CHESAPEAKE UTILITIES CORP
Form 10-Q
August 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: June 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)

Delaware	**51-0064146**
(State or other jurisdiction of incorporation or organization)	**(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 x 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 x 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	x
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 x

Common Stock, par value $0.4867 9,592,275 shares outstanding as of July 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 resulting from 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.

Remedial Action Plan (RAP): Procedures taken or being considered to remove contaminants from MGPs formerly owned or operated by Chesapeake or FPU.

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

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Income (Unaudited)

For the Three Months Ended June 30, *(in thousands, except shares and per share data)*	2012	2011
Operating Revenues		
Regulated Energy	**$ 55,553**	$ 54,193
Unregulated Energy	**25,176**	29,692
Other	**3,168**	2,946
Total operating revenues	**83,897**	86,831
Operating Expenses		
Regulated energy cost of sales	**23,433**	24,882
Unregulated energy and other cost of sales	**19,861**	24,420
Operations	**20,071**	20,401
Maintenance	**1,858**	1,892
Depreciation and amortization	**5,885**	4,937
Other taxes	**2,334**	2,523
Total operating expenses	**73,442**	79,055
Operating Income	**10,455**	7,776
Other income, net of expenses	**153**	27
Interest charges	**2,241**	2,114
Income Before Income Taxes	**8,367**	5,689
Income tax expense	**3,307**	2,169
Net Income	**$ 5,060**	$ 3,520
Weighted-Average Common Shares Outstanding:		
Basic	**9,586,159**	9,557,707
Diluted	**9,681,597**	9,650,887
Earnings Per Share of Common Stock:		
Basic	**$ 0.53**	$ 0.37
Diluted	**$ 0.52**	$ 0.37
Cash Dividends Declared Per Share of Common Stock	**$ 0.365**	$ 0.345

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

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Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Income (Unaudited)

For the Six Months Ended June 30, *(in thousands, except shares and per share data)*	**2012**	**2011**
Operating Revenues		
Regulated Energy	**$ 127,849**	$ 139,063
Unregulated Energy	**70,063**	88,442
Other	**6,899**	5,924
Total operating revenues	**204,811**	233,429
Operating Expenses		
Regulated energy cost of sales	**59,105**	72,872
Unregulated energy and other cost of sales	**54,453**	68,711
Operations	**40,027**	40,237
Maintenance	**3,834**	3,595
Depreciation and amortization	**11,646**	9,958
Other taxes	**5,218**	5,441
Total operating expenses	**174,283**	200,814
Operating Income	**30,528**	32,615
Other income, net of expenses	**349**	50
Interest charges	**4,532**	4,265
Income Before Income Taxes	**26,345**	28,400
Income tax expense	**10,558**	11,133
Net Income	**$ 15,787**	$ 17,267
Weighted-Average Common Shares Outstanding:		
Basic	**9,578,715**	9,546,606
Diluted	**9,674,240**	9,642,374
Earnings Per Share of Common Stock:		
Basic	**$ 1.65**	$ 1.81
Diluted	**$ 1.63**	$ 1.79
Cash Dividends Declared Per Share of Common Stock	**$ 0.710**	$ 0.675

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

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Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Comprehensive Income (Unaudited)

	Three months		Six months	
For the periods ended June 30,	**2012**	**2011**	**2012**	**2011**
(in thousands)				
Net Income	**$ 5,060**	$ 3,520	**$ 15,787**	$ 17,267
Other Comprehensive Income, net of tax:				
Employee Benefits net of tax:				
Amortization of prior service cost, net of tax of ($6), $1, ($13) and $3, respectively	**(9)**	2	**(19)**	4
Amortization of actuarial gain/loss, net of tax of $50, $28, $101 and $239, respectively	**76**	42	**152**	357
Other comprehensive income	**67**	44	**133**	361
Comprehensive income	**$ 5,127**	$ 3,564	**$ 15,920**	$ 17,628

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

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Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Balance Sheets (Unaudited)

Assets *(in thousands, except shares and per share data)*	**June 30, 2012**	**December 31, 2011**
Property, Plant and Equipment		
Regulated energy	**$ 544,118**	$ 528,790
Unregulated energy	**68,482**	67,327
Other	**18,334**	19,988
Total property, plant and equipment	**630,934**	616,105
Less: Accumulated depreciation and amortization	**(146,027)**	(137,784)
Plus: Construction work in progress	**24,629**	9,383
Net property, plant and equipment	**509,536**	487,704
Current Assets		
Cash and cash equivalents	**1,737**	2,637
Accounts receivable (less allowance for uncollectible accounts of $974 and $1,090, respectively)	**41,619**	76,605
Accrued revenue	**8,303**	10,403
Propane inventory, at average cost	**6,209**	9,726
Other inventory, at average cost	**2,999**	4,785
Regulatory assets	**2,375**	1,846
Storage gas prepayments	**3,229**	5,003
Income taxes receivable	**6,010**	6,998
Deferred income taxes	**2,116**	2,712
Prepaid expenses	**3,233**	5,072
Mark-to-market energy assets	**585**	1,754
Other current assets	**155**	219
Total current assets	**78,570**	127,760
Deferred Charges and Other Assets		
Goodwill	**4,090**	4,090
Other intangible assets, net	**2,961**	3,127
Investments, at fair value	**4,692**	3,918
Regulatory assets	**76,763**	79,256
Receivables and other deferred charges	**3,088**	3,211
Total deferred charges and other assets	**91,594**	93,602
Total Assets	**$ 679,700**	**$ 709,066**

