FORM 10−Q

AQUILA INC − ILA

Filed: November 06, 2003 (period: September 30, 2003)

Quarterly report which provides a continuing view of a company's financial position

Table of Contents

QuickLinks −− Click here to rapidly navigate through this document

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

FORM 10−Q

(Mark One)

☒ **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: 1−03562

AQUILA, INC.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**44−0541877** (IRS Employer Identification No.)
20 West Ninth Street, Kansas City, Missouri (Address of principal executive offices)	**64105** (Zip Code)

Registrant's telephone number, including area code **816−421−6600**

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 ☒ No ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b−2 of the Exchange Act). Yes ☒ No ☐

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Class	Outstanding at October 29, 2003
Common Stock, $1 par value	195,166,982

PART I—FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

Information regarding the consolidated financial statements is set forth on pages 3 through 23.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's discussion and analysis of financial condition and results of operations can be found on pages 24 through 47.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are subject to market risk as described on pages 65 through 68 of our 2002 Annual Report on Form 10−K. See discussion on page 46 of this document for changes in market risk since December 31, 2002.

ITEM 4. CONTROLS AND PROCEDURES

Information regarding disclosure controls and procedures can be found on page 47.

PART II—OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Not applicable.

ITEM 2. CHANGES IN SECURITIES AND USE OF PROCEEDS

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

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

Not applicable.

ITEM 5. OTHER INFORMATION

Not applicable.

ITEM 6. EXHIBITS AND REPORTS ON FORM 8−K

Exhibits and Reports on Form 8−K can be found on page 48.

Part I. Financial Information

Item 1. Financial Statements

Aquila, Inc.

Consolidated Statements of Income—Unaudited

In millions, except per share amounts	Three Months Ended September 30, 2003	2002
Sales:		
Electricity—regulated	$ 235.3	$ 220.0
Natural gas—regulated	98.4	77.3
Electricity—non−regulated	30.1	85.6
Natural gas—non−regulated	(64.3)	59.5
Other—non−regulated	22.5	8.9
Total sales	322.0	451.3
Cost of sales:		
Electricity—regulated	112.6	98.4
Natural gas—regulated	54.1	39.5
Electricity—non−regulated	18.2	177.6
Natural gas—non−regulated	2.7	83.2
Other—non−regulated	5.7	5.8
Total cost of sales	193.3	404.5
Gross profit	128.7	46.8
Operating expenses:		
Operating expense	122.2	141.5
Restructuring charges	.6	116.4
Impairment charges and net loss on sale of assets	90.9	39.0
Depreciation and amortization expense	38.6	39.4
Total operating expenses	252.3	336.3
Other income (expense):		
Equity in earnings of investments	(.1)	60.1
Minority interest in income of subsidiaries	—	2.4
Other income	4.0	.9
Total other income (expense)	3.9	63.4
Interest expense:		
Interest expense	75.1	62.4
Minority interest in income of partnership and trust	—	4.6
Total interest expense	75.1	67.0
Loss from continuing operations before income taxes	(194.8)	(293.1)
Income tax benefit	(50.6)	(101.7)
Loss from continuing operations	(144.2)	(191.4)
Loss from discontinued operations, net of tax	(25.7)	(140.2)
Net loss	$ (169.9)	$ (331.6)

Basic and diluted earnings (loss) per common share:

Continuing operations	$	(.74)	$	(1.07)
Discontinued operations		(.13)		(.78)
Net loss	$	(.87)	$	(1.85)
Dividends per common share	$	—	$	.175

See accompanying notes to consolidated financial statements.

Aquila, Inc.

Consolidated Statements of Income—Unaudited

In millions, except per share amounts	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
Sales:		
Electricity—regulated	$ 544.5	$ 525.8
Natural gas—regulated	675.9	506.1
Electricity—non−regulated	(.5)	299.1
Natural gas—non−regulated	(33.4)	348.8
Other—non−regulated	25.7	39.5
Total sales	1,212.2	1,719.3
Cost of sales:		
Electricity—regulated	264.6	239.9
Natural gas—regulated	462.0	315.1
Electricity—non−regulated	65.2	286.4
Natural gas—non−regulated	17.5	293.2
Other—non−regulated	16.8	17.2
Total cost of sales	826.1	1,151.8
Gross profit	386.1	567.5
Operating expenses:		
Operating expense	403.9	482.9
Restructuring charges	27.7	187.8
Impairment charges and net loss on sale of assets	191.7	933.6
Depreciation and amortization expense	123.8	117.8
Total operating expenses	747.1	1,722.1
Other income (expense):		
Equity in earnings of investments	61.0	128.4
Minority interest in income of subsidiaries	—	6.6
Other income	67.3	1.8
Total other income (expense)	128.3	136.8
Interest expense:		
Interest expense	206.9	148.8
Minority interest in income of partnership and trust	—	15.7
Total interest expense	206.9	164.5
Loss from continuing operations before income taxes	(439.6)	(1,182.3)
Income tax benefit	(125.7)	(196.4)
Loss from continuing operations	(313.9)	(985.9)
Earnings (loss) from discontinued operations, net of tax	11.5	(111.3)
Net loss	$ (302.4)	$ (1,097.2)
Basic and diluted earnings (loss) per common share:		
Continuing operations	$ (1.61)	$ (6.44)
Discontinued operations	.06	(.73)
Net loss	$ (1.55)	$ (7.17)
Dividends per common share	$ —	$ .775

See accompanying notes to consolidated financial statements.

Aquila, Inc.

Consolidated Balance Sheets

In millions	September 30, 2003	December 31, 2002
	(Unaudited)	
Assets		
Current assets:		
Cash and cash equivalents	$ 632.0	$ 386.1
Restricted cash	263.7	480.9
Funds on deposit	413.5	310.3
Accounts receivable, net	580.6	1,614.6
Inventories and supplies	174.2	136.2
Price risk management assets	278.9	519.3
Prepayments and other	157.2	390.8
Current assets of discontinued operations	273.5	236.0
Total current assets	2,773.6	4,074.2
Property, plant and equipment, net	2,683.3	2,656.3
Investments in unconsolidated subsidiaries	315.1	914.9
Price risk management assets	509.4	393.5
Goodwill, net	111.0	111.0
Deferred charges and other assets	275.8	260.1
Non−current assets of discontinued operations	998.1	849.2
Total Assets	$ 7,666.3	$ 9,259.2
Liabilities and Shareholders' Equity		
Current liabilities:		
Current maturities of long−term debt	$ 415.6	$ 355.9
Short−term debt	—	287.8
Accounts payable	516.1	1,572.6
Accrued liabilities	330.8	320.8
Price risk management liabilities	261.0	469.5
Current portion of long−term gas contracts	84.3	81.5
Customer funds on deposit	274.0	242.8
Current liabilities of discontinued operations	385.4	266.0
Total current liabilities	2,267.2	3,596.9
Long−term liabilities:		
Long−term debt, net	2,291.8	2,270.6
Deferred income taxes and credits	355.1	423.0
Price risk management liabilities	392.4	282.8
Long−term gas contracts, net	609.6	671.2
Minority interest	—	13.4
Deferred credits	194.3	207.7
Non−current liabilities of discontinued operations	178.3	185.7
Total long−term liabilities	4,021.5	4,054.4
Common shareholders' equity	1,377.6	1,607.9
Total Liabilities and Shareholders' Equity	$ 7,666.3	$ 9,259.2

See accompanying notes to consolidated financial statements.

Aquila, Inc.

Consolidated Statements of Comprehensive Income—Unaudited

In millions	Three Months Ended September 30, 2003	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
Net loss	$ (169.9)	$ (331.6)	$ (302.4)	$ (1,097.2)
Unrealized translation adjustments, net of tax	(17.7)	(13.4)	69.5	8.2
Unrealized cash flow hedges, net of tax	4.1	(19.4)	5.8	(30.0)
Unrealized loss from available−for−sale securities	—	—	(7.3)	—
Comprehensive loss	$ (183.5)	$ (364.4)	$ (234.4)	$ (1,119.0)

Aquila, Inc.

Consolidated Statements of Common Shareholders' Equity

In millions	September 30, 2003	December 31, 2002
	(Unaudited)	
Common stock: authorized 400 million shares at September 30, 2003 and December 31, 2002, par value $1 per share; 195,163,210 shares issued at September 30, 2003 and 193,782,782 shares issued at December 31, 2002; authorized 20 million shares of Class A common stock, par value $1 per share, none issued	$ 195.2	$ 193.8
Premium on capital stock	3,161.3	3,158.6
Retained deficit	(2,013.9)	(1,711.5)
Treasury stock, at cost (1,588 and 7,443 shares at September 30, 2003 and December 31, 2002, respectively)	—	—
Accumulated other comprehensive income (losses)	35.0	(33.0)
Total common shareholders' equity	$ 1,377.6	$ 1,607.9

See accompanying notes to consolidated financial statements.

Aquila, Inc.

Consolidated Statements of Cash Flows—Unaudited

In millions	Nine Months Ended September 30, 2003	2002
		(Restated— See Note 8)
Cash Flows From Operating Activities:		
Net loss	$ (302.4)	$ (1,097.2)
Adjustments to reconcile net loss to net cash used for operating activities:		
Depreciation and amortization expense	132.4	184.8
Restructuring charges	27.7	188.0
Cash paid for restructuring and impairment charges	(163.1)	(59.6)
Impairment charges and net loss on sale of assets	239.2	1,170.2
Provision for uncollectible notes receivable	—	20.0
Foreign currency gains	(41.2)	—
Net changes in price risk management assets and liabilities	34.5	301.1
Deferred income taxes and investment tax credits	(109.1)	(15.9)
Equity in earnings of investments	(61.0)	(133.3)
Dividends and fees from investments	38.9	74.5
Minority interests in income of subsidiaries	—	(6.5)
Changes in certain assets and liabilities, net of effects of acquisitions and divestitures:		
Restricted cash	(111.4)	(131.2)
Funds on deposit	(118.2)	(22.4)
Accounts receivable/payable, net	(42.3)	(76.6)
Accounts receivable sales programs	—	(234.5)
Inventories and supplies	(39.5)	81.8
Prepayments and other	221.0	(98.2)
Deferred charges and other assets	22.9	(.2)
Accrued liabilities	133.5	(246.3)
Customer funds on deposit	30.0	55.3
Deferred credits	(20.4)	(52.1)
Other	(26.1)	(9.4)
Cash used for operating activities	(154.6)	(107.7)
Cash Flows From Investing Activities:		
Network capital expenditures	(171.2)	(193.5)
Merchant capital expenditures	(36.3)	(142.7)
Net increase in merchant notes receivable	—	(67.4)
Investments in international businesses	—	(193.0)
Investments in communication services	(9.5)	(46.5)
Cash proceeds received on sale of assets	905.7	127.7
Merchant investment in unconsolidated subsidiaries	(44.5)	(10.5)
Other	(14.9)	31.5
Cash provided from (used for) investing activities	629.3	(494.4)
Cash Flows From Financing Activities:		
Issuance of common stock	—	549.8
Issuance of long−term debt	412.0	1,106.4
Retirement of long−term debt	(464.2)	(600.3)
Retirement of company−obligated preferred securities	—	(100.0)
Short−term borrowings (repayments), net	(57.9)	62.0
Cash paid on long−term gas contracts	(58.8)	(58.5)
Cash dividends paid	—	(115.7)
Other	2.2	10.4
Cash provided from (used for) financing activities	(166.7)	854.1
Increase in cash and cash equivalents	308.0	252.0
Cash and cash equivalents at beginning of period (includes $55.6 million and $45.0 million, respectively, of cash included in current assets of discontinued operations)	441.7	262.9

Cash and cash equivalents at end of period (includes $117.7 million and $64.8 million, respectively, of cash included in current assets of discontinued operations)	$	749.7	$	514.9

See accompanying notes to consolidated financial statements.

1. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying unaudited consolidated financial statements have been prepared in accordance with the accounting policies described in the consolidated financial statements and related notes included in our 2002 Annual Report on Form 10−K filed with the Securities and Exchange Commission on April 15, 2003. You should read our 2002 Form 10−K in conjunction with this report. The accompanying Consolidated Balance Sheets and Consolidated Statements of Common Shareholders' Equity as of December 31, 2002, were derived from our audited financial statements, but do not include all disclosures required by accounting principles generally accepted in the United States. In our opinion, the accompanying consolidated financial statements reflect all adjustments (which include only normal recurring adjustments) necessary for a fair representation of our financial position and the results of our operations. Certain estimates and assumptions have been made in preparing the consolidated financial statements that affect reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of sales and expenses during the reporting periods shown. Actual results could differ from these estimates.

Certain prior year amounts in the consolidated financial statements have been reclassified where necessary to conform to the 2003 presentation. In particular, as discussed in Note 4, the results of operations from certain assets that were sold in 2002 and 2003 and certain assets that are currently held for sale have been reclassified as discontinued operations in the accompanying balance sheets and statements of income for all periods presented.

Stock Based Compensation

We issue stock options to employees from time to time and account for these options under Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25). All stock options issued are granted at the common stock's market price at date of issuance. Therefore we record no compensation expense related to stock options. We historically offered employees a stock purchase plan that enabled them to purchase our common stock at a 15% discount from the market price. This program was suspended during the second quarter of 2003 when all authorized shares in the plan were issued. Shareholder approval is required to authorize additional shares for this program to continue.

