

CHESAPEAKE UTILITIES CORP

Form 10-Q

November 08, 2012

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

FORM 10-Q

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

For the quarterly period ended: September 30, 2012

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: 001-11590

CHESAPEAKE UTILITIES CORPORATION

(Exact name of registrant as specified in its charter)

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Delaware
(State or other jurisdiction of
incorporation or organization)

51-0064146
(I.R.S. Employer
Identification No.)

909 Silver Lake Boulevard, Dover, Delaware 19904
(Address of principal executive offices, including Zip Code)

(302) 734-6799
(Registrant's telephone number, including area code)

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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer Accelerated filer
Non-accelerated filer Smaller reporting company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No

Common Stock, par value \$0.4867 9,594,446 shares outstanding as of October 31, 2012.

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GLOSSARY OF KEY TERMS AND DEFINITIONS

Accounting Principles Generally Accepted in the United States of America (GAAP): A standard framework of accounting rules used to prepare and present financial statements in the United States of America.

Acquisition adjustment: The recovery, through rates, and inclusion in rate base, of the premium (amount in excess of net book value) paid for an acquisition as approved by the state PSCs for the regulated operations.

Application Evolution : A new product developed and launched by BravePoint. Application Evolution is a component of ProfitZoom and is being marketed to customers both in the fire suppression industry and other unrelated businesses.

BravePoint[®], Inc. (BravePoint): An advanced information services subsidiary, headquartered in Norcross, Georgia. BravePoint is a wholly owned subsidiary of Chesapeake Services Company, which is a wholly owned subsidiary of Chesapeake.

Chesapeake Utilities Corporation (Chesapeake or the Company): The Registrant, its divisions, the Registrant and its subsidiaries, or the Registrant's subsidiaries, as appropriate in the context of the disclosure.

Come-Back filing: The regulatory filing that was required by the Florida PSC within 18 months of the completion of the FPU merger to detail known benefits, synergies, cost savings and cost increases as a result of the merger.

Cooling Degree-Day (CDD): A measure of the variation in weather based on the extent to which the daily average temperature (from 10:00 am to 10:00 am the next day) is above 65 degrees Fahrenheit. This measurement is used to determine the impact of hot weather on our electric distribution operation during the cooling season.

Cost of sales: Includes the purchased cost of natural gas, electricity and propane commodities, costs of pipeline capacity needed to transport and store natural gas, transmission costs for electricity, costs to transport propane purchases to our storage facilities and the direct cost of labor spent on direct revenue-producing activities.

Dekatherm (Dt): A natural gas unit of measurement that measures heating value. A dekatherm (or 10 therms) of gas contains 10,000 British thermal units of heat, or the energy equivalent of burning approximately 1,000 cubic feet of natural gas under normal conditions.

Delmarva natural gas distribution operation: Chesapeake's Delaware and Maryland divisions.

Delmarva Peninsula: A peninsula on the east coast of the United States of America that includes Delaware and portions of Maryland and Virginia. Chesapeake provides natural gas distribution, transmission and marketing services and propane distribution service to its customers on the Delmarva Peninsula.

Eastern Shore Natural Gas Company (Eastern Shore): A wholly owned natural gas transmission subsidiary of Chesapeake. Eastern Shore operates an interstate pipeline system that transports natural gas from various points in Pennsylvania to customers in southern Pennsylvania and on the Delmarva Peninsula.

Federal Energy Regulatory Commission (FERC): An independent agency of the Federal government that regulates the interstate transmission of electricity, natural gas, and oil. The FERC also reviews proposals to build liquefied natural gas terminals and interstate natural gas pipelines. Eastern Shore is regulated by the FERC.

Florida natural gas distribution operation: Chesapeake's Florida division and the natural gas operation of Florida Public Utilities Company, including its Indiantown division.

Florida Public Utilities Company (FPU): A wholly owned subsidiary of Chesapeake as of October 28, 2009, the date we acquired FPU through the merger. FPU provides natural gas, electric and propane distribution services in Florida.

Gross margin: A non-GAAP measure, which Chesapeake uses to evaluate the performance of its business segments. Gross margin is calculated by deducting the cost of sales from operating revenues. A more detailed description of gross margin, including how we calculate it, is provided in the Management's Discussion and Analysis of Financial Condition and Results of Operations section of this Quarterly Report on Form 10-Q.

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Heating Degree-Day (HDD): A measure of the variation in weather based on the extent to which the daily average temperature (from 10:00 am to 10:00 am the next day) is below 65 degrees Fahrenheit. This measurement is used to determine the impact of cold weather on our natural gas, electric and propane distribution operations during the heating season.

Manufactured Gas Plant (MGP): A site that previously used coal to manufacture gaseous fuel used for industrial, commercial and residential use. Some MGPs are currently undergoing remedial action to remove contamination in the soil and water at or near these sites.

Normal Weather: The most recent 10 year average of heating and/or cooling degree-days in a particular geographic area.

Peninsula Pipeline Company, Inc. (Peninsula Pipeline): A wholly owned Florida intrastate pipeline subsidiary of Chesapeake.

Peninsula Energy Services Company, Inc. (PESCO): A wholly owned natural gas marketing subsidiary of Chesapeake. PESCO competes with regulated utilities and other unregulated third-party marketers to sell natural gas supplies directly to commercial and industrial customers through competitively-priced contracts.

ProfitZoom : A new product developed and launched by BravePoint. ProfitZoom is an integrated system encompassing financial, job costing and service management modules, which was designed specifically for the fire protection and specialty contracting industries.

Public Service Commission (PSC): The state agency that regulates the rates and services provided by Chesapeake's natural gas and electric distribution operations in Delaware, Maryland and Florida. Peninsula Pipeline's service and rates are also regulated by the Florida PSC.

Xeron, Inc. (Xeron): A wholly owned propane wholesale marketing subsidiary of Chesapeake based in Houston, Texas.

Table of Contents**PART I FINANCIAL INFORMATION****Item 1. Financial Statements****Chesapeake Utilities Corporation and Subsidiaries****Condensed Consolidated Statements of Income (Unaudited)**

For the Three Months Ended September 30, <i>(in thousands, except shares and per share data)</i>	2012	2011
Operating Revenues		
Regulated Energy	\$ 52,196	\$ 53,651
Unregulated Energy	23,259	23,721
Other	2,720	3,238
Total operating revenues	78,175	80,610
Operating Expenses		
Regulated energy cost of sales	22,102	25,811
Unregulated energy and other cost of sales	17,602	20,306
Operations	20,804	19,560
Maintenance	1,801	2,029
Depreciation and amortization	5,767	4,978
Other taxes	2,535	2,332
Total operating expenses	70,611	75,016
Operating Income	7,564	5,594
Other (loss) income, net of expenses	(136)	649
Interest charges	2,126	2,389
Income Before Income Taxes	5,302	3,854
Income tax expense	2,083	1,457
Net Income	\$ 3,219	\$ 2,397
Weighted-Average Common Shares Outstanding:		
Basic	9,592,417	9,564,012
Diluted	9,676,658	9,657,970
Earnings Per Share of Common Stock:		
Basic	\$ 0.34	\$ 0.25
Diluted	\$ 0.33	\$ 0.25
Cash Dividends Declared Per Share of Common Stock	\$ 0.365	\$ 0.345

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

Table of Contents**Chesapeake Utilities Corporation and Subsidiaries****Condensed Consolidated Statements of Income (Unaudited)**

For the Nine Months Ended September 30, <i>(in thousands, except shares and per share data)</i>	2012	2011
Operating Revenues		
Regulated Energy	\$ 180,045	\$ 192,713
Unregulated Energy	93,323	112,164
Other	9,619	9,162
Total operating revenues	282,987	314,039
Operating Expenses		
Regulated energy cost of sales	81,207	98,683
Unregulated energy and other cost of sales	72,056	89,017
Operations	60,831	59,796
Maintenance	5,635	5,624
Depreciation and amortization	17,413	14,936
Other taxes	7,753	7,774
Total operating expenses	244,895	275,830
Operating Income	38,092	38,209
Other income, net of expenses	212	699
Interest charges	6,657	6,654
Income Before Income Taxes	31,647	32,254
Income tax expense	12,641	12,590
Net Income	\$ 19,006	\$ 19,664
Weighted-Average Common Shares Outstanding:		
Basic	9,583,316	9,552,472
Diluted	9,673,681	9,647,632
Earnings Per Share of Common Stock:		
Basic	\$ 1.98	\$ 2.06
Diluted	\$ 1.97	\$ 2.04
Cash Dividends Declared Per Share of Common Stock	\$ 1.080	\$ 1.020

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

Table of Contents**Chesapeake Utilities Corporation and Subsidiaries****Condensed Consolidated Statements of Comprehensive Income (Unaudited)**

For the periods ended September 30, (in thousands)	Three months		Nine months	
	2012	2011	2012	2011
Net Income	\$ 3,219	\$ 2,397	\$ 19,006	\$ 19,664
Other Comprehensive Income, net of tax:				
Employee Benefits net of tax:				
Amortization of prior service cost, net of tax of (\$6), \$1, \$(19) and \$4, respectively	(9)	2	(28)	6
Amortization of actuarial gain/loss, net of tax of \$51, \$120, \$152 and \$359, respectively	76	180	228	537
Other comprehensive income	67	182	200	543
Comprehensive income	\$ 3,286	\$ 2,579	\$ 19,206	\$ 20,207

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

Table of Contents**Chesapeake Utilities Corporation and Subsidiaries****Condensed Consolidated Balance Sheets (Unaudited)**

	September 30, 2012	December 31, 2011
Assets		
<i>(in thousands, except shares and per share data)</i>		
Property, Plant and Equipment		
Regulated energy	\$ 549,318	\$ 528,790
Unregulated energy	68,956	67,327
Other	19,031	19,988
Total property, plant and equipment	637,305	616,105
Less: Accumulated depreciation and amortization	(150,859)	(137,784)
Plus: Construction work in progress	36,745	9,383
Net property, plant and equipment	523,191	487,704
Current Assets		
Cash and cash equivalents	2,046	2,637
Accounts receivable (less allowance for uncollectible accounts of \$961 and \$1,090, respectively)	42,107	76,605
Accrued revenue	8,394	10,403
Propane inventory, at average cost	6,256	9,726
Other inventory, at average cost	3,284	4,785
Regulatory assets	2,745	1,846
Storage gas prepayments	4,593	5,003
Income taxes receivable	7,967	6,998
Deferred income taxes	2,158	2,712
Prepaid expenses	6,097	5,072
Mark-to-market energy assets	721	1,754
Other current assets	121	219
Total current assets	86,489	127,760
Deferred Charges and Other Assets		
Goodwill	4,090	4,090
Other intangible assets, net	2,879	3,127
Investments, at fair value	4,670	3,918
Regulatory assets	75,634	79,256
Receivables and other deferred charges	2,999	3,211
Total deferred charges and other assets	90,272	93,602
Total Assets	\$ 699,952	\$ 709,066

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

Table of Contents**Chesapeake Utilities Corporation and Subsidiaries****Condensed Consolidated Balance Sheets (Unaudited)**

	September 30, 2012	December 31, 2011
Capitalization and Liabilities		
<i>(in thousands, except shares and per share data)</i>		
Capitalization		
Stockholders' equity		
Common stock, par value \$0.4867 per share (authorized 25,000,000 shares)	\$ 4,669	\$ 4,656
Additional paid-in capital	150,230	149,403
Retained earnings	99,912	91,248
Accumulated other comprehensive loss	(4,327)	(4,527)
Deferred compensation obligation	970	817
Treasury stock	(970)	(817)
Total stockholders' equity	250,484	240,780
Long-term debt, net of current maturities	108,721	110,285
Total capitalization	359,205	351,065
Current Liabilities		
Current portion of long-term debt	8,196	8,196
Short-term borrowing	30,756	34,707
Accounts payable	35,478	55,581
Customer deposits and refunds	29,832	30,918
Accrued interest	3,146	1,637
Dividends payable	3,501	3,300
Accrued compensation	6,417	6,932
Regulatory liabilities	2,641	6,653
Mark-to-market energy liabilities	556	1,496
Other accrued liabilities	10,078	8,079
Total current liabilities	130,601	157,499
Deferred Credits and Other Liabilities		
Deferred income taxes	127,262	115,624
Deferred investment tax credits	127	171
Regulatory liabilities	3,479	3,564
Environmental liabilities	9,170	9,492
Other pension and benefit costs	22,947	26,808
Accrued asset removal cost Regulatory liability	37,899	36,584
Other liabilities	9,262	8,259
Total deferred credits and other liabilities	210,146	200,502
Other commitments and contingencies (Note 6)		
Total Capitalization and Liabilities	\$ 699,952	\$ 709,066

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

Table of Contents**Chesapeake Utilities Corporation and Subsidiaries****Condensed Consolidated Statements of Cash Flows (Unaudited)**

For the Nine Months Ended September 30, <i>(in thousands)</i>	2012	2011
<i>Operating Activities</i>		
Net Income	\$ 19,006	\$ 19,664
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	17,413	14,936
Depreciation and accretion included in other costs	4,079	3,755
Deferred income taxes, net	12,102	14,183
(Gain) loss on sale of assets	18	(449)
Unrealized (gain) loss on commodity contracts	147	(33)
Unrealized gain on investments	(401)	(51)
Realized gain on sale of investments, net	(20)	
Employee benefits	435	823
Share-based compensation	1,111	1,078
Other, net	(21)	(43)
Changes in assets and liabilities:		
Sale (purchase) of investments	(292)	699
Accounts receivable and accrued revenue	36,523	28,975
Propane inventory, storage gas and other inventory	3,722	159
Regulatory assets	(249)	962
Prepaid expenses and other current assets	(856)	(744)
Accounts payable and other accrued liabilities	(20,138)	(24,884)
Income taxes receivable	(1,010)	(3,064)
Accrued interest	1,509	1,562
Customer deposits and refunds	(1,086)	727
Accrued compensation	(554)	(1,220)
Regulatory liabilities	(4,097)	(1,534)
Other liabilities	(3,245)	(2,727)
Net cash provided by operating activities	64,096	52,774
<i>Investing Activities</i>		
Property, plant and equipment expenditures	(50,982)	(33,377)
Proceeds from sales of assets	2,281	905
Purchase of investments	(124)	(300)
Environmental expenditures	(345)	(525)
Net cash used in investing activities	(49,170)	(33,297)
<i>Financing Activities</i>		
Common stock dividends	(9,160)	(8,673)
Purchase of stock for Dividend Reinvestment Plan	(946)	(920)
Change in cash overdrafts due to outstanding checks	(4,181)	1,079
Net repayment under line of credit agreements	229	(9,346)
Other short-term borrowing		(29,100)
Proceeds from issuance of long-term debt		29,000
Repayment of long-term debt	(1,459)	(1,390)
Net cash used in financing activities	(15,517)	(19,350)

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Net Increase (Decrease) in Cash and Cash Equivalents		(591)	127
Cash and Cash Equivalents	Beginning of Period	2,637	1,643
Cash and Cash Equivalents	End of Period	\$ 2,046	\$ 1,770

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

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Table of Contents**Chesapeake Utilities Corporation and Subsidiaries****Condensed Consolidated Statements of Stockholders Equity (Unaudited)**

<i>(in thousands, except shares and per share data)</i>	Common Stock			Accumulated				Total
	Number of Shares ⁽¹⁾	Par Value	Additional Paid-In Capital	Retained Earnings	Other Comprehensive Loss	Deferred Compensation	Treasury Stock	
Balances at December 31, 2010	9,524,195	\$ 4,635	\$ 148,159	\$ 76,805	(\$3,360)	\$ 777	(\$777)	\$ 226,239
Net Income				27,622				27,622
Other comprehensive loss					(1,167)			(1,167)
Dividend Reinvestment Plan			(22)					(22)
Retirement Savings Plan	2,002	1	79					80
Conversion of debentures	10,680	5	176					181
Share-based compensation ^{(2) (3)}	30,430	15	998					1,013
Tax benefit on share-based compensation			13					13
Deferred Compensation Plan						40	(40)	
Purchase of treasury stock	(993)						(40)	(40)
Sale and distribution of treasury stock	993						40	40
Dividends on share-based compensation				(129)				(129)
Cash dividends ⁽⁴⁾				(13,050)				(13,050)
Balances at December 31, 2011	9,567,307	4,656	149,403	91,248	(4,527)	817	(817)	240,780
Net Income				19,006				19,006
Other comprehensive income					200			200
Dividend Reinvestment Plan			(5)					(5)
Conversion of debentures	6,572	3	108					111
Share-based compensation ^{(2) (3)}	19,217	10	724					734
Deferred Compensation Plan						153	(153)	
Purchase of treasury stock	(768)						(33)	(33)
Sale and distribution of treasury stock	768						33	33
Dividends on share-based compensation				(36)				(36)
Cash dividends ⁽⁴⁾				(10,306)				(10,306)
Balances at September 30, 2012	9,593,096	\$ 4,669	\$ 150,230	\$ 99,912	(\$4,327)	\$ 970	(\$970)	\$ 250,484

⁽¹⁾ Includes 33,169 and 30,597 shares at September 30, 2012 and December 31, 2011, respectively, held in a Rabbi Trust established by the Company relating to the Deferred Compensation Plan.