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

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Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Balance Sheets (Unaudited)

Capitalization and Liabilities *(in thousands, except shares and per share data)*	**June 30, 2012**	**December 31, 2011**
Capitalization		
Stockholders equity		
Common stock, par value $0.4867 per share (authorized 25,000,000 shares)	**$ 4,668**	$ 4,656
Additional paid-in capital	**149,908**	149,403
Retained earnings	**100,225**	91,248
Accumulated other comprehensive loss	**(4,394)**	(4,527)
Deferred compensation obligation	**958**	817
Treasury stock	**(958)**	(817)
Total stockholders equity	**250,407**	240,780
Long-term debt, net of current maturities	**108,755**	110,285
Total capitalization	**359,162**	351,065
Current Liabilities		
Current portion of long-term debt	**8,196**	8,196
Short-term borrowing	**13,553**	34,707
Accounts payable	**37,018**	55,581
Customer deposits and refunds	**29,991**	30,918
Accrued interest	**1,422**	1,637
Dividends payable	**3,501**	3,300
Accrued compensation	**5,088**	6,932
Regulatory liabilities	**3,743**	6,653
Mark-to-market energy liabilities	**504**	1,496
Other accrued liabilities	**9,052**	8,079
Total current liabilities	**112,068**	157,499
Deferred Credits and Other Liabilities		
Deferred income taxes	**123,609**	115,624
Deferred investment tax credits	**142**	171
Regulatory liabilities	**3,614**	3,564
Environmental liabilities	**9,298**	9,492
Other pension and benefit costs	**25,832**	26,808
Accrued asset removal cost Regulatory liability	**37,461**	36,584
Other liabilities	**8,514**	8,259
Total deferred credits and other liabilities	**208,470**	200,502
Other commitments and contingencies (Note 6)		
Total Capitalization and Liabilities	**$ 679,700**	**$ 709,066**

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

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Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Cash Flows (Unaudited)

For the Six Months Ended June 30, *(in thousands)*	**2012**	**2011**
Operating Activities		
Net Income	**$ 15,787**	$ 17,267
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**11,646**	9,958
Depreciation and accretion included in other costs	**2,686**	2,473
Deferred income taxes, net	**8,562**	12,449
Loss on sale of assets	**33**	94
Unrealized loss on commodity contracts	**232**	30
Unrealized gain on investments	**(502)**	(131)
Employee benefits	**309**	571
Share-based compensation	**697**	705
Other, net	**(14)**	(18)
Changes in assets and liabilities:		
Sale (purchase) of investments	**(232)**	258
Accounts receivable and accrued revenue	**37,103**	14,017
Propane inventory, storage gas and other inventory	**5,416**	3,315
Regulatory assets	**(24)**	601
Prepaid expenses and other current assets	**2,084**	1,792
Accounts payable and other accrued liabilities	**(18,359)**	(11)
Income taxes receivable	**920**	(2,666)
Accrued interest	**(215)**	(241)
Customer deposits and refunds	**(927)**	(1,182)
Accrued compensation	**(1,853)**	(2,234)
Regulatory liabilities	**(2,859)**	2,887
Other liabilities	**23**	155
Net cash provided by operating activities	**60,513**	60,089
Investing Activities		
Property, plant and equipment expenditures	**(34,140)**	(21,236)
Proceeds from sales of assets	**2,249**	344
Purchase of investments	**(124)**	(200)
Environmental expenditures	**(194)**	(326)
Net cash used in investing activities	**(32,209)**	(21,418)
Financing Activities		
Common stock dividends	**(5,987)**	(5,685)
Purchase of stock for Dividend Reinvestment Plan	**(619)**	(609)
Change in cash overdrafts due to outstanding checks	**(2,144)**	(3,193)
Net repayment under line of credit agreements	**(19,010)**	(27,417)
Other short-term borrowing		(29,100)
Proceeds from issuance of long-term debt		29,000
Repayment of long-term debt	**(1,444)**	(1,482)
Net cash used in financing activities	**(29,204)**	(38,486)
Net Increase (Decrease) in Cash and Cash Equivalents	**(900)**	185

Cash and Cash Equivalents Beginning of Period		**2,637**		1,643
Cash and Cash Equivalents End of Period	**$**	**1,737**	$	1,828

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

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Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Stockholders Equity (Unaudited)

