CHESAPEAKE UTILITIES CORP
Form 10-Q
November 04, 2011

Table of Contents

United States
Securities and Exchange Commission
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended: September 30, 2011

OR

o **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 þ No o

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 þ No o

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 o	Accelerated filer þ	Non-accelerated filer o	Smaller reporting company o

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

Common Stock, par value $0.4867 9,565,253 shares outstanding as of October 31, 2011.

Table of Contents

Table of Contents

GLOSSARY OF KEY TERMS

Frequently used abbreviations, acronyms, or terms used in this report:

Subsidiaries of Chesapeake Utilities Corporation

BravePoint	BravePoint®, Inc. is a wholly-owned subsidiary of Chesapeake Services Company, which is a wholly-owned subsidiary of Chesapeake
Chesapeake	The Registrant, the Registrant and its subsidiaries, or the Registrant s subsidiaries, as appropriate in the context of the disclosure
Company	The Registrant, the Registrant and its subsidiaries, or the Registrant s subsidiaries, as appropriate in the context of the disclosure
Eastern Shore	Eastern Shore Natural Gas Company, a wholly-owned subsidiary of Chesapeake
FPU	Florida Public Utilities Company, a wholly-owned subsidiary of Chesapeake, effective October 28, 2009
PESCO	Peninsula Energy Services Company, Inc., a wholly-owned subsidiary of Chesapeake
Peninsula Pipeline	Peninsula Pipeline Company, Inc., a wholly-owned subsidiary of Chesapeake
Sharp	Sharp Energy, Inc., a wholly-owned subsidiary of Chesapeake s and Sharp s subsidiary, Sharpgas, Inc.
Xeron	Xeron, Inc., a wholly-owned subsidiary of Chesapeake

Regulatory Agencies

Delaware PSC	Delaware Public Service Commission
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FDEP	Florida Department of Environmental Protection
FDOT	Florida Department of Transportation
Florida PSC	Florida Public Service Commission
Maryland PSC	Maryland Public Service Commission
MDE	Maryland Department of the Environment
PSC	Public Service Commission
SEC	Securities and Exchange Commission

Accounting Standards Related

FASB	Financial Accounting Standards Board
GAAP	Generally Accepted Accounting Principles

Other

AS/SVE	Air Sparging and Soil/Vapor Extraction
BS/SVE	Bio-Sparging and Soil/Vapor Extraction
CDD	Cooling Degree-Days
DSCP	Directors Stock Compensation Plan
Dts	Dekatherms
Dts/d	Dekatherms per day
ECCR	Energy Conservation Cost Recovery
FGT	Florida Gas Transmission Company

FRP	Fuel Retention Percentage
GSR	Gas Sales Service Rates
Gulf Power	Gulf Power Corporation
Gulfstream	Gulfstream Natural Gas System, LLC
HDD	Heating Degree-Days
MWH	Megawatt Hour
Mcf	Thousand Cubic Feet
MGP	Manufactured Gas Plant
NYSE	New York Stock Exchange
OCI	Other Comprehensive Income
OTC	Over-the-Counter
PIP	Performance Incentive Plan
RAP	Remedial Action Plan
Sanford Group	FPU and Other Responsible Parties involved with the Sanford Environmental Site
TETLP	Texas Eastern Transmission, LP
TOU	Time-of-Use

Table of Contents

PART I FINANCIAL INFORMATION

Item 1. Financial Statements

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

For the Three Months Ended September 30,	2011	2010
(in thousands, except shares and per share data)		
Operating Revenues		
Regulated energy	**$ 53,789**	$ 53,412
Unregulated energy	**23,721**	20,134
Other	**3,100**	2,920
Total operating revenues	**80,610**	76,466
Operating Expenses		
Regulated energy cost of sales	**25,811**	27,257
Unregulated energy and other cost of sales	**20,306**	17,238
Operations	**19,560**	18,322
Maintenance	**2,029**	1,899
Depreciation and amortization	**4,978**	4,688
Other taxes	**2,332**	2,479
Total operating expenses	**75,016**	71,883
Operating Income	**5,594**	4,583
Other income, net of expenses	**649**	102
Interest charges	**2,389**	2,256
Income Before Income Taxes	**3,854**	2,429
Income tax expense	**1,457**	801
Net Income	**$ 2,397**	$ 1,628
Weighted-Average Common Shares Outstanding:		
Basic	**9,564,012**	9,493,425
Diluted	**9,657,970**	9,497,696
Earnings Per Share of Common Stock:		
Basic	**$ 0.25**	$ 0.17
Diluted	**$ 0.25**	$ 0.17

Cash Dividends Declared Per Share of Common Stock	**$**	**0.345**	$	0.330

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

Table of Contents

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

For the Nine Months Ended September 30, *(in thousands, except shares and per share data)*	2011	2010
Operating Revenues		
Regulated energy	**$ 193,118**	$ 197,779
Unregulated energy	**112,164**	104,018
Other	**8,757**	7,990
Total operating revenues	**314,039**	309,787
Operating Expenses		
Regulated energy cost of sales	**98,683**	106,146
Unregulated energy and other cost of sales	**89,017**	82,713
Operations	**59,796**	55,847
Maintenance	**5,624**	5,388
Depreciation and amortization	**14,936**	14,075
Other taxes	**7,774**	7,876
Total operating expenses	**275,830**	272,045
Operating Income	**38,209**	37,742
Other income, net of expenses	**699**	206
Interest charges	**6,654**	6,924
Income Before Income Taxes	**32,254**	31,024
Income tax expense	**12,590**	12,082
Net Income	**$ 19,664**	$ 18,942
Weighted-Average Common Shares Outstanding:		
Basic	**9,552,472**	9,460,462
Diluted	**9,647,632**	9,570,921
Earnings Per Share of Common Stock:		
Basic	**$ 2.06**	$ 2.00
Diluted	**$ 2.04**	$ 1.98
Cash Dividends Declared Per Share of Common Stock	**$ 1.020**	$ 0.975

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

Table of Contents

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

For the Nine Months Ended September 30,	**2011**	**2010**
(in thousands)		
Operating Activities		
Net Income	**$ 19,664**	$ 18,942
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**14,936**	14,075
Depreciation and accretion included in other costs	**3,755**	3,248
Deferred income taxes, net	**14,183**	9,847
(Gain) loss on sale of assets	**(449)**	37
Unrealized gain on commodity contracts	**(33)**	(443)
Unrealized gain on investments	**(51)**	(13)
Employee benefits	**(607)**	(594)
Share-based compensation	**1,078**	899
Other, net	**(43)**	(155)
Changes in assets and liabilities:		
Sale (purchase) of investments	**699**	(234)
Accounts receivable and accrued revenue	**28,975**	23,337
Propane inventory, storage gas and other inventory	**159**	(411)
Regulatory assets	**962**	967
Prepaid expenses and other current assets	**(744)**	621
Accounts payable and other accrued liabilities	**(25,783)**	(13,977)
Income taxes receivable	**(3,064)**	(6,392)
Accrued interest	**1,562**	1,381
Customer deposits and refunds	**727**	1,891
Accrued compensation	**(1,220)**	735
Regulatory liabilities	**(1,534)**	453
Other liabilities	**(398)**	580
Net cash provided by operating activities	**52,774**	54,794
Investing Activities		
Property, plant and equipment expenditures	**(33,377)**	(26,201)
Proceeds from sales of assets	**905**	90
Purchase of investments	**(300)**	(2,308)
Environmental expenditures	**(525)**	(522)
Net cash used in investing activities	**(33,297)**	(28,941)
Financing Activities		
Common stock dividends	**(8,673)**	(8,187)
(Purchase) issuance of stock for Dividend Reinvestment Plan	**(920)**	405
Change in cash overdrafts due to outstanding checks	**1,079**	7,020
Net repayment under line of credit agreements	**(9,346)**	(23,069)
Other short-term borrowing	**(29,100)**	29,100

Proceeds from issuance of long-term debt		**29,000**		
Repayment of long-term debt		**(1,390)**		(31,207)
Net cash used in financing activities		**(19,350)**		(25,938)
Net Increase (decrease) in Cash and Cash Equivalents		**127**		(85)
Cash and Cash Equivalents Beginning of Period		**1,643**		2,828
Cash and Cash Equivalents End of Period	**$**	**1,770**	$	2,743

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

Table of Contents

Chesapeake Utilities Corporation and Subsidiaries
Condensed Consolidated Balance Sheets (Unaudited)

Assets		**September 30, 2011**		**December 31, 2010**
(in thousands, except shares and per share data)				
Property, Plant and Equipment				
Regulated energy	**$**	**519,713**	$	500,689
Unregulated energy		**62,828**		61,313
Other		**19,359**		16,989
Total property, plant and equipment		**601,900**		578,991
Less: Accumulated depreciation and amortization		**(133,751)**		(121,628)
Plus: Construction work in progress		**10,610**		5,394
Net property, plant and equipment		**478,759**		462,757
Investments, at fair value		**3,688**		4,036
Current Assets				
Cash and cash equivalents		**1,770**		1,643
Accounts receivable (less allowance for uncollectible accounts of $906 and $1,194, respectively)		**65,692**		88,074
Accrued revenue		**8,434**		14,978
Propane inventory, at average cost		**8,351**		8,876
Other inventory, at average cost		**2,946**		3,084
Regulatory assets		**499**		51
Storage gas prepayments		**5,558**		5,084
Income taxes receivable		**9,812**		6,748
Deferred income taxes		**1,264**		2,191
Prepaid expenses		**5,549**		4,613
Mark-to-market energy assets		**1,229**		1,642
Other current assets		**212**		245
Total current assets		**111,316**		137,229
Deferred Charges and Other Assets				
Goodwill		**35,613**		35,613
Other intangible assets, net		**3,210**		3,459
Long-term receivables		**51**		155
Regulatory assets		**21,644**		23,884
Other deferred charges		**3,235**		3,860

Total deferred charges and other assets		**63,753**		66,971
Total Assets	**$**	**657,516**	$	670,993

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

Table of Contents

Chesapeake Utilities Corporation and Subsidiaries
Condensed Consolidated Balance Sheets (Unaudited)

Capitalization and Liabilities *(in thousands, except shares and per share data)*	**September 30, 2011**	**December 31, 2010**
Capitalization		
Stockholders equity		
Common stock, par value $0.4867 per share (authorized 25,000,000 shares)	**$ 4,655**	$ 4,635
Additional paid-in capital	**149,091**	148,159
Retained earnings	**86,619**	76,805
Accumulated other comprehensive loss	**(2,817)**	(3,360)
Deferred compensation obligation	**807**	777
Treasury stock	**(807)**	(777)
Total stockholders equity	**237,548**	226,239
Long-term debt, net of current maturities	**117,069**	89,642
Total capitalization	**354,617**	315,881
Current Liabilities		
Current portion of long-term debt	**9,196**	9,216
Short-term borrowing	**26,591**	63,958
Accounts payable	**38,539**	65,541
Customer deposits and refunds	**27,769**	26,317
Accrued interest	**3,351**	1,789
Dividends payable	**3,300**	3,143
Accrued compensation	**5,665**	6,784
Regulatory liabilities	**7,628**	9,009
Mark-to-market energy liabilities	**956**	1,492
Other accrued liabilities	**11,785**	10,393
Total current liabilities	**134,780**	197,642
Deferred Credits and Other Liabilities		
Deferred income taxes	**93,650**	80,031
Deferred investment tax credits	**187**	243
Regulatory liabilities	**3,581**	3,734
Environmental liabilities	**9,615**	10,587
Other pension and benefit costs	**16,596**	18,199
Accrued asset removal cost Regulatory liability	**36,280**	35,092
Other liabilities	**8,210**	9,584
Total deferred credits and other liabilities	**168,119**	157,470

Other commitments and contingencies (Note 4 and 5)				
Total Capitalization and Liabilities	**$**	**657,516**	$	670,993

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

Table of Contents

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[6]	Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total
Balances at December 31, 2009	**9,394,314**	**$ 4,572**	**$ 144,502**	**$ 63,231**	**$ (2,524)**	**$ 739**	**$ (739)**	**$ 209,781**
Net Income				26,056				26,056
Other comprehensive income, net of tax:								
Employee Benefit Plans, net of tax:								
Amortization of prior service costs [4]					8			8
Net Loss[5]					(844)			(844)
Total comprehensive income								25,220
Dividend Reinvestment Plan	53,806	26	1,699					1,725
Retirement Savings Plan	27,795	14	889					903
Conversion of debentures	11,865	6	196					202
Share based compensation [1] [3]	36,415	17	620					637
Tax benefit on share based compensation			253					253
Deferred Compensation Plan						38	(38)	
Purchase of treasury stock	(1,144)						(38)	(38)
Sale and distribution of treasury stock	1,144						38	38
Dividends on share-based compensation				(104)				(104)
Cash dividends [2]				(12,378)				(12,378)
Balances at December 31, 2010	**9,524,195**	**4,635**	**148,159**	**76,805**	**(3,360)**	**777**	**(777)**	**226,239**
Net Income				19,664				19,664
Other comprehensive income, net of tax:								
Employee Benefit Plans, net of tax:								
Amortization of prior service costs [4]					6			6
Net Gain [5]					537			537
Total comprehensive income								20,207
Dividend Reinvestment Plan			(16)					(16)
Retirement Savings Plan	2,002	1	79					80
Conversion of debentures	8,039	4	132					136
Share based compensation [1] [3]	30,430	15	737					752
Deferred Compensation Plan						30	(30)	
Purchase of treasury stock	(731)						(30)	(30)
Sale and distribution of treasury stock	731						30	30
Dividends on share-based compensation				(100)				(100)
Cash dividends [2]				(9,750)				(9,750)

Balances at September 30, 2011	**9,564,666**	**$ 4,655**	**$ 149,091**	**$ 86,619**	**$ (2,817)**	**$ 807**	**$ (807)**	**$ 237,548**

(1) Includes amounts for shares issued for Directors compensation.