⁽²⁾ Includes amounts for shares issued for Directors' compensation.

⁽³⁾ The shares issued under the Performance Incentive Plan ("PIP") are net of shares withheld for employee taxes. For nine months ended September 30, 2012 and for the year ended December 31, 2011, the Company withheld 5,670 and 12,234 shares, respectively, for taxes.

⁽⁴⁾ Cash dividends per share for the periods ended September 30, 2012 and December 31, 2011 were \$1.080 and \$1.365 respectively.

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

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. Summary of Accounting Policies

Basis of Presentation

References in this document to the Company, Chesapeake, we, us and our are intended to mean the registrant and its subsidiaries, or the registrant's subsidiaries, as appropriate in the context of the disclosure.

The accompanying unaudited condensed consolidated financial statements have been prepared in compliance with the rules and regulations of the Securities and Exchange Commission (SEC) and accounting principles generally accepted in the United States of America (GAAP). In accordance with these rules and regulations, certain information and disclosures normally required for audited financial statements have been condensed or omitted. These financial statements should be read in conjunction with the consolidated financial statements and notes thereto, included in our Annual Report on Form 10-K for the year ended December 31, 2011, as amended. In the opinion of management, these financial statements reflect normal recurring adjustments that are necessary for a fair presentation of our results of operations, financial position and cash flows for the interim periods presented.

Due to the seasonality of our business, results for interim periods are not necessarily indicative of results for the entire fiscal year. Revenue and earnings are typically greater during the first and fourth quarters, when consumption of energy is highest due to colder temperatures.

We have assessed and reported on subsequent events through the date of issuance of these condensed consolidated financial statements.

Reclassifications

We reclassified certain amounts in the condensed consolidated statement of income for the three and nine months ended September 30, 2011, in the Condensed Consolidated Statement of Cash Flows for the nine months ended September 30, 2012, and in the condensed consolidated balance sheet as of December 31, 2011 to conform to the current year's presentation. We also reclassified certain segment information as of December 31, 2011, and for the three and nine months ended September 30, 2011 to conform to the current year's presentation. These reclassifications are considered immaterial to the overall presentation of our condensed consolidated financial statements.

Sale of Assets

In September 2011, Florida Public Utilities Company (FPU) entered into an agreement with an unaffiliated entity to sell its office building located in West Palm Beach, Florida for \$2.2 million. The sale of FPU's West Palm Beach office building was finalized in February 2012 and did not result in a material gain or loss. We treated the West Palm Beach office building as an asset held for sale, and it was included in other property, plant and equipment at December 31, 2011 in the accompanying condensed consolidated balance sheet.

In June and July 2012, FPU entered into a contract to sell its land located in West Palm Beach, Florida and a contract to purchase two parcels of land also located in the same city. FPU entered into the contract to sell its land and the contract to purchase one of the parcels to effectively exchange those lands. Therefore, these transactions will be accounted for as a non-monetary exchange and are expected to qualify as a like-kind exchange for income tax purposes. There will be no gain or loss related to the exchange portion of these transactions. The contract to purchase the other parcel of land will be recorded at the purchase price allocated to that parcel, which is approximately \$600,000. The transactions are expected to be completed in the fourth quarter of 2012.

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Financial Accounting Standards Board (FASB) Statements and Other Authoritative Pronouncements

Recently Adopted Accounting Standards

In September 2011, the FASB issued Accounting Standards Update (ASU) 2011-08, Intangibles – Goodwill and Other (Topic 350): Testing Goodwill for Impairment, which allows an entity to assess qualitatively whether it is necessary to perform step one of the two-step annual goodwill impairment test. Step one would be required if it is more-likely-than-not that a reporting unit's fair value is less than its carrying amount. This differs from previous guidance, which required entities to perform step one of the test, at least annually, by comparing the fair value of a reporting unit to its carrying amount. An entity may elect to bypass the qualitative assessment and proceed directly to step one, for any reporting unit, in any period. ASU 2011-08 does not change the guidance on when to test goodwill for impairment. The amendments in ASU 2011-08 are effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. We adopted the guidance of ASU 2011-08, effective January 1, 2012. Adoption of ASU 2011-08 did not have a material impact on our financial position and results of operations.

In May 2011, the FASB issued ASU No. 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS. Amendments in the ASU do not extend the use of fair value accounting but provide guidance on how it should be applied where its use is already required or permitted by other standards within International Financial Accounting Standards (IFRS) or GAAP. ASU 2011-04 supersedes most of the guidance in Topic 820, although many of the changes are clarifications of existing guidance or wording changes to align with IFRS. Certain amendments in ASU 2011-04 change a particular principle or requirement for measuring fair value or disclosing information about fair value measurements. The amendments in ASU 2011-04 are effective for public entities for interim and annual periods beginning after December 15, 2011, and should be applied prospectively. We adopted the guidance of ASU 2011-04, effective January 1, 2012, and provided additional disclosures as required. Adoption of ASU 2011-04 did not have a material impact on our financial position and results of operations.

Table of Contents**2. Calculation of Earnings Per Share**

For the Periods Ended September 30, (in thousands, except shares and per share data)	Three Months		Nine Months	
	2012	2011	2012	2011
Calculation of Basic Earnings Per Share:				
Net Income	\$ 3,219	\$ 2,397	\$ 19,006	\$ 19,664
Weighted average shares outstanding	9,592,417	9,564,012	9,583,316	9,552,472
Basic Earnings Per Share	\$ 0.34	\$ 0.25	\$ 1.98	\$ 2.06
Calculation of Diluted Earnings Per Share:				
Reconciliation of Numerator:				
Net Income	\$ 3,219	\$ 2,397	\$ 19,006	\$ 19,664
Effect of 8.25% Convertible debentures	13	15	41	46
Adjusted numerator Diluted	\$ 3,232	\$ 2,412	\$ 19,047	\$ 19,710
Reconciliation of Denominator:				
Weighted shares outstanding Basic	9,592,417	9,564,012	9,583,316	9,552,472
Effect of dilutive securities:				
Share-based Compensation	23,770	23,925	22,684	22,623
8.25% Convertible debentures	60,471	70,033	67,681	72,537
Adjusted denominator Diluted	9,676,658	9,657,970	9,673,681	9,647,632
Diluted Earnings Per Share	\$ 0.33	\$ 0.25	\$ 1.97	\$ 2.04

3. Acquisition

On June 22, 2012, we entered into an agreement to purchase the operating assets of The Eastern Shore Gas Company and its affiliates (collectively, ESG). These assets are currently used to provide propane distribution service in Worcester County, Maryland to approximately 11,000 residential and commercial customers through underground propane gas distribution systems and to over 500 customers through bulk propane delivery service. The purchase price is approximately \$16.5 million, which is subject to certain adjustments as specified in the purchase agreement. At the closing of the purchase, we will enter into a capacity, supply and operating agreement with ESG for supply and storage of propane, which will be utilized to serve the ESG system customers. We are evaluating the potential conversion of some of the underground propane distribution systems to natural gas where it is both economical and feasible. The transaction is subject to approval by the Maryland Public Service Commission (PSC), the receipt of consents of certain local jurisdictions to the assignment of certain franchise agreements and satisfaction of other closing conditions. On September 7, 2012, we filed an application with the Maryland PSC for approval of the purchase (see Note 4, Rates and Other Regulatory Activities, for additional information). The transaction, which is a cash purchase of assets, is expected to be completed in 2013. We expect to finance the acquisition using unsecured short-term debt.

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4. Rates and Other Regulatory Activities

Our natural gas and electric distribution operations in Delaware, Maryland and Florida are subject to regulation by their respective PSC; Eastern Shore Natural Gas Company (Eastern Shore), our natural gas transmission subsidiary, is subject to regulation by the Federal Energy Regulatory Commission (FERC); and Peninsula Pipeline Company, Inc. (Peninsula Pipeline), our intrastate pipeline subsidiary, is subject to regulation by the Florida PSC. Chesapeake s Florida natural gas distribution division and the natural gas and electric operations of FPU continue to be subject to regulation by the Florida PSC as separate entities.

Delaware

On September 1, 2011, the Delaware division filed with the Delaware PSC its annual Gas Service Rates (GSR) Application, seeking approval to change its GSR, effective November 1, 2011. On September 20, 2011, the Delaware PSC authorized the Delaware division to implement the GSR charges, as filed on November 1, 2011, on a temporary basis. The Delaware PSC granted approval of the GSR charges at its regularly scheduled meeting on July 17, 2012.

On June 18, 2012, the Delaware division filed an application with the Delaware PSC requesting approval for a Town of Selbyville Franchise Fee Rider. This rider allows the Delaware division to charge all natural gas customers within the town limits the franchise fee paid by the Delaware division to the Town of Selbyville as a condition to providing natural gas service. The Delaware PSC granted approval of this Franchise Fee Rider on August 7, 2012.

On June 25, 2012, the Delaware division filed with the Delaware PSC an application for proposed natural gas expansion service offerings in order to increase the availability of natural gas within its Delaware service areas. In this filing, the Delaware division is seeking approval from the Delaware PSC of the following:

- (i) a monthly fixed charge to customers in portions of Eastern Sussex County, Delaware, which will enable the Delaware division to extend its distribution system to provide natural gas service to these customers economically without upfront contributions from these customers;
- (ii) optional service offerings to customers to assist them in conversions, including a conversion finance service to assist customers with their cost of conversion equipment; and
- (iii) a slight rate increase for all Delaware customers in order to support the additional costs associated with the administration and implementation of the proposed service offerings.

On July 3, 2012, the Delaware PSC officially opened the docket and set a period for formal interventions to be filed. The parties are in the process of developing a procedural schedule for this proceeding. We anticipate that the Delaware PSC will render a final decision on these proposals in the first quarter of 2013.

On September 21, 2012, the Delaware division filed with the Delaware PSC its annual GSR Application, seeking approval to change its GSR, effective November 1, 2012. On October 9, 2012, the Delaware PSC authorized the Delaware division to implement the GSR charges, as filed, effective November 1, 2012, on a temporary basis and subject to refund, pending the completion of a full evidentiary hearing and a final decision.

Maryland

On September 7, 2012, we filed an application with the Maryland PSC for approval of the purchase of the ESG operating assets and the transfer of the ESG franchises to Chesapeake (see Note 3, Acquisition, for additional information on the ESG asset purchase). In this application, we also requested the Maryland PSC to approve the overall regulatory framework, which we proposed for our operation in Worcester County. The proposed regulatory framework includes: (i) a request for approval of a new gas service tariff and rates applicable to natural gas and propane distribution customers in Worcester County, including the customers currently being served by ESG; (ii) a request for approval of the capacity, supply and operating agreement with ESG for the supply and storage of propane, which will be utilized to serve the ESG system customers; and (iii) a request for approval of the accounting treatment for certain of the purchased assets. We anticipate that the Maryland PSC will render a final decision on this filing in 2013.

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Come-Back Filing: On January 30, 2012, the Florida PSC issued an order, approving, among other things, the inclusion in our rate base in Florida of an acquisition adjustment of \$34.2 million and merger-related costs of \$2.2 million, to be amortized over a 30-year period and a five-year period, respectively, using the straight-line method beginning in November 2009. The acquisition adjustment permits the recovery, through rates, and inclusion in rate base, of the premium (amount in excess of net book value) paid for the acquisition of FPU. The Florida PSC also determined that FPU and Chesapeake's Florida division did not have any excess earnings in 2010 to be refunded to customers. The Florida PSC issued a consummating order on these matters on January 30, 2012.

The Florida PSC order allows us to classify the acquisition adjustment and merger-related costs as regulatory assets and include them in our investment, or rate base, when determining our Florida natural gas rates. In addition, our rate of return calculation will be based upon this higher level of investment, which enables us to earn a return on this investment. Pursuant to this order, we reclassified to a regulatory asset at December 31, 2011, \$31.7 million of the \$34.2 million in merger-related goodwill, which represents the portion of the goodwill allowed to be recovered in future rates after the effective date of the Florida PSC order.

We also recorded as a regulatory asset \$18.1 million related to the gross-up of the acquisition adjustment for income tax. Of the \$2.2 million of merger-related costs, \$1.3 million, which represents the portion of the merger-related costs allowed to be recovered in future rates after the effective date of the Florida PSC order, had previously been deferred as a regulatory asset. We also recorded as a regulatory asset \$349,000 related to the gross-up of the merger-related costs for income tax. Based upon the effective date and outcome of the order, we began reflecting the amortization of the acquisition adjustment and merger-related costs as an expense in January 2012, and included \$589,000 and \$1.8 million of the amortization expense in depreciation and amortization in the accompanying condensed consolidated statement of income for the three and nine months ended September 30, 2012, respectively. We will record \$2.4 million (\$1.4 million, net of tax) in amortization expense related to these assets in 2012 and 2013, \$2.3 million (\$1.4 million, net of tax) in 2014 and \$1.8 million (\$1.1 million, net of tax) annually thereafter until 2039. These amortization expenses will be non-cash charges, and the net effect of the recovery will be positive cash flow. Over the long term, inclusion of the acquisition adjustment and merger-related costs in our rate base and the recovery of these regulatory assets through amortization expense will increase our earnings and cash flows above what we would have been able to achieve absent this regulatory authorization.