(in thousands, except shares and per share data)	**Common Stock Number of Shares[1]**	**Par Value**	**Additional Paid-In Capital**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Deferred Compensation**	**Treasury Stock**	**Total**
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				15,787				15,787
Other comprehensive income					133			133
Dividend Reinvestment Plan			(4)					(4)
Conversion of debentures	5,341	3	88					91
Share-based compensation [2] (3)	19,217	9	421					430
Deferred Compensation Plan						141	(141)	
Purchase of treasury stock	(502)						(21)	(21)
Sale and distribution of treasury stock	502						21	21
Dividends on share-based compensation				(5)				(5)
Cash dividends [4]				(6,805)				(6,805)
Balances at June 30, 2012	**9,591,865**	**$ 4,668**	**$ 149,908**	**$ 100,225**	**($ 4,394)**	**$ 958**	**($ 958)**	**$ 250,407**

(1) Includes 32,903 and 30,597 shares at June 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 six months ended June 30, 2012 and for the year ended December 31, 2011, the Company withheld 5,670 and 12,324 shares, respectively , for taxes.

(4) Cash dividends per share for the periods ended June 30, 2012 and December 31, 2011 were $0.710 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 six months ended June 30, 2011 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 six months ended June 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 is 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 third 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 U.S. 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.

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2. Calculation of Earnings Per Share

For the Periods Ended June 30,	Three Months 2012	Three Months 2011	Six Months 2012	Six Months 2011
(in thousands, except shares and per share data)				
Calculation of Basic Earnings Per Share:				
Net Income	**$ 5,060**	$ 3,520	**$ 15,787**	$ 17,267
Weighted average shares outstanding	**9,586,159**	9,557,707	**9,578,715**	9,546,606
Basic Earnings Per Share	**$ 0.53**	$ 0.37	**$ 1.65**	$ 1.81
Calculation of Diluted Earnings Per Share:				
Reconciliation of Numerator:				
Net Income	**$ 5,060**	$ 3,520	**$ 15,787**	$ 17,267
Effect of 8.25% Convertible debentures	**13**	15	**27**	31
Adjusted numerator Diluted	**$ 5,073**	$ 3,535	**$ 15,814**	$ 17,298
Reconciliation of Denominator:				
Weighted shares outstanding Basic	**9,586,159**	9,557,707	**9,578,715**	9,546,606
Effect of dilutive securities:				
Share-based Compensation	**32,380**	20,699	**31,162**	21,958
8.25% Convertible debentures	**63,058**	72,481	**64,363**	73,810
Adjusted denominator Diluted	**9,681,597**	9,650,887	**9,674,240**	9,642,374
Diluted Earnings Per Share	**$ 0.52**	$ 0.37	**$ 1.63**	$ 1.79

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, Eastern Shore Propane Company, LLC and Eastern Gas & Water Investment Company, LLC (collectively, ESG). These assets are currently used to provide propane distribution service to approximately 11,000 residential and commercial customers through underground propane gas distribution systems and bulk propane delivery service to over 500 customers in Worcester County, Maryland. We are evaluating the potential conversion of some of these 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. The transaction, which is a cash purchase of assets, is expected to be completed in the fourth quarter of 2012. We expect to finance the acquisition using unsecured short-term debt.

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, subject to refund, pending the completion of a full evidentiary hearing and a final decision. 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 will allow 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. We anticipate that the Delaware PSC will grant approval of the Franchise Fee Rider in the third quarter of 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. We anticipate that the Delaware PSC will render a final decision on these proposals in the fourth quarter of 2012.

Maryland

There were no significant regulatory proceedings in Maryland pending during 2012.

Florida

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.

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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 $1.2 million of the amortization expense in depreciation and amortization in the accompanying condensed consolidated statement of income for the six months ended June 30, 2012. 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 $5.7 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 or early 2013. 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. Peninsula Pipeline will then utilize the transportation agreement with Peoples Gas and the jointly-owned pipeline capacity to provide transmission service to FPU for its natural gas distribution service in Nassau County.

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 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. 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.

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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. 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 applicable review of the decisions by the Florida PSC with respect to the protests by the City of Marianna. 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, to the Condensed Consolidated Financial Statements, 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.

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 previously discussed amendment to the Generation Services Agreement with Gulf Power, 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.

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.

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 February 3, 2012, FPU s natural gas distribution operation and the Florida Division of Chesapeake filed a petition with the Florida PSC for approval of a surcharge to customers for a Gas Reliability Infrastructure Program. We are seeking approval to recover 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. If the petition is approved, we will replace qualifying mains and services over a 10-year period. The Florida PSC staff is expected to issue a recommendation on this surcharge in early August 2012, and a decision is expected by the Florida PSC at the agenda conference on August 14, 2012.

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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 is proposing to establish approximately $1.9 million of regulatory liability ($1.2 million in the tax contingency gain and $748,000 in the tax gross-up) and amortize it over a period from January 2012 to October 2014. The agenda conference date for this petition has not yet been set, but FPU expects that a decision on this petition will be made by the end of 2012.