(2) Cash dividends declared per share for the periods ended September 30, 2011 and December 31, 2010 were $1.02 and $1.305, respectively.

(3) The shares issued under the Performance Incentive Plan (PIP) are net of shares withheld for employee taxes. For the periods ended September 30, 2011 and December 31, 2010 the Company withheld 12,324 and 17,695, respectively, shares for taxes.

(4) Tax expense recognized on the prior service cost component of employees benefit plans for the periods ended September 30, 2011 and December 31, 2010 were approximately $4 and $5, respectively.

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

Table of Contents

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 Registra 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 United States of America Generally Accepted Accounting Principles (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 latest Annual Report on Form 10-K filed with the SEC on March 8, 2011. 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.

Sale of Assets

In July 2011, we sold an Internet Protocol address asset to an unaffiliated entity for approximately $553,000. This particular Internet Protocol address was not used by us and did not have any net carrying value at the time of the sale. We recognized a non-operating gain of $553,000 from this sale, which is included in other income in the accompanying condensed consolidated statements of income.

In September 2011, we entered into an agreement with an unaffiliated entity to sell our office building located in West Palm Beach, Florida for $2.2 million. We also entered into a separate agreement to lease an office space at a different location in West Palm Beach, which is expected to commence in February 2012. The sale of our West Palm Beach office building is expected to be finalized in February 2012, at which point we expect to move some of the approximately 70 employees currently located in this building into the newly leased office space and the remaining employees into another nearby operational center in West Palm Beach, which we own. We are treating the West Palm Beach office building as an asset held for sale. The office building is included in other property, plant and equipment in the accompanying condensed consolidated balance sheets and had a net carrying value of approximately $2.0 million at September 30, 2011. Since the expected sales price, less costs to consummate the sale, exceed the net carrying value of the building, there was no impairment related to the West Palm Beach office building when we committed to the sale. As most of the West Palm Beach building is considered a property within the regulated businesses, most of the gain resulted from the sale will be charged to accumulated depreciation.

Reclassifications

We reclassified certain amounts in the condensed consolidated statements of income for the three and nine months ended September 30, 2010, and the condensed consolidated statement of cash flows for the nine months ended September 30, 2010, to conform to the current year s presentation. These reclassifications are considered immaterial to the overall presentation of our condensed consolidated financial statements.

Table of Contents

Recent Accounting Amendments Yet to be Adopted by the Company

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (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. Early adoption is not permitted for public entities. We expect the adoption of ASU 2011-04 to have no material impact on our financial position and results of operations.

In June 2011, the FASB issued ASU 2011-05, Presentation of Comprehensive Income. ASU 2011-05 amends the guidance in Topic 220 Comprehensive Income, by eliminating the option to present components of other comprehensive income (OCI) in the statement of stockholders equity. Instead, the new guidance now requires entities to present all non-owner changes in stockholders equity either as a single continuous statement of comprehensive income or as two separate but consecutive statements. The components of OCI have not changed nor has the guidance on when OCI items are reclassified to net income; however, the amendments require entities to present all reclassification adjustments from OCI to net income on the face of the statement of comprehensive income. Similarly, ASU 2011-05 does not change the guidance to disclose OCI components gross or net of the effect of income taxes, provided that the tax effects are presented on the face of the statement in which OCI is presented, or disclosed in the notes to the financial statements. For public entities, the amendments in ASU 2011-05 are effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2011. The amendments should be applied retrospectively, and early adoption is permitted. We plan to comply with the new OCI presentation at the end of 2011.

In September 2011, the FASB issued ASU 2011-08, Intangibles Goodwill and Other (Topic 350) Testing Goodwill for Impairment. ASU 2011-08 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 is different than 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 expect the adoption of ASU 2011-08 to have no material impact on our financial position and results of operations.

Table of Contents

2. Calculation of Earnings Per Share

	Three Months		Nine Months	
For the Periods Ended September 30,	**2011**	**2010**	**2011**	**2010**
(in thousands, except shares and per share data)				
Calculation of Basic Earnings Per Share:				
Net Income	**$ 2,397**	$ 1,628	**$ 19,664**	$ 18,942
Weighted average shares outstanding	**9,564,012**	9,493,425	**9,552,472**	9,460,462
Basic Earnings Per Share	**$ 0.25**	$ 0.17	**$ 2.06**	$ 2.00
Calculation of Diluted Earnings Per Share:				
Reconciliation of Numerator:				
Net Income	**$ 2,397**	$ 1,628	**$ 19,664**	$ 18,942
Effect of 8.25% Convertible debentures (1)	**15**		**46**	56
Adjusted numerator Diluted	**$ 2,412**	$ 1,628	**$ 19,710**	$ 18,998
Reconciliation of Denominator:				
Weighted shares outstanding Basic	**9,564,012**	9,493,425	**9,552,472**	9,460,462
Effect of dilutive securities (1):				
Share-based Compensation	**23,925**	4,271	**22,623**	23,708
8.25% Convertible debentures	**70,033**		**72,537**	86,751
Adjusted denominator Diluted	**9,657,970**	9,497,696	**9,647,632**	9,570,921
Diluted Earnings Per Share	**$ 0.25**	$ 0.17	**$ 2.04**	$ 1.98

(1) Amounts associated with securities resulting in an anti-dilutive effect on earnings per share are not included in this calculation.

3. Rates and Other Regulatory Activities

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

Delaware

Capacity Release: On September 2, 2008, our Delaware division filed with the Delaware PSC its annual Gas Sales Service Rates (GSR) Application, seeking approval to change its GSR, effective November 1, 2008. On July 7, 2009, the Delaware PSC granted approval of a settlement agreement presented by the parties in this docket, which included the Delaware PSC, our Delaware division and the Division of the Public Advocate. As part of the settlement agreement, the parties agreed to develop a record in a later proceeding on the price charged by the Delaware division for the temporary release of transmission pipeline capacity to our natural gas marketing subsidiary, Peninsula Energy Services Company, Inc. (PESCO). On January 8, 2010, the Hearing Examiner in this proceeding issued a report of Findings and Recommendations in which he recommended, among other things, that the Delaware PSC require the Delaware division to refund to its firm service customers the difference between what the Delaware division would have received had the capacity released to PESCO been priced at the maximum tariff rates under asymmetrical pricing principles and the amount actually received by the Delaware division for capacity released to PESCO. The Hearing Examiner also recommended that the Delaware PSC require us to adhere to asymmetrical pricing principles in all future capacity releases by the Delaware division to PESCO, if any. If the Hearing Examiner s refund recommendation for past capacity releases were ultimately approved without modification by the Delaware PSC, the Delaware division would have to credit to its firm service customers amounts equal to the maximum tariff rates that the Delaware division pays for long-term capacity, which we estimated to be approximately $700,000, even though the temporary releases were made at lower rates based on competitive bidding procedures required by the FERC s capacity release rules. On February 18, 2010, we filed exceptions to the Hearing Examiner s recommendations.

Table of Contents

At the hearing on March 30, 2010, the Delaware PSC agreed with us that the Delaware division had been releasing capacity based on a previous settlement approved by the Delaware PSC and, therefore, did not require the Delaware division to issue any refunds for past capacity releases. The Delaware PSC, however, required the Delaware division to adhere to asymmetrical pricing principles for future capacity releases to PESCO until a more appropriate pricing methodology is developed and approved. The Delaware PSC issued an order on May 18, 2010, elaborating its decisions at the March hearing and directing the parties to reconvene in a separate docket to determine if a pricing methodology other than asymmetrical pricing principles should apply to future capacity releases by the Delaware division to PESCO.

On June 17, 2010, the Division of the Public Advocate filed an appeal with the Delaware Superior Court, asking it to overturn the Delaware PSC s decision with regard to refunds for past capacity releases. On June 28, 2010, the Delaware division filed a Notice of Cross Appeal with the Delaware Superior Court, asking it to overturn the Delaware PSC s decision with regard to requiring the Delaware division to adhere to asymmetrical pricing principles for future capacity releases to PESCO. On June 13, 2011, the Delaware Superior Court issued its decision affirming all aspects of the Delaware PSC s Order on May 18, 2010, which included its decision not to require the Delaware division to issue any refunds for past releases.

On June 29, 2011, the Delaware Attorney General filed an appeal with the Delaware Supreme Court, asking it to review the Delaware Superior Court s decision affirming the Delaware PSC decision with regard to refunds for past capacity releases. On July 12, 2011, the Delaware division filed a Notice of Cross Appeal with the Delaware Supreme Court, asking it to overturn the Superior Court s decision with regard to the Delaware PSC s decision on future capacity releases to PESCO. On August 3, 2011, the Delaware Attorney General filed a Notice of Dismissal with the Supreme Court in which the Delaware Attorney General withdrew its appeal. Consequently, on August 4, 2011, the Delaware division filed a Notice of Dismissal with the Supreme Court to withdrawal its cross appeal. This officially closes the case and eliminates any potential liability related to potential refunds for past capacity releases. Due to the ongoing legal proceedings, the parties have not yet opened a separate docket to determine an alternative pricing methodology for future capacity releases.

Our Delaware division also had developments in the following matters with the Delaware PSC:

On September 1, 2010, the Delaware division filed with the Delaware PSC its annual GSR Application, seeking approval to change its GSR, effective November 1, 2010. On September 21, 2010, the Delaware PSC authorized the Delaware division to implement the GSR charges on November 1, 2010, on a temporary basis, subject to refund, pending the completion of full evidentiary hearings and a final decision. The Delaware PSC granted approval of the GSR charges at its regularly scheduled meeting on June 7, 2011.

On March 10, 2011, the Delaware division filed with the Delaware PSC an application requesting approval to guarantee certain debt of FPU. Specifically, the Delaware division sought approval to execute a Seventeenth Supplemental Indenture, in which Chesapeake guarantees the payment of certain debt of FPU and FPU is permitted to deliver Chesapeake s consolidated financial statements in lieu of FPU s stand-alone financial statements to satisfy certain covenants within the indentures of FPU s debt. The Delaware PSC granted approval of the guarantee of certain debt of FPU at its regularly scheduled meeting on April 4, 2011.

On September 1, 2011, the Delaware division filed with the Delaware PSC its annual 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 full evidentiary hearings and a final decision. We anticipate that the Delaware PSC will render a final decision on the GSR charges in the second or third quarter of 2012.

On September 19, 2011, the Delaware division filed with the Delaware PSC two applications seeking approval to begin charging customers for the franchise fees imposed upon the Delaware division by the City of Lewes, Delaware and the Town of Dagsboro, Delaware. These applications are very similar to requests the Delaware PSC has already approved for six other local governments. On October 3, 2011, the Delaware PSC issued orders on both matters, effectively opening the proceedings and setting evidentiary hearings for November 8, 2011. We anticipate that the Delaware PSC will render a decision in the fourth quarter of 2011.

Maryland

On December 14, 2010, the Maryland PSC held an evidentiary hearing to determine the reasonableness of the four quarterly gas cost recovery filings submitted by the Maryland division during the 12 months ended September 30, 2010. No issues were raised at the hearing, and on December 20, 2010, the Hearing Examiner in this proceeding issued a proposed Order approving the division s four quarterly filings. This proposed Order became a final Order of the Maryland PSC on January 20, 2011.