In FPU's future rate proceedings, if it is determined that the level of cost savings supporting recovery of the acquisition adjustment no longer exists, the remaining acquisition adjustment may be partially or entirely disallowed by the Florida PSC. In such event, we would have to expense the corresponding unamortized amount of the disallowed acquisition adjustment.

Peninsula Pipeline: At its April 10, 2012 agenda conference, the Florida PSC approved a joint territorial agreement between FPU and the Peoples Gas System division of Tampa Electric Company (Peoples Gas) and other related agreements among FPU, Peninsula Pipeline and Peoples Gas. These agreements were executed in January 2012 among the parties to enable Peninsula Pipeline and FPU to expand natural gas service into Nassau and Okeechobee Counties, Florida.

One of the agreements provides for the joint construction, ownership and operation of a pipeline extending approximately 16 miles from the Duval/Nassau County line to Amelia Island in Nassau County, Florida. Under the terms of the agreement, Peninsula Pipeline will own approximately 45 percent of this 16-mile pipeline, and its portion of the estimated project cost is expected to be approximately \$5.8 million. Peoples Gas will operate the pipeline, and Peninsula Pipeline will be responsible for its portion of the operation and maintenance expenses of the pipeline based on its ownership percentage. The new jointly-owned pipeline is expected to be completed and placed into service in late 2012. Under a separate agreement, Peninsula Pipeline will contract with Peoples Gas for transportation service from the Peoples Gas interconnection point with an unaffiliated upstream interstate pipeline to the new jointly-owned pipeline for an annual charge of approximately \$800,000. Peninsula Pipeline will then utilize the transportation agreement with Peoples Gas and the jointly-owned pipeline capacity to provide transmission service to FPU for an annual charge of approximately \$2.1 million for its natural gas distribution service in Nassau County. The cost of transportation service paid to Peninsula Pipeline by FPU based on the Florida-PSC-approved annual rate is included in FPU's fuel costs. In April 2012, pending the completion of the new 16-mile pipeline, Peninsula Pipeline commenced its service to FPU, using compressed natural gas.

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Marianna Franchise: On July 7, 2009, the City Commission of Marianna, Florida (the Marianna Commission) adopted an ordinance granting a franchise to FPU, effective February 1, 2010, for a period not to exceed 10 years for the operation and distribution and/or sale of electric energy (the Franchise Agreement). The Franchise Agreement provides that FPU will develop and implement new time-of-use (TOU) and interruptible electric power rates, or other similar rates, mutually agreeable to FPU and the City of Marianna. The Franchise Agreement further provides for the TOU and interruptible rates to be effective no later than February 17, 2011, and available to all customers within FPU 's northwest division, which includes the City of Marianna. If the rates were not in effect by February 17, 2011, the City of Marianna would have the right to give notice to FPU within 180 days thereafter of its intent to exercise an option in the Franchise Agreement to purchase FPU 's property (consisting of the electric distribution assets) within the City of Marianna. Any such purchase would be subject to approval by the Marianna Commission, which would also need to approve the presentation of a referendum to voters in the City of Marianna for the approval of the purchase and the operation by the City of Marianna of an electric distribution facility. If the purchase is approved by the Marianna Commission and by the referendum, the closing of the purchase must occur within 12 months after the referendum is approved. If the City of Marianna elects to purchase the Marianna property, the Franchise Agreement requires the City of Marianna to pay FPU the fair market value for such property as determined by three qualified appraisers. Our future financial results would be negatively affected by the loss of earnings generated by FPU from its approximately 3,000 customers in the City of Marianna.

In accordance with the terms of the Franchise Agreement, FPU developed TOU and interruptible rates, and on December 14, 2010, FPU filed a petition with the Florida PSC for authority to implement such proposed TOU and interruptible rates on or before February 17, 2011. On February 11, 2011, the Florida PSC issued an order approving FPU 's petition for authority to implement the proposed TOU and interruptible rates, which became effective on February 8, 2011. The City of Marianna objected to the proposed rates and filed a petition protesting the entry of the Florida PSC 's order. On January 24, 2012, the Florida PSC dismissed with prejudice the protest by the City of Marianna.

On January 26, 2011, FPU filed a petition with the Florida PSC for approval of an amendment to FPU 's Generation Services Agreement entered into between FPU and Gulf Power Company (Gulf Power). The amendment provides for a reduction in the capacity demand quantity, which generates the savings necessary to support the TOU and interruptible rates approved by the Florida PSC. The amendment also extends the current agreement by two years, with a new expiration date of December 31, 2019. By its order dated June 21, 2011, the Florida PSC approved the amendment. On July 12, 2011, the City of Marianna filed a protest of this decision and requested a hearing on the amendment. On January 24, 2012, the Florida PSC dismissed with prejudice the protest by the City of Marianna.

The City of Marianna filed an appeal with the Florida Supreme Court on March 7, 2012 and with the Florida PSC on March 19, 2012, seeking an appellate review of both of the decisions by the Florida PSC with respect to the protests by the City of Marianna and at this time, this appeal is pending before the Florida Supreme Court. These Florida PSC Dockets are currently in litigation status awaiting a decision by the Florida Supreme Court on the administrative appeal.

As disclosed in Note 6, Other Commitments and Contingencies, the City of Marianna, on March 2, 2011, filed a complaint against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida, alleging breaches of the Franchise Agreement by FPU and seeking a declaratory judgment that the City of Marianna has the right to exercise its option to purchase FPU 's property in the City of Marianna in accordance with the terms of the Franchise Agreement. The litigation remains pending and all related litigation expenses have been recorded as operating expenses.

On August 27, 2012, FPU filed a petition with the Florida PSC for approval to defer, as a regulatory asset, the litigation expenses associated with the litigation initiated by the City of Marianna and to amortize previously expensed and future litigation expenses over five years beginning January 2013. The proposed amortization period corresponds to the remaining life of FPU 's Generation Services Agreement with Gulf Power prior to the pending amendment. At the October 16, 2012 agenda conference, the Florida PSC approved FPU 's request for deferral and amortization of the litigation expenses for accounting and reporting purposes. This approval does not change the current rates charged by FPU to its electric customers. FPU expects the Florida PSC to issue an order in mid-November affirming the approval at the October 16, 2012 agenda conference. We are currently assessing the potential impact under GAAP of the expected Florida PSC order regarding the litigation expenses. Any deferral of the previously expensed litigation expense will not be recorded until an order is issued by the Florida PSC. The total litigation expense associated with the City of Marianna litigation could be as high as \$1.4 million by the end of 2012.

We have the following additional regulatory matters involving the City of Marianna:

On April 7, 2011, FPU filed a petition for approval of a mid-course reduction to its northwest division fuel rates based on two factors: (1) the amendment to the Generation Services Agreement with Gulf Power approved by the Florida PSC on June 21, 2011, and (2) a weather-related increase in sales resulting in an accelerated collection of the prior year 's under-recovered costs. Pursuant to its order dated July 5, 2011, the Florida PSC approved the petition, which reduced the fuel rates of FPU 's northwest division, which includes the fuel rates charged to customers in the City of Marianna.

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On February 24, 2012, FPU filed a revised petition for approval of a mid-course reduction to its northwest division fuel rates based on a reduction in its supplier's fuel rates, which would significantly lower purchased power costs for FPU's Northwest Division in 2012. FPU filed for this mid-course reduction in order to ensure that its customers receive these savings in the most timely manner. The Florida PSC issued an order on March 27, 2012, approving the mid-course correction reduction in fuel rates, effective April 1, 2012. This further reduced the fuel rates of FPU's northwest division, which includes the fuel rates charged to customers in the City of Marianna.

On June 1, 2012, the City of Marianna filed a petition with the Florida PSC for resolution of a territorial dispute for natural gas service in Jackson County as well as the surrounding areas included in FPU's planned expansion. On June 22, 2012, FPU filed a response to the petition defending its planned expansion. The Florida PSC has not yet issued a date for an agenda conference to resolve the matter.

Gas Reliability Infrastructure Program (GRIP): On February 3, 2012, FPU's natural gas distribution operation and Chesapeake's Florida division filed a petition with the Florida PSC for approval of a surcharge to customers for the GRIP. GRIP is designed to recover capital and other program-related costs, inclusive of an appropriate return on investment, associated with accelerating the replacement of qualifying distribution mains and services (defined as any material other than coated steel or plastic (Polyethylene)) in their respective systems. We expect to incur approximately \$75 million over a 10-year period to replace qualifying mains and services. At the August 14, 2012 agenda conference, the Florida PSC approved a GRIP for FPU and Chesapeake's Florida division to provide an annual surcharge mechanism with quarterly reporting requirements, effective January 1, 2013. The first year surcharge will include investments made in the period from August 14, 2012 through December 31, 2013.

We also had developments in the following regulatory matters in Florida:

On June 21, 2011, FPU, in accordance with the Florida PSC rules, filed its 2011 depreciation study and request for new depreciation rates for its electric distribution operation, effective January 1, 2012. The Florida PSC approved the depreciation study at its January 24, 2012 agenda conference. The new approved depreciation rates are expected to reduce annual depreciation expense by approximately \$227,000.

On March 21, 2012, FPU filed a petition with the Florida PSC for approval of a negotiated contract for the purchase of renewable energy power between FPU and an unaffiliated company, which is constructing and installing a new renewable generating facility within FPU's service territory. If constructed and installed, this facility will be capable of interconnecting and selling power to FPU's northeast electric division. Overall, this contract will provide a significant benefit to FPU's northeast electric customers, while also promoting the State of Florida's goal of encouraging energy independence and the growth of renewable energy projects. If the contract is approved, savings will be passed on to customers through lower fuel costs. At the agenda conference on July 17, 2012, the Florida PSC approved the contract.

On July 12, 2012, FPU filed a petition with the Florida PSC for approval of recognition of a regulatory liability for a one-time tax contingency gain related to FPU's income tax liability, which originated prior to the acquisition by Chesapeake from excess tax depreciation on vehicles. FPU recently determined that this tax liability was no longer needed because the applicable statute of limitation of the Internal Revenue Service and the tax remittance period related to this tax liability has expired. FPU believes that the treatment most consistent with prior regulatory treatment of one-time gains would be to record the amount as a regulatory liability and amortize that amount over a specified period. FPU proposed to establish approximately \$1.9 million of regulatory liability (\$1.2 million of the tax contingency gain and \$748,000 as the tax gross-up) and amortize it over a period from January 2012 to October 2014. At the October 16, 2012 agenda conference, the Florida PSC approved FPU's petition. FPU expects the Florida PSC to issue an order in mid-November affirming the approval at the October 16, 2012 agenda conference. Once an order is issued, FPU will begin to record the amortization of this regulatory liability, effective January 1, 2012, with the cumulative effect of the amortization recorded at that time.

On August 28, 2012, Chesapeake's Florida Division filed a petition with the Florida PSC for approval of a special contract with one of its customers for transportation service under its Special Contract Service tariff. The initial term of the new Special Contract Service is three years with provisions for extension unless either party gives notice of termination to the other party. We expect the Florida PSC to address this petition at its November 27, 2012 agenda conference.

On September 28, 2012, FPU provided a letter to the Florida PSC stating its intent to request approval of a positive acquisition adjustment associated with FPU's purchase of Indiantown Gas Company's operating assets in 2010. FPU provided this letter to the Florida PSC in response to the most recent earnings surveillance report of the FPU-Indiantown division showing potential overearnings. In this letter, FPU also acknowledged the jurisdiction of the Florida PSC to calculate and dispose prospective overearnings, if any, occurring after October 1, 2012 that may be found at the conclusion of the acquisition adjustment proceeding. FPU plans to file its request for approval of the acquisition adjustment before the end of 2012.

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The following are regulatory activities involving FERC orders applicable to Eastern Shore and the expansions of Eastern Shore's transmission system:

Rate Case Filing: On December 30, 2010, Eastern Shore filed with the FERC a base rate proceeding in accordance with the terms of the settlement in its prior base rate proceeding. Conferences involving Eastern Shore, the FERC Staff and other interested parties resulted in a settlement based on an annual cost of service of approximately \$29.1 million and a pre-tax return of 13.9 percent. Also included in the settlement is a negotiated rate adjustment, effective November 1, 2011, associated with the phase-in of an additional 15,000 dekatherms per day (Dts/d) of new transmission service on Eastern Shore's eight-mile extension to interconnect with Texas Eastern Transmission LP's (TETLP) pipeline system. This rate adjustment reduces the rate per dekatherm (Dt) of the service on this eight-mile extension by reflecting the increased service of 15,000 Dts/d with no additional revenue. This rate adjustment effectively offsets the increased revenue that would have been generated from the 15,000 Dts/d increase in firm service although Eastern Shore may still collect a commodity charge on the increased volume from the phase-in of service. The settlement also provides a five-year moratorium on the parties' rights to challenge Eastern Shore's rates and on Eastern Shore's right to file a base rate increase but allows Eastern Shore to file for rate adjustments during those five years in the event certain costs related to government-mandated obligations are incurred and Eastern Shore's pre-tax earnings do not equal or exceed 13.9 percent. The FERC approved the settlement on January 24, 2012.

From July 2011 through October 2011, Eastern Shore adjusted its billing to reflect the rates requested in the base rate proceeding, subject to refund to customers upon the FERC's approval of the new rates. Commencing in November 2011, Eastern Shore adjusted its billing to reflect the settlement rates, subject to refund to customers upon FERC's approval of the settlement. At December 31, 2011 Eastern Shore had recorded approximately \$1.3 million as a regulatory liability related to the refund due to customers as a result of the settlement; the refund was paid in January and February 2012.

Mainline Expansion Project: On May 14, 2012, Eastern Shore submitted to the FERC an Application for a Certificate of Public Convenience and Necessity for approval to construct, own and operate the facilities necessary to deliver additional firm service of 15,040 Dts/d to an existing electric power generation customer and to Chesapeake's Delaware and Maryland divisions. The estimated capital cost of the project is approximately \$16.3 million. The filing was publicly noticed on May 25, 2012. Two of Eastern Shore's existing customers and Chesapeake's Delaware and Maryland divisions filed motions to intervene in support of the project. One existing customer filed a motion to intervene and protest. On June 28, 2012, Eastern Shore submitted a response to the protest, and on August 31, 2012, the same existing customer filed a response to Eastern Shore's response. We expect the FERC ruling on this application by the end of 2012.