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Eastern Shore

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. We expect the FERC ruling on this application by the end of 2012.

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 $319,933, inclusive of interest, to its eligible customers in the third quarter of 2012 as a result of combining its over-recovered Gas Required for Operations and its over-recovered Cash-Out Cost.

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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 June 30, 2012, we had approximately $10.9 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 $8.5 million of which has been recovered as of June 30, 2012. We also had approximately $5.5 million in regulatory assets for future recovery of environmental costs from FPU s customers.

In addition to the FPU MGP sites, we had $223,000 in environmental liabilities as of June 30, 2012, related to Chesapeake s MGP sites in Maryland and Florida, representing our estimate of future costs associated with these sites. As of June 30, 2012, we had approximately $792,000 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 June 30, 2012, FPU has paid $650,000 to the Sanford Group escrow account for all of its share of the funding requirements.

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 June 30, 2012, FPU s remaining share of remediation expenses, including attorneys fees and costs, is 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 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 June 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 (NFA) 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. The total expected annual cost of operating and monitoring the system is approximately $46,000.

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, and we estimate the cost of this excavation at $250,000; however, this estimate does not include costs associated with dewatering or shoreline stabilization, which would be required to complete the excavation. 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 are in 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 is currently scheduled for trial on October 29, 2012. 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 $978,000 in legal costs associated with this litigation, approximately $440,000 of which was expensed in 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.

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 six 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 June 30, 2012, FPU was in compliance with all of the requirements of its fuel supply contracts.

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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 June 30, 2012 was $27.7 million, with the guarantees expiring on various dates through June 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, 2012, 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 the letter of credit for $725,000 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 June 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.

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

Agreements for Access to New Natural Gas Supplies

On April 8, 2010, our Delaware and Maryland divisions entered into the 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 provides that, upon satisfaction of certain conditions, the parties will execute two firm transportation service contracts, one for our Delaware division and one for our Maryland division, for 34,100 Dts/d and 15,900 Dts/d, respectively. The 34,100 Dts/d for our Delaware division and the 15,900 Dts/d for our Maryland division reflect the additional volume subscribed to by our divisions above the volume originally agreed to by the parties. These contracts will be effective on the service commencement date of the project, which is currently projected to occur in November 2012. Each firm transportation service contract shall, among other things, provide for: (a) the maximum daily quantity of Dts/d described above; (b) a term of 15 years; (c) a receipt point at Clarington, Ohio; (d) a delivery point at Honey Brook, Pennsylvania; and (e) certain credit standards and requirements for security. Commencement of service and TETLP s and our rights and obligations under the two firm transportation service contracts are subject to satisfaction of various conditions specified in the Precedent Agreement.

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Our Delmarva natural gas supplies have been received primarily from the Gulf of Mexico natural gas production region and have been transported through three interstate upstream pipelines, which interconnect directly or indirectly with Eastern Shore s transmission system. The new firm transportation service contracts between our Delaware and Maryland divisions and TETLP will provide gas supply through an interconnection with Eastern Shore s transmission system and provide access to new sources of supply from other natural gas production regions, including the Appalachian production region, thereby providing increased reliability and diversity of supply. They will also provide our Delaware and Maryland divisions with additional upstream transportation capacity to meet current customer demands and to plan for sustainable growth.

The Precedent Agreement provides that the parties shall promptly meet and work in good faith to negotiate a mutually acceptable reservation rate. In accordance with the Precedent Agreement, our Delaware and Maryland divisions executed the required reservation rate agreements with TETLP on July 2, 2010.

The Precedent Agreement requires us to reimburse TETLP for our proportionate share of TETLP s pre-service costs incurred to date, if we terminate the Precedent Agreement, are unwilling or unable to perform our material duties and obligations thereunder, or take certain other actions whereby TETLP is unable to obtain the authorizations and exemptions required for this project. If such termination were to occur, we estimate that our proportionate share of TETLP s pre-service costs could be approximately $25.5 million as of June 30, 2012. If we were to terminate the Precedent Agreement after TETLP completed its construction of all facilities, which is expected to be in the fourth quarter of 2012, our proportionate share could be as much as approximately $50 million. The actual amount of our proportionate share of such costs could differ significantly and would ultimately be based on the level of pre-service costs at the time of any potential termination. As our Delaware and Maryland divisions have now executed the required reservation rate agreements with TETLP, we believe that the likelihood of terminating the Precedent Agreement and having to reimburse TETLP for our proportionate share of TETLP s pre-service costs is remote.

As previously mentioned, we have provided a letter of credit to TETLP for $2.5 million, which is the maximum amount required 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.

In November 2011, TETLP obtained the necessary authorizations from the FERC for construction and operation of its portion of the project. Our Delaware and Maryland divisions require no regulatory approvals or exemptions to receive transmission service from TETLP or Eastern Shore.