On March 2, 2011, the Maryland division filed with the Maryland PSC an application for the approval of a franchise executed between the Maryland division and the Board of County Commissioners of Cecil County, Maryland. In this franchise agreement, the County granted the Maryland division a 50-year, non-exclusive franchise to construct and operate natural gas distribution facilities within the present and future jurisdictional boundaries of Cecil County. On April 11, 2011, the Maryland PSC issued an Order approving the franchise between the Maryland division and Cecil County, subject to no adverse comments being received within 30 days after the issuance of the Order. On May 10, 2011, comments opposing the application were filed by Pivotal Utility Holdings, Inc. d/b/a Elkton Gas (Pivotal). Pivotal also provides natural gas service to customers in a portion of Cecil County. On June 8, 2011, the Maryland PSC granted the Maryland division the authority to exercise its franchise in a majority of the area requested in the Maryland division s application. The approval for a small portion of the area within the requested franchise area, which is closest to the area served by Pivotal, has been withheld until an evidentiary hearing is convened. On August 16, 2011, the Maryland division submitted testimony in support of its proposed boundary with Pivotal. On September 29, 2011, the parties in the proceeding (Maryland division, Pivotal, Maryland PSC Staff, and the Office of People s Counsel) submitted a proposed settlement agreement for the Maryland PSC s consideration that outlines an agreed upon boundary between the Maryland division and Pivotal in the small portion of Cecil County that was subject to further review. On October 12, 2011, the assigned Public Utility Law Judge in this matter issued a Proposed Order, approving the proposed settlement agreement as submitted by the parties in the proceeding. The Proposed Order will become a final order of the Maryland PSC on November 15, 2011, unless an appeal is noted with the Maryland PSC before that date by any party to this proceeding, or the Maryland PSC modifies or reverses the Proposed Order or initiates further proceedings into this matter.

On May 17, 2011, the Maryland division filed with the Maryland PSC an application for approval of a franchise executed between the Maryland division and the Board of County Commissioners for Worcester County, Maryland. In this franchise agreement, the County granted the Maryland division a 25-year, non-exclusive, franchise to construct and operate natural gas distribution facilities within the present and future jurisdictional boundaries of Worcester County. On June 14, 2011, the Maryland PSC issued an Order approving the franchise between the Maryland division and Worcester County, subject to no adverse comments being received within 20 days after the issuance of the Order. No adverse comments were filed within the comment period and the order became effective on July 5, 2011.

On August 12, 2011, the Maryland division submitted a request to the Maryland PSC for approval of a negotiated delivery service rate for a large customer on its system. At its regularly scheduled meeting on September 21, 2011, the Maryland PSC granted approval of the negotiated delivery service rate effective for bills rendered after that date.

Florida

Come-Back Filing: As part of our 2010 rate case settlement in Florida, the Florida PSC required us to submit a Come-Back filing, detailing all known benefits, synergies, cost savings and cost increases resulting from the merger with FPU. We submitted this filing on April 29, 2011. We are requesting the recovery, through rates, of approximately $34.2 million in acquisition adjustment (the price paid in excess of the book value) and $2.2 million in merger-related costs. In the past, the Florida PSC has allowed recovery of an acquisition adjustment under certain circumstances to provide an incentive for larger utilities to purchase smaller utilities. The Florida PSC requires a company seeking recovery of the acquisition adjustment and merger-related costs to demonstrate that customers will benefit from the acquisition. They use the following five factor test to determine if the customers are benefiting from the transaction: (a) increased quality of service; (b) lower operating costs; (c) increased ability to attract capital for improvements; (d) lower overall cost of capital; and (e) more professional and experienced managerial, financial, technical and operational resources. With respect to lower costs, the Florida PSC effectively requires that the synergies be sufficient to offset the rate impact of the recovery of the acquisition adjustment and merger-related costs. The Florida PSC is expected to address our request for recovery of the acquisition adjustment and merger-related costs at the November 2011 agenda conference.

If the Florida PSC approves recovery of the acquisition adjustment and merger-related costs, we would be able to classify these amounts as regulatory assets and include them in our investment, or rate base, when determining our Florida natural gas rates. Additionally, we would calculate our rate of return based upon this higher level of investment, which would effectively enable us to earn a return on this investment. We would also be able to amortize the acquisition adjustment and merger-related costs over 30 and five years, respectively. Amortization expense would be included in the calculation of our rates.

If recovery of the acquisition adjustment and merger-related costs is approved, our earnings may be reduced by as much as $1.6 million annually for the amortization expense (approximately $1.3 million is non-tax-deductible) until 2014 and $1.1 million annually (non-tax deductible) thereafter until 2039. This amortization expense would be a non-cash charge, and the net effect of the recovery would be positive cash flow. Over the long-term, however, the 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 otherwise been able to achieve.

If the Florida PSC does not allow recovery of the acquisition adjustment and merger-related costs, there is some likelihood that we would have to reduce rates in the State of Florida, which would adversely affect our future earnings.

We continue to maintain a $750,000 accrual, which was recorded in 2010 based on management s assessment of FPU s earnings and regulatory risk to its earnings associated with possible Florida PSC action related to our requested recovery and the matters set forth in this filing.

Marianna Franchise: On July 7, 2009, the City Commission of Marianna, Florida (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. Future financial results would be negatively affected by the loss of earnings generated by FPU from its approximately 3,000 customers in the City under the Franchise Agreement.

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 has objected to the proposed rates and has filed a petition protesting the entry of the Florida PSC s Order. On March 17, 2011, FPU filed a Motion to Dismiss the petition by the City of Marianna and requested oral argument. On June 14, 2011, the Florida PSC granted FPU s request for oral argument and on July 5, 2011, issued an Order approving FPU s Motion to Dismiss the protest by the City of Marianna, without prejudice. On July 25, 2011, the City of Marianna filed an amended petition protesting the entry of the Florida PSC s Order. On August 12, 2011, FPU filed a new Motion to Dismiss the petition by the City of Marianna and requested oral argument. The Florida PSC s decision with respect to the amended petition by the City of Marianna is expected in December 2011.

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 Corporation (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. Pursuant to 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 July 28, 2011, FPU filed a Motion to Dismiss the petition by the City of Marianna and requested oral argument. The Florida PSC s decision with respect to the protest filed by the City of Marianna is expected in December 2011.

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 is projected to reduce customers fuel rates for the remaining months of 2011 by approximately 10 percent.

As disclosed in Note 5, Other Commitments and Contingencies, to the unaudited 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. On March 28, 2011, FPU filed its answer to the declaratory action by the City of Marianna, in which it denied the material allegation by the City of Marianna and asserted several affirmative defenses. The litigation remains pending and discovery is still underway.

Eastern Shore

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

Energylink Expansion Project: In 2006, Eastern Shore proposed to develop, construct and operate approximately 75 miles of new pipeline facilities from the existing Cove Point Liquefied Natural Gas terminal in Calvert County, Maryland, crossing under the Chesapeake Bay into Dorchester and Caroline Counties, Maryland, to points on the Delmarva Peninsula, where such facilities would interconnect with Eastern Shore s existing facilities in Sussex County, Delaware. In April 2009, Eastern Shore terminated this project based on increased construction costs over its original projection. As approved by the FERC, Eastern Shore initiated billing to recover approximately $3.2 million of costs incurred in connection with this project and the related cost of capital over a period of 20 years in accordance with the terms of the precedent agreements executed with the two participating customers. One of the two participating customers is Chesapeake, through its Delaware and Maryland divisions. During 2010, Eastern Shore and the participating customers negotiated to reduce the recovery period of this cost from 20 years to five years. On January 27, 2011, Eastern Shore filed with the FERC the request to amend the cost recovery period, which was approved by the FERC on February 14, 2011. Eastern Shore revised its billing to reflect the five-year surcharge effective March 1, 2011.

Table of Contents

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. The rate filing reflects increases in operating and maintenance expenses, depreciation expense, and a return on existing and new gas plant facilities expected to be placed into service before June 30, 2011. The FERC issued a notice of the filing on January 3, 2011. Protests were received from several interested parties, and other parties intervened in the proceeding. On January 31, 2011, the FERC issued its Order accepting the filing and suspending its effectiveness for the full five-month period permitted under the Natural Gas Act. The discovery process commenced on February 22, 2011, and FERC Staff performed an on-site audit on March 16-17, 2011. Settlement conferences involving Eastern Shore, FERC Staff and other interested parties have resulted in a settlement in principle, which provides a cost of service of approximately $29.1 million and a pre-tax return of 13.9 percent. This represents an annual rate increase of approximately $805,000, effective July 29, 2011. The settlement also includes a rate reduction, effective November 1, 2011, associated with the 15,000 Dekatherms per day (Dts/d) phase-in of new transportation services on Eastern Shore s eight-mile extension to interconnect with the Texas Eastern Transmission LP (TETLP) pipeline system. This rate reduction fully offsets the increased revenue that would have been generated from the 15,000 Dts/d increase in firm 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. The settlement 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. Eastern Shore expects to finalize the settlement with the parties in November 2011 and submit it to the FERC for approval. The FERC s approval is expected by late 2011 or early 2012.

Starting in July 2011, Eastern Shore adjusted its billing to reflect the rates requested in the base rate proceeding, subject to refund to customers upon the conclusion of this proceeding. Eastern Shore recorded approximately $911,000 as a regulatory liability as of September 30, 2011, to fully reserve any incremental revenues generated by the new rates until the settlement is filed and approved by the FERC.

Mainline Extension Project: On April 1, 2011, Eastern Shore filed a notice of its intent under its blanket certificate to construct, own and operate new mainline facilities to deliver additional firm service of 3,405 Dts/d of natural gas to an existing industrial customer. The FERC published notice of this filing on April 7, 2011. The 60-day comment period subsequent to the FERC notice expired on June 6, 2011, and the requested authorization became effective on that date.

On April 28, 2011, Eastern Shore filed a notice of intent under its blanket certificate to construct, own and operate new mainline facilities to deliver additional firm service of 6,250 Dts/d of natural gas to Chesapeake s Delaware and Maryland divisions and Eastern Shore Gas, an unaffiliated provider of piped propane service in Maryland. The FERC published notice of this filing on May 12, 2011 and one of Eastern Shore s customers filed a conditional protest with the FERC, which it withdrew on July 29, 2011. Upon withdrawal of the protest, the requested authorization became effective.

Also on April 28, 2011, Eastern Shore filed a notice of intent under its blanket certificate to construct, own and operate new mainline facilities to deliver additional firm service of 4,070 Dts/d of natural gas to Chesapeake s Maryland division to provide new natural gas service in Cecil County, Maryland. The FERC published notice of this filing on May 12, 2011 and one of Eastern Shore s customers filed a conditional protest with the FERC, which it withdrew on July 29, 2011. Upon withdrawal of the protest, the requested authorization became effective.

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 for an effective date of April 1, 2011, subject to Eastern Shore submitting certain clarifications with regard to several proposed revisions.

On April 18, 2011, Eastern Shore submitted its annual Interruptible Revenue Sharing Report to the FERC. Eastern Shore reported in this filing that its interruptible revenue did not exceed its annual threshold amount, which would trigger sharing of excess interruptible revenues with its firm service customers. Consequently, Eastern Shore is not required to refund to its firm customers any portion of its interruptible revenue received for the period April 2010 through March 2011.

On June 24, 2011, Eastern Shore filed certain tariff sheets to amend the General Terms and Conditions and the Firm Transportation Service Agreement contained in its FERC Gas Tariff to allow for specification of minimum delivery pressures and maximum hourly quantity. The FERC published the notice of this filing on June 27, 2011, and no protests or adverse comments opposing this filing were submitted. On July 15, 2011, the FERC issued a Letter Order, accepting the tariff revisions as proposed, effective July 24, 2011.

On August 15, 2011, Eastern Shore filed certain tariff sheets to update certain Delivery Point Area definitions contained in its FERC Gas Tariff. The FERC published the notice of this filing on August 16, 2011, and no protests or adverse comments opposing this filing were submitted. On September 13, 2011, the FERC issued a Letter Order, accepting the tariff revisions as proposed, effective September 14, 2011.

On September 7, 2011, Eastern Shore filed certain tariff sheets to reflect a decrease in the Annual Charge Adjustment, which is a surcharge designed to recover applicable program costs incurred by the FERC. The surcharge decreased from $0.0019 per Dt to $0.0018 per Dt. The FERC published the notice of this filing on September 8, 2011, and no protests or adverse comments opposing this filing were submitted. On September 27, 2011, the FERC issued a Letter Order, accepting the tariff revisions as proposed, effective October 1, 2011.

4. 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 certain exposures 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, 2011, we had approximately $11.1 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 $8.2 million of FPU s expected environmental costs have been recovered from insurance and customers through rates as of September 30, 2011. We also had approximately $5.8 million in regulatory assets for future recovery of environmental costs from FPU s customers.

Table of Contents

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. Pursuant to a Consent Order between FPU and the Florida Department of Environmental Protection (FDEP), effective April 8, 1991, FPU is required to complete the delineation of soil and groundwater impacts at the site, and implement an effective remedy.

