tax Paid 700
Receipt No. 118925 Date 4-16-86
Harris G. Hunter, Thurston County Treas.
Deputy

8604160014

8604160015

13 CK

CORRECTION DEED AND BILL OF SALE

The Grantor, WASHINGTON IRRIGATION & DEVELOPMENT COMPANY, a corporation, in consideration of Ten Dollars and other consideration in hand paid, bargains, sells and conveys to THE WASHINGTON WATER POWER COMPANY, a Washington corporation, Grantee, a Fifteen Percent (15%) undivided interest, as a tenant in common with Grantor and others, in and to the real estate situated in the County of Thurston, State of Washington, as described in Exhibit A attached hereto and by this reference made a part hereof; and in and to the structures, equipment and facilities now or hereafter constructed and installed in or on said real estate; SUBJECT TO rights of the City of Centralia as set forth in that certain letter agreement dated May 26, 1967 between Pacific Power & Light Company and the City of Centralia, also SUBJECT TO the easements, rights of way, restrictions, reservations and other encumbrances of record, including but not limited to an Easement for Access Roads, dated March 7, 1974, granted by Washington Irrigation & Development Company to Weyerhaeuser Company, recorded in Volume 666, Page 213, Records of Thurston County, Washington, an Easement for Access Roads, dated May 17, 1974, granted by Washington Irrigation & Development Company to Scott Paper Company, recorded in Volume 904, Page 578, Records of Thurston County, Washington, and an Easement for Access Roads, dated November 18, 1975, granted by Washington Irrigation & Development Company to the State of Washington, recorded in Volume 716 of Deeds, Page 366, Records of Thurston County, Washington.

8604160015

As condition of the making and acceptance of this conveyance:

(a) Grantor covenants with Grantee, and the Grantee covenants with Grantor and with all other tenants in common thereof, that so long as the

Real Estate Sales Tax Paid None
Receipt No. 1 4 8 9 2 1 Date 4-16-86
Harris G. Hunter, Thurston County Treas.
By Don Dewing Deputy

PD-26-WA-93

VOL 1406 PAGE 825

MICROFILMED

8604180016 13 ck

CORRECTION DEED AND BILL OF SALE

The Grantor, WASHINGTON IRRIGATION & DEVELOPMENT COMPANY, a corporation, in consideration of Ten Dollars and other consideration in hand paid, bargains, sells and conveys to PORTLAND GENERAL ELECTRIC COMPANY, an Oregon corporation, Grantee, a Two and Five Tenths Percent (2.5%) undivided interest, as a tenant in common with Grantor and others, in and to the real estate situated in the County of Thurston, State of Washington, as described in Exhibit A attached hereto and by this reference made a part hereof; and in and to the structures, equipment and facilities now or hereafter constructed and installed in or on said real estate; SUBJECT TO rights of the City of Centralia as set forth in that certain letter agreement dated May 26, 1967 between Pacific Power & Light Company and the City of Centralia, also SUBJECT TO the easements, rights of way, restrictions, reservations and other encumbrances of record, including but not limited to an Easement for Access Roads, dated March 7, 1974, granted by Washington Irrigation & Development Company to Weyerhaeuser Company, recorded in Volume 666, Page 213, Records of Thurston County, Washington, an Easement for Access Roads, dated May 17, 1974, granted by Washington Irrigation & Development Company to Scott Paper Company, recorded in Volume 904, Page 578, Records of Thurston County, Washington, and an Easement for Access Roads, dated November 18, 1975, granted by Washington Irrigation & Development Company to the State of Washington, recorded in Volume 716 of Deeds, Page 366, Records of Thurston County, Washington.

8604180016

As condition of the making and acceptance of this conveyance:

(a) Grantor covenants with Grantee, and the Grantee covenants with Grantor and with all other tenants in common thereof, that so long as the

Real Estate Sales Tax Paid

Receipt No. 148923 Date 4-6-86

Harris G. Hunter, Thurston County Treas.

By 148923

PD-26-WA-95

VOL 1406 PAGE 834

MICROFILMED

13 ok

8604160018

CORRECTION DEED AND BILL OF SALE

The Grantor, WASHINGTON IRRIGATION & DEVELOPMENT COMPANY, a corporation, in consideration of Ten Dollars and other consideration in hand paid, bargains, sells and conveys to the PUBLIC UTILITY DISTRICT NO. 1 of Snohomish County, a municipal corporation of the State of Washington, Grantee, an Eight Percent (8%) undivided interest, as a tenant in common with Grantor and others, in and to the real estate situated in the County of Thurston, State of Washington, as described in Exhibit A attached hereto and by this reference made a part hereof; and in and to the structures, equipment and facilities now or hereafter constructed and installed in or on said real estate; SUBJECT TO rights of the City of Centralia as set forth in that certain letter agreement dated May 26, 1967 between Pacific Power & Light Company and the City of Centralia, also SUBJECT TO the easements, rights of way, restrictions, reservations and other encumbrances of record, including but not limited to an Easement for Access Roads, dated March 7, 1974, granted by Washington Irrigation & Development Company to Weyerhaeuser Company, recorded in Volume 666, Page 213, Records of Thurston County, Washington, an Easement for Access Roads, dated May 17, 1974, granted by Washington Irrigation & Development Company to Scott Paper Company, recorded in Volume 904, Page 578, Records of Thurston County, Washington, and an Easement for Access Roads, dated November 18, 1975, granted by Washington Irrigation & Development Company to the State of Washington, recorded in Volume 716 of Deeds, Page 366, Records of Thurston County, Washington.