As the Eastern Shore and TETLP transmission services commence, our Delaware and Maryland divisions incur costs for those services based on the agreed and FERC-approved reservation rates, which will 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 June 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.

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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.

The following table presents information about our reportable segments.

For the Periods Ended June 30,	Three Months Ended 2012	Three Months Ended 2011	Six Months Ended 2012	Six Months Ended 2011
(in thousands)				
Operating Revenues, Unaffiliated Customers				
Regulated Energy	**$ 54,330**	$ 54,011	**$ 126,348**	$ 138,695
Unregulated Energy\	**25,176**	29,692	**70,063**	88,442
Other	**4,391**	3,128	**8,400**	6,292
Total operating revenues, unaffiliated customers	**$ 83,897**	$ 86,831	**$ 204,811**	$ 233,429
Intersegment Revenues [1]				
Regulated Energy	**$ 1,223**	$ 182	**$ 1,501**	$ 368
Unregulated Energy				
Other	**221**	195	**456**	389
Total intersegment revenues	**$ 1,444**	$ 377	**$ 1,957**	$ 757
Operating Income				
Regulated Energy	**$ 10,505**	$ 7,787	**$ 25,303**	$ 24,020
Unregulated Energy	**(401)**	80	**4,753**	8,669
Other and eliminations	**351**	(91)	**472**	(74)
Total operating income	**10,455**	7,776	**30,528**	32,615
Other income, net of other expenses	**153**	27	**349**	50
Interest	**2,241**	2,114	**4,532**	4,265
Income before income taxes	**8,367**	5,689	**26,345**	28,400
Income taxes	**3,307**	2,169	**10,558**	11,133
Net income	**$ 5,060**	$ 3,520	**$ 15,787**	$ 17,267

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

(in thousands)	**June 30, 2012**	**December 31, 2011**
Identifiable Assets		
Regulated energy	**$ 572,073**	$ 565,563
Unregulated energy	**70,166**	107,916
Other	**37,461**	35,587
Total identifiable assets	**$ 679,700**	$ 709,066

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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.

8. Employee Benefit Plans

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

	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP		Chesapeake Postretirement Plan		FPU Medical Plan	
For the Three Months Ended June 30,	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**
(in thousands)										
Service Cost	**$**	$	**$**	$	**$**	$	**$**	$	**$ 40**	$ 27
Interest Cost	**125**	130	**639**	672	**22**	27	**15**	15	**45**	39
Expected return on plan assets	**(109)**	(101)	**(657)**	(684)						
Amortization of prior service cost	**(2)**	(2)			**5**	5	**(20)**			
Amortization of net loss	**85**	39	**44**		**12**	9	**17**		**22**	5
Net periodic cost (benefit)	**99**	66	**26**	(12)	**39**	41	**12**	15	**107**	71
Amortization of pre-merger regulatory asset			**191**	191					**2**	2
Total periodic cost	**$ 99**	$ 66	**$ 217**	$ 179	**$ 39**	$ 41	**$ 12**	$ 15	**$ 109**	$ 73

	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP		Chesapeake Postretirement Plan		FPU Medical Plan	
For the Six Months Ended June 30,	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**
(in thousands)										
Service Cost	**$**	$	**$**	$	**$**	$	**$**	$	**$ 80**	$ 53
Interest Cost	**250**	260	**1,278**	1,343	**45**	54	**30**	30	**90**	78
Expected return on plan assets	**(218)**	(202)	**(1,315)**	(1,368)						
Amortization of prior service cost	**(3)**	(3)			**10**	10	**(40)**			
Amortization of net loss	**170**	78	**88**		**23**	19	**35**		**45**	10
Net periodic cost (benefit)	**199**	133	**51**	(25)	**78**	83	**25**	30	**215**	141
Settlement expense		217								
Amortization of pre-merger regulatory asset			**381**	381					**4**	4
Total periodic cost	**$ 199**	$ 350	**$ 432**	$ 356	**$ 78**	$ 83	**$ 25**	$ 30	**$ 219**	$ 145

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 $5.5 million and $5.9 million at June 30, 2012 and December 31, 2011, respectively.

During the three and six months ended June 30, 2012, we contributed $110,000 and $273,000 respectively, to the Chesapeake pension plan. We also contributed $413,000 and $705,000, respectively, to the FPU pension plan during the three and six months ended June 30, 2012. 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. We initially estimated our 2012 contributions to the Chesapeake and FPU pension plans to be $1.3

million and $2.0 million, respectively, which include minimum contribution payments required in 2012 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. We estimate that the new legislation could reduce our 2012 contributions to the Chesapeake and FPU pension plans by as much as $915,000 and $1.2 million, respectively.

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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 six months ended June 30, 2012, were $22,000 and $45,000, 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 six months ended June 30, 2012, totaled $28,000 and $40,000, 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 six months ended June 30, 2012, totaled $100,000 and $158,000, respectively. We have estimated that approximately $193,000 will be paid for such benefits in 2012.