On June 30, 2008, FPU transmitted to the FDEP a revised feasibility study, evaluating appropriate remedies for the site. This revised feasibility study evaluated a wide range of remedial alternatives based on criteria provided by applicable laws and regulations. On April 30, 2009, the FDEP issued a remedial action order, which it subsequently withdrew. In response to the Order and as a condition to its withdrawal, FPU committed to perform additional field work in 2009 and complete an additional engineering evaluation of certain remedial alternatives. The scope of this work has increased in response to FDEP s requests for additional information.

FPU performed additional field work in August 2010, which included the installation of additional groundwater monitoring wells and performance of a comprehensive groundwater sampling event. FPU also performed vapor intrusion sampling in October 2010. The results of the field work were submitted to FDEP for their review and comment in October 2010. On November 4, 2010, FDEP issued its comments on the feasibility study and the proposed remedy.

On November 16, 2010, FPU presented to FDEP a new remedial action plan for the site, and FDEP agreed with FPU s proposal to implement a phased approach to remediation. On December 22, 2010, FPU submitted to FDEP an interim Remedial Action Plan (RAP) to remediate the east parcel of the site, which FDEP conditionally approved on February 4, 2011. Subsequent modifications to the interim RAP, dated March 12, 2011 and April 18, 2011, were submitted to address potential concerns raised by FDEP. An Approval Order for the interim RAP was issued by FDEP on May 2, 2011, and subsequently modified by FDEP on May 18, 2011.

FPU is currently implementing the interim RAP for the east parcel of the West Palm Beach site, including the incorporation of FDEP s conditions for approval. The operations on the east parcel have been relocated, and the structures removed. New monitoring wells and Air Sparging and Soil-Vapor Extraction (AS/SVE) test wells were installed on the east parcel in May 2011. The initial round of SVE and sparging pilot testing was conducted in June 2011, and a subsequent round of testing was conducted in July of 2011. A supplement to the interim RAP is being prepared to present to FDEP the findings of the pilot testing and proposed design details for a full-scale remediation system.

Estimated costs of remediation for the West Palm Beach site range from approximately $4.7 million to $15.8 million. We have revised our estimated maximum cost of $13.1 million to $15.8 million to include costs associated with relocation of FPU s operations at this site, which may be 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 late September 2006, the United States Environmental Protection Agency (EPA) sent a Special Notice Letter, notifying FPU, and the other responsible parties at the site (Florida Power Corporation, Florida Power & Light Company, Atlanta Gas Light Company, and the city of Sanford, Florida, collectively with FPU, the Sanford Group), of EPA s selection of a final remedy for OU1 (soils), OU2 (groundwater), and OU3 (sediments) for the site. The EPA projected the total estimated remediation costs for this site to be approximately $12.9 million.

Table of Contents

In January 2007, FPU and other members of the Sanford Group signed a Third Participation Agreement, which provides for funding the final remedy approved by 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, 2011, FPU has paid $650,000 to the Sanford Group escrow account for its share of the funding requirements.

The Sanford Group, EPA and the U.S. Department of Justice agreed to a Consent Decree in March 2008, which was entered by the Federal Court in Orlando, Florida on January 15, 2009. The Consent Decree obligates the Sanford Group to implement the remedy approved by EPA for the site. The total cost of the final remedy is now estimated at approximately $18 million. 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.

Several members of the Sanford Group have concluded negotiations with two adjacent property owners to resolve damages that the property owners allege they have 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.

As of September 30, 2011, 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 September 30, 2011.

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 September 2010, FDEP issued a Preliminary Contamination Assessment Report, for additional soil and groundwater investigation work that was undertaken by FDEP in November 2009 and January 2010, after 17 years of regulatory inactivity. Because FDEP observed that some soil and groundwater standards were exceeded, FDEP is requesting implementation of additional fieldwork which FDEP believes is warranted for the site.

FPU and the current site owner have had several discussions regarding the approach to be taken with FDEP and the proposed scope of work. Representatives of FPU, FDEP and the current site owner participated in a teleconference on July 7, 2011. During that call, the scope of work was tentatively agreed upon, and FDEP agreed to proceed without using a consent order. FPU and the current site owner submitted a work plan and schedule to FDEP on September 30, 2011. Potential costs for investigation and remediation are projected to be $118,000.

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 November 9, 2010, an NFA Proposal was submitted to FDEP, along with a draft restrictive covenant for that portion of the property currently owned by FDOT. FPU, FDOT and the City of Pensacola are working together to obtain a restrictive covenant that is acceptable to FDEP to complete closure of the site, and it is anticipated that no further monitoring will be required on the site. FPU s total remaining consulting and remediation costs for this site are projected to be $7,000.

In addition, we had $284,000 in environmental liabilities at September 30, 2011, related to Chesapeake s MGP sites in Maryland and Florida, representing our estimate of future costs associated with these sites. As of September 30, 2011, we had approximately $1.1 million in regulatory and other assets for future recovery through rates. The following discussion provides details on MGP sites for Chesapeake s Maryland and Florida divisions:

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. During 1996, we completed construction of an AS/SVE system and began remediation procedures. We have reported the remediation and monitoring results to the MDE on an ongoing basis since 1996. In February 2002, the MDE granted permission to permanently decommission the AS/SVE system 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.

Through September 30, 2011, we have incurred and paid approximately $2.9 million for remedial actions and environmental studies related to this site. We have recovered approximately $2.3 million through insurance proceeds or in rates, and $580,000 is expected to be recovered through future rates.

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. In 2001, FDEP approved a RAP requiring construction and operation of a Bio-Sparging and Soil/Vapor Extraction (BS/SVE) treatment system to address soil and groundwater impacts at a portion of the site. The BS/SVE treatment system has been in operation since October 2002. Modifications and upgrades to the BS/SVE treatment system were completed in October 2009. The Seventeenth Semi-Annual RAP Implementation Status Report was submitted to FDEP in June 2011. The groundwater sampling results through June 2011 show a continuing reduction in contaminant concentrations and indicate that the recent treatment system modifications and upgrades have had a beneficial impact on the rate of reduction. At present, we predict that remedial action objectives could be met in approximately two to three years for the area being treated by the BS/SVE treatment system. The total expected cost of operating and monitoring the system is approximately $46,000.

The BS/SVE treatment system at the Winter Haven site does not address impacted soils in the southwest corner of the site. On April 16, 2010, a soil excavation interim RAP describing the proposed excavation of approximately 4,000 cubic yards of impacted soils from the southwest corner of the site was submitted to FDEP for review. On June 24, 2010, FDEP provided comments on the soil excavation interim RAP by letter, to which we responded, and a subsequent conditional approval letter was issued by FDEP on August 27, 2010. The cost to implement this excavation plan has been estimated 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 (including treatment and discharge of the pumped water) are likely to be substantial, alternatives to this excavation plan are being evaluated. One alternative currently being evaluated involves sparging into the southwest portion of the property to treat soils rather than excavating the soils. Two new sparge points were installed in the southwest portion of the property in February of 2011. Sparging into these points has been initiated and operational and monitoring data over the next few quarters should provide the information needed to make this evaluation.

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.

Through September 30, 2011, we have incurred and paid approximately $1.7 million for remedial activities at this site, and we have estimated and accrued for additional future costs of $284,000. We have recovered through rates $1.5 million of the costs to remediate the Winter Haven site and continue to expect that the remaining $481,000, which is included in regulatory assets, will be recoverable from customers through our approved rates.

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.

5. Other Commitments and Contingencies

Litigation

In May 2010, an FPU propane customer filed a class action complaint against FPU in Palm Beach County, Florida, alleging, among other things, that FPU acted in a deceptive and unfair manner related to a particular charge by FPU on its bills to propane customers and the description of such charge. The suit sought to certify a class comprised of FPU propane customers to whom such charge was assessed since May 2006 and requested damages and statutory remedies based on the amounts paid by FPU customers for such charge. FPU vigorously denied any wrongdoing and maintained that the particular charge at issue is customary, proper and fair. Without admitting any wrongdoing, validity of the claims or a properly certifiable class for the complaint, FPU entered into a settlement agreement with the plaintiff in September 2010 to avoid the burden and expense of continued litigation. The court approved the final settlement agreement, and the judgment became final on March 13, 2011. In 2010, we recorded $1.2 million of the total estimated costs related to this litigation. Pursuant to the final settlement agreement, the distribution to the class was made by May 13, 2011.

On March 2, 2011, the City of Marianna, Florida 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. The litigation remains pending and discovery is still underway. 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. FPU intends to continue its vigorous defense of the lawsuit filed by the City of Marianna and intends to oppose the adoption of any proposed referendum to approve the purchase of the FPU property in the City of Marianna.

Table of Contents

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 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 2011, PESCO renewed contracts to purchase natural gas from various suppliers. These contracts expire in May 2012.

As discussed in Note 3 Rates and Other Regulatory Activities, on January 25, 2011, FPU entered into an amendment to its Generation Services Agreement with Gulf Power, which reduces the capacity demand quantity and provides the savings necessary to support the TOU and interruptible rates for the customers in the City of Marianna, both of which were approved by the Florida PSC. The amendment also extends the current agreement by two years, with a new expiration date of December 31, 2019.

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 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 September 30, 2011, FPU was in compliance with all of the requirements of its fuel supply contracts.

Corporate Guarantees

The Board of Directors has previously authorized the Company to issue up to $35 million of corporate guarantees or letters of credit on behalf of our subsidiaries. On March 2, 2011, the Board increased this limit from $35 million to $45 million.

We have issued corporate guarantees to certain vendors of our subsidiaries, the largest portion of which are 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 our financial statements when incurred. The aggregate amount guaranteed at September 30, 2011 was $26.7 million, with the guarantees expiring on various dates through December 2012.

Table of Contents

Chesapeake guarantees the payment of FPU s first mortgage bonds. The maximum exposure under the guarantee is the outstanding principal and accrued interest balances. The outstanding principal balances of FPU s first mortgage bonds approximate their carrying values (see Note 12, Long-Term Debt, to the unaudited 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, 2011, 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, 2012. There have been no draws on these letters of credit as of September 30, 2011. 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, which is further described below.

Agreements for Access to New Natural Gas Supplies

On April 8, 2010, our Delaware and Maryland divisions entered into a Precedent Agreement with TETLP 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 and 15,900 Dts/d, respectively, including the additional volume subscribed in a subsequent agreement, to 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.

Our Delmarva natural gas supplies are currently received primarily from the Gulf of Mexico natural gas production region and are transported through three interstate upstream pipelines, two of which interconnect directly with Eastern Shore s transmission system. The new firm transportation service contracts between our Delaware and Maryland divisions and TETLP will provide an additional direct interconnection with Eastern Shore s transmission system and access to new sources of natural gas supplies 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. Failure to agree upon a mutually acceptable reservation rate would have enabled either party to terminate the Precedent Agreement, and would have subjected us to reimburse TETLP for certain pre-construction costs; however, on July 2, 2010, our Delaware and Maryland divisions executed the required reservation rate agreements with TETLP.

Table of Contents

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 $3.8 million as of September 30, 2011. 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 with TETLP.

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. As discussed in Note 3, Rates and Other Regulatory Activities, to the unaudited condensed consolidated financial statements, Eastern Shore completed the extension project in December 2010 and commenced the service in January 2011. The rate for the transportation service on this extension is Eastern Shore s current tariff rate for service in that area.

TETLP is proceeding with obtaining the necessary approvals, authorizations or exemptions for construction and operation of its portion of the project, including, but not limited to, approval by the FERC. TETLP is expecting the FERC approval by the end of 2011. 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 firm transportation 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 a sales tax audit in Florida. As of September 30, 2011, we maintained an accrual of $578,000 related to additional sales taxes and gross receipts taxes owed to various states, all of which were recorded in 2010.

Other Contingency

As of September 30, 2011, we maintained a $750,000 accrual, which was recorded in 2010 based on management s assessment of FPU s earnings and regulatory risk to its earnings associated with possible Florida PSC action related to our requested recovery and the matters set forth in the Come-Back filing (See Note 3, Rates and Other Regulatory Activities, to the unaudited condensed consolidated financial statements for further discussion).

Table of Contents

6. 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.