As condition of the making and acceptance of this conveyance...

8604160018

Real Estate Excise Tax: None

Receipt No. 148921 Date 4-16-86

Harris G. Hunter, Thurston County Treas.

By Don Ormsy Deputy

FD-26-WA-93

VOL 1406 PAGE 852

8604160019

13
8

CORRECTION DEED AND BILL OF SALE

The Grantor, WASHINGTON IRRIGATION & DEVELOPMENT COMPANY, a corporation, in consideration of Ten Dollars and other consideration in hand paid, bargains, sells and conveys to the PUBLIC UTILITY DISTRICT NO. 1 of Greys Harbor County, a municipal corporation of the State of Washington, Grantee, a Four Percent (4%) undivided interest, as a tenant in common with Grantor and others, in and to the real estate situated in the County of Thurston, State of Washington, as described in Exhibit A attached hereto and by this reference made a part hereof; and in and to the structures, equipment and facilities now or hereafter constructed and installed in or on said real estate; SUBJECT TO rights of the City of Centralia as set forth in that certain letter agreement dated May 26, 1967 between Pacific Power & Light Company and the City of Centralia, also SUBJECT TO the easements, rights of way, restrictions, reservations and other encumbrances of record, including but not limited to an Easement for Access Roads, dated March 7, 1974, granted by Washington Irrigation & Development Company to Weyerhaeuser Company, recorded in Volume 666, Page 213, Records of Thurston County, Washington, an Easement for Access Roads, dated May 17, 1974, granted by Washington Irrigation & Development Company to Scott Paper Company, recorded in Volume 904, Page 578, Records of Thurston County, Washington, and an Easement for Access Roads, dated November 18, 1975, granted by Washington Irrigation & Development Company to the State of Washington, recorded in Volume 716 of Deeds, Page 366, Records of Thurston County, Washington.

8604160019

As condition of the making and acceptance of this conveyance:

Real Estate Sales Tax Paid None

Receipt No. 148920 Date 4-16-86

Harris G. Hunter, Thurston County Treas.

Don Ouerz Deputy

MICROFILMED

PD-26-WA-93

VOL 1400 PAGE 561

EXHIBIT B

Percentage Shares

PacifiCorp	47.5%
Avista Corporation	17.5%
City of Seattle, Washington	8%
City of Tacoma, Washington	8%
Public Utility District No. 1 of Snohomish County, Washington	8%
Puget Sound Energy, Inc.	7%
Public Utility District No. 1 of Grays Harbor County, Washington	4%

Exhibit No. ___(CPJ-1T)
Docket No. ___________
Witness: Craig P. Johnson

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Application of PACIFICORP for an Order Approving the Sale of its Interest in the Skookumchuck Hydroelectric Plant and for EWG Determinations	Docket No. _________

PACIFICORP

DIRECT TESTIMONY OF CRAIG P. JOHNSON

Q. Please state your name and business address.

A. My name is Craig P. Johnson. My business address is 201 South Main, Suite 2300, Salt Lake City, Utah.

Q. Briefly describe your educational background, professional training and experience.

A. I graduated from Brigham Young University in 1981 with a Bachelor of Science Degree in Accounting. After working at General Telephone, I joined PacifiCorp in 1984. My assignments at the Company have included working in the Regulation, Financial Planning, and Financial Analysis departments. At present I am a Regulatory Consultant. My primary responsibilities include preparing rate cases and analyzing regulatory issues facing the utility.

Q. What is the purpose of your testimony?

A. My testimony explains the revenue requirement impact of the sale of the Skookumchuck Dam, hydroelectric generating station and related assets (the "Skookumchuck Project" or the "Project") and describes the anticipated benefits to customers from the sale of the Skookumchuck Project.

Q. What is the current and future cost of generating power from the Skookumchuck Project?

A. The average cost of energy generated is approximately $250 per megawatt hour ("MWh"), according to the Company bus bar report. Looking forward, the cost of generating energy at the Project is not expected to decline, and it is expected to exceed projected market prices. Low energy production volume combined with high investment costs have translated into a high cost per MWh for several years. Historically, the generator produced about 3,000 MWh annually. However, over the last four years output has been limited to about 1,000 MWh/year. The Skookumchuck Dam was not built as a generating resource. In fact the reservoir was primarily constructed to ensure a water supply at the nearby Centralia Steam Plant.