9. Investments

The investment balance at June 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. We recorded $185,000 and $502,000, for an unrealized gain, net of other expenses, in other income in the consolidated statements of income for the three and six months ended June 30, respectively. We also have recorded an associated liability that is adjusted each month for the gains and losses incurred by the Rabbi Trusts. At June 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 six months ended June 30, 2012 and 2011:

	Three Months Ended		Six Months Ended	
For the Periods Ended June 30,	**2012**	**2011**	**2012**	**2011**
(in thousands)				
Directors Stock Compensation Plan	**$ 111**	$ 102	**$ 222**	$ 185
Performance Incentive Plan	**240**	274	**475**	520
Total compensation expense	**351**	376	**697**	705
Less: tax benefit	**(141)**	(151)	**(280)**	(283)
Share-Based Compensation amounts included in net income	**$ 210**	$ 225	**$ 417**	$ 422

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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 six months ended June 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 June 30, 2012		

At June 30, 2012, there was $370,000 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 six months ended June 30, 2012:

	Number of Shares	Weighted Average Fair Value
Outstanding December 31, 2011	87,414	$ 34.47
Granted	30,906	$ 38.79
Vested	13,837	$ 29.84
Forfeited [(1)]	21,600	$ 35.55
Expired	3,038	$ 26.29
Outstanding June 30, 2012	79,845	$ 37.44

(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.

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 June 30, 2012, the aggregate intrinsic value of the PIP awards was $1.2 million.

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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 June 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 June 30, 2012, the call options had a fair value of $123,000. 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 June 30, 2012, we had the following outstanding trading contracts, which we accounted for as derivatives:

At June 30, 2012	Quantity in Gallons	Estimated Market Prices		Weighted Average Contract Prices
Forward Contracts				
Sale	5,754,000	$ 0.7200	$1.3775	$ 0.8933
Purchase	5,670,000	$ 0.6825	$1.3300	$ 0.8724

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

All contracts expire by the first quarter of 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 June 30, 2012 and December 31, 2011, are as follows:

	Asset Derivatives		
		Fair Value	
(in thousands)	**Balance Sheet Location**	**June 30, 2012**	**December 31, 2011**
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy assets	**$ 462**	$ 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	**123**	
Total asset derivatives		**$ 585**	$ 1,754

	Liability Derivatives		
		Fair Value	
(in thousands)	**Balance Sheet Location**	**June 30, 2012**	**December 31, 2011**
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy liabilities	**$ 504**	$ 1,496
Total liability derivatives		**$ 504**	$ 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 June 30, 2012.

(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:

		Amount of Gain (Loss) on Derivatives			
	Location of Gain	**For the Three Months Ended June 30,**		**For the Six Months Ended June 30,**	
(in thousands)	**(Loss) on Derivatives**	**2012**	**2011**	**2012**	**2011**
Derivatives not designated as hedging instruments:					
Unrealized gain (loss) on forward contracts	Revenue	**$ (172)**	$ (112)	**$ (232)**	$ (30)
Derivatives designated as fair value hedges:					
Put Option	Cost of sales			**27**	
Call Option[1]	Inventory	**(16)**		**(16)**	
Total		**$ (188)**	$ (112)	**$ (221)**	$ (30)

(1) The change in fair value of the 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:

(in thousands)	Location in the Statement of Income	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Realized gains on forward contracts/put option	Revenue	**$ 807**	$ 647	**$ 1,321**	$ 1,554
Unrealized loss on forward contracts	Revenue	**(172)**	(112)	**(232)**	(30)
Total		**$ 635**	$ 535	**$ 1,089**	$ 1,524

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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 June 30, 2012:

		Fair Value Measurements Using:		
(in thousands)	**Fair Value**	**Quoted Prices in Active Markets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Assets:				
Investments equity securities	$ 2,594	$ 2,594	$	$
Investments other	$ 2,097	$ 2,098	$	$
Mark-to-market energy assets, including call option	$ 585	$	$ 585	$
Liabilities:				
Mark-to-market energy liabilities	$ 504	$	$ 504	$

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 Measurements Using:		
(in thousands)	**Fair Value**	**Quoted Prices in Active Markets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
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 June 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 June 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 June 30, 2012, long-term debt, which includes the current maturities of long-term debt, had a carrying value of $117.0 million, compared to a fair value of $140.2 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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13. Long-Term Debt

Our outstanding long-term debt is shown below:

(in thousands)	June 30, 2012	December 31, 2011
FPU secured first mortgage bonds [A]:		
9.57% bond, due May 1, 2018	**$ 5,442**	$ 6,348
10.03% bond, due May 1, 2018	**2,993**	3,492
9.08% bond, due June 1, 2022	**7,960**	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	**1,038**	1,134
Promissory note	**155**	186
Total long-term debt	**116,951**	118,481
Less: current maturities	**(8,196)**	(8,196)
Total long-term debt, net of current maturities	**$ 108,755**	$ 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 existing other loan facilities available from the same lender. The maximum aggregate short-term borrowing authorized by our Board of Directors remains at $85 million.