Because we account for options and discounts under APB 25, we disclose a pro forma net loss and a basic and diluted loss per share as if we reflected the estimated fair value of options and discounts as compensation expense. Our pro forma net loss and basic and diluted loss per share are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions, except per share amounts	**2003**	**2002**	**2003**	**2002**
Net loss:				
As reported	$ (169.9)	$ (331.6)	$ (302.4)	$ (1,097.2)
Total stock−based employee compensation expense determined under fair value method, net of related tax	(1.3)	(1.3)	(4.1)	(3.8)
Pro forma net loss	$ (171.2)	$ (332.9)	$ (306.5)	$ (1,101.0)
Basic and diluted loss per share:				
As reported	$ (.87)	$ (1.85)	$ (1.55)	$ (7.17)
Pro forma	(.88)	(1.85)	(1.58)	(7.19)

In April 2003, the Financial Accounting Standards Board (FASB) announced that it would require all companies to expense the value of employee stock options. The FASB plans to issue a new statement in the second half of 2004 that will further define the method of determining fair value and recognizing compensation expense.

New Accounting Pronouncements

Variable Interest Entities

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities, an interpretation of ARB No. 51." This interpretation addresses the consolidation by business enterprises of variable interest entities as defined in the interpretation. The interpretation is effective immediately for variable interest entities created or obtained after January 31, 2003 and is effective on December 31, 2003 for variable interest entities that existed prior to February 1, 2003. We do not expect the application of this interpretation to have a material impact on our financial position or results of operations.

Derivative Instruments

In May 2003, the FASB issued Statement of Financial Accounting Standards No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS 149). This Statement clarified under what circumstances a contract with an initial net investment meets the characteristic of a derivative as discussed in Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). It also clarified when a derivative contains a financing component that warrants special reporting in the statement of cash flows. SFAS 149 also amended certain other existing pronouncements regarding derivatives. It is generally effective for contracts entered into or modified after June 30, 2003, and was applied prospectively. The adoption of this standard had no material impact on our financial position or results of operations.

Financial Instruments

In May 2003, the FASB issued SFAS No. 150, "Accounting for Financial Instruments with Characteristics of both Liabilities and Equity" (SFAS 150). This statement established standards for the classification and measurement of certain financial instruments that have the characteristics of both liabilities and equities. It requires that an issuer classify a financial instrument that is within the scope of the standard as a liability. This standard is effective for all financial instruments entered into or modified after May 31, 2003, and for the first interim reporting period beginning after June 15, 2003. The adoption of this standard had no impact on our financial position or results of operations.

2. Restructuring Charges

In connection with our continued exit from Wholesale Services and the restructuring of our Domestic Networks group, we have recorded the following restructuring charges:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions	**2003**	**2002**	**2003**	**2002**
Domestic Networks:				
Severance costs	$ —	$ (.5)	$ 2.1	$ 14.8
Disposal of corporate aircraft	—	.5	—	5.1
Total Domestic Networks	—	—	2.1	19.9
Capacity Services:				
Interest rate swap reductions	—	—	23.1	—
Severance costs	—	(.6)	—	—
Total Capacity Services	—	(.6)	23.1	—
Wholesale Services:				
Severance costs	—	6.5	.8	31.3
Retention payments	1.0	28.9	1.7	28.9
Lease agreements	(.3)	36.7	(.3)	36.7
Leasehold improvements and equipment	—	36.6	—	59.0
Disposal of corporate aircraft	—	(.2)	—	2.0
Other	—	.5	(.6)	2.0
Total Wholesale Services	.7	109.0	1.6	159.9
Corporate and Other severance costs	(.1)	8.0	.9	8.0
Total restructuring charges	$ .6	$ 116.4	$ 27.7	$ 187.8

Severance Costs and Retention Payments

We incurred severance costs of $2.1 million for the nine months ended September 30, 2003, in connection with the restructuring of Everest Connections, our communications business within Domestic Networks. This resulted from a reduction of approximately 160 employees. We also incurred $1.0 million and $1.7 million of retention payments in the three months and nine months ended September 30, 2003, respectively, related to the continued wind−down of our domestic and international energy trading operations in Wholesale Services.

We incurred $13.4 million and $54.1 million of total severance costs for the three and nine months ended September 30, 2002, respectively, related to the restructuring of Domestic Networks in order to more closely align it with its regulatory service areas and the decision to exit our energy trading business in Wholesale Services. These actions resulted in the termination of approximately 1,205 energy trading employees, 500 Domestic Networks employees and 75 Corporate employees. These charges were expensed and accrued during the second and third quarters of 2002 and paid out bi−weekly over the term of the severance benefit. In addition, certain employees of the wholesale energy trading operations had retention agreements in 2002 to ensure an orderly exit of this business. During the third quarter of 2002, we paid approximately $28.9 million of retention payments to these employees.

Disposal of Corporate Aircraft

The $7.1 million charge for disposal of corporate aircraft for the nine months ended September 30, 2002, primarily included the termination of applicable lease agreements and losses associated with the sale of our corporate aircraft.

Interest Rate Swap Reductions

We incurred $23.1 million of restructuring charges for the nine months ended September 30, 2003, to exit interest rate swaps related to our Clay County and Piatt County construction financing arrangements. As debt related to these facilities was paid down, our interest rate swaps exceeded the outstanding debt. Thus we reduced our position and realized the loss associated with the cancelled swaps.

Lease Agreements

During the third quarter of 2002, we recorded a $36.7 million restructuring charge for operating leases for various office facilities used in the wholesale energy trading operations that we determined would no longer be used. This charge represented the estimated future net lease costs of these facilities after estimated sublease recoveries.

Leasehold Improvements and Equipment

During the three and nine months ended September 30, 2002, we wrote down $36.6 million and $59.0 million, respectively, of leasehold improvements and equipment in our wholesale energy trading business that were no longer realizable based on our best estimate of their fair value.

Restructuring Reserve Activity

The following is a summary of the activity for accrued restructuring charges for the nine months ended September 30, 2003:

In millions

Severance and Retention Costs:		
Accrued severance costs as of December 31, 2002	$	16.6
Additional expense during the period		5.5
Cash payments during the period		(19.5)
Accrued severance and retention costs as of September 30, 2003	$	2.6
Other Restructuring Costs:		
Accrued other restructuring costs as of December 31, 2002	$	32.6
Additional expense during the period		22.2
Cash payments during the period		(38.1)
Accrued other restructuring costs as of September 30, 2003 (a)	$	16.7

(a) The majority of this liability represents costs accrued for future unused office space with various lease terms through 2009.

3. Impairment Charges and Net Loss on Sale of Assets

We recorded the following impairment charges and net loss (gain) on sale of assets:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions	**2003**	**2002**	**2003**	**2002**
Domestic Networks:				
Quanta Services	$ —	$ 5.2	$ —	$ 698.1
Communications investments	—	—	—	23.1
Other	—	—	(2.2)	—
Total Domestic Networks	—	5.2	(2.2)	721.2
International Networks:				

Australia	(1.0)	(3.0)	1.6	(3.0)
Midlands	4.0	—	4.0	—
Total International Networks	3.0	(3.0)	5.6	(3.0)
Capacity Services:				
Acadia tolling agreement	—	—	105.5	—
Turbines	—	—	(5.1)	—
Independent power plants	87.9	—	87.9	—
Exit from Lodi gas storage investment	—	21.9	—	21.9
Termination of Cogentrix acquisition	—	12.2	—	12.2
Other	—	1.4	—	1.4
Total Capacity Services	87.9	35.5	188.3	35.5
Wholesale Services:				
Goodwill	—	—	—	178.6
Other	—	1.3	—	1.3
Total Wholesale Services	—	1.3	—	179.9
Total impairment charges and net loss on sale of assets	$ 90.9	$ 39.0	$ 191.7	$ 933.6

Quanta Services

At June 30, 2002, the cost basis in our 38% equity investment in Quanta Services was $26.69 per share and was significantly above the trading price of Quanta Services' stock. On July 1, 2002, Quanta Services announced that it had reduced its earnings forecast due to a continued decline in the telecommunications industry, reduced utility construction spending, and financial difficulties surrounding Quanta Services' two largest customers. Quanta Services' share price dropped to approximately $3.00 per share after this announcement. Because of these factors, and the termination of our proxy contest for control of Quanta Services in May 2002, we concluded that there was an other−than−temporary decline in the fair value of this investment. Accordingly, we wrote the investment down by $692.9 million before tax, or $627.3 million after tax, to its estimated fair value of $3.00 a share.

In the third quarter of 2002, we sold approximately 8.4 million shares of Quanta stock at an average price of $2.38 per share for an additional pretax and after−tax loss of $5.2 million, reducing our ownership percentage from 38% to approximately 27%. In October 2002, we sold an additional 8.0 million Quanta shares at a price of $3.00 per share. After this sale, our ownership percentage was approximately 14%. As a result, beginning in November 2002, we accounted for this asset as an available−for−sale security in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS 115). We sold our remaining 11.6 million shares during the first quarter of 2003 at a net price of $2.90 a share.

Communications Investments

During the second quarter of 2002, we determined that certain cost and equity method investments in communications technology−related businesses were impaired based on continued losses in these businesses, their failure to achieve certain operational goals, the inability of these businesses to obtain additional capital, and our assessment of the long−term prospects of these businesses. Accordingly, we recorded a $23.1 million pretax, or $13.9 million after−tax, impairment charge related to these investments.

Australia

In the fourth quarter 2002, we recorded $127.2 million of pretax impairment charges related to our Australian investments.

In April 2003, we reached an agreement to sell our interests in Multinet Gas, United Energy Limited and AlintaGas Limited to a consortium consisting of AlintaGas, AMP Henderson and their affiliates. In May 2003, as the first step in the sale process, we sold our interest in AlintaGas. We received approximately $97.0 million in cash proceeds before transaction costs and taxes in May and July from this sale. In June, we retired $90.7 million of our $200.0 million, 364−day secured credit facility with these proceeds. We recorded a pretax loss of $2.6 million, or $1.6 million after tax, in the second quarter of 2003 in connection with this sale.

In July 2003, we completed the sale of our interests in United Energy and Multinet Gas and received cash proceeds of $525.0 million before transaction costs and taxes. Approximately $109.3 million of these proceeds were used in July to retire the remaining balance outstanding under the 364−day secured credit facility. We recorded a pretax gain of $1.0 million, or $.5 million after tax, in the third quarter of 2003 in connection with this sale.

Midlands

In September 2003, we agreed to terminate our agreement to sell our 79.9% interest in Aquila Sterling Limited (ASL), the owner of Midlands Electricity plc, to a subsidiary of Scottish and Southern Energy plc. The sale was subject to a number of conditions including the successful redemption of the outstanding bonds issued by Avon Energy Partners Holdings (AEPH), an ASL subsidiary, at 86% of their par value plus accrued interest. The efforts to meet this bond redemption condition were unsuccessful and therefore, the parties terminated the agreement.

In October 2003, we and FirstEnergy Corp. reached a definitive agreement to sell 100% of the ASL shares outstanding to a subsidiary of Powergen UK plc (Powergen) for approximately $60.0 million. Our share of the proceeds is expected to be approximately $52.0 million before transaction costs. As a result of this agreement and our continuing analysis of fair value surrounding this investment, we recorded an additional $4.0 million pretax and after−tax impairment charge to write this investment down to its estimated fair value less costs to sell. In the fourth quarter 2002, we recorded a $247.5 million pretax impairment charge related to our investment in Midlands.

Powergen's obligation to acquire ASL is conditioned upon a commitment of the holders of the outstanding bonds of AEPH to sell their bonds to an affiliate of Powergen for 95.8% of their nominal value (less fees) plus accrued interest to the date of completion. The sale is also subject to approval from the European Commission and Kansas Corporation Commission, as well as other customary closing conditions. We expect this sale to close in the first quarter of 2004.

Acadia Tolling Agreement

In May 2003, we entered into an agreement to terminate our 20−year tolling agreement for the Acadia power plant in Louisiana. We made a termination payment of $105.5 million in the second quarter of 2003. We were then released from the remaining aggregate payment obligation of $833.9 million, or $43.5 million on an annual basis.

Turbines

During the second quarter of 2003, we completed the contract termination and sale of certain turbines which had been written down to an estimated realizable value at December 31, 2002. In connection with the disposition, we recorded a pretax gain of $5.1 million, or $3.2 million after tax.

Independent Power Plants

In the third quarter of 2003, we decided to proceed with the sale of our investments in independent power plants. We have received bids from parties interested in acquiring these plants and are in discussions with these bidders. Two of the power plants, Lake Cogen Ltd. (Lake Cogen) and Onondaga Cogen Ltd Partnership (Onondaga), are consolidated on our balance sheet. Therefore, in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long−Lived Assets" (SFAS 144), we have reported the results of operations and assets of these two plants in discontinued operations.

The remaining plants are equity method investments that do not qualify for reporting as discontinued operations under SFAS 144 and are therefore included in continuing operations. We evaluated the carrying value of these equity method investments based on the bids received and other internal valuations. The results of this assessment indicated that these investments were impaired. Therefore, we recorded a pretax impairment charge of $87.9 million, or $69.9 million after tax, to reduce the carrying value of our investments to their estimated fair value less costs to sell.

Exit from Lodi Gas Storage Investment

In August 2001, Merchant Services and a partner agreed to acquire a 12 Bcf gas storage facility under construction near Lodi, California. In October 2002, we exited our investment in the Lodi project due to our exit from the wholesale energy trading business. We owned 50% of WHP Acquisition Company LLC, a company jointly established with an affiliate of ArcLight Energy Partners Fund I, L.P. in 2001 to purchase Western Hub Properties, LLC, the developer of the Lodi gas storage project. Under the settlement, WHP Acquisition Company LLC redeemed Aquila's ownership interest for cash payments totaling $5.0 million over a five−year period. We were also released from all of our guarantee obligations relating to this transaction. We recorded a $21.9 million pretax, or $21.6 million after−tax loss, on this transaction in the third quarter of 2002.