Q. Are there benefits to PacifiCorp customers if the Project is retained?

A. Based on the Company analysis, the answer is no. Although the Skookumchuck Project generated benefits for customers for many years as a reliable water source for the Centralia Steam Plant, today the situation is different. PacifiCorp no longer owns the Centralia Steam Plant. The Project is a small 1 MW hydroelectric generation asset. It is not equivalent to large projects like those on the Lewis and Umpqua Rivers, which provide valuable peaking power and generate relatively large amounts of energy compared to the fixed cost of operations. The reservoir was constructed in 1973 to ensure a water supply at the Centralia power station during drought years. An electric generator was added in 1991 to mitigate the cost of operating the reservoir. After the sale of Centralia Steam Plant the new owner, TransAlta, (through its direct wholly-owned subsidiary, TransAlta Centralia Generation LLC), paid the operating costs of the Project. Recently, TransAlta (through its direct wholly-owned subsidiary, Washington LLC) agreed to purchase the Project, i.e., the Skookumchuck reservoir and hydroelectric facilities, as the reservoir has more value to the Centralia Steam Plant owner than it does to PacifiCorp and the other current owners. The future unit cost of generation is not cost competitive. Continued ownership of the Project results in future customers of PacifiCorp paying prices for energy that will exceed the market value. A sale of the Skookumchuck Project is expected to benefit customers by lowering future revenue requirements below what it otherwise would be if the Project were not sold.

Q. What is the revenue requirement impact of selling the Skookumchuck Project?

A. Selling the reservoir, powerhouse, water rights and associated assets of the Skookumchuck Project is expected to lower total future revenue requirement $12 million on a present value basis. The operating costs of the Project are high and they may increase. As Mr. Landolt explains, the future cost of operating the Skookumchuck Project, particularly the cost exposure to mitigate potential seismic risks, are likely to diminish the economics of generating power from the Project. The base case assumptions contrasted with future power prices show that selling the Skookumchuck Project will lower the present value of the total Company revenue requirement. In other words, it is now and will continue to be less expensive to purchase energy at market prices than operate the Skookumchuck Project, which produces power at a cost of $250 per MWh.

Q. What is the revenue requirement benefit in Washington?

A. As indicated above, the base case assumptions indicate a total company benefit of $12 million in present value terms. Washington's allocated share of that benefit is approximately $1 million.

Q. Will the sale of the Project produce a gain?

A. No. PacifiCorp's share of the sale price is equal to PacifiCorp's net book value. As a result, PacifiCorp estimates a slight loss of $68,613. Exhibit ___ (CPJ-2) shows the calculation of the estimated book and tax gain/loss. These preliminary figures may change depending upon when the sale actually occurs. In the event there is any gain realized on the sale, PacifiCorp proposes to credit its Washington customers with 100 percent of Washington's allocated share of the actual net gain. Should an appreciable loss be realized, PacifiCorp proposes to reduce the Centralia Steam Plant and Mine credit, reflected in the Company's Schedule 97, by an amount reflecting the realized loss.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Johnson
Exhibit (CPJ-2)

Exhibit No.___(CPJ-2)
Docket No._________
Witness: Craig P. Johnson

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Application of PACIFICORP for an Order Approving the Sale of its Interest in the Skookumchuck Hydroelectric Plant and for EWG Determinations	Docket No. _________

PACIFICORP

EXHIBIT OF CRAIG P. JOHNSON

Calculation of Estimated Book and Tax Gain/Loss

February 2004

Proforma Gain Calculation on Sale of the Skookumchuck Project w/ Pickup
As of April 1, 2004

					Column 1	Column 2
1. Proceeds from Sale of Facilities to TransAlta						$ 3,557,801
2. Cost of Sale						(110,000)
3. Adjusted Sales Price						$ 3,447,801
4. Original Cost of Facilities					8,668,529	
5. Accumulated Depreciation					(5,110,728)	
6. Net Book Value					3,557,801	(3,557,801)
7. Pre-tax Gain (Loss) on Disposition of Property						$ (110,000)
8. Income Tax on Taxable Gain -	$	1,306,982	@	37.95%	496,000	
9. Provided Deferred Taxes					(537,387)	
10. Income Tax Expense on Sale					(41,387)	41,387
11. After-Tax Gain (Loss) on Sale of Facilities						**($68,613)**

Taxable Gain Calculation

12. Net Proceeds		$ 3,447,801
13. Tax Cost Basis	8,668,529	
Book/Tax Differences in Tax Cost Basis	(1,284,865)	
Adjusted Tax Basis	7,383,664	
14. Tax Depreciation/Reserve (as of 4/1/03)	(5,242,845)	
15. Net Tax Basis	2,140,819	(2,140,819)
16. Taxable Gain		$ 1,306,982