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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, o potential, forecast or other similar words, or future or conditional verbs such as may, will, should, would or could. These statements re 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;

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;

- 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 $632,000, respectively, in additional gross margin for the second quarter of 2012, compared to the same quarter in 2011. New natural gas transmission services and growth in natural gas distribution customers generated $1.7 million and $1.3 million, respectively, in additional gross margin for the first six months of 2012, compared to the same period in 2011. Most of these increases in gross margin were related to continued execution of our strategic plan, with the objectives of expanding natural gas service to new areas and identifying opportunities to convert 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 six months of 2012, we expanded natural gas transmission and distribution services to Lewes, Delaware, southeastern 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 by providing natural gas service in areas where natural gas was not previously available. These initiatives generated $866,000 of additional gross margin for the natural gas transmission operations and $139,000 of additional gross margin for the natural gas distribution operations during the second quarter of 2012. For the first six months of 2012, these initiatives generated $1.1 million and $286,000 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 $3.0 million in 2012 ($1.9 million expected to generate in the second half of the year), 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, which include new distribution service to two large industrial customers in Lewes, Delaware and two facilities of an existing customer located in southeastern Sussex County, Delaware, are expected to generate gross margin of $552,000 in 2012 ($266,000 expected to generate in the second half of the year) and $616,000 in annualized gross margin thereafter.

In addition to the major expansion initiatives, the Delmarva natural gas distribution operation has added 10 other new large industrial and commercial customers since the beginning of 2011, which generated $161,000 in additional gross margin in the second quarter of 2012 and $343,000 in the first six months of 2012, compared to the same periods in 2011, respectively. These 10 new customers are expected to generate $960,000 of gross margin in 2012, compared to $429,000 generated in 2011. Customer growth in Florida, primarily in commercial and industrial customers, also generated $241,000 and $362,000 in additional gross margin in the second quarter and first six months of 2012, respectively.

Future Major Expansion Initiatives and Opportunities

Although not affecting our results in the second quarter and first six months of 2012, we are continuing our effort to extend natural gas service to Cecil County, Maryland. Service by Eastern Shore, our interstate natural gas transmission subsidiary, is expected to commence in September 2012. This expansion is expected to generate annual gross margin of $882,000, $294,000 of which will be recorded in 2012.

Eastern Shore also 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 services. A firm transportation service agreement is expected to be executed by NRG and Delaware City Refinery with Eastern Shore upon satisfying certain conditions pursuant to the respective precedent agreements. These additional services are expected to be initiated in mid to late 2013. The additional transmission service to NRG is expected to generate estimated annual gross margin of $2.4 to $2.8 million. The additional transmission service to Delaware City Refinery is expected to generate estimated annual gross margin of $1.6 million.

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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, in June 2012, our Delaware natural gas distribution division filed an application with the Delaware PSC 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. These assets are currently used to provide propane distribution service to approximately 11,000 residential and commercial customers through underground propane gas distribution systems and bulk propane delivery service to over 500 customers in Worcester County, Maryland. We are evaluating the potential conversion of some of these underground propane distribution systems to natural gas where it is both economical and feasible. The transaction, which is subject to the approval of the Maryland PSC, 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 the fourth quarter of 2012. 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 to grow at the rates that we have in the past, we will be increasing our resources to both execute on current opportunities and identify new opportunities to fuel tomorrow s growth. We are at the early stages of several natural gas expansions on the Delmarva Peninsula. These include Lewes, Delaware, southeastern Sussex County, Delaware, and Worcester and Cecil Counties in Maryland. These expansions will not only require the construction or conversion of distribution facilities, but also require the conversion of customers appliances or equipment inside their home. To do this we have re-organized our natural gas distribution operations and are increasing our staffing. Secondly, as a result of BravePoint s growth over the last several quarters, BravePoint is continuing to add staff. Finally, to increase our capacity for future growth we will be adding resources in several key functional areas. This includes, among others, the Human Resources, Communications and Strategic Business Development functions.

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 quarter, lower customer energy consumption directly attributable to warmer temperatures in the six months ended June 30, 2012, compared to temperatures in the same period in 2011, reduced gross margin by $3.9 million, most of which occurred in the first three months of the year. Temperatures on the Delmarva Peninsula and in Florida in the first six months of 2012 were 19 percent (531 HDD) and 35 percent (187 HDD), respectively, warmer than the same period in 2011. Comparing first half 2012 temperatures to normal, based on the 10-year historic average of HDD, the weather on the Delmarva Peninsula and in Florida was 19 percent (556 HDD) and 41 percent (240 HDD), respectively, warmer than normal. We estimate that this variance reduced gross margin for the first half of 2012 by approximately $3.5 million, compared to gross margin under normal temperatures.