Termination of Cogentrix Acquisition

In August 2002, we agreed to terminate the purchase agreement we signed in April 2002 to acquire Cogentrix Energy, Inc., an independent power producer. We agreed with Cogentrix that due to the uncertainty of the electric power market, the deterioration of the creditworthiness of some of Cogentrix's customers and our exit from the wholesale energy trading business, proceeding with the transaction was impractical and not in either company's interest. In connection with the termination of this transaction, we expensed legal, consulting and termination fees of $12.2 million pretax, or $7.4 million after tax, in the third quarter of 2002.

Goodwill

In connection with our decision to exit our energy trading operations, we assessed our ability to realize the goodwill associated with our Wholesale Services business. This assessment was based on our best estimate of the value of this business in a liquidation, which we determined was less than the carrying value of its net assets. Because future earnings or sufficient sales proceeds could no longer support this asset, we wrote off the entire unamortized goodwill balance of $178.6 million in the second quarter of 2002.

4. Discontinued Operations

In 2002 and early 2003, we sold our Texas natural gas storage facility, our Texas and Mid−Continent natural gas pipeline systems, including our natural gas and natural gas liquids processing assets, our ownership interest in the Oasis Pipe Line Company, our coal terminal and handling facility (which were all included in our Capacity Services segment) and our Merchant loan portfolio (which was included in our Wholesale Services segment).

In September 2003, we reached an agreement to sell our Canadian utility businesses (which are included in our International Networks segment) for approximately $992 million, including the repayment or assumption of $228 million of debt, or a net $764 million in proceeds to us before closing adjustments, transaction costs and taxes. In addition, we will be required to repay $115 million borrowed by Aquila Networks Canada Corp. under its 364−day unsecured loan. We expect to use the remaining net proceeds from the sale to pay related taxes and transaction fees, improve our liquidity, and reduce debt and other obligations. The transaction is subject to approval by the regulatory commissions in Alberta and British Columbia, among other regulatory bodies, as well as other customary closing conditions, and is expected to close in the first half of 2004. If the sale does not close by June 30, 2004, the sale agreement will automatically terminate. We expect to record a gain on this sale at the date of close.

In the third quarter of 2003, we decided to proceed with the sale of our investments in independent power plants. We have received bids from parties interested in acquiring these plants and are in discussions with these bidders. Two of the power plants, Lake Cogen and Onondaga, are consolidated on our balance sheet. We have reported the results of operations and assets of these two plants in discontinued operations. We evaluated the carrying value of these assets based on the bids received and other internal valuations. The results of this assessment indicated these assets were impaired. We recorded a pretax impairment charge of $47.5 million, or $39.8 million after tax, to reduce the carrying value of these assets to their estimated fair value less costs to sell.

We have reported the results of operations from the above assets in discontinued operations in the Consolidated Statements of Income. The related assets and liabilities included in the sale of these businesses, as detailed below, have been reclassified as current and non−current assets and liabilities of discontinued operations on the Consolidated Balance Sheets.

In millions	**September 30, 2003**	**December 31, 2002**
Current assets of discontinued operations:		
Cash and cash equivalents	$ 117.7	$ 55.6
Accounts receivable, net	35.2	58.2
Price risk management assets	41.2	25.9
Other current assets	79.4	96.3
Total current assets of discontinued operations	$ 273.5	$ 236.0
Non−current assets of discontinued operations:		
Property, plant and equipment, net	$ 688.2	$ 524.5
Price risk management assets	52.1	98.1
Goodwill, net	220.4	188.6
Other non−current assets	37.4	38.0
Total non−current assets of discontinued operations	$ 998.1	$ 849.2
Current liabilities of discontinued operations:		
Current maturities of long−term debt	$ 47.7	$ 174.8
Short−term debt	215.0	13.2
Accounts payable	29.2	44.0
Other current liabilities	93.5	34.0
Total current liabilities of discontinued operations	$ 385.4	$ 266.0
Non−current liabilities of discontinued operations:		
Long−term debt, net	$ 129.9	$ 127.4
Deferred credits	48.4	58.3
Total non−current liabilities of discontinued operations	$ 178.3	$ 185.7

Operating results from our discontinued operations are as follows:

In millions	Three Months Ended September 30, 2003	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2002	Nine Months Ended September 30, 2003
Sales	$ 75.1	$ 172.1	$ 235.4	$ 474.9
Cost of sales	14.9	69.2	47.0	208.9
Gross profit	60.2	102.9	188.4	266.0
Operating expenses:				
Operating expense	33.5	68.3	95.4	157.1
Restructuring charges	—	(.2)	—	.2
Impairment charges and net loss on sale of assets	47.5	236.6	47.5	236.6
Depreciation and amortization expense	.1	22.5	8.6	67.0
Total operating expenses	81.1	327.2	151.5	460.9
Other income (expense):				
Equity in earnings of investments	—	2.0	—	4.9
Other income (expense)	(9.2)	18.3	(5.3)	45.1
Earnings (loss) before interest and taxes	(30.1)	(204.0)	31.6	(144.9)
Interest expense	3.7	7.2	15.0	17.8
Earnings (loss) before income taxes	(33.8)	(211.2)	16.6	(162.7)
Income tax expense (benefit)	(8.1)	(71.0)	5.1	(51.4)
Earnings (loss) from discontinued operations	$ (25.7)	$ (140.2)	$ 11.5	$ (111.3)

5. Earnings (Loss) per Common Share

The table below shows how we calculated basic and diluted earnings (loss) per share. Basic earnings (loss) per share and basic weighted average shares are the starting point in calculating the dilutive measures. To calculate basic earnings (loss) per share, divide our net loss for the period by our weighted average shares outstanding, without adjusting for dilutive items. Diluted earnings (loss) per share is calculated by dividing our net loss, after assumed conversion of dilutive securities, by our weighted average shares outstanding, adjusted for the effect of dilutive securities. As a result of the net losses in the three and nine months ended September 30, 2003 and 2002, the potential issuances of common stock for dilutive securities were considered anti−dilutive and therefore not included in the calculation of diluted earnings (loss) per share.

In millions, except per share amounts	Three Months Ended September 30, 2003	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
Loss from continuing operations	$ (144.2)	$ (191.4)	$ (313.9)	$ (985.9)
Earnings (loss) from discontinued operations	(25.7)	(140.2)	11.5	(111.3)
Net loss	$ (169.9)	$ (331.6)	$ (302.4)	$ (1,097.2)
Basic and diluted earnings (loss) per share:				
Loss from continuing operations	$ (.74)	$ (1.07)	$ (1.61)	$ (6.44)
Earnings (loss) from discontinued operations	(.13)	(.78)	.06	(.73)
Net loss	$ (.87)	$ (1.85)	$ (1.55)	$ (7.17)
Weighted average number of common shares used in basic and diluted earnings (loss) per share	195.1	179.6	194.6	153.1

6. Reportable Segment Reconciliation

Our reportable segment reconciliation is shown below.

In millions	Three Months Ended September 30, 2003	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
Sales:				
Domestic Networks	$ 352.2	$ 401.5	$ 1,281.5	$ 1,391.7
International Networks	—	—	—	—
Total Global Networks Group	352.2	401.5	1,281.5	1,391.7
Capacity Services	20.7	139.6	(14.4)	285.4
Wholesale Services	(50.9)	(89.8)	(54.9)	42.2
Total Merchant Services	(30.2)	49.8	(69.3)	327.6
Total	$ 322.0	$ 451.3	$ 1,212.2	$ 1,719.3
Earnings (Loss) Before Interest and Taxes (EBIT):				
Domestic Networks	$ 44.5	$ 32.0	$ 125.1	$ (640.2)
International Networks	3.7	44.0	17.0	81.5
Total Global Networks Group	48.2	76.0	142.1	(558.7)
Capacity Services	(100.5)	(53.4)	(294.0)	(27.3)
Wholesale Services	(55.9)	(236.2)	(97.0)	(405.8)
Total Merchant Services	(156.4)	(289.6)	(391.0)	(433.1)
Corporate and Other	(11.5)	(12.5)	16.2	(26.0)
Total EBIT	(119.7)	(226.1)	(232.7)	(1,017.8)
Interest expense	75.1	67.0	206.9	164.5
Loss from continuing operations before income taxes	$ (194.8)	$ (293.1)	$ (439.6)	$ (1,182.3)

In millions	September 30, 2003	December 31, 2002
Assets:*		
Domestic Networks	$ 2,857.5	$ 2,666.5
International Networks	1,372.0	1,607.1
Total Global Networks Group	4,229.5	4,273.6
Capacity Services	1,015.5	1,203.2
Wholesale Services	1,863.7	3,092.1
Total Merchant Services	2,879.2	4,295.3
Corporate and Other	557.6	690.3
Total assets	$ 7,666.3	$ 9,259.2

* Included in total assets as of September 30, 2003 and December 31, 2002 are total current and non−current assets of discontinued operations as follows: Wholesale Services, $20.1 million and $19.3 million, Capacity Services, $153.8 million and $190.6 million and International Networks, $1,097.7 million and $875.3 million, respectively.

7. Financings

Revolving Credit Facility

In April 2002, we entered into a revolving credit facility totaling $650.0 million. The credit facility consisted of two $325.0 million credit agreements, one with a maturity of 364 days, and the other with a maturity of three years. In April 2003, the 364−day credit facility was repaid in full and the unused portion of the three−year credit facility was terminated. During the second quarter of 2003, we terminated the remainder of the three−year facility and replaced the letters of credit issued under it with new letters of credit issued under our letter of credit facility discussed below.

364−Day Secured Credit Facility

In April 2003, we closed on a $200.0 million, 364−day secured loan. The borrower was UtiliCorp Australia, Inc., a wholly−owned subsidiary. At closing, we borrowed $100.0 million of the available $200.0 million. The interest rate on this financing was initially the London Inter Bank Offering Rate (LIBOR) (with a 3% floor) plus 4.0% for the first 90 days. After the first 90 days, the interest rate increased an additional 2% and would increase an additional 2% every subsequent 90 days with a maximum rate at maturity of LIBOR (with a 3% floor) plus 10%. We paid up−front arrangement fees of $4.1 million in connection with this borrowing. Proceeds from this borrowing were used to retire debt.

In May 2003, we exercised our option under the 364−day financing to borrow the remaining $100.0 million available under the facility. The proceeds were used to terminate our Acadia Tolling Agreement as discussed in Note 3. We paid additional arrangement fees of $4.1 million for this borrowing. We retired $90.7 million of this borrowing in June 2003 with proceeds from the sale of our interest in AlintaGas. The remaining balance of $109.3 million was retired in July 2003 with proceeds from the sale of our interests in United Energy and Multinet Gas.

Three−Year Secured Credit Facility

In April 2003, we closed on a $430.0 million, three−year secured loan. The initial interest rate on the facility was LIBOR (which has a 3% floor) plus 5.75%. In addition, we were required to pay up−front arrangement fees of $17.8 million. Proceeds from the financing were used to retire debt and support letters of credit.

The three−year facility is secured by (i) $430.0 million of first mortgage bonds issued under a new indenture that constitutes a lien on our existing and future Michigan, Nebraska and Colorado utility network assets, (ii) a pledge of the equity of two wholly−owned subsidiaries that indirectly hold our Canadian utility business, and (iii) a pledge of the equity of a wholly−owned subsidiary that indirectly holds our interests in independent power plants. In October 2003, the Iowa Utility Board conditionally approved our request to pledge Iowa utility network assets as collateral for the loan. We are in the process of amending the agreement to include these assets as collateral. If we default on this loan, the lenders would be entitled to be fully repaid from the sale proceeds of this collateral before other creditors could assert their claims against the pledged assets.

We have also committed to use reasonable efforts to obtain approvals that would provide these lenders additional domestic utility assets as collateral for their loans. If, as a result of the addition of any such collateral, the value of the domestic regulated utility asset collateral securing the indenture exceeds 167% of the loan secured by the indenture, the pledge of the Canadian and independent power projects equity interest may be released and the interest rate would be reduced to LIBOR (which has a 3% floor) plus 5.00%. In April 2003, we filed applications with the state regulatory bodies in Kansas, Minnesota and Missouri requesting authority to pledge our utility assets located in their respective states. In September 2003, the Staff of the Missouri Public Service Commission recommended that our request to pledge Missouri utility assets be denied. Hearings were held before the Commission in October 2003 and a ruling is expected by the end of 2003. However, there is no statutory deadline for a decision in Missouri. In October 2003, the Minnesota Public Utility Commission also voted to deny our request to pledge Minnesota utility assets. We are currently evaluating whether we will seek a reconsideration of this decision or re−file the application to address the concerns raised by the Minnesota Commission. We continue to work with the Kansas Corporation Commission to obtain its approval for the additional collateral. A hearing is scheduled for November 2003.

After our Iowa utility assets have been formally pledged, we will request that our interest rate be reduced as described above, and we will have pledged utility assets in Michigan, Nebraska, Iowa and Colorado which would then fully collateralize the loan. Following the pledge of our Iowa utility assets, we will not be required by the credit facility to maintain collateral for the loan beyond the utility assets pledged. However, it is our intention that borrowings under the credit facility that are not needed to support our utility operations be collateralized by non−utility assets.

The $430.0 million secured debt would become immediately due and payable if we do not complete an exchange offer, tender offer, refinancing or other retirement transaction with regard to 80% of our $250.0 million, 7% senior note series due July 15, 2004 and our $150.0 million, 6.875% senior note series due October 1, 2004, at least two weeks prior to their respective maturity dates. Among other restrictions, the three−year secured facility contains the following financial covenants with which we were in compliance as of September 30, 2003:

(1) We must maintain a ratio of total debt to total capital of not more than .75 to 1.00 as of September 30, 2003 and December 31, 2003, decreasing to .70 to 1.00 for quarters ending after December 31, 2003.