	Three Months Ended		Nine Months Ended	
For the Periods Ended September 30,	**2011**	**2010**	**2011**	**2010**
(in thousands)				
Operating Revenues, Unaffiliated Customers				
Regulated Energy	**$ 53,435**	$ 53,112	**$ 192,130**	$ 196,957
Unregulated Energy	**23,720**	20,134	**112,163**	103,654
Other	**3,455**	3,220	**9,746**	9,176
Total operating revenues, unaffiliated customers	**$ 80,610**	$ 76,466	**$ 314,039**	$ 309,787
Intersegment Revenues (1)				
Regulated Energy	**$ 354**	$ 300	**$ 988**	$ 822
Unregulated Energy	**1**		**1**	364
Other	**196**	197	**586**	644
Total intersegment revenues	**$ 551**	$ 497	**$ 1,575**	$ 1,830
Operating Income (Loss)				
Regulated Energy	**$ 7,023**	$ 6,536	**$ 31,194**	$ 32,360
Unregulated Energy	**(1,472)**	(2,237)	**7,047**	4,732
Other and eliminations	**43**	284	**(32)**	650
Total operating income	**5,594**	4,583	**38,209**	37,742
Other income, net of other expenses	**649**	102	**699**	206
Interest	**2,389**	2,256	**6,654**	6,924

Income taxes	**1,457**	801	**12,590**	12,082
Net income	**$ 2,397**	$ 1,628	**$ 19,664**	$ 18,942

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

(in thousands)	**September 30, 2011**	**December 31, 2010**
Identifiable Assets		
Regulated energy	**$ 528,492**	$ 520,192
Unregulated energy	**96,760**	113,039
Other	**32,264**	37,762
Total identifiable assets	**$ 657,516**	$ 670,993

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.

Table of Contents

7. Employee Benefit Plans

Net periodic benefit costs for our pension and post-retirement benefits plans for the three and nine months ended September 30, 2011 and 2010 are set forth in the following table:

	Chesapeake		FPU		Chesapeake		Chesapeake Postretirement		FPU Medical	
(in thousands)	Pension Plan		Pension Plan		SERP		Plan		Plan	
For the Three Months Ended September 30,	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**
Service Cost	**$**	$	**$**	$	**$**	$	**$**	$	**$ 26**	$ 28
Interest Cost	**130**	147	**671**	638	**26**	35	**14**	30	**38**	33
Expected return on plan assets	**(100)**	(108)	**(683)**	(618)						
Amortization of prior service cost	**(1)**	(1)			**4**	5				
Amortization of net loss	**39**	40			**10**	15		15	**5**	
Net periodic cost (benefit)	**68**	78	**(12)**	20	**40**	55	**14**	45	**69**	61
Settlement expense					**219**					
Amortization of pre-merger regulatory asset			**190**	191					**2**	2
Total periodic cost	**$ 68**	$ 78	**$ 178**	$ 211	**$ 259**	$ 55	**$ 14**	$ 45	**$ 71**	$ 63

	Chesapeake		FPU		Chesapeake		Chesapeake Postretirement		FPU Medical	
(in thousands)	Pension Plan		Pension Plan		SERP		Plan		Plan	
For the Nine Months Ended September 30,	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**
Service Cost	**$**	$	**$**	$	**$**	$	**$**	$	**$ 79**	$ 83
Interest Cost	**390**	441	**2,014**	1,913	**80**	105	**44**	91	**116**	101
Expected return on plan assets	**(302)**	(323)	**(2,051)**	(1,856)						
Amortization of prior service cost	**(4)**	(4)			**14**	15				
Amortization of net loss	**117**	119			**29**	45		44	**15**	
Net periodic cost (benefit)	**201**	233	**(37)**	57	**123**	165	**44**	135	**210**	184
Settlement expense	**217**				**219**					
Amortization of pre-merger regulatory asset			**571**	698					**6**	6
Total periodic cost	**$ 418**	$ 233	**$ 534**	$ 755	**$ 342**	$ 165	**$ 44**	$ 135	**$ 216**	$ 190

We expect to record pension and postretirement benefit costs of approximately $1.9 million for 2011. Included in that amount is a pension settlement expense of $217,000 recorded during the first nine months of 2011 related to a lump-sum pension distribution of $844,000 from the Chesapeake Pension Plan in January 2011 and $219,000 of settlement expense in July 2011 related to a lump-sum distribution of $765,000 from the Chesapeake SERP. Also included in the $1.9 million pension and postretirement benefit costs for 2011 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 $6.1 million and $6.7 million at September 30, 2011 and December 31, 2010, respectively. During the three and nine months ended September 30, 2011, we contributed $818,000 and $885,000, respectively, to the Chesapeake Pension Plan. We also contributed $466,000 and $1.0 million to the FPU Pension Plan during the three and nine months ended September 30, 2011, respectively. We expect to contribute $1.0 million and $1.3 million to the Chesapeake and FPU Pension Plans, respectively, during the year 2011.

Table of Contents

The Chesapeake 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 SERP for the three and nine months ended September 30, 2011, were $22,000 and $67,000, respectively; for the year 2011, such benefits paid are expected to be approximately $853,000, which includes the lump-sum distribution of $765,000 as mentioned above. Cash benefits paid for the Chesapeake Postretirement Plan, primarily for medical claims for the three and nine months ended September 30, 2011, totaled $22,000 and $68,000, respectively; for the year 2011, we have estimated that approximately $96,000 will be paid for such benefits. Cash benefits paid for the FPU Medical Plan, primarily for medical claims for the three and nine months ended September 30, 2011, totaled $72,000 and $107,000, respectively; for the year 2011, we have estimated that approximately $158,000 will be paid for such benefits.

In connection with the lump-sum pension distribution from the Chesapeake Pension Plan in January 2011 and the Chesapeake SERP in July 2011, and related settlement accounting, we re-measured the assets and obligations of the Chesapeake Pension Plan and the Chesapeake SERP. The assumptions used for the discount rate to calculate the benefit obligation remained unchanged at five percent. The average expected return on plan assets also did not change and remained at six percent.

8. Investments

The investment balance at September 30, 2011, represents: (a) a Rabbi Trust associated with our Supplemental Executive Retirement Savings Plan, (b) a Rabbi Trust related to a stay bonus agreement with a former executive, and (c) investments in equity securities. We classify these investments as trading securities and report them at their fair value. Any unrealized gains and losses, net of other expenses, are included in other income in the condensed consolidated statements of income. We also have recorded an associated liability that is adjusted each month for the gains and losses incurred by the Rabbi Trusts. At September 30, 2011 and December 31, 2010, total investments had a fair value of $3.7 million and $4.0 million, respectively.

9. Share-Based Compensation

Our non-employee directors and key employees are awarded share-based awards through our Directors Stock Compensation Plan (DSCP) and the 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 primarily based on the fair value of the grant on the date it was awarded.

The table below presents the amounts included in net income related to share-based compensation expense for the awards granted under the DSCP and the PIP for the three and nine months ended September 30, 2011 and 2010:

For the Periods Ended September 30,	**Three Months Ended 2011**	**Three Months Ended 2010**	**Nine Months Ended 2011**	**Nine Months Ended 2010**
(in thousands)				
Directors Stock Compensation Plan	**$ 111**	$ 74	**$ 296**	$ 209
Performance Incentive Plan	**262**	213	**782**	690
Total compensation expense	**373**	287	**1,078**	899
Less: tax benefit	**150**	115	**432**	361
Share-Based Compensation amounts included in net income	**$ 223**	$ 172	**$ 646**	$ 538

Table of Contents

Directors Stock Compensation Plan

Shares granted under the DSCP are issued in advance of the directors service periods and are fully vested as of the date of the grant. We record a prepaid expense of the shares issued and amortize the expense equally over a service period of one year. In May 2011, each of our non-employee directors received an annual retainer of 900 shares of common stock under the DSCP. A summary of stock activity under the DSCP during the nine months ended September 30, 2011 is presented below:

	Number of Shares		Weighted Average Grant Date Fair Value
Outstanding December 31, 2010			
Granted [1]	11,104	$	41.03
Vested	11,104	$	41.03
Forfeited			
Outstanding September 30, 2011			

(1) In January 2011, our former Chief Executive Officer John Schimkaitis, retired from the Company and was awarded 304 shares of common stock for the prorated portion of his service period as he began his service as a non-executive board member.

At September 30, 2011, there was $258,000 of unrecognized compensation expense related to the DSCP awards. This expense is expected to be recognized over the remaining directors service periods ending as of the 2012 Annual Meeting.

Performance Incentive Plan

The table below presents the summary of the stock activity for the PIP for the nine months ended September 30, 2011:

	Number of Shares		Weighted Average Fair Value
Outstanding December 31, 2010	101,150	$	28.78
Granted	41,664		40.16
Vested	31,400		27.63
Forfeited	24,000		29.31
Expired			
Outstanding September 30, 2011	87,414	$	34.47

In January 2011, the Board of Directors granted awards under the PIP for 41,664 shares. The shares granted in January 2011 are multi-year awards, of which 10,500 shares will vest at the end of the two-year service period, or December 31, 2012. The remaining 31,164 shares will vest at the end of the three-year service period, or December 31, 2013. These awards are earned based upon the successful achievement of long-term goals, growth and financial results, which comprised both market-based and performance-based conditions or targets. The fair value of each performance-based condition or target is equal to the market price of our common stock on the date of the grant. For the market-based conditions, we used the Black-Scholes pricing model to estimate the fair value of each market-based award granted.

In conjunction with his retirement, our former Chief Executive Officer forfeited 24,000 shares, which represents the shares awarded under the PIP in January 2009 for the performance period ending December 31, 2011 and in January 2010 for the performance period ending December 31, 2012, that had not vested.

At September 30, 2011, the aggregate intrinsic value of the PIP awards was $1.9 million.

Table of Contents

10. Derivative Instruments

We use derivative and non-derivative contracts to engage in trading activities and manage risks related to obtaining adequate supplies and the price fluctuations of natural gas, electricity and propane. Our natural gas, electric and propane distribution operations have entered into agreements with suppliers to purchase natural gas, electricity and propane for resale to their customers. Purchases under these contracts either do not meet the definition of derivatives or are considered normal purchases and sales and are accounted for on an accrual basis. Our propane distribution operation may also enter into fair value hedges of its inventory in order to mitigate the impact of wholesale price fluctuations. As of September 30, 2011, our natural gas and electric distribution operations did not have any outstanding derivative contracts. 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 is exercised if the propane prices fall below the strike price of $1.445 per gallon in January through March of 2012 and we will receive the difference between the market price and the strike price during those months. We paid $91,000 to purchase the put option. We account for this put option as a fair value hedge. As of September 30, 2011, the put option had a fair value of $92,000. The change in the fair value of the put option reduced our propane inventory balance.

Xeron, our propane wholesale and marketing subsidiary, engages in trading activities using forward and futures contracts. These contracts are considered derivatives and have been accounted for using the mark-to-market method of accounting. Under the mark-to-market method of accounting, the trading contracts are recorded at fair value, and the changes in fair value of those contracts are recognized as unrealized gains or losses in the statement of income in the period of change. As of September 30, 2011, we had the following outstanding trading contracts which we accounted for as derivatives:

At September 30, 2011	**Quantity in Gallons**	**Estimated Market Prices**		**Weighted Average Contract Prices**
Forward Contracts				
Sale	21,361,200	$ 1.3900	$1.6200	$ 1.5231
Purchase	21,193,200	$ 1.3344	$1.6047	$ 1.5149

Estimated market prices and weighted average contract prices are in dollars per gallon.
All contracts expire during or prior to the first quarter of 2012.

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.

Table of Contents

Fair values of the derivative contracts recorded in the condensed consolidated balance sheet as of September 30, 2011 and December 31, 2010, are the following:

		Asset Derivatives	
		Fair Value	
(in thousands)	**Balance Sheet Location**	**September 30, 2011**	**December 31, 2010**
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy assets	**$ 1,137**	$ 1,642
Put option (1)	Mark-to-market energy assets		
Derivatives designated as fair value hedges			
Put option (2)	Mark-to-market energy assets	**92**	
Total asset derivatives		**$ 1,229**	$ 1,642

		Liability Derivatives	
		Fair Value	
(in thousands)	**Balance Sheet Location**	**September 30, 2011**	**December 31, 2010**
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy liabilities	**$ 956**	$ 1,492
Total liability derivatives		**$ 956**	$ 1,492

(1) We purchased a put option for the Pro-Cap (propane price cap) Plan in October 2010. The put option, which expired in January and February 2011, had a fair value of $0 at December 31, 2010.

(2) We purchased a put option for the Pro-Cap Plan in August 2011. The put option, which will expire during the first quarter of 2012, has a fair value of $92 at September 30, 2011.

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

		Amount of Gain (Loss) on Derivatives:			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(in thousands)	**Location of Gain (Loss) on Derivatives**	**2011**	**2010**	**2011**	**2010**
Derivatives not designated as hedging instruments:					
Put Option(1)	Cost of Sales	**$**	$	**$**	$

Unrealized gain on forward contracts	Revenue		**62**		69		**32**		443
Derivatives designated as fair value hedges:									
Put Option[2]	Propane inventory		**1**				**1**		
Total		**$**	**63**	$	69	**$**	**33**	$	443

(1) We purchased a put option for the Pro-Cap Plan in October 2010. The put option, which expired in January and February 2011, had a fair value of $0 at December 31, 2010.

(2) We purchased a put option for the Pro-Cap Plan in August 2011. The put option, which will expire during the first quarter of 2012, has a fair value of $92 at September 30, 2011.