CDD variations were not a significant factor during the first six 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 $588,000 in the second quarter of 2012 and $1.2 million in the first six 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 related to these assets.

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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.

Gross margin from our Delmarva propane distribution operation decreased by $581,000 and $608,000 during the first three and six months of 2012, compared to the same periods in 2011, respectively, due to lower retail margins per gallon. This decrease was attributable to a significant decline in wholesale propane prices during 2012, which resulted in a write-down of $338,000 and $465,000 in the inventory value during the first three and six months of 2012. Our Florida propane distribution operation continued to adjust retail pricing in response to local market conditions and generated $452,000 and $1.1 million in additional gross margin during the first three and six months of 2012, compared to the same periods in 2011, respectively, from higher retail margins per gallon.

Xeron, our propane wholesale marketing subsidiary, executed trades with higher margins, which generated an increase in gross margin of $100,000 in the second quarter of 2012, compared to the same quarter of 2011, as the market presented opportunities from the steady decline in wholesale prices. Xeron s gross margin decreased by $435,000 in the first six months of 2012, compared to the same period in 2011, as a result of a 37-percent decrease in trading activity. High price volatility in the wholesale propane market during the first six months of 2011 resulted in higher-than-usual trading volume and profitability for Xeron. Lower price volatility during the first six months of 2012, coupled with lower wholesale propane demand, due partially to warmer weather, reduced Xeron s trading volume and gross margin in the first half of 2012.

Advanced Information Services

BravePoint, our advanced information services subsidiary, reported operating income of $238,000 and $245,000 in the second quarter and first six months of 2012, compared to an operating loss of $188,000 and $283,000 in the same periods in 2011, respectively. Approximately 17 percent and nine percent of the period-over-period increase in BravePoint s operating income for the quarter and six-month period, respectively, was 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 $284,000 and

$577,000 in revenue from the sale of those two products and related services during the second quarter of 2012, and first six months of 2012, respectively. To date, BravePoint has successfully implemented ProfitZoom for four customers in the fire suppression industry, and two additional customers have executed sales contracts with implementations scheduled in the second half of 2012. 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 new contracts are expected to generate $664,000 in additional revenue in the remainder of 2012. Additional sales proposals are under consideration by existing customers to expand their use of the product and also by other potential customers.

Results of Operations for the Quarter Ended June 30, 2012

Overview and Highlights

Our net income for the quarter ended June 30, 2012 was $5.1 million, or $0.52 per share (diluted). This represents an increase of $1.5 million, or $0.15 per share (diluted), compared to a net income of $3.5 million, or $0.37 per share (diluted), as reported for the same quarter in 2011.

For the Three Months Ended June 30, *(in thousands except per share)*	2012	2011	Increase (decrease)
Business Segment:			
Regulated Energy	**$ 10,505**	$ 7,787	$ 2,718
Unregulated Energy	**(401)**	80	(481)
Other	**351**	(91)	442
Operating Income	**10,455**	7,776	2,679
Other Income	**153**	27	126
Interest Charges	**2,241**	2,114	127
Income Taxes	**3,307**	2,169	1,138
Net Income	**$ 5,060**	$ 3,520	$ 1,540
Earnings Per Share of Common Stock			
Basic	**$ 0.53**	$ 0.37	$ 0.16
Diluted	**$ 0.52**	$ 0.37	$ 0.15

Highlights of our results in the second quarter of 2012 included:

New natural gas transmission services generated $1.1 million in additional gross margin.

Growth from new natural gas distribution customers generated $632,000 in additional gross margin.

Amortization related to the recovery of the FPU acquisition adjustment and merger-related costs increased other operating expenses by $588,000.

Other items affecting our quarter-over-quarter results included:

An adjustment to accrued revenue of approximately $568,000 ($440,000 of which corresponds to the first quarter of 2012), which increased gross margin in the second quarter of 2012;

A $549,000 non-recurring severance charge in the second quarter of 2011, which decreased other operating expenses for that quarter; and

An increase in BravePoint s operating income of $425,000, approximately 17 percent of which was a result of ProfitZoom and Application Evolution™ sales and related services and the remaining of which was due to higher consulting revenues and other product sales.

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

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Regulated Energy

For the Three Months Ended June 30, *(in thousands, except degree-day and customer information)*	**2012**	**2011**	**Increase (decrease)**
Revenue	**$ 55,553**	$ 54,193	$ 1,360
Cost of sales	**23,433**	24,882	(1,449)
Gross margin	**32,120**	29,311	2,809
Operations & maintenance	**14,872**	15,533	(661)
Depreciation & amortization	**4,920**	3,984	936
Other taxes	**1,823**	2,007	(184)
Other operating expenses	**21,615**	21,524	91
Operating Income	**$ 10,505**	$ 7,787	$ 2,718
Weather and Customer Analysis			
Delmarva Peninsula			
HDD:			
Actual	**416**	382	34
10-year average			