Daleville Compressor Station Upgrade Filing: On October 12, 2012, Eastern Shore submitted to the FERC an Application for a Certificate of Public Convenience and Necessity, seeking authorization to construct, own, operate, and maintain a new gas fired compressor unit at its existing Daleville Compressor Station located in Chester County, Pennsylvania. The new compressor unit will provide 17,500 Dts/d of additional firm transportation service to two of Eastern Shore's existing customers. In this application, Eastern Shore also included a description of a second new gas fired compressor unit to be installed at the Daleville Compressor Station, which will replace the three existing compressors that serve as back up units to existing primary compressor units. Eastern Shore also plans to replace the engine exhaust devices of the existing primary compressor units with air emissions control equipment to comply with new required environmental regulations. The replacement compressor unit and new engine exhaust devices will result in improved air emissions, reliability and flexibility on Eastern Shore's system. Eastern Shore does not need specific FERC approval to construct the replacement compressor unit or emission controls. While approval is not required for the replacement compressor unit, Eastern Shore wants the FERC to be fully advised of these improvement efforts. The estimated capital costs of the project are approximately \$12.1 million. Eastern Shore anticipates a completion date that will allow for service to commence utilizing the new facilities in November 2013.

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Eastern Shore also had developments in the following FERC matters:

On March 7, 2011, Eastern Shore filed certain tariff sheets to amend the creditworthiness provisions contained in its FERC Gas Tariff. On April 6, 2011, the FERC issued an order accepting and suspending Eastern Shore's filed tariff revisions, effective April 1, 2011, subject to Eastern Shore submitting certain clarifications with regard to several proposed revisions. Eastern Shore responded with a revised filing on January 13, 2012, which the FERC approved on February 24, 2012.

On March 1, 2012, Eastern Shore filed revised tariff sheets to amend certain provisions contained in the Construction of Facilities and Right of First Refusal sections of its FERC Gas Tariff. On April 6, 2012, the FERC issued an order accepting Eastern Shore's revised tariff sheet, effective April 1, 2012, subject to Eastern Shore submitting two additional revisions proposed by an intervening party during the review period. Eastern Shore responded with a revised filing on April 16, 2012, which the FERC accepted.

On June 27, 2012, Eastern Shore submitted a combined filing for its Fuel Retention Percentage (FRP) and Cash-Out Surcharge to the FERC, which encompassed a 24-month period from April 2010 to March 2012. In the filing, Eastern Shore proposed to maintain its existing zero FRP rate and its existing zero rate for the Cash-Out Surcharge. Eastern Shore also proposed to refund approximately \$320,000, inclusive of interest, to its eligible customers as a result of combining its over-recovered Gas Required for Operations and its over-recovered Cash-Out Cost. On October 19, 2012, the FERC issued an order accepting Eastern Shore's proposal. The proposed refund has been accrued and included in regulatory liabilities (current) in the accompanying condensed consolidated balance sheet at September 30, 2012.

5. Environmental Commitments and Contingencies

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy at current and former operating sites the effect on the environment of the disposal or release of specified substances.

We have participated in the investigation, assessment or remediation, and have exposure at six former Manufactured Gas Plant (MGP) sites. Those sites are located in Salisbury, Maryland, and Winter Haven, Key West, Pensacola, Sanford and West Palm Beach, Florida. We have also been in discussions with the Maryland Department of the Environment (MDE) regarding a seventh former MGP site located in Cambridge, Maryland.

As of September 30, 2012, we had approximately \$10.7 million in environmental liabilities related to all of FPU's MGP sites in Florida, which include the Key West, Pensacola, Sanford and West Palm Beach sites, representing our estimate of the future costs associated with those sites. FPU has approval to recover up to \$14.0 million of its environmental costs related to all of its MGP sites from insurance and from customers through rates, approximately \$8.6 million of which has been recovered as of September 30, 2012. We also had approximately \$5.4 million in regulatory assets for future recovery of environmental costs from FPU's customers.

In addition to the FPU MGP sites, we had \$207,000 in environmental liabilities as of September 30, 2012, related to Chesapeake's MGP sites in Maryland and Florida, representing our estimate of future costs associated with these sites. As of September 30, 2012, we had approximately \$702,000 in regulatory and other assets for future recovery through Chesapeake's rates.

We continue to expect that all costs related to environmental remediation and related activities will be recoverable from customers through rates.

The following discussion provides a brief summary of each MGP site:

West Palm Beach, Florida

Remedial options are being evaluated to respond to environmental impacts to soil and groundwater at and in the immediate vicinity of a parcel of property owned by FPU in West Palm Beach, Florida, where FPU previously operated an MGP. FPU is currently implementing a remedial plan approved by the Florida Department of Environmental Protection (FDEP) for the east parcel of the West Palm Beach site which includes installation of monitoring test wells, sparging of air into the groundwater system and extraction of vapors from the subsurface. It is anticipated that similar remedial actions ultimately will be implemented for other portions of the site. Estimated costs of remediation for the West Palm Beach site range from approximately \$4.6 million to \$15.7 million, including costs associated with the relocation of FPU's operations at this site, which is necessary to implement the remedial plan, and any potential costs associated with future redevelopment of the properties. We continue to expect that all costs related to these activities will be recoverable from customers through rates.

Sanford, Florida

FPU is the current owner of property in Sanford, Florida, which was a former MGP site that was operated by several other entities before FPU acquired the property. FPU was never an owner or an operator of the MGP. In January 2007, FPU and other responsible parties at the Sanford site (collectively with FPU the Sanford Group) signed a Third Participation Agreement, which provides for the funding of the final remedy approved by the Environmental Protection Agency (EPA) for the site. FPU s share of remediation costs under the Third Participation Agreement is set at five percent of a maximum of \$13 million, or \$650,000. As of September 30, 2012, FPU has paid \$650,000 to the Sanford Group escrow account for all of its share of the funding requirements.

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The total cost of the final remedy is now estimated at over \$20 million, which includes long-term monitoring and the settlement of claims asserted by two adjacent property owners to resolve damages that the property owners allege they have incurred and will incur as a result of the implementation of the EPA-approved remediation. In settlement of these claims, members of the Sanford Group, which in this instance does not include FPU, have agreed to pay specified sums of money to the parties. FPU has refused to participate in the funding of the third-party settlement agreements based on its contention that it did not contribute to the release of hazardous substances at the site giving rise to the third-party claims. FPU has advised the other members of the Sanford Group that it is unwilling at this time to agree to pay any sum in excess of the \$650,000 committed by FPU in the Third Participation Agreement.

As of September 30, 2012, FPU's remaining remediation expenses, including attorneys' fees and costs, are estimated to be \$24,000. However, we are unable to determine, to a reasonable degree of certainty, whether the other members of the Sanford Group will accept FPU's asserted defense to liability for costs exceeding \$13.0 million as provided in the Third Participation Agreement to implement the final remedy for this site or will pursue a claim against FPU for a sum in excess of the \$650,000 that FPU has paid under the Third Participation Agreement. No such claims have been made as of September 30, 2012.

Key West, Florida

FPU formerly owned and operated an MGP in Key West, Florida. Field investigations performed in the 1990s identified limited environmental impacts at the site, which is currently owned by an unrelated third party. In 2010, after 17 years of regulatory inactivity, FDEP observed that some soil and groundwater standards were exceeded and requested implementation of additional soil and groundwater fieldwork. The scope of work is limited to the installation of two additional monitoring wells and periodic monitoring of the new and existing wells. The two new monitoring wells were installed in November 2011, and groundwater monitoring began in December 2011. The first semi-annual report from the monitoring program was issued in May 2012. It is anticipated that the next semi-annual report, which may include recommendations for further actions, if appropriate, will be issued before the end of 2012. Prior to completion of the monitoring program, we cannot determine to a reasonable degree of certainty the probable costs to resolve FPU's liability for the Key West MGP Site, although we do not anticipate the cost to exceed \$100,000.

Pensacola, Florida

FPU formerly owned and operated an MGP in Pensacola, Florida, which was subsequently owned by Gulf Power. Portions of the site are now owned by the City of Pensacola and the Florida Department of Transportation (FDOT). In October 2009, FDEP informed Gulf Power that FDEP would approve a conditional No Further Action determination for the site, which must include a requirement for institutional and engineering controls. On December 13, 2011, Gulf Power, the City of Pensacola, FDOT and FPU submitted to FDEP a draft covenant for institutional and engineering controls for the site. Upon FDEP's approval and the subsequent recording of the institutional and engineering controls, no further work is expected to be required of the parties. Assuming FDEP approves the draft institutional and engineering controls, it is anticipated that FPU's share of remaining legal and cleanup costs will not exceed \$5,000.

Salisbury, Maryland

We have substantially completed remediation of a site in Salisbury, Maryland, where it was determined that a former MGP caused localized ground-water contamination. In February 2002, the MDE granted permission to permanently decommission the systems used for remediation and to discontinue all on-site and off-site well monitoring, except for one well, which is being maintained for periodic product monitoring and recovery. We anticipate that the remaining costs of the one remaining monitoring well will not exceed \$5,000 annually. We cannot predict at this time when the MDE will grant permission to permanently decommission the one remaining monitoring well.

Winter Haven, Florida

The Winter Haven site is located on the eastern shoreline of Lake Shipp, in Winter Haven, Florida. Pursuant to a consent order entered into with the FDEP, we are obligated to assess and remediate environmental impacts at this former MGP site. The recent groundwater sampling results show a continuing reduction in contaminant concentrations from the treatment system, which has been in operation since 2002. Currently, we predict that remedial action objectives could be met in approximately two to three years for the area being treated by the remediation system. On August 7, 2012, FDEP issued a letter discussing the need to evaluate further remedial options, which could incorporate risk-management options, including natural attenuation and the use of institutional and engineering controls. Modifications to the existing consent order and the remedial action plan modification could be required to incorporate risk-management options into the remedy for the site. If such modifications are required, we estimate that future remediation costs could be as much as \$443,000, which includes an estimate of \$100,000 to implement additional actions, such as institutional controls, at the site. If we are required to incur this cost, we continue to believe that the entire amount will be recoverable from customers through our approved rates.

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The current treatment system at the Winter Haven site does not address impacted soils in the southwest corner of the site. In 2010, we obtained a conditional approval from FDEP for a soil excavation plan; however, because the costs associated with shoreline stabilization and dewatering are likely to be substantial, alternatives to this excavation plan are being evaluated.

FDEP has indicated that we may be required to remediate sediments along the shoreline of Lake Shipp, immediately west of the site. Based on studies performed to date, we object to FDEP's suggestion that the sediments have been adversely impacted by the former operations of the MGP. Our early estimates indicate that some of the corrective measures discussed by FDEP could cost as much as \$1.0 million. We believe that corrective measures for the sediments are not warranted and intend to oppose any requirement that we undertake corrective measures in the offshore sediments. We have not recorded a liability for sediment remediation, as the final resolution of this matter cannot be predicted at this time.

Other

We have had discussions with the MDE regarding a former MGP site located in Cambridge, Maryland. The outcome of this matter cannot be determined at this time; therefore, we have not recorded an environmental liability for this location.

6. Other Commitments and Contingencies

Litigation

On March 2, 2011, the City of Marianna filed a complaint against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida. In the complaint, the City of Marianna alleged three breaches of the Franchise Agreement by FPU: (i) FPU failed to develop and implement TOU and interruptible rates that were mutually agreed to by the City of Marianna and FPU; (ii) mutually agreed upon TOU and interruptible rates by FPU were not effective or in effect by February 17, 2011; and (iii) FPU did not have such rates available to all of FPU's customers located within and without the corporate limits of the City of Marianna. The City of Marianna is seeking a declaratory judgment allowing it to exercise its option under the Franchise Agreement to purchase FPU's property (consisting of the electric distribution assets) within the City of Marianna. Any such purchase would be subject to approval by the Marianna Commission, which would also need to approve the presentation of a referendum to voters in the City of Marianna related to the purchase and the operation by the City of Marianna of an electric distribution facility. If the purchase is approved by the Marianna Commission and the referendum is approved by the voters, the closing of the purchase must occur within 12 months after the referendum is approved. On March 28, 2011, FPU filed its answer to the declaratory action by the City of Marianna, in which it denied the material allegations by the City of Marianna and asserted several affirmative defenses. On August 3, 2011, the City of Marianna notified FPU that it was formally exercising its option to purchase FPU's property. On August 31, 2011, FPU advised the City of Marianna that it has no right to exercise the purchase option under the Franchise Agreement and that FPU would continue to oppose the effort by the City of Marianna to purchase FPU's property. In December 2011, the City of Marianna filed a motion for summary judgment. FPU opposed the motion. On April 3, 2012, the court conducted a hearing on the City of Marianna's motion for summary judgment. The court subsequently denied in part and granted in part the City of Marianna's motion after concluding that fact issues remained for trial with respect to each of the three alleged breaches of the Franchise Agreement. Mediation was conducted on May 11, 2012, and again on July 6, 2012, but no resolution was reached. The parties will continue to conduct informal negotiations to explore a potential settlement. The case was originally scheduled for trial in October 2012, however, due to a scheduling conflict, the trial has been rescheduled to February 2013. Unless resolved through informal negotiations, we anticipate that the case will be tried and intend to defend this lawsuit vigorously. We also intend to oppose the adoption of any proposed referendum to approve the purchase of the FPU property by the City of Marianna. We have expensed approximately \$1.2 million in legal costs associated with this litigation, approximately \$689,000 of which was expensed in 2012. The total litigation expense associated with this litigation could be as high as \$1.4 million by the end of 2012.

We are involved in certain other legal actions and claims arising in the normal course of business. We are also involved in certain legal proceedings and administrative proceedings before various governmental agencies concerning rates. In the opinion of management, the ultimate disposition of these proceedings will not have a material effect on our consolidated financial position, results of operations or cash flows.

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Natural Gas, Electric and Propane Supply

Our natural gas, electric and propane distribution operations have entered into contractual commitments to purchase gas, electricity and propane from various suppliers. The contracts have various expiration dates. We have a contract with an energy marketing and risk management company to manage a portion of our natural gas transportation and storage capacity. This contract expires on March 31, 2013.

Chesapeake's Florida natural gas distribution division has firm transportation service contracts with Florida Gas Transmission Company (FGT) and Gulfstream Natural Gas System, LLC (Gulfstream). Pursuant to a capacity release program approved by the Florida PSC, all of the capacity under these agreements has been released to various third parties, including Peninsula Energy Services Company, Inc. (PESCO). Under the terms of these capacity release agreements, Chesapeake is contingently liable to FGT and Gulfstream, should any party that acquired the capacity through release fail to pay for the service.

In May 2012, PESCO renewed contracts to purchase natural gas from various suppliers. These contracts expire in May 2013.

FPU's electric fuel supply contracts require FPU to maintain an acceptable standard of creditworthiness based on specific financial ratios. FPU's agreement with JEA (formerly known as Jacksonville Electric Authority) requires FPU to comply with the following ratios based on the results of the prior 12 months: (a) total liabilities to tangible net worth less than 3.75 times, and (b) fixed charge coverage ratio greater than 1.5 times. If either ratio is not met by FPU, it has 30 days to cure the default or provide an irrevocable letter of credit if the default is not cured. FPU's electric fuel supply agreement with Gulf Power requires FPU to meet the following ratios based on the average of the prior nine quarters: (a) funds from operations interest coverage ratio (minimum of 2 times), and (b) total debt to total capital (maximum of 65 percent). If FPU fails to meet the requirements, it has to provide the supplier a written explanation of actions taken or proposed to be taken to become compliant. Failure to comply with the ratios specified in the Gulf Power agreement could result in FPU providing an irrevocable letter of credit. As of September 30, 2012, FPU was in compliance with all of the requirements of its fuel supply contracts.