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 September 30,**				**Nine months ended September 30,**			
		2011		**2010**		**2011**		**2010**	
Realized gains on forward contracts	Revenue	**$**	**380**	$	271	**$**	**1,934**	$	1,010
Changes in mark-to-market energy assets	Revenue		**62**		69		**32**		443
Total		**$**	**442**	$	340	**$**	**1,966**	$	1,453

Table of Contents

11. Fair Value of Financial Instruments

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

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

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

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

The following table summarizes our financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements, by level, within the fair value hierarchy used at September 30, 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	$ 1,937	$ 1,937	$	$
Investments other	$ 1,751	$ 1,751	$	$
Mark-to-market energy assets, including put option	$ 1,229	$	$ 1,229	$
Liabilities:				
Mark-to-market energy liabilities	$ 956	$	$ 956	$

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, 2010:

		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	$ 1,515	$ 1,515	$	$
Investments other	$ 2,521	$ 2,521	$	$
Mark-to-market energy assets, including put option	$ 1,642	$	$ 1,642	$
Liabilities:				
Mark-to-market energy liabilities	$ 1,492	$	$ 1,492	$

Table of Contents

The following valuation techniques were used to measure fair value assets in the table above on a recurring basis as of September 30, 2011 and December 31, 2010:

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

At September 30, 2011, 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 carrying value of these financial assets and liabilities approximates fair value due to their short maturities and because interest rates approximate current market rates for short-term debt.

At September 30, 2011, long-term debt, which includes the current maturities of long-term debt, had a carrying value of $126.3 million, compared to a fair value of $150.4 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, 2010, long-term debt, including the current maturities, had a carrying value of $98.9 million, compared to the estimated fair value of $113.4 million.

Table of Contents

12. Long-Term Debt

Our outstanding long-term debt is shown below:

(in thousands)	September 30, 2011	December 31, 2010
FPU secured first mortgage bonds [A]:		
9.57% bond, due May 1, 2018	**$ 6,347**	$ 7,248
10.03% bond, due May 1, 2018	**3,491**	3,986
9.08% bond, due June 1, 2022	**7,957**	7,950
Uncollateralized senior notes:		
6.85% note, due January 1, 2012	**1,000**	1,000
7.83% note, due January 1, 2015	**8,000**	8,000
6.64% note, due October 31, 2017	**19,091**	19,091
5.50% note, due October 12, 2020	**20,000**	20,000
5.93% note, due October 31, 2023	**30,000**	30,000
5.68% note, due June 30, 2026	**29,000**	
Convertible debentures:		
8.25% due March 1, 2014	**1,179**	1,318
Promissory note	**200**	265
Total long-term debt	**126,265**	98,858
Less: current maturities	**(9,196)**	(9,216)
Total long-term debt, net of current maturities	**$ 117,069**	$ 89,642

(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 have similar covenants and default provisions as Chesapeake s existing senior notes, and they 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.

Table of Contents

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 for the year ended December 31, 2010, 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, continue, potential, forecast or other si or conditional verbs such as may, will, should, would or could. These statements represent our intentions, 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;
- 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;
- 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;
- growth in opportunities for 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 and maintain key customer relationships;
- the ability to maintain 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.

Table of Contents

The discussion of forward-looking gross margin information for Eastern Shore is based on the rates currently agreed to by the parties in the settlement of Eastern Shore s base rate proceeding. The settlement has not been finalized and is subject to FERC approval. Depending on the final resolution of the base rate proceeding, which is expected in late 2011 or early 2012, forward-looking gross margin information may change.

Results of Operations for the Quarter Ended September 30, 2011

Overview and Highlights

Our net income for the quarter ended September 30, 2011 was $2.4 million, or $0.25 per share (diluted). This represents an increase of $769,000, or $0.08 per share (diluted), compared to a net income of $1.6 million, or $0.17 per share (diluted), as reported in the same period in 2010.

For the Three Months Ended September 30,	2011	2010	Increase (decrease)
(in thousands except per share)			
Business Segment:			
Regulated Energy	**$ 7,023**	$ 6,536	$ 487
Unregulated Energy	**(1,472)**	(2,237)	765
Other	**43**	284	(241)
Operating Income	**5,594**	4,583	1,011
Other Income	**649**	102	547
Interest Charges	**2,389**	2,256	133
Income Taxes	**1,457**	801	656
Net Income	**$ 2,397**	$ 1,628	$ 769
Earnings Per Share of Common Stock			
Basic	**$ 0.25**	$ 0.17	$ 0.08
Diluted	**$ 0.25**	$ 0.17	$ 0.08

Our results for the quarter ended September 30, 2011 were enhanced by a one-time, non-operating gain of $553,000 from the sale of an Internet Protocol address asset, offset partially by a one-time pension charge of $219,000. Our results for the quarter ended September 30, 2010 were reduced by a $500,000 accrual for the regulatory risk to FPU s earnings associated with our request for recovery of the FPU acquisition adjustment and merger-related costs and a $278,000 non-recurring charge for the Florida propane class action settlement. These non-recurring items, net of the income tax effect, contributed approximately $673,000, or $0.07 per share (diluted), to the increase in our net income.

Key Factors Affecting Our Businesses

The following is a summary of key factors affecting our businesses and their impacts on our results during the third quarter of 2011. The following section also provides a more detailed analysis of our results by segment.

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

Eastern Shore, our natural gas transmission subsidiary, continues to extend its natural gas transmission system on the Delmarva Peninsula. Eastern Shore generated additional gross margin of $717,000 in the third quarter of 2011 from the following new transportation services:

Eastern Shore s new service on the eight-mile mainline extension to interconnect with TETLP s pipeline system, which commenced in January 2011, generated $542,000 of additional gross margin in the quarter. These new services for 19,324 Mcfs per day are expected to generate annual gross margin of approximately $1.9 million. Based upon the proposed settlement (see further discussion later in the section), as the services increase in November 2011 to 33,817 Mcfs per day, the new rate under the proposed settlement for these incremental services will negate the gross margin impact from the increase in volumes. In November 2012, as the new services increase to 38,647 Mcfs per day, additional annual gross margin of approximately $263,000 is expected to be generated from these services.

Eastern Shore entered into two additional transportation service agreements with an existing industrial customer, one for the period of May 2011 through April 2021 for an additional 3,290 Mcfs per day and the other for the period of November 2011 through October 2012 for an additional 9,192 Mcfs per day. These new services generated additional gross margin of $92,000 in the third quarter of 2011. The 10-year service from May 2011 to April 2021 is expected to generate gross margin of $243,000 in 2011 and $361,000 annually thereafter. The one-year service from November 2011 to October 2012 is expected to generate gross margin of $168,000 in 2011 and $842,000 in 2012.

Table of Contents

Eastern Shore began construction of its mainline extension projects to serve southern Delaware and Cecil and Worcester Counties, Maryland. These mainline extension projects are expected to be completed between November 2011 and June 2012. Once completed, these projects will enable Eastern Shore to deliver additional firm service of 6,039 Mcfs per day to our Delaware and Maryland divisions and an affiliated customer. These new services are expected to generate additional gross margin of $156,000 in 2011, $1.6 million in 2012 and $1.8 million annually thereafter.

Our Delmarva natural gas distribution operation has successfully expanded its service to large commercial and industrial customers and has continued its efforts to extend natural gas service to Lewes, Delaware and Cecil and Worcester Counties, Maryland. We signed service agreements with two industrial customers in Lewes, Delaware, for natural gas service expected to commence in the foutth quarter 2011. Gross margin from these customers is expected to equate to gross margin generated by approximately 1,000 residential customers. In August 2011, we entered into a new agreement to provide natural gas service to an existing industrial customer at two of its facilities located in southern Delaware. These new services are expected to begin in the first quarter 2012 and generate estimated annual gross margin equivalent to 415 residential customers. We also added 21 other large commercial and industrial services since July 2010, which generated $334,000 in additional gross margin during the third quarter of 2011. These new services are expected to generate annual gross margin of $1.2 million in 2011, compared to the $196,000 of gross margin they generated in 2010. Our Delmarva natural gas distribution operation also experienced two-percent growth in residential customers, generating additional gross margin of $58,000 for the third quarter of 2011.

Our Florida natural gas distribution operations generated $159,000 of additional gross margin in the third quarter of 2011, primarily from a two-percent growth in commercial customers in the quarter, compared to the same quarter in 2010.

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.

Our propane distribution operations generated additional gross margin of $522,000 from higher retail margins per gallon in the third quarter of 2011, compared to the same quarter in 2010. A favorable physical inventory adjustment and positive differential between propane wholesale prices and our average cost of inventory, as well as continued adjustment of Florida retail pricing in response to market opportunities, contributed to the increased retail margins.

Higher price volatility in the wholesale propane market resulted in a 20-percent increase in its trading volumes for Xeron, our propane wholesale marketing subsidiary, during the third quarter of 2011, compared to the same quarter in 2010, and generated $102,000 of additional gross margin.

Rates and Regulatory Matters. We have various rates and regulatory proceedings currently underway. The proceedings with potentially material financial impact are discussed below. See Note 3, Rates and Other Regulatory Activities, to the unaudited condensed consolidated financial statements for further discussion.

Eastern Shore, FERC Staff and other interested parties in Eastern Shore s base rate proceeding reached a settlement in principle, which provides a cost of service of approximately $29.1 million and pre-tax return of 13.9 percent. This represents an annual rate increase of approximately $805,000, effective July 29, 2011. The settlement also includes a rate reduction, effective November 1, 2011, to correspond with the 15,000 Dts/d (approximately 14,493 Mcfs per day) phase-in of new transportation services on Eastern Shore s eight-mile extension. This rate reduction fully offsets the increased revenue that would have been generated from the 15,000 Dts/d increase in firm 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. The settlement 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. Eastern Shore expects to finalize the settlement with the parties in November 2011 and submit it to the FERC for approval. The FERC s approval is expected by late 2011 or early 2012. Starting in July 2011, Eastern Shore adjusted its billing to reflect the rates requested in the base rate proceeding, subject to refund to customers upon the conclusion of this proceeding. Eastern Shore recorded approximately $911,000 as a regulatory liability as of September 30, 2011, to fully reserve any incremental revenues generated by the new rates until the settlement is filed and approved by the FERC.

The Come-Back filing in Florida, which includes our request for recovery, through rates, of approximately $34.2 million in acquisition adjustment and $2.2 million in merger-related costs, is also still underway. We expect the Florida PSC to address our request at the November 2011 agenda conference. If the Florida PSC approves recovery of the acquisition adjustment and merger-related costs, we would be able to classify these amounts as regulatory assets and include them in our investment, or rate base, when determining our Florida natural gas rates. Additionally, we would calculate our rate of return based upon this higher level of investment, which would effectively enable us to earn a return on this investment. We would also be able to amortize the acquisition adjustment and merger-related costs, which may reduce our earnings by as much as $1.6 million annually until 2014 and $1.1 million annually thereafter until 2039. This amortization expense would be a non-cash charge and included in the calculation of our rates, which, along with the recovery of these assets, will increase our earnings and cash flows above what we would have otherwise been able to achieve.

In addition to regulatory proceedings, we are currently involved in a legal dispute with the City of Marianna, Florida, in which the City alleges breaches of the Franchise Agreement by FPU and seeks a declaratory judgment that the City has the right to exercise its option to purchase FPU s electric distribution property in the City. FPU intends to vigorously contest this litigation and intends to oppose the adoption of any proposed referendum to approve the purchase of the FPU property in the City. FPU serves approximately 3,000 customers in the City. FPU incurred approximately $145,000 in legal, regulatory and other costs associated with this electric franchise dispute in the third quarter of 2011.

Advanced Information Services. In September 2011, BravePoint, our advanced information services subsidiary, released a new product, ProfitZoom , an integrated system encompassing financial, job costing and service management module, which was designed specifically for the fire protection and specialty contracting industries. ProfitZoom was built as a successor product to another software solution that BravePoint previously marketed and supported for companies in the fire suppression industry. Understanding the needs of the industry and utilizing its technology expertise, BravePoint began developing the ProfitZoom product in 2009. BravePoint incurred $274,000 in additional costs associated with the release and initial implementation of this product in the third quarter of 2011. BravePoint has successfully implemented this product for three customers, and two additional customers have executed sales contracts with implementations scheduled for December 2011 and January 2012. Several other sales proposals are under consideration by other potential customers.