(2) Beginning July 1, 2003, we must maintain a trailing 12−month ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) from pledged assets to interest expense related to these assets of no less than 1.05 to 1.00, increasing to 2.0 to 1.0 for quarters ending after December 31, 2004.

(3) Beginning July 1, 2003, we must maintain a trailing 12−month ratio of debt outstanding on our pledged assets to EBITDA from our pledged assets of no more than 10.5 to 1.0, decreasing to 5.5 to 1.0 for quarters ending after June 30, 2004.

The three−year facility also contains covenants that restrict certain activities including, among others, limitations on additional indebtedness, restrictions on acquisitions, sale transactions, and the amount that we can fund our unregulated merchant businesses and our Everest Connections communications business. In addition, we are prohibited from paying dividends and from making certain other payments if our senior unsecured debt is not rated at least Ba2 by Moody's and BB by Standard & Poor's, or if such a payment would cause a default under the facility.

Amounts under the three−year facility cannot be voluntarily prepaid except with payment of a make−whole amount. Amounts that are repaid cannot be re−borrowed. To the extent we default on any of our loan covenants, our interest rate will increase an additional 2% during the default period.

Letter of Credit Facility

In April 2003, we executed a 364−day Letter of Credit Agreement with a commercial bank. Under terms of the Agreement, the bank committed to initially issue letters of credit under the facility subject to a limit of $200.0 million outstanding at any one time. All letters of credit issued are fully secured by cash deposits with the bank. The committed amount automatically decreased to $175.0 million at June 30, 2003 and will decrease further to $150.0 million at December 31, 2003. At September 30, 2003, $65.3 million of letters of credit were outstanding under this facility.

Canadian Subsidiaries

On July 31, 2003, we closed on a $215.0 million, 364−day unsecured loan. The borrowers are Aquila Networks Canada Corp. (ANCC) and Aquila Networks Canada (Alberta) Ltd. (ANCA), each of which is an indirect wholly−owned subsidiary. At closing, ANCC borrowed $115.0 million and ANCA borrowed $100.0 million. The interest rate on this financing is LIBOR (with 2.50% floor) plus 4.25%. Proceeds were used by ANCA to repay and terminate its existing 364−day credit agreement that matured on July 31, 2003, and a letter of credit facility. ANCC will use its proceeds to finance the capital expenditure and working capital requirements of its regulated utility subsidiaries, as well as repay certain bank debt of Aquila Networks Canada (British Columbia) Ltd (ANCBC). The facilities will be repaid with the proceeds received in connection with the sale of our Canadian utility businesses. We paid up−front arrangement fees of $4.3 million in connection with this borrowing.

Aquila has fully and unconditionally guaranteed $200.0 million of 7.75% senior notes issued in the U.S. debt market by our wholly−owned Canadian finance subsidiary, Aquila Networks Canada Finance Corporation in June 2001. Aquila Networks Canada Finance Corporation has since been merged into its direct parent corporation, UtiliCorp Canada Ventures LLC, a Delaware limited liability company.

8. Restatement of Consolidated Statement of Cash Flow

As stated in previous filings, between 1997 and 2000, we entered into long−term gas contracts that require us to deliver natural gas to municipal utility customers over periods of 10 to 12 years. In exchange for our commitment to deliver the natural gas, we were paid in advance. We considered these contracts part of our energy trading operations. As such, both the receipt of the advance cash payments and the monthly cash outflows to purchase the gas to be delivered to the customers in satisfaction of our commitments historically were included in our Consolidated Statements of Cash Flows under the caption Net Changes in Price Risk Management Assets and Liabilities and included in Cash Flows From Operating Activities. These contracts were included under the caption Price Risk Management Liabilities in our Consolidated Balance Sheets prior to December 31, 2002, but are now separately disclosed as Long−term Gas Contracts for all periods presented.

In 2002, the Emerging Issues Task Force (EITF), in its deliberations regarding EITF No. 02−3, discussed a number of items related to energy trading and risk management activities. In order to more fully address certain of the items discussed, the EITF formed a working group. One of the items discussed by the working group was "prepaid gas contracts." These discussions included the cash flow presentation of contracts similar to our long−term gas contracts. Based on this discussion, and other accounting and industry discussions and guidance occurring in 2002, we believe that the current industry and accounting consensus is to report these contracts as financing activities in the statement of cash flows. As a result, we have reported these cash flows in accordance with the current accounting interpretations and guidance for all periods presented in our Consolidated Statements of Cash Flows. This resulted in a $58.5 million increase in Cash Flows From Operating Activities for the nine months ended September 30, 2002, as compared to the amount previously reported. Cash Flows From Financing Activities changed by the corresponding amount, resulting in no change in total cash flow. This change had no impact on earnings or losses.

The net effects of the change discussed above are shown in the following table:

In millions	Nine Months Ended September 30, 2002 As Previously Reported	Nine Months Ended September 30, 2002 As Restated
Cash used for operating activities	$ (166.2)	$ (107.7)
Cash used for investing activities	(494.4)	(494.4)
Cash provided from financing activities	912.6	854.1
Net increase in cash and cash equivalents	$ 252.0	$ 252.0

9. Aries Power Project

MEP Pleasant Hill, LLC, our 50 percent−owned joint venture that owns and operates the Aries Power Project in Pleasant Hill, Missouri, did not refinance or repay $270.0 million of construction loans prior to their June 26, 2003 maturity. In response to the default, the lenders have drawn on $75.0 million of letters of credit that we and our partner equally pledged to support the loans, reducing the loan balances to $195.0 million. Although the project is current on its interest payments and other operating expenses, the loans remain in default. The loans are non−recourse to us and the default has no direct impact on our other credit arrangements or utility operations. We are currently working with our partner and lenders to cure the default. As of September 30, 2003, our investment balance in the Aries Power Project was $44.4 million.

10. Legal and Environmental Matters

In February 2002, we filed a suit against Chubb Insurance Group, the issuer of surety bonds in support of certain of our long−term gas supply contracts. Previously, Chubb had demanded that it be released from its surety obligation of up to $523.8 million or, alternatively, that we post collateral to secure its obligation. We do not believe that Chubb is entitled to be released from its surety obligations or that we are obligated to post collateral to secure its obligations unless it is likely we will default on the contracts. Chubb has not alleged that we are likely to default on the contracts. If Chubb were to prevail, it would have a material adverse impact on our liquidity and financial position. We rely on other sureties in support of long−term gas supply contracts similar to those described above. There can be no assurance that these sureties will not make claims similar to those raised by Chubb. We have performed under these contracts since their inception and intend to continue to fully perform under these contracts.

A consolidated lawsuit was filed against us in federal court in Missouri in connection with our recombination with our Aquila Merchant subsidiary that occurred pursuant to an exchange offer completed in January 2002. The suit raised allegations concerning the lack of independent members on the board of directors of Aquila Merchant to negotiate the terms of the exchange offer on behalf of the public shareholders of Aquila Merchant. Persons holding certificates formerly representing approximately 1.8 million shares of Aquila Merchant common stock are also pursuing their appraisal rights in connection with the recombination. The dissenters' rights action is scheduled for trial in May 2004. We do not believe that either of these actions will have an outcome materially adverse to us.

A number of companies that have engaged in energy trading activities, including us, have received requests from various regulatory agencies to furnish data and answer questions relating to the possible inaccurate reporting of gas trade information to various industry publications in 2000 and 2001. In response to such inquiries, we initiated a review of our reported information relative to recorded data and are fully cooperating with these investigations. Additionally, we have reported to the Federal Energy Regulatory Commission and the Commodity Futures Trading Commission (CFTC) that we have been unable to reconcile all of the gas trade data reported to various trade publications with the gas trade data in our internal records and that our former traders may have reported inaccurate information. We are continuing to work with the CFTC on this matter.

A lawsuit was filed against us and numerous other energy trading companies in November 2002 by the Lieutenant Governor of the State of California alleging that we misreported gas trade data that, in turn, affected the market price of electricity in California. Our motion to be dismissed from the lawsuit was granted by the court on July 11, 2003.

The Environmental Protection Agency (EPA) has been conducting enforcement initiatives nationwide, and recently has inquired at several coal−fired power plants operated by other companies in our region. These investigations are being made to determine whether modifications at those facilities were subject to New Source Review requirements (NSR) under the Clean Air Act. The EPA contends that power plants are required to update emission controls at the time of major maintenance or capital activity, and it has initiated civil enforcement actions in some cases. The EPA has not requested any information from our company in that regard, nor has it indicated that it intends to do so. We believe that the maintenance and capital activities performed at our power plants are routine and not subject to NSR. It is possible, if the EPA does pursue such action with us, that our additional investment to comply could be material. We would expect to obtain recovery of such costs through rates.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

AQUILA, INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Except where noted, the following discussion refers to the consolidated entity, Aquila, Inc. During the periods covered by this report, our businesses were structured as follows: (a) Global Networks Group, consisting of two segments, (i) Domestic Networks, our electric and gas utilities in seven mid−continent states, which also includes our communications business and our former investment in Quanta Services, Inc. (sold in late 2002 and early 2003), and (ii) International Networks, our investments in Australian electric and gas utilities (sold in the second and third quarters of 2003), our United Kingdom investment in an electric utility business (in the process of being sold), our investment in New Zealand electric and gas utility businesses (sold in the fourth quarter of 2002) and our Canadian electric utility businesses (which are in the process of being sold and are classified as discontinued operations for all periods presented); and (b) Merchant Services, consisting of two segments, (i) Capacity Services, our power generation operations, our investments in independent power plants (in the process of being sold; two consolidated plants, Lake Cogen and Onondaga, have been classified as discontinued operations for all periods presented), our natural gas gathering and processing operations (sold in 2002 and classified as discontinued operations for all periods presented), and (ii) Wholesale Services, our North American and European commodity and client service businesses (including our capital business which was also sold in 2002 and is classified as discontinued operations for all periods presented).

FORWARD−LOOKING INFORMATION AND RISK FACTORS

This report contains forward−looking information, including statements that (i) we expect our utility rates to be increased in certain states where we have utility operations, and (ii) our long−term liquidity depends upon the sale of assets, return of collateral posted, restructuring of generation capacity obligations, the ability to refinance or retire maturing obligations such as long−term gas contracts and the ability to use regulated assets as collateral for debt. The words "may," "will," "should," "expect," "anticipate," "intend," "plan," "believe," "seek," "estimate," or the negative of these terms or similar expressions identify further forward−looking statements. Similar statements that identify our objectives, plans and goals are forward−looking statements.

These forward−looking statements involve risks and uncertainties, and there are certain important factors that can cause actual results to differ materially from those anticipated. Some of the important factors and risks that could cause actual results to differ materially from those anticipated include:

- Failure to close pending asset sales would have a material adverse impact on our long−term liquidity.
- Proceeds from future asset sales could be lower than book value which would generate additional losses and may not adequately reduce our debt to levels where our operations are able to generate sufficient cash flows to service our remaining debt.
- Regulatory commissions may refuse to approve some or all of the utility rate increases we have requested.
- Counterparties may default on their obligations to pay, supply commodities, return collateral to us or to meet their obligations under commercial contracts, including those designed to hedge against movements in commodity prices.
- Our credit ratings and financial condition will limit our ability to access the capital markets we historically used to refinance our debt. Because we recently pledged a significant portion of our assets as collateral for loans, it will be difficult for us to obtain additional financing. We must

obtain regulatory approvals to use the majority of our remaining unencumbered assets as collateral for additional loans, as well as issue additional debt.

- If our financial condition improves, market prices for our long−term debt may increase and limit our ability to repurchase it. Our new credit agreements may require us to use a portion of the proceeds from the sale of our assets to reduce our obligations to those lenders before retiring other debt.
- Our commitments under long−term gas delivery contracts and capacity generation contracts will generate significant losses and negative cash flows for an extended period of time. Because these obligations represent favorable contracts to the counterparties, absent a risk of our default, they may be unwilling to restructure or sell the contracts.
- There are numerous ongoing state and federal investigations of the trading activities of companies that participated in the energy trading industry, including us, as well as an internal investigation in connection with allegations contained in an anonymous letter. Companies that have violated laws or rules of the investigating agencies have been required to pay significant amounts to settle these investigations. Even if no wrongdoing is found, we will incur legal and forensic accounting costs associated with complying with the discovery requests of the investigating bodies.

RESULTS OF OPERATIONS

Financial Review

This review of performance is organized by business segment, reflecting the way we managed our business during the periods covered by this report. Each business group leader is responsible for operating results down to earnings before interest and taxes (EBIT). We use EBIT as a performance measure as it captures the income and expenses within the management control of our segment business leaders. Corporate management is responsible for making all financing decisions. Therefore, each segment discussion focuses on the factors affecting EBIT, while interest expense and income taxes are separately discussed at the corporate level.

The use of EBIT as a performance measure is not meant to be considered an alternative to net income or cash flows from operating activities, which are determined in accordance with generally accepted accounting principles (GAAP), as an indicator of operating performance or as a measure of liquidity, or other performance measures used under GAAP. In addition, the term may not be comparable to similarly titled measures used by other companies.