Corporate Guarantees

The Board of Directors has authorized the Company to issue corporate guarantees securing obligations of our subsidiaries and to obtain letters of credit securing our obligations, including the obligations of our subsidiaries. The maximum authorized liability under such guarantees and letters of credit is \$45 million.

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily for our propane wholesale marketing subsidiary and our natural gas marketing subsidiary. These corporate guarantees provide for the payment of propane and natural gas purchases in the event of the respective subsidiary's default. Neither subsidiary has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded in the condensed consolidated financial statements when incurred. The aggregate amount guaranteed at September 30, 2012 was \$28.5 million, with the guarantees expiring on various dates through September 2013.

Chesapeake guarantees the payment of FPU's first mortgage bonds. The maximum exposure under the guarantee is the outstanding principal plus accrued interest balances. The outstanding principal balances of FPU's first mortgage bonds approximate their carrying values (see Note 13, Long-Term Debt, to the condensed consolidated financial statements for further details).

In addition to the corporate guarantees, we have issued a letter of credit for \$1.0 million, which expires on September 12, 2013, related to the electric transmission services for FPU's northwest electric division. We have also issued a letter of credit to our current primary insurance company for \$656,000, which expires on December 2, 2012, as security to satisfy the deductibles under our various outstanding insurance policies. As a result of a change in our primary insurance company in 2010, we renewed and decreased the letter of credit for \$304,000 to our former primary insurance company, which will expire on June 1, 2013. There have been no draws on these letters of credit as of September 30, 2012. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future.

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We provided a letter of credit for \$2.5 million to TETLP related to the Precedent Agreement and firm transportation service agreement between our Delaware and Maryland divisions and TETLP, which is described below.

Agreements for Access to New Natural Gas Supplies

On April 8, 2010, our Delaware and Maryland divisions entered into a Precedent Agreement to secure firm transportation service from TETLP in conjunction with its new expansion project, which is expected to expand TETLP's mainline system by up to 190,000 Dts/d. The Precedent Agreement provided that, upon satisfaction of certain conditions, the parties would execute two firm transportation service contracts, one for our Delaware division and one for our Maryland division. On February 23, 2012, in accordance with the terms outlined in the Precedent Agreement, our Delaware and Maryland divisions entered into two separate firm transportation service agreements with TETLP for 30,000 Dts/d and 10,000 Dts/d, respectively, commencing in November 2012. The maximum daily quantity under these agreements increases to 34,100 Dts/d and 15,900 Dts/d, respectively in November 2013. By entering into these agreements, our Delaware and Maryland divisions satisfied the requirements of the Precedent Agreement and no longer have any financial exposure under the Precedent Agreement.

On March 17, 2010, our Delaware and Maryland divisions entered into a separate precedent agreement with Eastern Shore to extend its mainline by eight miles to interconnect with TETLP at Honey Brook, Pennsylvania. Eastern Shore completed the extension project in December 2010 and commenced the service in January 2011. The rate for the transmission service on this extension is Eastern Shore's current tariff rate for service in that area.

As the Eastern Shore and TETLP transmission services commence, our Delaware and Maryland divisions incur costs for those services based on the agreed upon FERC-approved reservation rates. These rates become an integral component of the costs associated with providing natural gas supplies to our Delaware and Maryland divisions and will be included in the annual GSR filings for each of our respective divisions.

Non-income-based Taxes

From time to time, we are subject to various audits and reviews by the states and other regulatory authorities regarding non-income-based taxes. We are currently undergoing sales tax audits in Florida. As of September 30, 2012 and December 31, 2011, we maintained accruals of \$173,000 and \$307,000, respectively, related to additional sales taxes and gross receipts taxes that we may owe to various states.

7. Segment Information

We use the management approach to identify operating segments. We organize our business around differences in regulatory environment and/or products or services, and the operating results of each segment are regularly reviewed by the chief operating decision maker (our Chief Executive Officer) in order to make decisions about resources and to assess performance. The segments are evaluated based on their pre-tax operating income. Our operations comprise three operating segments:

Regulated Energy. The regulated energy segment includes natural gas distribution, electric distribution and natural gas transmission operations. All operations in this segment are regulated, as to their rates and services, by the PSC having jurisdiction in each operating territory or by the FERC in the case of Eastern Shore.

Unregulated Energy. The unregulated energy segment includes natural gas marketing, propane distribution and propane wholesale marketing operations, which are unregulated as to their rates and charges for their services.

Other. The other segment consists primarily of the advanced information services operation, unregulated subsidiaries that own real estate leased to Chesapeake and certain corporate costs not allocated to other operations.

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The following table presents information about our reportable segments.

For the Periods Ended September 30, (in thousands)	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
Operating Revenues, Unaffiliated Customers				
Regulated Energy	\$ 51,868	\$ 53,504	\$ 179,139	\$ 192,513
Unregulated Energy	21,861	23,721	91,001	112,164
Other	4,446	3,385	12,846	9,362
Total operating revenues, unaffiliated customers	\$ 78,175	\$ 80,610	\$ 282,986	\$ 314,039
Intersegment Revenues ⁽¹⁾				
Regulated Energy	\$ 328	\$ 147	\$ 906	\$ 200
Unregulated Energy	1,398		2,322	
Other	220	266	675	970
Total intersegment revenues	\$ 1,946	\$ 413	\$ 3,903	\$ 1,170
Operating Income				
Regulated Energy	\$ 7,848	\$ 6,943	\$ 33,151	\$ 30,964
Unregulated Energy	(709)	(1,392)	4,044	7,276
Other and eliminations	425	43	897	(31)
Total operating income	7,564	5,594	38,092	38,209
Other (loss) income, net of other expenses	(136)	649	212	699
Interest	2,126	2,389	6,657	6,654
Income before income taxes	5,302	3,854	31,647	32,254
Income taxes	2,083	1,457	12,641	12,590
Net income	\$ 3,219	\$ 2,397	\$ 19,006	\$ 19,664

⁽¹⁾ All significant intersegment revenues are billed at market rates and have been eliminated from consolidated operating revenues.

(in thousands)	September 30, 2012	December 31, 2011
Identifiable Assets		
Regulated energy	\$ 593,336	\$ 565,563
Unregulated energy	68,757	107,916
Other	37,859	35,587
Total identifiable assets	\$ 699,952	\$ 709,066

Our operations are almost entirely domestic. Our advanced information services subsidiary, BravePoint, has infrequent transactions in foreign countries, primarily Canada, which are denominated and paid in U.S. dollars. These transactions are immaterial to the consolidated revenues.

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Net periodic benefit costs for our pension and post-retirement benefits plans for the three and nine months ended September 30, 2012 and 2011 are set forth in the following table:

For the Three Months Ended September 30, (in thousands)	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP		Chesapeake Postretirement Plan		FPU Medical Plan	
	2012	2011	2012	2011	2012	2011	2012	2011	2012	2011
Service Cost	\$	\$	\$	\$	\$	\$	\$	\$	\$ 40	\$ 26
Interest Cost	125	130	638	671	23	26	15	14	45	38
Expected return on plan assets	(108)	(100)	(658)	(683)						
Amortization of prior service cost	(1)	(1)			5	4	(20)			
Amortization of net loss	85	39	43		11	10	18		23	5
Net periodic cost (benefit)	101	68	23	(12)	39	40	13	14	108	69
Settlement expense						219				
Amortization of pre-merger regulatory asset			190	190					2	2
Total periodic cost	\$ 100	\$ 68	\$ 213	\$ 178	\$ 39	\$ 259	\$ 13	\$ 14	\$ 110	\$ 71

For the Nine Months Ended September 30, (in thousands)	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP		Chesapeake Postretirement Plan		FPU Medical Plan	
	2012	2011	2012	2011	2012	2011	2012	2011	2012	2011
Service Cost	\$	\$	\$	\$	\$	\$	\$	\$	\$ 120	\$ 79
Interest Cost	375	390	1,916	2,014	68	80	45	44	135	116
Expected return on plan assets	(326)	(302)	(1,973)	(2,051)						
Amortization of prior service cost	(4)	(4)			15	14	(60)			
Amortization of net loss	255	117	131		34	29	53		68	15
Net periodic cost (benefit)	300	201	74	(37)	117	123	38	44	323	210
Settlement expense		217				219				
Amortization of pre-merger regulatory asset			571	571					6	6
Total periodic cost	\$ 300	\$ 418	\$ 645	\$ 534	\$ 117	\$ 342	\$ 38	\$ 44	\$ 329	\$ 216

We expect to record pension and postretirement benefit costs of approximately \$1.9 million for 2012. Included in that amount is \$769,000 related to continued amortization of the FPU pension regulatory asset, which represents the portion attributable to FPU's regulated energy operations of the changes in funded status that occurred but were not recognized as part of net periodic benefit costs prior to the merger. This was deferred as a regulatory asset by FPU prior to the merger to be recovered through rates pursuant to a previous order by the Florida PSC. The unamortized balance of this regulatory asset was \$5.4 million and \$5.9 million at September 30, 2012 and December 31, 2011, respectively.

On June 29, 2012, the U.S. Congress passed the Moving Ahead for Progress in the 21st Century Act (also known as the Transportation and Student Loan Bill). Included in this legislation was pension funding relief, which allowed pension sponsors to use 25-year average corporate bond rates rather than current interest rates, which are lower, to measure pension obligations for pension funding purposes. Although this legislation does not affect accounting for pension plans, the use of higher interest rates to measure pension obligations for funding purposes reduces the minimum pension contribution requirements. Despite the reduction in the minimum pension contribution requirements under this legislation, we have decided to continue our 2012 pension contributions at similar levels as we had initially estimated prior to the passage of the legislation, which included minimum contribution payments using the current interest rate to measure pension obligations and any additional contributions that we may make to maintain a certain level of funding in those plans. During the three and nine months ended September 30,

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2012, we contributed \$1.1 million and \$1.3 million respectively, to the Chesapeake pension plan. We also contributed \$1.9 million and \$2.6 million to the FPU pension plan during the three and nine months ended September 30, 2012, respectively. All of the expected contributions to the pension plans during 2012 have been made as of September 30, 2012.

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The Chesapeake Pension Supplemental Executive Retirement Plan (SERP), the Chesapeake Postretirement Plan and the FPU Medical Plan are unfunded and are expected to be paid out of our general funds. Cash benefits paid under the Chesapeake Pension SERP for the three and nine months ended September 30, 2012, were \$22,000 and \$67,000, respectively; we expect to pay cash benefits of approximately \$88,000 in 2012. Cash benefits paid for the Chesapeake Postretirement Plan, primarily for medical claims for the three and nine months ended September 30, 2012, totaled \$20,000 and \$60,000, respectively, and we have estimated that approximately \$87,000 will be paid for such benefits in 2012. Cash benefits paid for the FPU Medical Plan, primarily for medical claims for the three and nine months ended September 30, 2012, totaled \$40,000 and \$198,000, respectively. We have originally estimated that approximately \$193,000 will be paid for such benefits in 2012.

9. Investments

The investment balance at September 30, 2012, represents: (a) a Rabbi Trust associated with our Supplemental Executive Retirement Savings Plan, (b) a Rabbi Trust related to the deferral of certain director compensation, and (c) investments in equity securities. We classify these investments as trading securities and report them at their fair value. For the three months ended September 30, 2012 and 2011, we recorded net unrealized loss of \$102,000 and \$80,000, respectively, in other (loss) income in the condensed consolidated statements of income related to these investments. For the nine months ended September 30, 2012 and 2011, we recorded net unrealized gain of \$401,000 and \$51,000, respectively, in other income in the condensed consolidated statements of income related to these investments. We also have recorded an associated liability that is adjusted each month for the gains and losses incurred by the Rabbi Trusts. At September 30, 2012 and December 31, 2011, total investments had a fair value of \$4.7 million and \$4.0 million, respectively.

10. Share-Based Compensation

Our non-employee directors and key employees are awarded share-based awards through our Directors Stock Compensation Plan (DSCP) and our Performance Incentive Plan (PIP), respectively. We record these share-based awards as compensation costs over the respective service period for which services are received in exchange for an award of equity or equity-based compensation. The compensation cost is based primarily on the fair value of the grant on the date it was awarded.

The table below presents the amounts included in net income related to share-based compensation expense for the awards granted under the DSCP and the PIP for the three and nine months ended September 30, 2012 and 2011:

For the Periods Ended September 30, <i>(in thousands)</i>	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
Directors Stock Compensation Plan	\$ 111	\$ 111	\$ 332	\$ 296
Performance Incentive Plan	304	262	779	782
Total compensation expense	415	373	1,111	1,078
Less: tax benefit	(166)	(150)	(446)	(432)
Share-Based Compensation amounts included in net income	\$ 249	\$ 223	\$ 665	\$ 646

Table of Contents**Directors Stock Compensation Plan**

Shares granted under the DSCP are issued in advance of the directors' service periods and are fully vested as of the date of the grant. We record a prepaid expense of the shares issued and amortize the expense equally over a service period of one year.

In May 2012, each of our non-employee directors received an annual retainer of 900 shares of common stock under the DSCP. A summary of stock activity under the DSCP during the nine months ended September 30, 2012 is presented below.

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding December 31, 2011		
Granted	10,800	\$ 41.06
Vested	10,800	\$ 41.06
Forfeited		
Outstanding September 30, 2012		

At September 30, 2012, there was \$259,000 of unrecognized compensation expense related to the DSCP awards. This expense is expected to be recognized over the directors' remaining service period ending April 30, 2013.

Performance Incentive Plan

The table below presents the summary of the stock activity for the PIP for the nine months ended September 30, 2012:

	Number of Shares	Weighted Average Fair Value
Outstanding December 31, 2011	87,414	\$ 34.47
Granted	35,706	\$ 39.62
Vested	13,837	\$ 29.19
Forfeited ⁽¹⁾	21,600	\$ 36.57
Expired	3,038	\$ 26.29
Outstanding September 30, 2012	84,645	\$ 37.86

⁽¹⁾ Includes shares settled with a cash payment pursuant to the terms of a separation agreement with a former named executive officer. In January 2012, the Board of Directors granted awards under the PIP for 30,906 shares. The shares granted in January 2012 are multi-year awards that will vest at the end of the three-year service period, or December 31, 2014. These awards are earned based upon the successful achievement of long-term goals, growth and financial results, which comprised both market-based and performance-based conditions or targets. The fair value of each performance-based condition or target is equal to the market price of our common stock on the date of the grant. For the market-based conditions, we used the Black-Scholes pricing model to estimate the fair value of each market-based award granted.

In July 2012, we replaced a subsidiary officer's multi-year cash-based incentive award with an award of 4,800 shares under the PIP. These shares will vest at the end of the service period ending December 31, 2014 and have terms and market/performance targets similar to other shares granted under the PIP in January 2012.

Effective February 24, 2012, one of our named executive officers, who was a participant in the PIP, resigned. Pursuant to a separation agreement entered into between the Company and the named executive officer, the executive officer received a cash payment of \$181,500 and other

benefits in lieu of other performance-based compensation, which he might have been entitled to receive.