Regulated Energy

For the Three Months Ended September 30, *(in thousands, except degree-day and customer information)*	2011	2010	Increase (decrease)
Revenue	**$ 53,789**	$ 53,412	$ 377
Cost of sales	**25,811**	27,257	(1,446)
Gross margin	**27,978**	26,155	1,823
Operations & maintenance	**14,938**	13,881	1,057
Depreciation & amortization	**4,132**	3,722	410
Other taxes	**1,885**	2,016	(131)
Other operating expenses	**20,955**	19,619	1,336
Operating Income	**$ 7,023**	$ 6,536	$ 487
Weather and Customer Analysis			
Delmarva Peninsula			
Heating degree-days (HDD):			
Actual	**49**	50	(1)
10-year average	**53**	60	(7)
Per residential customer added:			
Estimated gross margin	**$ 375**	$ 375	$ 0
Estimated other operating expenses	**$ 111**	$ 105	$ 6
Florida			
HDD:			
Actual	**0**	0	0
10-year average	**0**	0	0
Cooling degree-days:			
Actual	**1,569**	1,654	(85)
10-year average	**1,483**	1,466	17
Residential Customer Information			
Average number of customers:			
Delmarva natural gas distribution	**47,810**	46,908	902
Florida natural gas distribution	**61,261**	60,813	448
Florida electric distribution	**23,583**	23,594	(11)
Total	**132,654**	131,315	1,339

Operating income for the regulated energy segment increased by approximately $487,000, or seven percent, in the third quarter of 2011, compared to the same quarter in 2010. An increase in gross margin of $1.8 million was partially offset by an increase in operating expenses of $1.3 million.

Gross Margin

Gross margin for our regulated energy segment increased by $1.8 million, or seven percent, in the third quarter of 2011 compared to the same quarter in 2010.

Our Delmarva natural gas distribution operation generated an increase in gross margin of $279,000 in the third quarter of 2011, compared to the same quarter in 2010. The factors contributing to this increase were as follows:

- Customer growth generated a $385,000 increase in gross margin in the third quarter of 2011, compared to the same quarter in 2010. Commercial and industrial customer growth, due primarily to additional gross margin generated from 21 large commercial and industrial services added since July 2010, generated $337,000 of this increase. These 21 new large commercial and industrial services are expected to generate annual gross margin of $1.2 million in 2011. The same services generated $196,000 of gross margin following their addition in the second half of 2010. Two-percent growth in residential customers generated an additional $58,000 in gross margin.
- Offsetting these gross margin increases were decreases in gross margin of $68,000 and $37,000 attributable to a change in customer rates and rate classes and decreased non-weather-related customer consumption, respectively.

Gross margin for our Florida natural gas distribution operation increased by $749,000 in the third quarter of 2011, compared to the same quarter in 2010. The factors contributing to this increase were as follows:

- During the third quarter of 2010, the Florida natural gas distribution operation recorded an accrual of $500,000 to reserve for regulatory risk. The establishment of this reserve was based on management s assessment of its earnings and the risk associated with possible action by the Florida PSC related to our request for recovery of the acquisition adjustment and merger-related costs.
- Two-percent growth in commercial customers and the addition of 700 customers as a result of our purchase of the operating assets of Indiantown Gas Company in August 2010, generated additional gross margin of $200,000 in the third quarter of 2011, compared to the same quarter in 2010.

Our natural gas transmission operations achieved gross margin growth of $830,000 in the third quarter of 2011, compared to the same quarter in 2010. The factors contributing to this increase were as follows:

- New transportation services associated with Eastern Shore s eight-mile mainline extension to interconnect with TETLP s pipeline system generated an additional $542,000 of gross margin in the third quarter of 2011. These new services for 19,324 Mcfs per day, which commenced in January 2011, are expected to generate annual gross margin of approximately $1.9 million. Based upon the proposed settlement discussed previously, as the services increase in November 2011 to 33,817 Mcfs per day, the new rate under the proposed settlement of these incremental services will negate the gross margin impact from the increase in volumes. In November 2012, as the new services increase to 38,647 Mcfs per day, additional annual gross margin of approximately $263,000 is expected to be generated from these services.
- Eastern Shore entered into two additional transportation service agreements with an existing industrial customer, one for the period of May 2011 through April 2021 for an additional 3,290 Mcfs per day and the other for the period of November 2011 through October 2012 for an additional 9,192 Mcfs. These services generated additional gross margin of $92,000 in the third quarter of 2011. The 10-year service from May 2011 to April 2021 is expected to generate gross margin of $243,000 in 2011 and $361,000 annually thereafter. The one-year service from November 2011 to October 2012 is expected to generate gross margin of $168,000 in 2011 and $842,000 in 2012.
- New transportation services implemented by Eastern Shore in November 2010 as a result of its system expansion projects generated an additional $83,000 of gross margin in the third quarter of 2011, compared to the same quarter in 2010. This expansion added 1,546 Mcfs per day and an estimated annual gross margin of $351,000 in 2011. In 2010, this project generated $56,000 of gross margin.

The remaining gross margin increase of $113,000 was attributable primarily to higher volumes delivered during the third quarter of 2011 on a non-recurring basis to customers that operate electric generation facilities.

Gross margin for our Florida electric distribution operation remained relatively unchanged with a slight decrease of $46,000 in the third quarter of 2011, compared to the same quarter in 2010.

Other Operating Expenses

Other operating expenses for the regulated energy segment increased by $1.3 million, or seven percent, in the third quarter of 2011, compared to the same period in 2010, due largely to the following factors:

$260,000 in higher depreciation expense and asset removal costs from capital investments made since the third quarter of 2010;

$220,000 in increased costs related to Florida customer-service-related activities, due to service enhancements;

$212,000 in additional expenses related to pipeline integrity projects for Eastern Shore to comply with increased pipeline regulatory requirements;

$173,000 related to a one-time pension charge allocated to the regulated energy operations during the quarter;

$145,000 in increased regulatory, legal and other costs associated with the electric franchise dispute in Marianna, Florida; and

$122,000 in additional costs related to maintenance of mains, electric lines and facilities.

Other Development

In June 2011, Allen Family Foods, Inc. and related entities (collectively, Allen) filed for bankruptcy. Our Delmarva natural gas distribution operation serves two of Allen s poultry facilities, one of which is included in our discussion of the 21 new large commercial and industrial services added since July 2010. The total gross margin for 2010 from our natural gas service to these two facilities was approximately $156,000. Since the bankruptcy filing, these two facilities have been sold to another poultry processor. The facilities continue to operate and we continue to serve them. While we cannot predict the future plan for these two facilities by the new purchaser, the level of natural gas consumption at these two facilities has not changed significantly.

Unregulated Energy

For the Three Months Ended September 30,	2011	2010	Increase (decrease)
(in thousands, except degree-day data)			
Revenue	**$ 23,721**	$ 20,134	$ 3,587
Cost of sales	**18,622**	15,714	2,908
Gross margin	**5,099**	4,420	679
Operations & maintenance	**5,552**	5,435	117
Depreciation & amortization	**739**	896	(157)
Other taxes	**280**	326	(46)
Other operating expenses	**6,571**	6,657	(86)
Operating Loss	**$ (1,472)**	$ (2,237)	$ 765

Weather Analysis Delmarva Peninsula

Actual HDD	**49**	50	(1)
10-year average HDD	**53**	60	(7)

The unregulated energy segment reported an operating loss of $1.5 million, an improvement of $765,000, or 34 percent, compared to the operating loss in the same period in 2010. An increase in gross margin of $679,000 and a decrease in operating expenses of $86,000 contributed to the increase in operating results.

Table of Contents

Gross Margin

Gross margin for our unregulated energy segment increased by $679,000, or 15 percent, in the third quarter of 2011, compared to the same quarter in 2010.

Our Delmarva propane distribution operation generated an increase in gross margin of $274,000, or 16 percent, in the third quarter of 2011, compared to the same quarter in 2010. The factors contributing to this increase were as follows:

- Our Delmarva propane distribution operation generated additional gross margin of $184,000 in the third quarter of 2011, compared to the same quarter in 2010. A favorable physical inventory adjustment and the positive differential between propane wholesale prices and our average cost of inventory during the third quarter of 2011 contributed to the increased margins per gallon on the Delmarva Peninsula.
- The remaining gross margin increase of $90,000 is due primarily to increased wholesale margins and higher fees generated from continued growth and successful implementation of various customer pricing programs, slightly offset by a decrease in gross margins attributable to decreased non-weather-related customer consumption.

Our Florida propane distribution operation generated increased gross margin of $353,000 in the third quarter of 2011, compared to the same quarter in 2010, due primarily to improved margins per gallon in Florida as the Florida propane distribution operation continued to adjust its retail pricing in response to local market conditions.

Xeron generated $102,000 of additional gross margin during the third quarter of 2011, compared to the same quarter in 2010, due primarily to an increase in Xeron s trading activity by 20 percent in the third quarter of 2011, compared to the same period in 2010.

Gross margin generated by PESCO, our natural gas marketing subsidiary, remained substantially unchanged at $621,000 and $627,000 for the quarters ended September 30, 2011 and 2010, respectively.

Merchandise sales in Florida decreased in the third quarter of 2011, compared to the same period in 2010, resulting in lower gross margin of $44,000.

Other Operating Expenses

Other operating expenses for the unregulated energy segment decreased by $86,000 for the third quarter of 2011, compared to the same period in 2010. The decrease in operating expenses as a result of the absence of a $278,000 non-recurring charge in the third quarter of 2010 related to Florida propane class action settlement was partially offset by higher vehicle fuel and maintenance costs and increased bad debt expenses in the propane distribution operations.

Table of Contents

Other

For the Three Months Ended September 30,	2011	2010	Increase (decrease)
(in thousands)			
Revenue	**$ 3,100**	$ 2,920	$ 180
Cost of sales	**1,684**	1,524	160
Gross margin	**1,416**	1,396	20
Operations & maintenance	**1,099**	905	194
Depreciation & amortization	**107**	70	37
Other taxes	**167**	137	30
Other operating expenses	**1,373**	1,112	261
Operating Income Other	**43**	284	(241)
Operating Income Eliminations			
Operating Income	**$ 43**	$ 284	$ (241)

Note: Eliminations are entries required to eliminate activities between business segments from the consolidated results.

Operating income for the other segment decreased by approximately $241,000 in the third quarter of 2011, compared to the same quarter in 2010, which was attributable to an operating expense increase of $261,000, partially offset by a gross margin increase of $20,000.

Gross margin

The gross margin for our other segment remained substantially unchanged, at $1.4 million for the three months ended September 30, 2011 and 2010.

Other Operating expenses

Other operating expenses for our other segment increased by $261,000 in the third quarter of 2011, compared to the same quarter in 2010. Other operating expenses for BravePoint increased by $362,000, due primarily to $274,000 in additional marketing and development costs, as it began to roll out ProfitZoom , and $94,000 in increased benefit costs. Benefit costs increased for BravePoint as Chesapeake adopted a safe harbor 401(k) plan design on January 1, 2011, which resulted in an increased 401(k) benefit for BravePoint employees in 2011.

Interest Expense

Interest expense for the quarter ended September 30, 2011 increased by approximately $133,000, or six percent, compared to the same quarter in 2010. The long-term debt issuance of $29 million in June 2011 to permanently finance the redemption of two series of FPU mortgage bonds resulted in additional interest expense of $240,000 for the third quarter of 2011, compared to the same period in 2010. Prior to the long-term debt issuance, we had temporarily financed the redemption of these bonds through a short-term loan credit facility. This increase was partially offset by lower interest expense as a result of scheduled principal payments of other long-term debt.

Income Taxes

We recorded an income tax expense of $1.5 million for the quarter ended September 30, 2011, compared to $801,000 for the quarter ended September 30, 2010. The increase is attributable to increased earnings in the third quarter of 2011 compared to the same period in 2010.

Table of Contents

Results of Operations for the Nine Months Ended September 30, 2011

Overview and Highlights

Our net income during the nine months ended September 30, 2011 was $19.7 million, or $2.04 per share (diluted). This represents an increase of $722,000, or $0.06 per share (diluted), compared to net income of $18.9 million, or $1.98 per share (diluted), as reported for the same period in 2010.

For the Nine Months Ended September 30,		**2011**		**2010**		**Increase (decrease)**
(in thousands, except per share)						
Business Segment:						
Regulated Energy	**$**	**31,194**	$	32,360		($1,166)
Unregulated Energy		**7,047**		4,732		2,315
Other		**(32)**		650		(682)
Operating Income		**38,209**		37,742		467
Other Income		**699**		206		493
Interest Charges		**6,654**		6,924		(270)
Income Taxes		**12,590**		12,082		508
Net Income	**$**	**19,664**	$	18,942	$	722
Earnings Per Share of Common Stock						
Basic	**$**	**2.06**	$	2.00	$	0.06
Diluted	**$**	**2.04**	$	1.98	$	0.06

Our results for the nine months ended September 30, 2011 were enhanced slightly by one-time gains of $575,000 from the proceeds received from an antitrust litigation settlement with a major propane supplier and $553,000 from the sale of an Internet Protocol address asset, offset almost entirely by non-recurring severance and pension charges of $1.1 million. Our results for the nine months ended September 30, 2010 were reduced by a $500,000 accrual for the Florida natural gas regulatory reserve previously discussed and a $278,000 non-recurring charge for the Florida propane class action settlement. These non-recurring items, net of the income tax effect, contributed approximately $475,000, or $0.05 per share (diluted), to the increase in our net income.