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions	**2003**	**2002**	**2003**	**2002**
Earnings (Loss) Before Interest and Taxes:				
Domestic Networks	$ 44.5	$ 32.0	$ 125.1	$ (640.2)
International Networks	3.7	44.0	17.0	81.5
Total Global Networks Group	48.2	76.0	142.1	(558.7)
Capacity Services	(100.5)	(53.4)	(294.0)	(27.3)
Wholesale Services	(55.9)	(236.2)	(97.0)	(405.8)
Total Merchant Services	(156.4)	(289.6)	(391.0)	(433.1)
Corporate and Other	(11.5)	(12.5)	16.2	(26.0)
Total EBIT	(119.7)	(226.1)	(232.7)	(1,017.8)
Interest expense	75.1	67.0	206.9	164.5
Income tax benefit	(50.6)	(101.7)	(125.7)	(196.4)
Loss from continuing operations	(144.2)	(191.4)	(313.9)	(985.9)
Earnings (loss) from discontinued operations, net of tax	(25.7)	(140.2)	11.5	(111.3)
Net loss	$ (169.9)	$ (331.6)	$ (302.4)	$ (1,097.2)

DISCONTINUED OPERATIONS

As further discussed in Note 4 to the Consolidated Financial Statements, we have reported the results of operations of the following assets in discontinued operations in the Consolidated Statements of Income: (1) our Texas natural gas storage facility, our Texas and Mid−Continent natural gas pipeline systems, including our natural gas and natural gas liquids processing assets and our ownership interest in the Oasis Pipe Line Company, our coal terminal and handling facility and our Merchant loan portfolio that were all sold in 2002 and early 2003, and (2) our Canadian network businesses and our consolidated independent power plants, Lake Cogen and Onondaga, that we are in the process of selling. The unaudited operating results of our operations that are considered discontinued operations for accounting purposes are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions	**2003**	**2002**	**2003**	**2002**
Sales	$ 75.1	$ 172.1	$ 235.4	$ 474.9
Cost of sales	14.9	69.2	47.0	208.9
Gross profit	60.2	102.9	188.4	266.0
Operating expenses:				
Operating expense	33.5	68.3	95.4	157.1
Restructuring charges	—	(.2)	—	.2
Impairment charges and net loss on sale of assets	47.5	236.6	47.5	236.6
Depreciation and amortization expense	.1	22.5	8.6	67.0
Total operating expenses	81.1	327.2	151.5	460.9
Other income (expense):				
Equity in earnings of investments	—	2.0	—	4.9
Other income (expense)	(9.2)	18.3	(5.3)	45.1
Earnings (loss) before interest and taxes	(30.1)	(204.0)	31.6	(144.9)
Interest expense	3.7	7.2	15.0	17.8
Earnings (loss) before income taxes	(33.8)	(211.2)	16.6	(162.7)
Income tax expense (benefit)	(8.1)	(71.0)	5.1	(51.4)
Earnings (loss) from discontinued operations	$ (25.7)	$ (140.2)	$ 11.5	$ (111.3)

Quarter−to−Quarter

Sales, Cost of Sales and Gross Profit

Sales, cost of sales and gross profit decreased $97.0 million, $54.3 million and $42.7 million, respectively, in 2003 compared to 2002. These decreases were primarily due to the sale of our gas gathering and pipeline assets and our coal handling facility in the fourth quarter of 2002. In addition, sales, cost of sales and gross profit for Lake Cogen and Onondaga were lower in 2003 by $21.8 million, $4.7 million and $17.1 million, respectively, due to mark−to−market losses on long−term gas and power swaps resulting from lower natural gas and power prices and lower volumes delivered in the third quarter of 2003 compared to 2002.

Operating Expense

Operating expense decreased $34.8 million in 2003 compared to 2002 primarily due to the sale of our gas gathering and pipeline assets, our Merchant loan portfolio and our coal handling facility in the fourth quarter of 2002.

Impairment Charges and Net Loss on Sale of Assets

Impairment charges and net loss on sale of assets consisted of $47.5 million related to our consolidated independent power plants, Lake Cogen and Onondaga. In the third quarter of 2003, we decided to proceed with the sale of these assets and therefore wrote these assets down to estimated fair value less costs to sell, which was less than their carrying value. Impairment charges in 2002 consisted of a $236.6 million loss on the sale of our gas gathering and pipeline assets.

Depreciation and Amortization Expense

Depreciation and amortization expense decreased $22.4 million in 2003 compared to 2002. The elimination of depreciation from our Canadian utility plant was due to its classification as held for sale in accordance with SFAS 144, which decreased depreciation expense $14.5 million. SFAS 144 requires that depreciation expense no longer be recorded for those assets classified for accounting purposes as held for sale. In addition, approximately $7.9 million of the decrease was due to the sale of our gas gathering and pipeline assets and our coal handling facility in the fourth quarter of 2002.

Other Income

Other income decreased $27.5 million in 2003 compared to 2002 primarily due to the sale of our Merchant loan portfolio in the fourth quarter of 2002. This business generated $13.4 million of other income in the third quarter of 2002. In 2003, we incurred $6.8 million of costs related to a currency put option intended to protect us from unfavorable currency movements on the Canada sale proceeds and $2.2 million of foreign currency losses related to U.S. dollar denominated debt issued by our Canadian subsidiaries.

Interest Expense

Interest expense decreased $3.5 million in 2003 compared to 2002 primarily due to the retirement of $85.3 million of Canadian bank borrowings in April 2003.

Income Tax Benefit

The income tax benefit for 2003 decreased $62.9 million from 2002 primarily due to lower pretax losses in 2003.

Year−to−Date

Sales, Cost of Sales and Gross Profit

Sales, cost of sales and gross profit decreased $239.5 million, $161.9 million and $77.6 million, respectively, in 2003 compared to 2002. These decreases were primarily due to the sale of our gas gathering and pipeline assets and our coal handling facility in the fourth quarter of 2002. In addition, sales and gross profit for our Canadian network operations decreased $30.0 million and $27.0 million, respectively, due to the decision by the Alberta Energy and Utilities Board (AEUB) to decrease our 2002 and 2003 customer billing rates. Offsetting these decreases were sales and gross profit for Lake Cogen and Onondaga that were higher in 2003 by $12.7 million and $14.3 million, respectively, due to mark−to−market gains on long−term gas and power swaps resulting from higher natural gas and power prices in the first half of 2003, partially offset by lower volumes delivered.

Operating Expense

Operating expense decreased $61.7 million in 2003 compared to 2002 primarily due to the sale of our gas gathering and pipeline assets, our Merchant loan portfolio and our coal handling facility in 2002 and early 2003.

Impairment Charges and Net Loss on Sale of Assets

Impairment charges and net loss on sale of assets consisted of $47.5 million related to our consolidated independent power plants, Lake Cogen and Onondaga. In the third quarter of 2003, we decided to proceed with the sale of these assets and therefore wrote these assets down to estimated fair value less costs to sell, which was less than their carrying value. Impairment charges in 2002 consisted of a $236.6 million loss on the sale of our gas gathering and pipeline assets.

Depreciation and Amortization Expense

Depreciation and amortization expense decreased $58.4 million in 2003 compared to 2002. The elimination of depreciation from our Canadian utility plant was due to its classification as held for sale which decreased depreciation expense $14.5 million as discussed above. In addition, approximately $23.2 million of the decrease was due to the sale of our gas gathering and pipeline assets and our coal handling facility in the fourth quarter of 2002. The remaining decrease was primarily due to the decision by the AEUB to reduce the depreciation rates on most of our distribution assets in Alberta, which impacted the first six months of 2003.

Equity in Earnings of Investments

Equity in earnings of investments decreased $4.9 million due to the sale of our investment in the Oasis Pipe Line Company in the fourth quarter of 2002.

Other Income

Other income decreased $50.4 million in 2003 compared to 2002, primarily due to the sale of our Merchant loan portfolio in the fourth quarter of 2002. This business generated $37.1 million of other income in 2002. In 2003, we incurred $6.8 million of costs related to a currency put option intended to protect us from unfavorable currency movements on the Canada sale proceeds and $2.2 million of foreign currency losses related to U.S. dollar denominated debt issued by our Canadian subsidiaries.

Income Tax Expense (Benefit)

Income tax expense (benefit) decreased $56.5 million primarily due to pretax income in 2003 compared to a pretax loss in 2002 and the AEUB decision discussed above. This decision decreased sales and depreciation; however, only the sales impact is tax effected for Canadian regulatory purposes.

DOMESTIC NETWORKS

The table below summarizes the operations of our Domestic Networks.

Dollars in millions	Three Months Ended September 30, 2003	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
Sales	$ 352.2	$ 401.5	$ 1,281.5	$ 1,391.7
Cost of sales	174.5	226.9	754.2	865.5
Gross profit	177.7	174.6	527.3	526.2
Operating expenses:				
Operating expense	101.0	99.2	305.3	331.2
Restructuring charges	—	—	2.1	19.9
Impairment charges and net loss (gain) on sale of assets	—	5.2	(2.2)	721.2
Depreciation and amortization expense	32.0	36.8	97.1	106.5
Total operating expenses	133.0	141.2	402.3	1,178.8
Other income (expense):				
Equity in earnings (loss) of investments	—	(2.8)	—	1.7
Minority interest in income of subsidiaries	—	2.4	—	6.6
Other income (expense)	(.2)	(1.0)	.1	4.1
Earnings (loss) before interest and taxes	$ 44.5	$ 32.0	$ 125.1	$ (640.2)
Electric sales and transportation volumes (GWh)	3,426.7	3,622.4	8,933.8	9,593.0
Gas sales and transportation volumes (Bcf)	34.4	38.0	165.9	166.5
Electric customers at end of period			445,000	437,000
Gas customers at end of period			879,000	870,000

Quarter−to−Quarter

Sales, Cost of Sales and Gross Profit

Sales and cost of sales for the Domestic Networks businesses decreased $49.3 million and $52.4 million, respectively, and gross profit increased $3.1 million in 2003 compared to 2002. These changes were primarily due to the following factors:

- Sales and cost of sales for our regulated gas utilities increased $21.1 million and $14.6 million, respectively, for a net increase in gross profit of $6.5 million. Sales and cost of sales increased due to a 34% increase in natural gas prices. However, because gas purchase costs for our gas utility operations are passed through to our customers, the change in gas prices does not have a corresponding impact on gross profit. The increase in gross profit for our regulated gas utilities resulted primarily from rate increases in Michigan and Iowa of $1.3 million, $3.6 million of excess pipeline capacity sales and customer growth.

- Regulated electric utility sales and cost of sales increased $15.3 million and $14.2 million, respectively, in 2003 compared to 2002, for a gross profit increase of $1.1 million. Sales and gross profit increased $5.5 million due to a rate increase in Colorado effective in July 2003,

$6.0 million of additional margin from favorable weather and $1.6 million from customer growth. These increases were partially offset by a net $5.0 million decrease in margin from off−system sales and $7.2 million of increased cost of sales due to the higher cost of natural gas used to fuel our power plants.

- Non−regulated gas sales, cost of sales and gross profit decreased $88.2 million, $81.1 million and $7.1 million, respectively, in 2003 compared to 2002, primarily as the result of the sale of our non−regulated retail gas operations on September 30, 2002.

Impairment Charges and Net Loss (Gain) on Sale of Assets

As further discussed in Note 3 to the Consolidated Financial Statements, Domestic Networks incurred $5.2 million of losses in 2002 related to the sale of part of our investment in Quanta Services.

Depreciation and Amortization Expense

Depreciation and amortization expense decreased $4.8 million in 2003 compared to 2002 primarily due to the reduced depreciable base at Everest Connections resulting from the impairment charge recorded in the fourth quarter of 2002.

Year−to−Date

Sales, Cost of Sales and Gross Profit

Sales and cost of sales for the Domestic Networks businesses decreased $110.2 million and $111.3 million, respectively, and gross profit increased $1.1 million in 2003 compared to 2002. These changes were primarily due to the following factors:

- Sales and cost of sales for our regulated gas utilities increased $169.8 million and $146.9 million, respectively, for a net increase in gross profit of $22.9 million. Sales and cost of sales increased due to a 38% increase in natural gas prices. However, because gas purchase costs for our gas utility operations are passed through to our customers, the change in gas prices did not have a corresponding impact on gross profit. Gross profit for our regulated gas utilities increased primarily due to $9.7 million of rate increases in Michigan and Iowa, $3.6 million of excess pipeline capacity sales and $4.3 million from colder than normal weather in the first quarter of 2003.

- Regulated electric utility sales and cost of sales increased $18.7 million and $24.7 million, respectively, in 2003 compared to 2002, while gross profit decreased $6.0 million. Sales and gross profit increased by $5.5 million due to a rate increase in Colorado effective in July 2003, $3.0 million of additional margin from favorable weather and from customer growth. These increases were partially offset by a net $8.0 million decrease in margin from off−system sales and $5.3 million of increased cost of sales due to the higher cost of natural gas used to fuel our power plants.

- Non−regulated gas sales, cost of sales and gross profit decreased $305.6 million, $282.3 million and $23.3 million, respectively, in 2003 compared to 2002, primarily as the result of the sale of our non−regulated retail gas operations on September 30, 2002.

- Other non−regulated sales and gross profit were higher by $6.9 million and $7.5 million, respectively, in 2003 primarily due to an increase in customers at Everest Connections.

Operating Expense

Operating expense decreased $25.9 million in 2003 compared to 2002, primarily due to lower labor, benefits and administrative expenses resulting from our restructuring in 2002.

Restructuring Charges

Restructuring charges decreased $17.8 million in 2003 compared to 2002. In the first half of 2003, we completed the restructuring of the operations of Everest Connections resulting in the termination of approximately 160 employees and $2.1 million of severance costs.

We restructured our domestic utility business in the second quarter of 2002 to more closely align it with our state service areas. In connection with this restructuring, we incurred $19.9 million in costs, primarily for severance for terminated employees and the disposition of our corporate aircraft operation.

Impairment Charges and Net (Gain) Loss on Sale of Assets

As further discussed in Note 3 to the Consolidated Financial Statements, Domestic Networks incurred $721.2 million of losses resulting from impairments in 2002. The impairments consisted of $698.1 million and $23.1 million related to our investments in Quanta Services and other communication technology investments, respectively.