At September 30, 2012, the aggregate intrinsic value of the PIP awards was \$1.2 million.

Table of Contents**11. Derivative Instruments**

We use derivative and non-derivative contracts to engage in trading activities and manage risks related to obtaining adequate supplies and the price fluctuations of natural gas, electricity and propane. Our natural gas, electric and propane distribution operations have entered into agreements with suppliers to purchase natural gas, electricity and propane for resale to their customers. Purchases under these contracts either do not meet the definition of derivatives or are considered normal purchases and sales and are accounted for on an accrual basis. Our propane distribution operation may also enter into fair value hedges of its inventory in order to mitigate the impact of wholesale price fluctuations. As of September 30, 2012, our natural gas and electric distribution operations did not have any outstanding derivative contracts.

In May 2012, our propane distribution operation entered into call options to protect against an increase in propane prices associated with 1,260,000 gallons purchased for the propane price cap program in December 2012 through March 2013. The call options are exercised if the propane prices rise above the strike prices, which range from \$0.905 per gallon to \$0.99 per gallon during this four-month period. We will receive the difference between the market price and the strike price during those months. We paid \$139,000 to purchase the call options and we accounted for the call options as a fair value hedge. As of September 30, 2012, the call options had a fair value of \$121,000. There has been no ineffective portion of this fair value hedge thus far in 2012.

In August 2011, our propane distribution operation entered into a put option to protect against the decline in propane prices and related potential inventory losses associated with 630,000 gallons purchased for the propane price cap program in the upcoming heating season. This put option was exercised as the propane prices fell below the strike price of \$1.445 per gallon in January through March of 2012. We received \$118,000, representing the difference between the market price and the strike price during those months. We had paid \$91,000 to purchase the put option, and we accounted for it as a fair value hedge.

Xeron, our propane wholesale and marketing subsidiary, engages in trading activities using forward and futures contracts. These contracts are considered derivatives and have been accounted for using the mark-to-market method of accounting. Under the mark-to-market method of accounting, the trading contracts are recorded at fair value, and the changes in fair value of those contracts are recognized as unrealized gains or losses in the statement of income in the period of change. As of September 30, 2012, we had the following outstanding trading contracts, which we accounted for as derivatives:

At September 30, 2012	Quantity in Gallons	Estimated Market Prices		Weighted Average Contract Prices	
Forward Contracts					
Sale	5,964,000	\$ 0.7200	\$1.3775	\$	0.9469
Purchase	5,670,000	\$ 0.6825	\$1.3300	\$	0.9251

Estimated market prices and weighted average contract prices are in dollars per gallon.

All contracts expire by the end of March 2013.

The following tables present information about the fair value and related gains and losses of our derivative contracts. We did not have any derivative contracts with a credit-risk-related contingency.

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Fair values of the derivative contracts recorded in the condensed consolidated balance sheet as of September 30, 2012 and December 31, 2011, are as follows:

<i>(in thousands)</i>	Balance Sheet Location	Asset Derivatives	
		September 30, 2012	December 31, 2011
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy assets	\$ 600	\$ 1,686
Derivatives designated as fair value hedges			
Put option ⁽¹⁾	Mark-to-market energy assets		68
Call option ⁽²⁾	Mark-to-market energy assets	121	
Total asset derivatives		\$ 721	\$ 1,754

<i>(in thousands)</i>	Balance Sheet Location	Liability Derivatives	
		September 30, 2012	December 31, 2011
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy liabilities	\$ 556	\$ 1,496
Total liability derivatives		\$ 556	\$ 1,496

- (1) We purchased a put option for the Pro-Cap Plan in August 2011. The put option, which expired in March 2012, had a fair value of \$0 at December 31, 2011.
- (2) As a fair value hedge with no ineffective portion, the unrealized gains and losses associated with this call option are recorded in cost of sales, offset by the corresponding change in the value of propane inventory (hedged item), which is also recorded in cost of sales. The amounts in cost of sales offset to zero and the unrealized gains and losses of this call option effectively changed the value of propane inventory.

The effects of gains and losses from derivative instruments on the condensed consolidated financial statements are as follows:

<i>(in thousands)</i>	Location of Gain (Loss) on Derivatives	Amount of Gain (Loss) on Derivatives			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2012	2011	2012	2011
Derivatives not designated as hedging instruments:					
Unrealized gain (loss) on forward contracts	Revenue	\$ 86	\$ 62	\$ (147)	\$ 32
Derivatives designated as fair value hedges:					
Put Option	Cost of sales			27	
Put/Call Option ⁽¹⁾	Inventory	(2)	1	(17)	1
Total		\$ 84	\$ 63	\$ (137)	\$ 33

(1) The change in fair value of the put/call option effectively adjusts the propane inventory balance until it is exercised, at which point the proceeds, if any, reduce cost of sales. There is no ineffective portion of this call option.

The effects of trading activities on the condensed consolidated statements of income are the following:

<i>(in thousands)</i>	Location in the Statement of Income	Three Months Ended September 30,		Nine Months Ended September 30,	
		2012	2011	2012	2011
Realized gains on forward contracts/put option	Revenue	\$ 911	\$ 380	\$ 2,233	\$ 1,934
Unrealized gain (loss) on forward contracts	Revenue	86	62	(147)	32
Total		\$ 997	\$ 442	\$ 2,086	\$ 1,966

Table of Contents**12. Fair Value of Financial Instruments**

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation methods used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy are the following:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities;

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability; and

Level 3: Prices or valuation techniques requiring inputs that are both significant to the fair value measurement and unobservable (i.e. supported by little or no market activity).

The following table summarizes our financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements, by level, within the fair value hierarchy used at September 30, 2012:

	Fair Value	Fair Value Measurements Using:		
		Quoted Prices in Active Markets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
<i>(in thousands)</i>				
Assets:				
Investments equity securities	\$ 2,341	\$ 2,341	\$	\$
Investments other	\$ 2,329	\$ 2,329	\$	\$
Mark-to-market energy assets, including call option	\$ 721	\$	\$ 721	\$
Liabilities:				
Mark-to-market energy liabilities	\$ 556	\$	\$ 556	\$

The following table summarizes our financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements, by level, within the fair value hierarchy used at December 31, 2011:

	Fair Value	Fair Value Measurements Using:		
		Quoted Prices in Active Markets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
<i>(in thousands)</i>				
Assets:				
Investments equity securities	\$ 2,224	\$ 2,224	\$	\$
Investments other ⁽¹⁾	\$ 1,734	\$ 1,734	\$	\$
Mark-to-market energy assets, including put option	\$ 1,754	\$	\$ 1,754	\$
Liabilities:				
Mark-to-market energy liabilities	\$ 1,496	\$	\$ 1,496	\$

⁽¹⁾ The current portion of this investment (\$40) is included in other current assets in the accompanying consolidated balance sheets.

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The following valuation techniques were used to measure fair value assets in the table above on a recurring basis as of September 30, 2012 and December 31, 2011:

Level 1 Fair Value Measurements:

Investments- equity securities - The fair values of these trading securities are recorded at fair value based on unadjusted quoted prices in active markets for identical securities.

Investments- other - The fair values of these investments, comprised of money market and mutual funds, are recorded at fair value based on quoted net asset values of the shares.

Level 2 Fair Value Measurements:

Mark-to-market energy assets and liabilities These forward contracts are valued using market transactions in either the listed or over the counter (OTC) markets.

Propane put/call option The fair value of the propane put option is determined using market transactions for similar assets and liabilities in either the listed or OTC markets.

At September 30, 2012, there were no non-financial assets or liabilities required to be reported at fair value. We review our non-financial assets for impairment at least on an annual basis, as required.

Other Financial Assets and Liabilities

Financial assets with carrying values approximating fair value include cash and cash equivalents and accounts receivable. Financial liabilities with carrying values approximating fair value include accounts payable and other accrued liabilities and short-term debt. The fair value of cash and cash equivalents is measured using the comparable value in the active market and approximates its carrying value (Level 1 measurement). The fair value of short-term debt approximates the carrying value due to its short maturities and because interest rates approximate current market rates (Level 3 measurement).

At September 30, 2012, long-term debt, which includes the current maturities of long-term debt, had a carrying value of \$116.9 million, compared to a fair value of \$140.5 million, using a discounted cash flow methodology that incorporates a market interest rate based on published corporate borrowing rates for debt instruments with similar terms and average maturities, with adjustments for duration, optionality, and risk profile. At December 31, 2011, long-term debt, including the current maturities, had a carrying value of \$118.5 million, compared to the estimated fair value of \$142.3 million. The valuation technique used to estimate the fair value of long-term debt would be considered Level 3 measurement.

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Our outstanding long-term debt is shown below:

<i>(in thousands)</i>	September 30, 2012	December 31, 2011
<i>(A)</i>		
FPU secured first mortgage bonds ^(A) :		
9.57% bond, due May 1, 2018	\$ 5,443	\$ 6,348
10.03% bond, due May 1, 2018	2,993	3,492
9.08% bond, due June 1, 2022	7,961	7,958
Uncollateralized senior notes:		
7.83% note, due January 1, 2015	6,000	6,000
6.64% note, due October 31, 2017	16,363	16,363
5.50% note, due October 12, 2020	18,000	18,000
5.93% note, due October 31, 2023	30,000	30,000
5.68% note, due June 30, 2026	29,000	29,000
Convertible debentures:		
8.25% due March 1, 2014	1,017	1,134
Promissory note	140	186
Total long-term debt	116,917	118,481
Less: current maturities	(8,196)	(8,196)
Total long-term debt, net of current maturities	\$ 108,721	\$ 110,285

(A) FPU secured first mortgage bonds are guaranteed by Chesapeake.

On June 23, 2011, we issued \$29.0 million of 5.68 percent unsecured senior notes to Metropolitan Life Insurance Company and New England Life Insurance Company, pursuant to an agreement we entered into with them on June 29, 2010. These notes require annual principal payments of \$2.9 million beginning in the sixth year after the issuance. We used the proceeds to permanently finance the redemption of the 6.85 percent and 4.90 percent series of FPU first mortgage bonds. These redemptions occurred in January 2010 and were previously financed by Chesapeake's short-term loan facilities. Under the same agreement, we may issue an additional \$7.0 million of unsecured senior notes prior to May 3, 2013, at a rate ranging from 5.28 percent to 6.43 percent based on the timing of the issuance. These notes, if issued, will have similar covenants and default provisions as the senior notes issued in June 2011.

14. Short-Term Borrowing

On June 22, 2012, we entered into a new \$40 million unsecured, short-term credit facility with an existing lender. The credit facility, which was structured in the form of a revolving credit note maturing on June 1, 2013, increases the short-term loan capacity available from this lender from \$50 million to \$90 million, and the total short-term loan capacity available to us from all lenders from \$100 million to \$140 million, during that period. Borrowings under this new facility bear interest at LIBOR plus 80 basis points or, at our discretion, this lender's Base Rate (as defined in the term note agreement) plus 80 basis points. Other terms and conditions of this facility are substantially the same as the other existing loan facilities available from the same lender. In November 2012, our Board of Directors has authorized us to borrow up to \$100.0 million in the aggregate short-term borrowings.

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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 is designed to provide a reader of the financial statements with a narrative report on our financial condition, results of operations and liquidity. This discussion and analysis should be read in conjunction with the attached unaudited condensed consolidated financial statements and notes thereto and our Annual Report on Form 10-K, as amended, for the year ended December 31, 2011, including the audited consolidated financial statements and notes thereto.

Safe Harbor for Forward-Looking Statements

We make statements in this Quarterly Report on Form 10-Q that do not directly or exclusively relate to historical facts. Such statements are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. One can typically identify forward-looking statements by the use of forward-looking words, such as project, believe, expect, anticipate, intend, plan, estimate, potential, forecast or other similar words, or future or conditional verbs such as may, will, should, would or could. These statements reflect our intentions, plans, expectations, assumptions and beliefs about future financial performance, business strategy, projected plans and objectives of the Company. These statements are subject to many risks, uncertainties and other important factors that could cause actual results to differ materially from those expressed in the forward-looking statements. Such factors include, but are not limited to:

state and federal legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rate structures, and affect the speed at and degree to which competition enters the electric and natural gas industries (including deregulation);

the outcomes of regulatory, tax, environmental and legal matters, including whether pending matters are resolved within current estimates;

the loss of customers due to government-mandated sale of our utility distribution facilities;

industrial, commercial and residential growth or contraction in our service territories;

the weather and other natural phenomena, including the economic, operational and other effects of hurricanes and ice storms and other damaging weather events;

the timing and extent of changes in commodity prices and interest rates;

general economic conditions, including any potential effects arising from terrorist attacks and any consequential hostilities or other hostilities or other external factors over which we have no control;

changes in environmental and other laws and regulations to which we are subject and environmental conditions of property that we now or may in the future own or operate;

the results of financing efforts, including our ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general economic conditions;

declines in the market prices of equity securities and resultant cash funding requirements for our defined benefit pension plans;

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the creditworthiness of counterparties with which we are engaged in transactions;

opportunities for growth in our business units;

the extent of success in connecting natural gas and electric supplies to transmission systems and in expanding natural gas and electric markets;

the effect of accounting pronouncements issued periodically by accounting standard-setting bodies;

conditions of the capital markets and equity markets during the periods covered by the forward-looking statements;

the ability to successfully execute, manage and integrate merger, acquisition or divestiture plans, regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, and the success of the business following a merger, acquisition or divestiture;

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the ability to manage, maintain and grow key customer relationships;

the ability to maintain and establish new key supply sources;

the effect of spot, forward and future market prices on our distribution, wholesale marketing and energy trading businesses;

the effect of competition on our businesses;

the ability to construct facilities at or below estimated costs;

changes in technology affecting our advanced information services business; and

operation and litigation risks that may not be covered by insurance.

Introduction

We are a diversified utility company engaged, directly or through subsidiaries, in regulated energy businesses, unregulated energy businesses, and other unregulated businesses, including advanced information services.

Our strategy is focused on growing earnings from a stable utility foundation and investing in related businesses and services that provide opportunities for returns greater than traditional utility returns. The key elements of this strategy include:

executing a capital investment program in pursuit of organic growth opportunities that generate returns equal to or greater than our cost of capital;

expanding the regulated energy distribution and transmission businesses into new geographic areas and providing new services in our current service territories;

expanding the propane distribution business in existing and new markets through leveraging our community gas system services and our bulk delivery capabilities;

utilizing our expertise across our various businesses to improve overall performance;

enhancing marketing channels to attract new customers;

providing reliable and responsive customer service to retain existing customers;

maintaining a capital structure that enables us to access capital as needed;

maintaining a consistent and competitive dividend for shareholders; and

creating and maintaining a diversified customer base, energy portfolio and utility foundation.

Due to the seasonality of our business, results for interim periods are not necessarily indicative of results for the entire fiscal year. Revenue and earnings are typically greater during the first and fourth quarters, when consumption of energy is normally highest due to colder temperatures.

