CHESAPEAKE UTILITIES CORP
Form 10-Q
November 08, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended: September 30, 2012

OR

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

For the transition period from to

Commission File Number: 001-11590

CHESAPEAKE UTILITIES CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**51-0064146**
(State or other jurisdiction of	**(I.R.S. Employer**
incorporation or organization)	**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 9,594,446 shares outstanding as of October 31, 2012.

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GLOSSARY OF KEY TERMS AND DEFINITIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Income (Unaudited)

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

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

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Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Comprehensive Income (Unaudited)

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

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

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Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Balance Sheets (Unaudited)

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

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

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

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

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Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Cash Flows (Unaudited)

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

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

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

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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]**	**Common Stock 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				19,006				19,006
Other comprehensive income					200			200
Dividend Reinvestment Plan			(5)					(5)
Conversion of debentures	6,572	3	108					111
Share-based compensation [2] [3]	19,217	10	724					734
Deferred Compensation Plan						153	(153)	
Purchase of treasury stock	(768)						(33)	(33)
Sale and distribution of treasury stock	768						33	33
Dividends on share-based compensation				(36)				(36)
Cash dividends [4]				(10,306)				(10,306)
Balances at September 30, 2012	**9,593,096**	**$ 4,669**	**$ 150,230**	**$ 99,912**	**($4,327)**	**$ 970**	**($970)**	**$ 250,484**

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

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

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

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

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

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. Summary of Accounting Policies

Basis of Presentation

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

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

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

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

Reclassifications

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

Sale of Assets

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

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

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

Recently Adopted Accounting Standards

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

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

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2. Calculation of Earnings Per Share

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

3. Acquisition

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

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4. Rates and Other Regulatory Activities

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

Delaware

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

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

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

(i) a monthly fixed charge to customers in portions of Eastern Sussex County, Delaware, which will enable the Delaware division to extend its distribution system to provide natural gas service to these customers economically without upfront contributions from these customers;

(ii) optional service offerings to customers to assist them in conversions, including a conversion finance service to assist customers with their cost of conversion equipment; and

(iii) a slight rate increase for all Delaware customers in order to support the additional costs associated with the administration and implementation of the proposed service offerings.

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

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

Maryland

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

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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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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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, and on August 31, 2012, the same existing customer filed a response to Eastern Shore s response. We expect the FERC ruling on this application by the end of 2012.

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

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Eastern Shore also had developments in the following FERC matters:

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

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

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

5. Environmental Commitments and Contingencies

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

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

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

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

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

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

West Palm Beach, Florida

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

Sanford, Florida

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

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

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

Key West, Florida

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

Pensacola, Florida

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

Salisbury, Maryland

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

Winter Haven, Florida

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

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

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

Other

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

6. Other Commitments and Contingencies

Litigation

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

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

Natural Gas, Electric and Propane Supply

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

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

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

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

Corporate Guarantees

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

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

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

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

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

Agreements for Access to New Natural Gas Supplies

On April 8, 2010, our Delaware and Maryland divisions entered into a Precedent Agreement to secure firm transportation service from TETLP in conjunction with its new expansion project, which is expected to expand TETLP s mainline system by up to 190,000 Dts/d. The Precedent Agreement provided that, upon satisfaction of certain conditions, the parties would execute two firm transportation service c