Depreciation and Amortization Expense

Depreciation and amortization expense decreased $9.4 million in 2003 compared to 2002, primarily due to the reduced depreciable base at Everest Connections resulting from the impairment charge recorded in the fourth quarter of 2002.

Minority Interest in Income of Subsidiaries

Minority interest in income of subsidiaries decreased $6.6 million in 2003 compared to 2002 due to the reduction of Everest Connections' minority capital balances to zero in October 2002. Therefore, we have recorded all of Everest Connections' losses in 2003.

Regulatory Matters

The following is a summary of our recent rate case activity:

In millions	**Type of Service**	**Date Requested**	**Date Approved**	**Amount Requested**	**Amount Approved**
Minnesota	Gas	8/2000	7/2003	$ 9.8	$ 5.7
Iowa	Gas	6/2002	2/2003	9.3	4.3
Michigan	Gas	8/2002	3/2003	14.3	8.4
Colorado	Electric	10/2002	6/2003	23.4	16.0
Nebraska	Gas	6/2003	Pending	9.9	Pending
Missouri	Electric	7/2003	Pending	80.9	Pending
Missouri	Gas	8/2003	Pending	6.4	Pending

2003 Regulatory Activity

A settlement was reached with the intervenors in the Minnesota rate case for $5.7 million. The settlement was approved by the Commission in July 2003. This rate increase has been collected on an interim basis since November 2001.

In June 2002, we filed for a $9.3 million general rate increase in Iowa. We received approval to place an interim increase of $5.6 million into effect, subject to refund. In February 2003, a settlement was approved by the Commission for an increase of $4.3 million.

In August 2002, we filed for a $14.3 million general rate increase in Michigan. We received approval to place an interim increase of $8.2 million into effect as of December 2002. We reached a settlement with the Commission staff and other intervening parties for an increase of $9.1 million. This settlement was approved by the Commission in March 2003 and the new rates were effective in second quarter 2003. This increase was partially offset by a separate depreciation case whereby our annual rates were reduced by $.7 million. This decrease relates to our depreciation rates, which have little impact on earnings, but reduces cash flow.

In October 2002, we filed for a $23.4 million increase in our Colorado electric rates. In April 2003, we reached a settlement with the Commission staff and other intervening parties for an increase of $16.0 million. This settlement was approved in June 2003 by the Commission and new rates were effective beginning in July 2003.

In June 2003, we filed for a total of $9.9 million of gas rate increases in three rate areas of Nebraska. We received approval to place an interim rate increase of $9.9 million into effect beginning in October 2003. Hearings will be held in December 2003 regarding each request and decisions rendered in February 2004.

In July 2003, we filed for rate increases totaling $80.9 million for our electric territories in Missouri. These applications were to recover increased costs of natural gas used to fuel our power plants, necessary capital expenditures since our prior rate case, increased pension costs and decreased off−system sales. Hearings are scheduled to be held in February and March 2004.

In August 2003, we filed for a rate increase totaling $6.4 million for our gas territories in Missouri. These increases are needed primarily to recover the cost of system improvements and higher operating costs. Hearings are scheduled to be held in March and April 2004.

INTERNATIONAL NETWORKS

The operating results for our Canadian networks have been reclassified as discontinued operations for all periods presented. The table below summarizes our remaining operations in International Networks, including our equity method investments in Australia (sold in the second and third quarters of 2003), New Zealand (sold in the fourth quarter of 2002) and the United Kingdom (in the process of being sold).

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
In millions	**2003**	**2002**	**2003**	**2002**
Operating expenses:				
Operating expense	$ 3.3	$ 2.6	$ 10.0	$ 7.1
Impairment charges and net loss (gain) on sale of assets	3.0	(3.0)	5.6	(3.0)
Total operating expenses	6.3	(.4)	15.6	4.1
Other income (expense):				
Equity in earnings of investments	1.9	42.6	16.0	83.0
Other income	8.1	1.0	16.6	2.6
Earnings before interest and taxes	$ 3.7	$ 44.0	$ 17.0	$ 81.5

Quarter−to−Quarter

Impairment Charges and Net Loss (Gain) on Sale of Assets

Impairment charges and net loss (gain) on sale of assets for 2003 included a $1.0 million pretax gain on the sale of our interests in United Energy and Multinet Gas in Australia, offset by a $4.0 million impairment charge related to our investment in Midlands (our United Kingdom electric network) resulting from the new sale agreement with Powergen. The gain in 2002 reflected United Energy's sale of its interest in its retail energy businesses and utility back−office business.

Equity in Earnings of Investments

Equity in earnings of investments decreased $40.7 million in 2003 compared to 2002. This decrease was primarily due to the October 2002 sale of our interest in UnitedNetworks Limited in New Zealand, which contributed equity earnings of $12.8 million in the third quarter of 2002, and the recent sale of our Australian investments which contributed equity earnings of $13.0 million in the third quarter of 2002 compared to $1.9 million in 2003.

Our share of undistributed net earnings from Midlands was $5.1 million in the third quarter of 2003, however, as we stated in our 2002 Form 10−K, we did not recognize the equity earnings from this investment due to regulatory limitations on cash payments by Midlands to its owners. We record equity earnings and management fees from this investment only to the extent cash is received. In the third quarter of 2002, we recorded equity earnings of $16.8 million from our Midlands' investment.

Other Income

Other income increased $7.1 million in 2003 compared to 2002. This increase was primarily due to $9.3 million of second quarter 2003 costs related to a currency put option intended to protect us from unfavorable currency movements on the Australian sale proceeds. These currency put option costs were reclassified to Impairment Charges and Net Loss on Sale of Assets in the third quarter of 2003.

Year−to−Date

Impairment Charges and Net Loss (Gain) on Sale of Assets

Impairment charges and net loss (gain) on sale of assets for 2003 included a $1.6 million pretax loss on the sale of our interests in AlintaGas, United Energy and Multinet Gas in Australia and a $4.0 million impairment charge related to our investment in Midlands resulting from the new sale agreement with Powergen. The gain in 2002 reflected United Energy's sale of its interest in its retail energy businesses and utility back−office business.

Equity in Earnings of Investments

Equity in earnings of investments decreased $67.0 million in 2003 compared to 2002. This decrease was primarily due to the October 2002 sale of our interest in UnitedNetworks Limited in New Zealand, which contributed equity earnings of $30.6 million in the first nine months of 2002, and the recent sale of our Australian investments which contributed $27.2 million of equity earnings in 2002 compared to $16.0 million in 2003.

We recorded no equity earnings from our investment in Midlands in 2003 for the reasons discussed above. Our share of undistributed net earnings from Midlands was $38.8 million in 2003. During 2002, we recorded equity earnings of $25.2 million related to our Midlands' investment.

Other Income

Other income increased $14.0 million in 2003 compared to 2002. This increase was primarily due to $12.1 million of foreign currency gains recognized in the second quarter of 2003 due to the strengthening of the Canadian dollar on U.S. dollar obligations.

Current Operating Developments

Australia. In April 2003, we reached an agreement to sell our interests in Multinet Gas, United Energy Limited and AlintaGas Limited to a consortium consisting of AlintaGas, AMP Henderson and their affiliates. In May 2003, as the first step in the sale process, we sold our interest in AlintaGas. We received approximately $97.0 million in cash proceeds in May and July before transaction costs and taxes from this sale. In June, we retired $90.7 million of our $200.0 million, 364−day secured credit facility with these proceeds. We recorded a pretax loss of $2.6 million, or $1.6 million after tax, in the second quarter of 2003 in connection with this sale.

In July 2003, we completed the sale of our interests in United Energy and Multinet Gas and received cash proceeds of $525.0 million before transaction costs and taxes. Approximately $109.3 million of these proceeds were used in July to retire the remaining balance outstanding under the 364−day secured credit facility. We recorded a pretax gain of $1.0 million, or $.5 million after tax, in connection with this sale.

Midlands. In September 2003, we agreed to terminate the agreement to sell our 79.9% interest in Aquila Sterling Limited (ASL), the owner of Midlands Electricity plc, to a subsidiary of Scottish and Southern Energy plc. The sale was subject to a number of conditions including the successful redemption of the outstanding bonds issued by Avon Energy Partners Holdings (AEPH), an Aquila Sterling subsidiary, at 86% of their par value plus accrued interest. The efforts to meet this bond redemption condition were unsuccessful and therefore, all parties agreed to terminate the agreement.

In October 2003, we and FirstEnergy Corp. reached a definitive agreement to sell 100% of the ASL shares outstanding to a subsidiary of Powergen UK plc (Powergen) for approximately $60.0 million. Our share of the proceeds is expected to be approximately $52.0 million before transaction costs. As a result of this agreement and our continuing analysis of fair value surrounding this investment, we recorded an additional $4.0 million pretax and after−tax impairment charge to write this investment down to its estimated fair value less costs to sell.

Powergen's obligation to acquire ASL is conditioned upon a commitment of the holders of the outstanding bonds of AEPH to sell their bonds to an affiliate of Powergen for 95.8% of their nominal value (less fees) plus accrued interest to the date of completion. The sale is also subject to approval from the European Commission and Kansas Corporation Commission, as well as other customary closing conditions. We expect this sale to close in the first quarter of 2004.

Canada. In September 2003, we reached an agreement to sell our Canadian utility businesses for approximately $992 million. The transaction is subject to approval of the regulatory commissions in Alberta and British Columbia, among other regulatory bodies, as well as other customary closing conditions, and is expected to close in the first half of 2004. If the sale does not close by June 30, 2004, the sale agreement will automatically terminate. We expect to record a gain on this sale at the date of close. The results of operations and related assets and liabilities of our Canadian utility business are included in discontinued operations.

CAPACITY SERVICES

The table below summarizes the operations of our Capacity Services businesses.

In millions	Three Months Ended September 30, 2003	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
Sales	$ 20.7	$ 139.6	$ (14.4)	$ 285.4
Cost of sales	18.8	177.6	71.9	286.3
Gross profit (loss)	1.9	(38.0)	(86.3)	(.9)
Operating expenses:				
Operating expense	6.4	(1.2)	16.7	29.0
Restructuring charges	—	(.6)	23.1	—
Impairment charges and net loss on sale of assets	87.9	35.5	188.3	35.5
Depreciation and amortization expense	6.2	1.9	25.3	5.8
Total operating expenses	100.5	35.6	253.4	70.3
Other income (expense):				
Equity in earnings (losses) of investments	(2.0)	20.2	44.9	43.5
Other income	.1	—	.8	.4
Loss before interest and taxes	$ (100.5)	$ (53.4)	$ (294.0)	$ (27.3)

Quarter−to−Quarter

Sales, Cost of Sales and Gross Profit

Sales and cost of sales for our Capacity Services operations decreased approximately $118.9 million and $158.8 million, respectively, in 2003 compared to 2002, resulting in an increase in gross profit of $39.9 million. These changes were primarily due to the following factors:

- Sales and cost of sales were approximately $188.7 million and $148.0 million lower, respectively, as higher natural gas prices used for fuel in our merchant power plants and lack of profitable contracted sales agreements made it uneconomical to operate the plants in the third quarter of 2003 compared to the third quarter of 2002.

- In 2002 we generated $55.2 million of mark−to−market losses as forward prices moved against our open positions. In 2003, we recorded $14.6 million of mark−to−market gains related to favorable gas hedges and a long−term power supply transaction. This transaction, which expires in 2009, provides power at predetermined prices and matches the demand requirements of the customer.

- In connection with our merchant power plants, we make fixed capacity payments evenly throughout the year that entitle us to generate power at power plants owned by others. For the third quarter of 2003, capacity payments decreased by $10.7 million compared to 2002 as we terminated our Acadia tolling agreement in the second quarter of 2003, resulting in a decrease in cost of sales.

Operating Expense

Operating expense increased $7.6 million primarily due to higher insurance, legal and other costs related to the continuing wind−down of these operations in 2003.

Impairment Charges and Net Loss on Sale of Assets

Impairment charges and net loss on sale of assets in 2003 consists of $87.9 million related to our equity method investments in independent power plants. In the third quarter of 2003, we decided to sell our interest in these plants and therefore wrote our investments down to estimated fair value less costs to sell, which was less than their carrying value.

Impairment charges and net loss on sale of assets in 2002 primarily consisted of $21.9 million related to our exit from the Lodi Gas Storage investment and $12.2 million related to fees and expenses associated with the termination of the Cogentrix acquisition.

Equity in Earnings of Investments

Equity in earnings of investments decreased $22.2 million mainly due to $13.8 million of decreased earnings resulting from mark−to−market losses occurring at the operating level of one of our equity investments. These losses are directly related to a decrease in gas prices during the third quarter. The remaining decrease stems from $2.9 million of earnings related to our Lockport Energy investment that was sold in September 2002 and lower earnings from several of our remaining equity investments.

Year−to−Date

Sales, Cost of Sales and Gross Profit

Sales and cost of sales for our Capacity Services operations decreased approximately $299.8 million and $214.4 million, respectively, in 2003 compared to 2002, resulting in a decrease in gross profit of $85.4 million. These decreases were primarily due to the following factors:

- Sales and cost of sales were approximately $285.5 million and $222.8 million lower, respectively, as higher natural gas prices used for fuel in our merchant power plants and lack of profitable contracted sales agreements made it uneconomical to operate the plants in 2003 compared to 2002.
- In 2002, we generated $5.2 million of mark−to−market losses as forward prices moved against our open positions. In 2003, we recorded $19.7 million of mark−to−market losses mainly related to unfavorable gas hedges and a long−term power supply transaction as previously described.
- In connection with our merchant power plants, we make fixed capacity payments evenly throughout the year. For 2003, capacity payments increased by $8.3 million compared to 2002 as new plants became operational late in 2002, resulting in an increase in cost of sales. This additional capacity was utilized on a limited basis at prices that were not sufficient to cover the fixed capacity payments.