The following discussions and those later in the document on operating income and segment results include the use of the term gross margin. Gross margin is determined by deducting the cost of sales from operating revenue. Cost of sales includes the purchased cost of natural gas, electricity and propane and the cost of labor spent on direct revenue-producing activities. Gross margin should not be considered an alternative to operating income or net income, which are determined in accordance with GAAP. We believe that gross margin, although a non-GAAP measure, is useful and meaningful to investors as a basis for making investment decisions. It provides investors with information that demonstrates the profitability achieved by the Company under its allowed rates for regulated energy operations and under its competitive pricing structure for unregulated natural gas marketing and propane distribution operations. Our management uses gross margin in measuring our business units performance and has historically analyzed and reported gross margin information publicly. Other companies may calculate gross margin in a different manner.

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Summary of Key Factors

The following is a summary of key factors affecting our businesses and their impact on our results during the periods presented as well as the future.

Growth

We continue to see growth in our natural gas businesses from our efforts over the past several years to expand our services. We are committed to delivering clean-burning, environmentally friendly natural gas to customers, and we are identifying and developing additional opportunities that will generate growth over the next several years.

New natural gas transmission services and growth in natural gas distribution customers generated \$1.1 million and \$615,000, respectively, in additional gross margin for the third quarter of 2012, compared to the same period in 2011. New natural gas transmission services and growth in natural gas distribution customers generated \$2.8 million and \$1.8 million, respectively, in additional gross margin for the first nine months of 2012, compared to the same period in 2011. Most of these increases in gross margin were related to the continued execution of our strategic plan, including expansion of natural gas service to new areas and conversion of several large commercial and industrial customers to natural gas. New services are being initiated by our natural gas transmission subsidiaries in response to increased demand for natural gas service on the Delmarva Peninsula and in Florida, both from our natural gas distribution operations and other unaffiliated customers directly connected to the transmission systems.

Major Expansion Initiatives and Customer Growth Reflected in Results

In late 2011 and during the first nine months of 2012, we expanded natural gas transmission and distribution services to Sussex County, Delaware and Nassau County, Florida and also initiated natural gas transmission service in Worcester County, Maryland. These major expansion initiatives increased our natural gas footprint, delivering natural gas service to areas where it was not previously available. These initiatives generated \$903,000 of additional gross margin for the natural gas transmission operations and \$110,000 of additional gross margin for the natural gas distribution operations during the third quarter of 2012. For the first nine months of 2012, these initiatives generated \$2.0 million and \$396,000 of additional gross margin for the natural gas transmission and distribution operations, respectively. New transmission services associated with these initiatives are expected to generate gross margin of \$2.9 million in 2012 (\$2.0 million has been recorded in the first nine months of 2012), compared to \$156,000 in 2011 (all of which occurred in the fourth quarter) and \$3.9 million in annualized gross margin thereafter. New distribution services associated with these initiatives are expected to generate gross margin of \$534,000 in 2012 (\$396,000 has been recorded in the first nine months of 2012) and \$545,000 in annualized gross margin thereafter.

Sussex County, Delaware In November 2011, Eastern Shore increased its transmission service by 3,250 Dts/d to our Delaware division in response to its expansion of natural gas distribution service in Lewes, Delaware. Eastern Shore generated \$234,000 and \$701,000 in additional gross margin for the three and nine months ended September 30, 2012, respectively, from this service. Estimated annual gross margin from this service is expected to be \$935,000 in 2012. We recorded \$156,000 in gross margin in 2011 upon the commencement of the service. In December 2011, our Delaware division commenced new distribution service to two large industrial customers in Lewes, Delaware. Our Delaware division generated \$91,000 and \$357,000 in additional gross margin from these new customers for the three and nine months ended September 30, 2012, respectively. Estimated annual gross margin from these new customers is expected to be \$456,000 in 2012. We recorded \$1,000 in gross margin upon the commencement of the service in December 2011.

In March through May of 2012, Eastern Shore expanded its mainline capacity to provide an additional transmission service of 1,550 Dts/d to our Delaware division in response to its expansion of natural gas distribution service in the southeastern part of Sussex County. This new transmission service generated \$111,000 and \$223,000 in gross margin for the three and nine months ended September 30, 2012, respectively. We expect to generate \$334,000 in gross margin in 2012 from this new service. Estimated future annual gross margin is \$446,000. In March and August 2012, our Delaware division commenced new distribution services to two industrial facilities of an existing customer in southeastern Sussex County and generated \$19,000 and \$39,000 in gross margin for the three and nine months ended September 30, 2012, respectively, from these new services. We expect to generate \$78,000 in gross margin in 2012 from these services. Estimated future annual gross margin expected to be generated from these services is \$154,000.

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Worcester County, Maryland Eastern Shore expanded its mainline capacity to provide additional transmission services totaling 1,450 Dts/d to our Maryland division and to an unaffiliated customer. A portion of these services began in June 2012 and Eastern Shore expects to complete its expansion by December 2012. These new transmission services generated \$29,000 and \$39,000 in gross margin for the three and nine months ended September 30, 2012, respectively. We expect to generate \$102,000 in gross margin in 2012 from these new services and estimated future annual gross margin of \$391,000 thereafter.

Nassau County, Florida In April 2012, the Florida PSC approved the firm transportation agreement between Peninsula Pipeline and FPU. Under this agreement, Peninsula Pipeline provides natural gas transmission service to support FPU's expansion of natural gas distribution service in Nassau County, Florida for an annual rate of \$2.1 million. Peninsula Pipeline began its service to FPU in April 2012, using compressed natural gas pending the completion of a 16-mile pipeline, which generated \$529,000 and \$1.1 million in additional gross margin for the three and nine months ended September 30, 2012, respectively. Peninsula Pipeline expects to incur approximately \$800,000 in annual transportation costs once the new pipeline is completed, which will reduce gross margin.

In addition to the recent expansion initiatives, the Delmarva natural gas distribution operation has added another 10 new large industrial and commercial customers since the beginning of 2011, which generated \$122,000 in additional gross margin in the third quarter of 2012 and \$468,000 in the first nine months of 2012, compared to the same periods in 2011, respectively. These 10 new customers are expected to generate \$950,000 of gross margin in 2012, compared to \$429,000 generated in 2011. Customer growth in Florida, primarily from commercial and industrial customers, also generated \$351,000 and \$686,000 in additional gross margin in the third quarter and first nine months of 2012, respectively.

Future Major Expansion Initiatives and Opportunities

Although not affecting results in the third quarter and first nine months of 2012, we are continuing our effort to extend natural gas service to Cecil County, Maryland, with the transmission service expected to commence in November 2012. Eastern Shore has executed precedent agreements with NRG Energy Center Dover LLC (NRG) and PBF Energy Inc. (Delaware City Refinery) to further expand its transmission system to provide additional capacities to these customers. Firm transportation service agreements are expected to be executed by NRG and Delaware City Refinery with Eastern Shore for 13,440 Dts/d and 15,000 Dts/d, respectively, upon satisfaction of certain conditions pursuant to the respective precedent agreements. These additional services are expected to be initiated in mid-to-late 2013.

As we expand our natural gas service to new areas, first through transmission service and distribution service to large industrial customers, our natural gas distribution operations continue to pursue additional opportunities to provide service to residential and other commercial and industrial customers in those areas. In an effort to increase the availability of natural gas within our Delaware service areas, our Delaware natural gas distribution division filed an application with the Delaware PSC in June 2012 to add several natural gas expansion service offerings. These offerings include a monthly fixed charge in lieu of upfront contributions from customers to extend the distribution system and optional service offerings to assist customers in the process of converting to natural gas. The goal of these new offerings is to meet the energy needs of residents, communities and businesses throughout our service territory, specifically in areas of southeastern Sussex County, where natural gas will now be available.

Acquisition

In June 2012, we entered into an agreement to purchase the operating assets of ESG for approximately \$16.5 million. These assets are currently used to provide propane distribution service to approximately 11,000 residential and commercial customers in Worcester County, Maryland, primarily through underground propane gas distribution systems. We are evaluating the potential conversion of some of these underground propane distribution systems to natural gas where it is economical and feasible. In August 2012, we filed an application for approval of the transaction with the Maryland PSC. The transaction, which is also subject to the receipt of consents of certain local jurisdictions to the assignment of certain franchise agreements and satisfaction of other closing conditions, is expected to be completed in 2013. We expect to finance the acquisition using unsecured short-term debt. The acquisition is expected to be accretive to earnings per share in 2013 and thereafter.

Investing in Growth

To continue our growth, we are expanding our resources and capabilities. We are in the early stages of several natural gas expansions on the Delmarva Peninsula. These include expansions into Sussex County, Delaware, and Worcester and Cecil Counties in Maryland. These expansions will require not only the construction or conversion of distribution facilities, but also the conversion of customers' appliances or equipment inside their homes. We are currently in the process of reorganizing our Delmarva natural gas distribution operation and expect to

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increase our staffing to support these expansions. Secondly, as a result of BravePoint's growth over the last several quarters, BravePoint is continuing to add staff. During the quarter and nine months ended September 30, 2012, BravePoint's other operating expenses increased by \$208,000 and \$937,000, respectively, compared to the same periods in 2011, due primarily to additional staff. Finally, to increase our capacity for future growth, resources will be added in several key functional areas, including, but not limited to, Human Resources, Communications and Strategic Business Development. For the quarter and nine months ended September 30, 2012, we incurred \$105,000 and \$429,000, respectively, on acquisition-related costs and \$292,000 and \$314,000, respectively, associated with increased capacity for future growth. We expect additional increases in costs associated with these key functional areas in the future.

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Table of Contents**Weather**

Weather affects customer energy consumption, especially the consumption by residential and certain commercial customers during the peak heating and cooling seasons. Natural gas, electricity and propane are all used for heating in our service territories and we use the number of heating degree-days (HDD) to analyze the weather impact. Only electricity is used for cooling, and we use the number of cooling degree-days (CDD) to analyze the weather impact. A degree-day is the measure of the variation in the weather based on the extent to which the average daily temperature (from 10:00 am to 10:00 am next day) falls above or below 65 degrees Fahrenheit. Each degree of temperature above or below 65 degrees Fahrenheit is counted as one CDD or one HDD. We use 10-year historical averages to define the normal weather for this analysis.

Although weather was not a significant factor in the second and third quarters of 2012, warmer temperatures during the first three months of the year, compared to temperatures in 2011, had a significant impact on our earnings. Lower customer energy consumption directly attributable to warmer temperatures in the nine months ended September 30, 2012, compared to temperatures in the same period in 2011, reduced gross margin by \$4.0 million. Temperatures on the Delmarva Peninsula in the first nine months of 2012 were 17 percent (501 heating degree-days) warmer than the same period in 2011 and 18 percent (524 heating degree-days) warmer than normal temperatures, based on 10-year historic average of heating degree-days. Temperatures in Florida in the first nine months of 2012 were 35 percent (187 heating degree-days) warmer than the same period in 2011 and 41 percent (240 heating degree-days) warmer than normal temperatures. We estimate that this variance reduced gross margin for the first nine months of 2012 by approximately \$3.9 million, compared to gross margin under normal temperatures.

Variations due to CDD, in comparison to the prior periods and normal temperatures, were not a significant factor during the third quarter and the first nine months of 2012.

Rates and Regulatory Matters

In January 2012, the Florida PSC issued an order, approving the recovery of \$34.2 million in acquisition adjustment and \$2.2 million in merger-related costs in connection with Chesapeake's acquisition of FPU in 2009. The inclusion of the acquisition adjustment and merger-related costs in our rate base and the recovery of these assets through amortization expense will increase our earnings and cash flows above what FPU would have achieved absent the regulatory approval. The acquisition adjustment and merger-related costs are amortized over 30 years and five years, respectively, beginning in November 2009. Based upon the effective date and outcome of the order, we recorded the amortization as an expense in 2012, which increased amortization expense by \$589,000 in the third quarter of 2012 and \$1.8 million in the first nine months of 2012. We expect to record \$2.4 million (\$1.4 million, net of tax) in amortization expense in 2012 and 2013, \$2.3 million (\$1.4 million, net of tax) in 2014, and \$1.8 million (\$1.1 million, net of tax) annually thereafter until 2039.

In August 2012, the Florida PSC approved a GRIP for FPU's natural gas operation and Chesapeake's Florida division which provides an annual surcharge mechanism to recover capital and other program-related-costs, inclusive of an appropriate return on investment, associated with accelerating the replacement of qualifying distribution mains and services (defined as any material other than coated steel or plastic). The annual surcharge is effective January 1, 2013, and the first year surcharge will include investments made in the period from August 14, 2012 through December 31, 2013. We expect to incur approximately \$75 million over a 10-year period to replace qualifying mains and services in Florida.

At the October 16, 2012 agenda conference, the Florida PSC approved two petitions, which had been filed by FPU: (a) recognition of a \$1.9 million regulatory liability for a one-time tax contingency gain, including appropriate gross-up for tax, to be amortized over a period from January 2012 to October 2014, and (b) deferral, as a regulatory asset, of the previously expensed and future litigation expenses associated with the litigation initiated by the City of Marianna to be amortized over five years beginning in January 2013 for accounting and reporting purposes. We expect the Florida PSC to issue its order in mid-November 2012, affirming its approval at the October 16, 2012 agenda conference. Once the order is issued, we will begin to record the amortization of the tax regulatory liability, effective January 1, 2012, with the cumulative effect of the amortization recorded at that time, which will increase operating income by approximately \$684,000 in 2012 and 2013 and \$570,000 in 2014. We are currently assessing the potential impact under GAAP of the expected Florida PSC order regarding the litigation expenses. Any deferral of the previously expensed litigation expense will not be recorded until the order is issued by the Florida PSC. The total litigation expense associated with the City of Marianna litigation could be as high as \$1.4 million by the end of 2012.

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Propane Prices

Propane prices affect both retail and wholesale marketing margins. Our propane distribution operation usually benefits from rising propane prices by selling propane to its distribution customers based upon higher wholesale prices, while its average cost of inventory trails behind. Retail prices generally take into account replacement cost, along with other factors, such as competition and market conditions. When wholesale prices (replacement costs) increase, retail prices generally increase and our margins expand until the current wholesale price is fully reflected in the average cost of inventory. The opposite occurs when propane prices decline. Our propane wholesale marketing operation benefits from price volatility in the propane wholesale market by entering into trading transactions.

Retail margins per gallon did not have a significant impact on gross margin of our Delmarva propane distribution operation during the third quarter of 2012, compared to the same quarter in 2011. For the first nine months of 2012, compared to the same periods in 2011, lower retail margins per gallon primarily during the first half of 2012 decreased gross margin of our Delmarva propane distribution operation by \$675,000. A significant decline in wholesale propane prices during mid-2012, which resulted in a write-down of \$465,000 in the inventory value during the first half of 2012, contributed to this decrease. Our Florida propane distribution operation generated \$524,000 and \$1.6 million in additional gross margin during the third quarter and first nine months of 2012, compared to the same periods in 2011, respectively, from higher retail margins per gallon. Sustained retail pricing in Florida in response to local market conditions and lower average propane inventory cost are contributing to the increased retail margins per gallon.