Operating Expense

Operating expense decreased $12.3 million primarily due to labor, benefit savings and lower corporate costs resulting from the restructuring of this business in 2002.

Restructuring Charges

During the first nine months of 2003, we recorded restructuring charges of $23.1 million relating to the termination of our remaining interest rate swaps associated with the construction financings for our Clay County and Piatt County power plants. As debt related to these facilities was retired earlier than anticipated, our swaps were in excess of our outstanding debt. We therefore reduced our position and realized the loss associated with the cancelled portion of the swaps.

Impairment Charges and Net Loss on Sale of Assets

During the first nine months of 2003, we recorded $188.3 million of impairment charges and net loss on sale of assets. These charges consist of $87.9 million related to the write−down of our equity method investments in independent power plants. In the third quarter of 2003, we decided to sell our interest in these plants and therefore wrote our investments down to estimated fair value less costs to sell, which was less than their carrying value. Impairment charges also includes a $105.5 million payment for the termination our 20−year tolling contract for the Acadia power plant, partially offset by a $5.1 million gain related to the contract termination and sale of certain turbines that we had previously written down to estimated fair value.

Impairment charges and net loss on sale of assets in 2002 primarily consisted of $21.9 million related to our exit from the Lodi Gas Storage investment and $12.2 million related to fees and expenses associated with the termination of the Cogentrix acquisition.

Depreciation and Amortization Expense

Depreciation and amortization expense increased $19.5 million in 2003 compared to 2002. Approximately $12.5 million of this increase was due to a decrease in the estimated amortizable life of certain plant premiums relating to our acquisition of GPU International in December 2000. In addition, the start of commercial operations at three owned power plants contributed an additional $7.9 million of depreciation and amortization expense in 2003.

Earnings Trend and Impact of Changing Business Environment

The merchant energy sector has been negatively impacted by the increase in generation capacity that became operational in 2002 and by the continued construction of additional power plants. This increase in supply has placed downward pressure on power prices and subsequently the value of unsold merchant generation capacity. As a result of the above factors, we do not expect our Capacity Services unit to be profitable in the foreseeable future.

We attempt to optimize and hedge our power plants with forward contracts which qualify as derivative instruments. When we enter into these positions, they are accounted for at fair value under mark−to−market accounting. The hedges are an offset to our power plants, which use accrual accounting. Because different accounting methods are required for each side of the transaction, significant fluctuations in earnings can occur with limited impacts on future cash flow.

Current Operating Development

Independent Power Plants. In the third quarter of 2003, we decided to proceed with the sale of our investments in independent power plants. We have received bids from parties interested in acquiring these plants and are in discussions with these bidders. We recorded an impairment charge to reduce the carrying amount of our interests in these plants to their estimated fair value less costs to sell. Two of the power plants, Lake Cogen and Onondaga, are consolidated on our balance sheet. We have included the results of operations from these plants in discontinued operations. The remaining plants are equity method investments whose results of operations are included in continuing operations.

WHOLESALE SERVICES

The table below summarizes the operations of our domestic and international Wholesale Services businesses.

In millions	Three Months Ended September 30, 2003	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
Sales	$ (50.9)	$ (89.8)	$ (54.9)	$ 42.2
Cost of sales	—	—	—	—
Gross profit (loss)	(50.9)	(89.8)	(54.9)	42.2
Operating expenses:				
Operating expense	8.4	36.3	44.8	106.6
Restructuring charges	.7	109.0	1.6	159.9
Impairment charges and net loss on sale of assets	—	1.3	—	179.9
Depreciation and amortization expense	.7	.9	2.3	5.6
Total operating expenses	9.8	147.5	48.7	452.0
Other income	4.8	1.1	6.6	4.0
Loss before interest and taxes	$ (55.9)	$ (236.2)	$ (97.0)	$ (405.8)

As a result of the implementation of EITF No. 02−3 (which requires that all gains and losses on derivatives held for trading purposes be reported net in sales), all Wholesale Services' sales are reported net for all periods presented. To the extent losses exceeded gains, sales are shown as a negative number.

Quarter−to−Quarter

Sales and Gross Profit (Loss)

Sales and gross profit for our Wholesale Services operations increased by $38.9 million, primarily due to the following factors:

- Included in the $50.9 million loss in 2003 was $26.9 million of non−cash losses related to the discounting of our trading portfolio. Substantially all of these losses relate to our long−term gas contracts. During the quarter, average gas prices decreased over the life of these contracts by $.35 per MMbtu, which caused both the price risk management asset and price risk management liability related to these contracts to decrease in value. However, because our price risk management liabilities are discounted based on our credit standing, versus the receivable side of these transactions, which are discounted at our counterparties' credit ratings (which on average are substantially higher than our credit rating), non−cash mark−to−market losses were created. The discounting of these liabilities and receivables is in accordance with SFAS 133 and is more fully described in Statement of Financial Accounting Concepts No. 7, "Using Cash Flow Information and Present Value in Accounting Measurement."
- In 2003, we also incurred $7.1 million in mark−to−market losses from two weather−related contracts which expire in 2005 and 2006 and are driven by precipitation and stream flow levels.
- Our remaining 2003 losses mainly stem from $10.4 million of margin losses related to our long−term gas contracts. (See Note 14 to Consolidated Financial Statements included in our 2002 Annual Report on Form 10−K.)
- In the third quarter of 2002, we incurred gross margin losses of approximately $70.8 million to balance counterparty positions, reduce open positions and terminate existing contracts as a result of our decision to exit the wholesale trading business.

Operating Expense

Operating expense decreased $27.9 million primarily due to labor and benefit savings and related operating cost reductions resulting from the exit from our wholesale energy trading operations in 2002.

Restructuring Charges

In connection with the exit from our wholesale energy trading business, we incurred $109.0 million of restructuring charges in the third quarter of 2002. These charges mainly included $35.4 million of severance and retention payments to terminated employees, $36.7 million of lease costs connected to future lease commitments and $36.6 million of excess leasehold improvements and equipment that were expensed when we vacated the related leased properties.

Year−to−Date

Sales and Gross Profit

Sales and gross profit for our Wholesale Services operations decreased by $97.1 million, primarily due to the following factors:

- In the second quarter of 2002, we announced that we were exiting the wholesale energy trading business. Thus, in 2003, we were not adding new or speculative positions to our trading portfolio and therefore had limited opportunities for earnings.

- Included in the $54.9 million loss in 2003 was approximately $27.0 million of non−cash losses related to the sale of our capacity under certain long−term gas transportation agreements at substantially less than our future commitments. The loss was recognized for accounting purposes; however, the cash associated with the loss will be paid out over the term of the contracts. In addition, we recorded a $5.5 million loss related to terminating additional trading contracts.

- Also included in the $54.9 million loss in 2003 was approximately $40.1 million of non−cash earnings related to the discounting of our trading portfolio. Substantially all of these earnings relate to our long−term gas contracts. During the first nine months, average gas prices rose over the life of these contracts by $.57 per MMbtu, which caused both the price risk management asset and price risk management liability related to these contracts to increase in value for reasons described above. In 2002, we recorded $30.9 million of similar mark−to−market earnings attributable to our credit rating downgrades.

  As of September 30, 2003, we have recorded $84.0 million of mark−to−market gains related to increasing gas prices and the widening of our credit spreads between us and our counterparties. Substantially all of these gains relate to our long−term gas contracts discussed above. These gains will be reversed in later periods as contracts settle, our credit rating improves and/or as gas prices decline.

- Our remaining 2003 losses mainly stem from $33.2 million of margin losses related to our long−term gas contracts and $24.6 million of unfavorable settlements related to our European merchant operation as we continue to wind down that business.

Operating Expense

Operating expense decreased $61.8 million primarily due to labor and benefit savings and related operating cost reductions resulting from the exit from our wholesale energy trading operations in 2002, partially offset by regulatory review costs in 2003.

Restructuring Charges

In connection with the exit from our wholesale energy trading business, we incurred $159.9 million of restructuring charges in 2002. These charges mainly included $60.2 million of severance and retention payments to terminated employees, $36.7 million of lease costs connected to future lease commitments and $59.0 million of excess leasehold improvements and equipment that were expensed when we vacated the related leased properties.

Impairment Charges and Net Loss on Sale of Assets

Impairment charges and net loss on sale of assets in 2002 consisted primarily of an impairment charge of $178.6 million related to goodwill associated with Wholesale Services that became unrealizable due to our exit from wholesale energy trading.

CORPORATE AND OTHER

The table below summarizes our Corporate and Other expenses and other income.

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions	**2003**	**2002**	**2003**	**2002**
Operating expenses:				
Operating expense	$ 3.1	$ 4.6	$ 27.1	$ 9.0
Restructuring charges	(.1)	8.0	.9	8.0
Depreciation and amortization expense	(.3)	(.2)	(.9)	(.1)
Total operating expenses	2.7	12.4	27.1	16.9
Other income (expense):				
Equity in earnings of investments	—	.1	.1	.2
Other income (expense)	(8.8)	(.2)	43.2	(9.3)
Earnings (loss) before interest and taxes	$ (11.5)	$ (12.5)	$ 16.2	$ (26.0)

Quarter−to−Quarter

Restructuring Charges

Restructuring charges decreased $8.1 million in the third quarter of 2003 compared to 2002. This decrease was primarily due to $7.6 million of executive severance that was paid in 2002 in connection with the separation agreement with the former Chief Executive Officer.

Other Income (Expense)

Other income (expense) decreased $8.6 million mainly due to foreign currency losses in 2003 resulting from unfavorable movements in the Australian and New Zealand dollar against the U.S. dollar.

Year−to−Date

Operating Expense

Operating expense increased $18.1 million in 2003 compared to 2002, primarily due to $11.3 million of restructuring consulting fees and $14.9 million of increased insurance and other costs associated with having non−investment grade credit. This increase was partially offset by $3.7 million of costs incurred in 2002 associated with retiring debt and company−obligated preferred securities. In addition, we incurred a net $2.7 million of losses in 2002 on investments associated with the cash surrender value of certain life insurance policies that did not occur in 2003.

Restructuring Charges

Restructuring charges decreased $7.1 million in 2003 compared to 2002. This decrease was primarily due to $7.6 million of executive severance that was paid in 2002 in connection with the separation agreement with the former Chief Executive Officer.

Other Income (Expense)

Other income (expense) increased $52.5 million mainly due to $41.2 million of foreign currency gains in 2003 resulting from favorable movements in the Australian and New Zealand dollar against the U.S. dollar. In addition, 2002 included $5.9 million of foreign exchange and interest rate hedge losses relating to our original planned financing structure that was not consummated in connection with our Midlands acquisition.

INTEREST EXPENSE AND INCOME TAX BENEFIT

The table below summarizes our consolidated interest expense and income tax benefit:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions	**2003**	**2002**	**2003**	**2002**
Interest expense	$ 75.1	$ 67.0	$ 206.9	$ 164.5
Income tax benefit	$ (50.6)	$ (101.7)	$ (125.7)	$ (196.4)

Quarter−to−Quarter

Interest Expense

Interest expense increased $8.1 million in the third quarter of 2003 compared to 2002. The increase was primarily the result of $3.8 million of higher interest costs related to the $500.0 million of 14.875% senior notes issued in July 2002, the April 2003 borrowing of $430.0 million under our three−year secured facility that resulted in $8.3 million of interest expense and $4.3 million of debt amortization costs mainly associated with the early retirement of our remaining debt balance under our 364−day secured credit facility. These increases were offset in part by the retirement of debt outstanding in Australia, New Zealand and the United Kingdom in late 2002 and early 2003 and the conversion of the premium equity participating securities to common equity in November 2002.

Income Tax Benefit

The income tax benefit decreased $51.1 million in 2003 compared to 2002, primarily as a result of lower losses before income taxes in 2003 compared to 2002 and certain expenses not being deductible in 2003 for income tax purposes.

Year−to−Date

Interest Expense

Interest expense increased $42.4 million in 2003 compared to 2002. The increase was primarily the result of $41.0 million of higher interest costs related to the $500.0 million of 14.875% senior notes issued in July 2002, the borrowing in the 2003 second quarter of $430.0 million under our three−year secured facility that resulted in $17.2 million of additional interest expense and $11.3 million of debt amortization costs mainly associated with the early retirement of our 364−day secured credit facility. These increases were offset in part by the retirement of debt outstanding in Australia, New Zealand and the United Kingdom in late 2002 and early 2003 and the conversion of the premium equity participating securities to common equity in November 2002.

Income Tax Benefit

The income tax benefit decreased $70.7 million in 2003 compared to 2002, primarily as a result of lower losses before income taxes in 2003 compared to 2002 and equity earnings in Australia that were taxed in 2003 due to the removal of our permanent investment election. Partially offsetting these increases were certain tax benefits not being recognized on a significant amount of the 2002 losses as a result of valuation allowances being provided and certain expenses in 2002 not being deductible for income tax purposes.

SIGNIFICANT BALANCE SHEET MOVEMENTS

Total assets decreased by $1,592.9 million since December 31, 2002. This decrease is primarily due to the following:

- Cash increased $245.9 million. See our Consolidated Statement of Cash Flows for analysis of this increase.
- Restricted cash decreased $217.2 million primarily due to the release of cash held in escrow from the sale of our Merchant loan portfolio, the use of restricted cash collateral to retire debt related to our Piatt County and turbine construction facilities, offset by an increase in customer funds on deposit that were required to be restricted.
- Funds on deposit increased $103.2 million primarily due to the cash collateralization requirement for our letters of credit and additional margin deposits paid to counterparties due to the significant increase in natural gas prices in 2003.
- Accounts receivable, net decreased $1,034.0 million primarily due to lower volumes of natural gas and electricity delivered due to our exit from wholesale energy trading, offset in part by increased natural gas prices since December 31, 2002.
- Price risk management assets decreased $124.5 million primarily due to a reduction in the number of trading contracts, partially offset by an increase in natural gas prices since December 31, 2002.
- Prepayments and other decreased $233.6 million primarily due to the collection of a $191.1 million income tax refund anticipated at December 31, 2002.
- Investments in unconsolidated subsidiaries decreased by $599.8 million primarily due to the sale of our Australian investments in the second and third quarters of 2003, as well as the $87.9 million 2003 impairment charge related to our investments in independent power plants.
- Non−current assets of discontinued operations increased $148.9 million primarily due to an increase in the exchange rate on our Canadian utility assets, partially offset by the $47.5 million 2003 impairment charge on the consolidated independent power plants.

Total liabilities decreased by $1,362.6 million and common shareholders' equity decreased by $230.3 million since December 31, 2002. These changes are primarily attributable to the following:

- Accounts payable decreased by $1,056.5 million primarily due to lower volumes of natural gas and electricity delivered due to our exit from wholesale energy trading, offset in part by increased natural gas prices since December 31, 2002.

- Price risk management liabilities decreased $98.9 million primarily due to a reduction in the number of trading contracts, partially offset by an increase in natural gas prices since December 31, 2002.
- Current liabilities of discontinued operations increased by $119.4 million primarily due to our Canadian subsidiary borrowing $215.0 million under a 364−day unsecured loan, partially offset by the repayment of current maturities of long−term debt by our Canadian subsidiary.
- Short−term and long−term debt, including current maturities of long−term debt, together decreased by $206.9 million primarily due to the repayment of $88.3 million of Australian notes, $245.1 million of debt related to our Clay and Piatt County power plants, $244.4 million of revolving credit borrowings and $43.4 million related to our turbine facility. These decreases were offset by net borrowings of $430.0 million under the three−year secured credit facility.
- Deferred income taxes and credits decreased $67.9 million primarily due to current year losses and continued asset sales.
-

Common shareholders' equity decreased $230.3 million primarily as a result of the $302.4 million net loss in the first nine months of 2003, partially offset by improved exchange rates on our foreign investments that created $69.5 million of comprehensive income.

LIQUIDITY AND CAPITAL RESOURCES

Short−term Liquidity

As of September 30, 2003, we had the following cash and short−term debt (including cash and short−term debt reported in discontinued operations):

In millions		**September 30, 2003**
Cash	$	749.7
Short−term debt:		
Bank borrowings—Canada	$	215.0
Subtotal		215.0
Current maturities of long−term debt:		
Senior notes due on July 15 and October 1, 2004		400.0
Canadian asset securitization (a)		47.4
Miscellaneous		15.9
Subtotal		463.3
Total	$	678.3

(a)
This facility is secured by certain future rate collections and will be repaid monthly through February 2004.

On July 31, 2003, we closed on a $215.0 million, 364−day unsecured loan. The borrowers are ANCC and ANCA, each of which is an indirect wholly−owned subsidiary. At closing, ANCC borrowed $115.0 million and ANCA borrowed $100.0 million. The interest rate on this financing is LIBOR (with 2.50% floor) plus 4.25%. Proceeds were used by ANCA to repay and terminate its existing 364−day credit agreement that matured on July 31, 2003 and a letter of credit facility. ANCC will use its proceeds to finance the capital expenditure and working capital requirements of its regulated utility subsidiaries, as well as repay certain bank debt of ANCBC. The facilities will be repaid with the proceeds received in connection with the sale of its Canadian utility investments. We paid up−front arrangement fees of $4.3 million in connection with this borrowing.

In September 2003, we reached an agreement to sell our Canadian utility businesses for approximately $992 million, including the repayment or assumption of $228 million of debt, or a net $764 million in proceeds to us before closing adjustments, transaction costs and taxes. In addition, we will be required to repay $115 million borrowed by ANCC under its 364−day unsecured loan. We expect to use the remaining net proceeds from the sale to pay related taxes and transaction fees, improve our liquidity and reduce debt and other obligations. The transaction is subject to approval of the regulatory commissions in Alberta and British Columbia, among other regulatory bodies, as well as other customary closing conditions, and is expected to close in the first half of 2004. If the sale does not close by June 30, 2004, the sale agreement will automatically terminate.

In October 2003, we reached a definitive agreement to sell our 79.9% interest in ASL, the owner of Midlands Electricity plc, to a subsidiary of Powergen UK plc (Powergen), for approximately $52.0 million, before transaction costs. The sale is subject to a number of conditions including approval from the European Commission and Kansas Corporation Commission and the commitment of the holders of the outstanding bonds of AEPH to sell their bonds to an affiliate of Powergen for 95.8% of their par value (less fees) plus accrued interest to the date of completion. We expect this sale to close in the first quarter of 2004.

Due to our non−investment grade credit rating and lack of short−term lines of credit, we must maintain sufficient cash on hand to cover all of the working capital requirements of our business. The most significant activity impacting working capital is the purchase of natural gas for our gas utility customers. We could experience significant working capital requirements during peak winter heating months due to higher natural gas consumption, potential periods of high natural gas prices and the fact that we are currently required to prepay certain of our gas commodity suppliers and pipeline companies. However, based on our current forecast and cash on hand at September 30, 2003, we believe we have sufficient cash on hand to meet our short−term cash requirements. In addition, we expect to have our Canadian asset sale closed during the first half of 2004, which will significantly improve our overall short−term liquidity.

Long−term Liquidity

As we continue to transition the company back to a domestic utility business, our long−term liquidity is dependent upon the following actions:

- Obtaining additional rate increases for our domestic networks which would then allow us to earn our allowed return;
- Restructuring our generation capacity (or tolling) obligations;
- Completing successful asset sales;
- Receiving posted collateral in accordance with contractual requirements;
- Refinancing or retiring maturing obligations such as our long−term gas delivery contracts; and
- Using regulated assets as collateral for debt.

Cash Flows

Cash Flows from Operating Activities—Cash used for operating activities increased in the nine months ended September 30, 2003, compared to the same period in 2002, primarily due to increases in funds on deposit resulting from higher natural gas prices and required collaterization on our letters of credit, higher net cash outflows for inventory as our wholesale operations liquidated its gas storage inventory in 2002, less cash received from our trading portfolio as we announced our exit from this business in 2002, and cash paid for restructuring and impairment charges. These decreases in cash flows were partially offset by the collection of $217.8 million of income tax refunds that we received in 2003.

Cash Flows from Investing Activities—Cash flows from investing activities increased in the first nine months of 2003 primarily due to the collection of cash proceeds in 2003 from the sale of assets in 2002 and 2003, reduced Merchant capital expenditures in 2003 due to the completion of construction on several new plants in 2002 and no additional investments in international businesses.

Cash Flows from Financing Activities—Cash flows from financing activities decreased in the first nine months of 2003 compared to 2002 primarily as a result of our issuance in 2002 of common stock and senior notes. These proceeds were used to pay down short−term debt on our revolving credit agreement and to replace the liquidity under the Merchant Services accounts receivable sales program that was terminated. In the first nine months of 2003, the primary financing activities were the borrowings under the secured credit facilities, the repayment of debt under the revolving credit facility, the Clay County and Piatt County construction financings and our Australian notes.

Certain Trading Activities

We engage in price risk management activities for both trading and non−trading activities. Transactions carried out in connection with trading activities that are derivatives under SFAS 133 are accounted for under the fair value method of accounting. Under SFAS 133, our energy commodity trading contracts, including physical transactions (mainly gas and power) and financial instruments, are recorded at fair value. As part of the valuation of our portfolio, we value the credit risks associated with the financial condition of counterparties and the time value of money. We primarily use quoted market prices from published sources or comparable transactions in liquid markets to value our contracts. If actively quoted market prices are not available, we contact brokers and other external sources or use comparable transactions to obtain current values of our contracts. In addition, the market prices or fair values used in determining the value of the portfolio are our best estimates utilizing information such as historical volatility, time value, counterparty credit and the potential impact on market prices of liquidating our positions in an orderly manner over a reasonable period of time under current market conditions. When market prices are not readily available or determinable, certain contracts are recorded at fair value using an alternative approach such as model pricing.

The changes in fair value of our trading and other contracts for 2003 are summarized below:

In millions	**Wholesale Services**	**Capacity Services and other**	**Total**
Fair value at December 31, 2002	$ 180.2	$ (19.7)	$ 160.5
Change in fair value during the period	4.8	(37.1)	(32.3)
Contracts realized or cash settled	(14.5)	21.2	6.7
Fair value at September 30, 2003	$ 170.5	$ (35.6)	$ 134.9

The fair value of contracts maturing in the remainder of 2003, each of the next three years and thereafter are shown below:

In millions	**Wholesale Services**	**Capacity Services and other**	**Total**
2003	$ (2.4)	$ .3	$ (2.1)
2004	29.7	(6.8)	22.9
2005	33.3	(18.9)	14.4
2006	26.8	(3.1)	23.7
Thereafter (a)	83.1	(7.1)	76.0
Total fair value	$ 170.5	$ (35.6)	$ 134.9

(a)
As these contracts have been significantly hedged, movement in commodity prices will have a limited impact on the net cash value provided.

Item 4. Controls and Procedures

Our Chief Executive Officer (CEO) and Chief Financial Officer (CFO) are responsible for establishing and maintaining the company's disclosure controls and procedures. These controls and procedures were designed to ensure that material information relating to the company and its subsidiaries are communicated to the CEO and the CFO. We evaluated these disclosure controls and procedures as of the end of the period covered by this report under the supervision of our CEO and CFO. Based on this evaluation, our CEO and CFO concluded that our disclosure controls and procedures are effective in timely alerting them to material information required to be included in our periodic reports filed with the Securities and Exchange Commission. There has been no change in our internal controls over financial reporting during the quarter covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Part II—Other Information

Item 6. Exhibits and Reports on Form 8−K

(a)

List of Exhibits

Exhibit No.	Description
31.1	Certification of Chief Executive Officer under Section 302
31.2	Certification of Chief Financial Officer under Section 302
32.1	Certification of Chief Executive Officer under Section 906
32.2	Certification of Chief Financial Officer under Section 906

(b)

Reports on Form 8−K

We furnished Current Reports on Form 8−K to the Securities and Exchange Commission during the quarter ended September 30, 2003, as follows:

Date Filed	Item No.	
August 12, 2003	Item 7—	Press release dated August 12, 2003.
	Item 12—	Announcement of net losses for the second quarter and six months ended June 30, 2003.

Signatures

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.

AQUILA, INC.

By: /s/ RICK J. DOBSON

Rick J. Dobson
Chief Financial Officer

Signing on behalf of the registrant and as principal financial and accounting officer

Date: November 5, 2003

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Exhibit 31.1

Aquila, Inc.
Chief Executive Officer
Certification Pursuant to Section 302 of the Sarbanes−Oxley Act of 2002

I, Richard C. Green, Jr., certify that:

1. I have reviewed the quarterly report of Aquila, Inc. for the quarterly period ending September 30, 2003;

2. Based on my knowledge, the 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 the report;

3. Based on my knowledge, the financial statements, and other financial information included in the 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 report;

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

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, 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 periodic report is being prepared;

b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weakness in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

November 5, 2003

/s/ RICHARD C. GREEN, JR.

Richard C. Green, Jr.
Chairman, President and Chief Executive Officer,
Aquila, Inc.

QuickLinks

Exhibit 31.1

QuickLinks −− Click here to rapidly navigate through this document

Exhibit 31.2

Aquila, Inc.
Chief Financial Officer
Certification Pursuant to Section 302 of the Sarbanes−Oxley Act of 2002

I, Rick J. Dobson, certify that:

1. I have reviewed the quarterly report of Aquila, Inc. for the quarterly period ending September 30, 2003;

2. Based on my knowledge, the 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 the report;

3. Based on my knowledge, the financial statements, and other financial information included in the 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 report;

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

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, 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 periodic report is being prepared;

b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weakness in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

November 5, 2003	/s/ RICK J. DOBSON
	Rick J. Dobson Chief Financial Officer, Aquila, Inc.

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Exhibit 32.1

Aquila, Inc.
Chief Executive Officer
Certification Pursuant to Section 906 of the Sarbanes−Oxley Act of 2002

I, Richard C. Green, Jr., certify that, to my knowledge:

1. Aquila, Inc.'s quarterly report on Form 10−Q for the quarterly period ending September 30, 2003 accompanying this Certification, in the form filed with the Securities and Exchange Commission (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 (the "Exchange Act"); and

2. The information in the Report fairly presents, in all material respects, the financial condition and results of operations of Aquila, Inc.

Dated: November 5, 2003

/s/ RICHARD C. GREEN, JR.

Richard C. Green, Jr.
Chairman, President and Chief Executive Officer
Aquila, Inc.

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Exhibit 32.1

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Exhibit 32.2

Aquila, Inc.
Chief Financial Officer
Certification Pursuant to Section 906 of the Sarbanes−Oxley Act of 2002

I, Rick J. Dobson, certify that, to my knowledge:

1. Aquila, Inc.'s quarterly report on Form 10−Q for the quarterly period ending September 30, 2003 accompanying this Certification, in the form filed with the Securities and Exchange Commission (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 (the "Exchange Act"); and

2. The information in the Report fairly presents, in all material respects, the financial condition and results of operations of Aquila, Inc.

Dated: November 5, 2003

/s/ RICK J. DOBSON

Rick J. Dobson
Chief Financial Officer
Aquila, Inc.

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Exhibit 32.2