Xeron, our propane wholesale marketing subsidiary, executed trades with higher margins, which generated an increase in gross margin of \$481,000 in the third quarter of 2012, compared to the same quarter of 2011, as the market presented opportunities resulting from the fluctuation in propane wholesale prices. Xeron's gross margin increased by \$231,000 in the first nine months of 2012, compared to the same period in 2011.

Advanced Information Services

BravePoint, our advanced information services subsidiary, reported operating income of \$312,000 and \$557,000 in the third quarter and first nine months of 2012, compared to an operating loss of \$74,000 and \$356,000 in the same periods in 2011, respectively. \$188,000 and \$464,000 of BravePoint's operating income for the quarter and nine-month period, respectively, were a result of ProfitZoom and Application Evolution sales and related services. The remaining increase was due to higher consulting revenues and other product sales.

BravePoint continues to market its new products, ProfitZoom and Application Evolution. BravePoint generated \$324,000 and \$900,000 in revenue from the sale of these two products and related services during the third quarter and first nine months of 2012, respectively. To date, BravePoint has successfully implemented or is currently implementing ProfitZoom for eight customers in the fire suppression industry. Application Evolution, which is a component of ProfitZoom, is being marketed to customers both in the fire suppression industry and other unrelated businesses. Nine customers are currently utilizing this product. These ProfitZoom and Application Evolution contracts are expected to generate approximately \$1.0 million in additional revenue over the next 12 months. Additional sales proposals are under consideration by both existing and potential new customers.

Table of Contents**Results of Operations for the Quarter Ended September 30, 2012****Overview and Highlights**

Our net income for the quarter ended September 30, 2012 was \$3.2 million, or \$0.33 per share (diluted). This represents an increase of \$822,000, or \$0.09 per share (diluted), compared to a net income of \$2.4 million, or \$0.25 per share (diluted), as reported for the same quarter in 2011.

For the Three Months Ended September 30, (in thousands except per share)	2012	2011	Increase (decrease)
Business Segment:			
Regulated Energy	\$ 7,848	\$ 6,943	\$ 905
Unregulated Energy	(709)	(1,392)	683
Other	425	43	382
Operating Income	7,564	5,594	1,970
Other (loss) Income, net of other expenses	(136)	649	(785)
Interest Charges	2,126	2,389	(263)
Pre-tax Income	5,302	3,854	1,448
Income Taxes	2,083	1,457	626
Net Income	\$ 3,219	\$ 2,397	\$ 822
Earnings Per Share of Common Stock			
Basic	\$ 0.34	\$ 0.25	\$ 0.09
Diluted	\$ 0.33	\$ 0.25	\$ 0.08

Key variances for the quarter ended September 30, 2012 include:

(in thousands, except per share amounts)	Pre-tax Income	Net Income	Diluted Earnings Per Share
Q3 2011 Reported Results	\$ 3,854	\$ 2,397	\$ 0.25
Normalizing Items:			
Amortization of acquisition premium and costs	(589)	(366)	(0.04)
Pension settlement charge in 2011	219	136	0.01
Gain from the sale of Internet Protocol asset in 2011	(553)	(344)	(0.03)
	(923)	(574)	(0.06)
Increased Margins:			
Natural gas growth	1,731	1,077	0.11
BravePoint	594	369	0.04
Higher propane retail margins per gallon	497	309	0.03
Propane wholesale marketing	481	299	0.03
	3,303	2,054	0.21
Increased Other Expenses:			
Higher depreciation and asset removal costs	(339)	(211)	(0.02)
Increased capacity for future growth	(292)	(182)	(0.02)
BravePoint, primarily due to employee-related costs	(208)	(129)	(0.01)
Acquisition-related costs	(105)	(65)	(0.01)

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	(944)	(587)	(0.06)
Net other changes	12	(71)	(0.01)
Q3 2012 Reported Results	\$ 5,302	\$ 3,219	\$ 0.33

The strong third-quarter performance in 2012 was due primarily to increased gross margin generated by natural gas transmission and distribution operations, higher revenues from BravePoint product sales and consulting activities and higher margins generated from propane retail sales in Florida and wholesale marketing activities. These gross margin increases more than offset amortization expense related to the recovery of the FPU acquisition adjustment and merger-related costs, higher costs associated with growth initiatives, depreciation on new capital investments and the one-time gain recorded in 2011 from the sale of a non-operating Internet Protocol asset.

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The following section also provides a more detailed analysis of our results by segment.

Regulated Energy

For the Three Months Ended September 30, <i>(in thousands, except degree-day and customer information)</i>	2012	2011	Increase (decrease)
Revenue	\$ 52,196	\$ 53,651	(\$1,455)
Cost of sales	22,102	25,811	(3,709)
Gross margin	30,094	27,840	2,254
Operations & maintenance	15,421	14,918	503
Depreciation & amortization	4,798	4,098	700
Other taxes	2,027	1,881	146
Other operating expenses	22,246	20,897	1,349
Operating Income	\$ 7,848	\$ 6,943	\$ 905
Weather and Customer Analysis			
Delmarva Peninsula			
HDD:			
Actual	79	49	30
10-year average	47	53	(6)
Estimated gross margin per HDD	\$ 2,064	\$ 1,995	\$ 69
Per residential customer added:			
Estimated gross margin	\$ 375	\$ 375	\$ 0
Estimated other operating expenses	\$ 113	\$ 111	\$ 2
Florida			
HDD:			
Actual	0	0	0
10-year average	0	0	0
CDD:			
Actual	1,475	1,569	(94)
10-year average	1,505	1,483	22
Residential Customer Information			
Average number of customers:			
Delmarva natural gas distribution	48,927	47,810	1,117
Florida natural gas distribution	62,215	61,261	954
Florida electric distribution	23,703	23,583	120
Total	134,845	132,654	2,191

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Operating income for the regulated energy segment increased by approximately \$905,000, or 13 percent, in the third quarter of 2012, compared to the same quarter in 2011. An increase in gross margin of \$2.3 million, partially offset by an increase in operating expenses of \$1.4 million, contributed to this increase.

Gross Margin

Gross margin for our regulated energy segment increased by \$2.3 million, or eight percent, in the third quarter of 2012, compared to the same quarter in 2011.

Our Delmarva natural gas distribution operation experienced an increase in gross margin of \$462,000 in the third quarter of 2012, compared to the same quarter in 2011, due primarily to the following factors:

Gross margin from distribution service to four commercial and industrial customers added as part of the major expansion initiatives in Sussex County, Delaware generated \$110,000 in additional gross margin in the third quarter of 2012, compared to the same quarter in 2011.

Gross margin from commercial and industrial customers for the Delmarva natural gas distribution operation increased by \$82,000 in the third quarter of 2012, due primarily to the additional margin of \$122,000 generated by another 10 new large commercial and industrial customers since the beginning of 2011, offset by a slight decline in other commercial and industrial customers of \$40,000. Two-percent growth in residential customers generated an additional \$72,000 in gross margin for the Delmarva natural gas distribution operation.

Additional gross margin of \$198,000 was due primarily to an increase in customer consumption of natural gas.

Gross margin for our Florida natural gas distribution operation increased by \$519,000 in the third quarter of 2012, compared to the same quarter in 2011. The factors contributing to this increase were as follows:

Customer growth, primarily in commercial and industrial customers, generated \$352,000 of additional gross margin.

The remaining increase was due to margins generated from an increase in customer consumption of natural gas, partially offset by lower gross margin as a result of a decline in fees and service revenues and a change in customer rates and rate classes.

Our natural gas transmission operations generated gross margin growth of \$1.4 million in the third quarter of 2012, compared to the same quarter in 2011. The factors contributing to this increase were as follows:

Peninsula Pipeline, our Florida intrastate natural gas transmission subsidiary, generated \$529,000 in additional gross margin as part of the major expansion initiative in Nassau County, Florida.

Major expansion initiatives in Sussex County, Delaware, and Worcester County, Maryland generated \$374,000 in additional gross margin in the third quarter of 2012 for Eastern Shore, our interstate natural gas transmission subsidiary.

Eastern Shore also generated \$213,000 in additional gross margin in the third quarter of 2012, due primarily to a new transmission agreement with an existing industrial customer for an additional 9,514 Dts/d for a one-year period from November 2011 to October 2012. This additional service, which is the result of a system expansion, is expected to generate additional gross margin of \$84,000 during the fourth quarter of 2012.

Also contributing to gross margin was an additional increase of \$241,000 due to additional gross margin by Eastern Shore as a result of new rates implemented, effective July 2011, pursuant to a rate case settlement. Eastern Shore did not record the additional margin from the base rate increase until November 2011, when the rate case settlement was finalized by Eastern Shore, the FERC Staff and other interested parties and submitted for approval. The rate case settlement was approved without any modification by the FERC in January 2012.

Gross margin for our Florida electric distribution operation decreased by \$163,000 in the third quarter of 2012, compared to the same quarter in 2011, due primarily to lower energy consumption by customers.

Table of Contents**Other Operating Expenses**

Other operating expenses for the regulated energy segment increased by \$1.4 million in the third quarter of 2012, compared to the same quarter in 2011, due largely to \$589,000 in increased amortization expense associated with the recovery of the FPU acquisition adjustment and merger-related costs, \$314,000 in increased costs associated with investing in growth and \$249,000 in higher depreciation expense and asset removal costs associated with capital investments made during 2011 and early 2012.

Unregulated Energy

For the Three Months Ended September 30, <i>(in thousands, except degree-day data)</i>	2012	2011	Increase (decrease)
Revenue	\$ 23,259	\$ 23,721	(\$462)
Cost of sales	17,033	18,622	(1,589)
Gross margin	6,226	5,099	1,127
Operations & maintenance	5,756	5,432	324
Depreciation & amortization	861	774	87
Other taxes	318	285	33
Other operating expenses	6,935	6,491	444
Operating Loss	(\$709)	(\$1,392)	\$ 683
Weather Analysis Delmarva Peninsula			
Actual HDD	79	49	30
10-year average HDD	47	53	(6)
Estimated gross margin per HDD	\$ 2,869	\$ 2,611	\$ 258

Operating loss for the unregulated energy segment decreased by \$683,000, or 49 percent, in the third quarter of 2012, compared to the same quarter in 2011. An increase in gross margin of \$1.1 million was partially offset by an increase in other operating expenses of \$444,000.

Gross Margin

Gross margin for our unregulated energy segment increased by \$1.1 million, or 22 percent, in the third quarter of 2012, compared to the same quarter in 2011.

Our Delmarva propane distribution operation reported an increase in gross margin of \$51,000 in the third quarter of 2012, compared to the same quarter in 2011, due primarily to higher gross margin generated by wholesale volumes.

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Gross margin for our Florida propane distribution operation increased by \$581,000 in the third quarter of 2012, compared to 2011.

The factors contributing to this increase were as follows:

Higher retail margins per gallon in Florida generated an additional gross margin of \$524,000 due to our ability to maintain our current level of retail pricing in response to local market condition and lower average propane inventory cost.

Additional gross margin of \$57,000 was generated from 1,180 customers acquired in late 2011 and early 2012, following the purchase of the operating assets of several small propane distribution companies.

Xeron, our propane wholesale marketing subsidiary, generated an increase in gross margin of \$481,000 in the third quarter of 2012, compared to the same quarter in 2011, as a result of higher margins in its trading activity. Xeron executed trades with higher margins during the third quarter of 2012 as the market presented opportunities resulting from fluctuation in wholesale propane prices.

Gross margin from PESCO slightly decreased by \$28,000 during the third quarter of 2012, compared to the same quarter in 2011. Additional gross margin generated by new customers and contracts was more than offset by a quarter-over-quarter decrease in imbalance resolutions.

Other Operating Expenses

Other operating expenses for the unregulated energy segment increased by \$444,000 in the third quarter of 2012, compared to the same quarter in 2011. This increase was due largely to increased payroll and benefits costs in the Florida propane operation, resulting from resources added to serve new territories, and increased costs associated investing in growth.

Table of Contents**Other**

For the Three Months Ended September 30, <i>(in thousands)</i>	2012	2011	Increase (decrease)
Revenue	\$ 2,720	\$ 3,238	(\$518)
Cost of sales	569	1,684	(1,115)
Gross margin	2,151	1,554	597
Operations & maintenance	1,428	1,238	190
Depreciation & amortization	108	106	2
Other taxes	190	167	23
Other operating expenses	1,726	1,511	215
Operating Income Other	425	43	382
Operating Income Eliminations (1)			
Operating Income	\$ 425	\$ 43	\$ 382

(1) Eliminations are entries required to eliminate activities between business segments from the consolidated results. Operating income for our other segment increased by approximately \$382,000 in the third quarter of 2012, compared to the same quarter in 2011, which was attributable to a gross margin increase of \$597,000, partially offset by an operating expense increase of \$215,000.

Gross margin

Our other segment generated gross margin of \$2.2 million during the third quarter, compared to \$1.6 million for the same quarter of 2011, as a result of an increase of \$594,000 in gross margin generated by BravePoint, \$188,000 of which represented higher margin from ProfitZoom and Application Evolution sales and related services. The remaining increase was generated from higher consulting revenues and other product sales.

Other Operating Expenses

Other operating expenses for our other segment increased by \$215,000 in the third quarter of 2012, compared to the same quarter in 2011. BravePoint accounted for \$208,000 of this increase as it added resources to support consulting and other service engagements.

Interest Expense

Total interest expense for the quarter ended September 30, 2012 decreased by approximately \$263,000, or 11 percent, compared to the same quarter in 2011. The decrease in interest expense is attributable primarily to decreases of \$168,000 in other long-term interest expense due to scheduled repayments reducing the outstanding principal balance and \$141,000 in interest on deposits from FPU's customers due to a lower interest rate applied to those deposits. Partially offsetting this decrease was an increase of \$46,000 in short-term interest expense due to slightly increased short-term borrowings and rates in 2012 compared to the same quarter in 2011.

Income Taxes

Income tax expense was \$2.1 million in the third quarter of 2012, compared to \$1.5 million in the same quarter in 2011. The increase in income tax expense was due primarily to higher earnings for the period.

Table of Contents**Results of Operations for the Nine Months Ended September 30, 2012****Overview and Highlights**

Our net income for the nine months ended September 30, 2012 was \$19.0 million, or \$1.97 per share (diluted). This represents a decrease of \$658,000, or \$0.07 per share (diluted), compared to a net income of \$19.7 million, or \$2.04 per share (diluted), as reported for the same period in 2011.

For the Nine Months Ended September 30, <i>(in thousands except per share)</i>	2012	2011	Increase (decrease)
Business Segment:			
Regulated Energy	\$ 33,151	\$ 30,964	\$ 2,187
Unregulated Energy	4,044	7,276	(3,232)
Other	897	(31)	928
Operating Income	38,092	38,209	(117)
Other Income, net of other expenses	212	699	(487)
Interest Charges	6,657	6,654	3
Pre-tax Income	31,647	32,254	(607)
Income Taxes	12,641	12,590	51
Net Income	\$ 19,006	\$ 19,664	(\$658)
Earnings Per Share of Common Stock			
Basic	\$ 1.98	\$ 2.06	(\$0.08)
Diluted	\$ 1.97	\$ 2.04	(\$0.07)