Key Factors Affecting Our Businesses

The following is a summary of key factors affecting our businesses and their impacts on our results during the first nine months of 2011. The following section also provides a more detailed analysis of our results by segment.

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

Eastern Shore, our natural gas transmission subsidiary, continues to extend its natural gas transmission system on the Delmarva Peninsula. Eastern Shore generated additional gross margin of $2.1 million in the nine months ended September 30, 2011, compared to the same period in 2010, from the following new transportation services:

Eastern Shore s new service on the eight-mile mainline extension to interconnect with TETLP s pipeline system, which commenced in January 2011, generated $1.6 million of the additional gross margin in the first nine months of 2011. These new services for 19,324 Mcfs per day are expected to generate annual gross margin of approximately $1.9 million. Based upon the proposed settlement discussed previously, as the services increase in November 2011 to 33,817 Mcfs per day, the new rate under the proposed settlement for these incremental services will negate the gross margin impact from the increase in volumes. In November 2012, as the new services increase to 38,647 Mcfs per day, additional annual gross margin of approximately

$263,000 is expected to be generated from these services.

Eastern Shore entered into two additional transportation service agreements with an existing industrial customer, one for the period of May 2011 through April 2021 for an additional 3,290 Mcfs per day and the other for the period of November 2011 through October 2012 for an additional 9,192 Mcfs per day. These new services generated additional gross margin of $154,000 in the first nine months of 2011. The 10-year service from May 2011 to April 2021 is expected to generate gross margin of $243,000 in 2011 and $361,000 annually thereafter. The one-year service from November 2011 to October 2012 is expected to generate gross margin of $168,000 in 2011 and $842,000 in 2012.

Also generating additional gross margin of $330,000 in the first nine months of 2011, compared to the same period in 2010, were new transportation services that commenced in May and November 2010 as a result of Eastern Shore s system expansion projects. These expansions added 2,666 Mcfs per day of capacity with an estimated annual gross margin of $606,000 in 2011 ($431,000 in the first nine months of 2011). These projects generated $216,000 of gross margin in 2010 ($40,000 in the first nine months of 2010).

Eastern Shore began construction of its mainline extension projects to serve southern Delaware and Cecil and Worcester Counties, Maryland. These mainline extension projects are expected to be completed between November 2011 and June 2012. Once completed, these projects will enable Eastern Shore to deliver additional firm service of 6,039 Mcfs per day to our Delaware and Maryland divisions and an affiliated customer. These new services are expected to generate additional gross margin of $156,000 in 2011, $1.6 million in 2012 and $1.8 million annually thereafter.

Our Delmarva natural gas distribution operation has successfully expanded its service to large commercial and industrial customers and has continued its efforts to extend natural gas service to Lewes, Delaware and Cecil and Worcester Counties, Maryland. We signed service agreements with two industrial customers in Lewes, Delaware, for natural gas service expected to commence in the fourth quarter 2011. Gross margin from these customers is expected to equate to the gross margin that would be generated by approximately 1,000 residential customers. In August 2011, we entered into a new agreement to provide natural gas service to an existing industrial customer at two of its facilities located in southern Delaware. These new services are expected to begin in the first quarter 2012 and generate estimated annual gross margin equivalent to 415 residential customers. Our Delmarva natural gas distribution operation also added 21 other large commercial and industrial services since July 2010, which generated $859,000 in additional gross margin during the first nine months of 2011. These new services are expected to generate annual gross margin of $1.2 million in 2011, compared to the $196,000 of gross margin they generated in 2010. Our Delmarva natural gas distribution operation also experienced two-percent growth in residential customers, generating additional gross margin of $328,000 for the nine months ended September 30, 2011.

Our Florida natural gas distribution operations generated $754,000 of additional gross margin in the first nine months of 2011, primarily from a two-percent growth in commercial customers in the first nine months of 2011, compared to the same period in 2010. In addition, 700 new customers, added as a result of our purchase of the operating assets of Indiantown Gas Company in August 2010, generated $367,000 of additional gross margin during the period

Weather. Warmer temperatures on the Delmarva Peninsula and in Florida during the first nine months of 2011, compared to the same period in 2010, particularly during the peak heating season, decreased consumer consumption of natural gas and electricity. Lower consumption, attributable primarily to warmer weather, decreased our period-over-period gross margin by approximately $2.5 million. Heating degree-days decreased by five percent, or 145 heating degree-days, on the Delmarva Peninsula and by 43 percent, or 408 heating degree-days, in Florida during the first nine months of 2011, compared to the same period in 2010.

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.

Table of Contents

Our propane distribution operations generated additional gross margin of $2.1 million due to higher retail margins per gallon in the first nine months of 2011, compared to the same period in 2010. Propane retail margins per gallon on the Delmarva Peninsula during the first nine months of 2011 returned to more normal levels, compared to the lower margins per gallon reported during the same period in 2010, which was caused by colder temperatures and the high cost of spot purchases during the peak heating season. Also contributing to the gross margin increase were higher margins per gallon in Florida as the Florida propane operation continued to adjust its retail pricing in response to market opportunities, which contributed to the increased retail margins.

Higher price volatility in the wholesale propane market resulted in a 40-percent increase in its trading volumes for Xeron during the first nine months of 2011, compared to the same period in 2010, and generated $514,000 of additional gross margin.

Rates and Regulatory Matters. We have various rates and regulatory proceedings currently underway. The proceedings with potentially material financial impact are discussed below. See Note 3, Rates and Other Regulatory Activities, to the unaudited condensed consolidated financial statements for further discussion.

Eastern Shore, FERC Staff and other interested parties in Eastern Shore s base rate proceeding reached a settlement in principle, which provides a cost of service of approximately $29.1 million and pre-tax return of 13.9 percent. This represents an annual rate increase of approximately $805,000, effective July 29, 2011. The settlement also includes a rate reduction, effective November 1, 2011, associated with the 15,000 Dts/d (approximately 14,493 Mcfs perday) phase-in of new transportation services on Eastern Shore s eight-mile extension. This rate reduction fully offsets the increased revenue that would have been generated from the 15,000 Dts/d increase in firm 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. The settlement 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. Eastern Shore expects to finalize the settlement with the parties in November 2011 and submit it to the FERC for approval. The FERC s approval is expected by late 2011 or early 2012. Starting in July 2011, Eastern Shore adjusted its billing to reflect the rates requested in the base rate proceeding, subject to refund to customers upon the conclusion of this proceeding. Eastern Shore recorded approximately $911,000 as regulatory liability as of September 30, 2011, to fully reserve any incremental revenues generated by the new rates until the settlement is filed and approved by the FERC.

The Come-Back filing in Florida, which includes our request for recovery, through rates, of approximately $34.2 million in acquisition adjustment and $2.2 million in merger-related costs, is also still underway. We expect the Florida PSC to address our request at the November 2011 agenda conference. If the Florida PSC approves recovery of the acquisition adjustment and merger-related costs, we would be able to classify these amounts as regulatory assets and include them in our investment, or rate base, when determining our Florida natural gas rates. Additionally, we would calculate our rate of return based upon this higher level of investment, which would effectively enable us to earn a return on this investment. We would also be able to amortize the acquisition adjustment and merger-related costs, which may reduce our earnings by as much as $1.6 million annually until 2014 and $1.1 million annually thereafter until 2039. This amortization expense would be a non-cash charge and included in the calculation of our rates, which, along with the recovery of these assets, will increase our earnings and cash flows above what we would have otherwise been able to achieve.

Table of Contents

In addition to regulatory proceedings, we are currently involved in a legal dispute with the City of Marianna, Florida, in which the City alleges breaches of the Franchise Agreement by FPU and seeks a declaratory judgment that the City has the right to exercise its option to purchase FPU s electric distribution property in the City. FPU intends to vigorously contest this litigation and intends to oppose the adoption of any proposed referendum to approve the purchase of the FPU property in the City. FPU serves approximately 3,000 customers in the City. FPU incurred approximately $439,000 in legal, regulatory and other costs associated with this electric franchise dispute in the first nine months of 2011.

Advanced Information Services. In September 2011, BravePoint, our advanced information services subsidiary, released a new product, ProfitZoom , an integrated system encompassing financial, job costing and service management modules, which was designed specifically for the fire protection and specialty contracting industries. ProfitZoom was built as a successor product to another software solution that BravePoint previously marketed and supported for companies in the fire suppression industry. Understanding the needs of the industry and utilizing its technology expertise, BravePoint began developing the ProfitZoom product in 2009. BravePoint incurred $823,000 in additional costs associated with the release and initial implementation of this product in the nine months ended September 30, 2011. BravePoint has successfully implemented this product for three customers, and two additional customers have executed sales contracts with implementations scheduled for December 2011 and January 2012. Several other sales proposals are under consideration by other potential customers.

Table of Contents

Regulated Energy

For the Nine Months Ended September 30,	2011	2010	Increase (decrease)
(in thousands, except degree-day and customer information)			
Revenue	**$ 193,118**	$ 197,779	($4,661)
Cost of sales	**98,683**	106,146	(7,463)
Gross margin	**94,435**	91,633	2,802
Operations & maintenance	**44,800**	41,771	3,029
Depreciation & amortization	**12,319**	11,199	1,120
Other taxes	**6,122**	6,303	(181)
Other operating expenses	**63,241**	59,273	3,968
Operating Income	**$ 31,194**	$ 32,360	$ (1,166)
Weather and Customer Analysis			
Delmarva Peninsula			
Heating degree-days (HDD):			
Actual	**2,876**	3,021	(145)
10-year average	**2,905**	2,923	(18)
Per residential customer added:			
Estimated gross margin	**$ 375**	$ 375	$ 0
Estimated other operating expenses	**$ 111**	$ 105	$ 6
Florida			
HDD:			
Actual	**534**	942	(408)
10-year average	**594**	547	47
Cooling degree-days:			
Actual	**2,676**	2,694	(18)
10-year average	**2,444**	2,418	26
Residential Customer Information			
Average number of customers:			
Delmarva natural gas distribution	**48,594**	47,508	1,086
Florida natural gas distribution	**61,489**	61,087	402
Florida electric distribution	**23,588**	23,570	18
Total	**133,671**	132,165	1,506

Operating income for the regulated energy segment decreased by approximately $1.2 million, or four percent, during the first nine months of 2011, compared to the same period in 2010. An increase in gross margin of $2.8 million was offset by an increase in other operating expenses of $4.0 million and resulted in this decrease in operating income.

Table of Contents

Gross Margin

Gross margin for our regulated energy segment increased by $2.8 million, or three percent, during the first nine months of 2011, compared to the same period in 2010.

Our Delmarva natural gas distribution operation generated an increase in gross margin of $1.2 million in the first nine months of 2011, compared to the same period in 2010, due primarily to customer growth. Commercial and industrial customer growth, due primarily to $859,000 in additional gross margin generated from 21 large commercial and industrial services added since the second half of 2010, generated $921,000 of this increase. These 21 new large commercial and industrial services are expected to generate annual gross margin of $1.2 million in 2011. The same services generated $196,000 of gross margin following their addition in the second half of 2010. Two-percent growth in residential customers generated an additional $328,000 in gross margin for the Delmarva natural gas distribution operation.

Gross margin for our Florida natural gas distribution operations decreased by $228,000 during the first nine months of 2011 compared to the same period in 2010. Included in gross margin for the first nine months of 2010 is the impact of the $500,000 reserve for regulatory risk as previously described. The factors contributing to the remaining $728,000 decrease were as follows:

- Lower customer consumption during the first nine months of 2011, compared to the same period in 2010, due primarily to significantly warmer weather during the heating season, decreased gross margin by $1.6 million. Heating degree-days in Florida decreased by 43 percent, or 408 heating degree-days, during the first nine months of 2011, compared to the same period in 2010.
- Offsetting the decrease from lower customer consumption are: (1) two-percent growth in commercial customers for our Florida natural gas distribution operation, which generated additional gross margin of $754,000 in the first nine months of 2011, compared to the same period in 2010; and (2) 700 new customers, added as a result of our purchase of the operating assets of Indiantown Gas Company in August 2010, which generated $367,000 in additional gross margin in the first nine months of 2011.

Our natural gas transmission operations achieved gross margin growth of $2.2 million during the first nine months of 2011 compared to the same period in 2010. The factors contributing to this increase were as follows:

- New transportation services associated with Eastern Shore s eight-mile mainline extension to interconnect with TETLP s pipeline system generated an additional $1.6 million of gross margin in the nine months ended September 30, 2011. These new services for 19,324 Mcfs per day, which commenced in January 2011, are expected to generate annual gross margin of approximately $1.9 million. Based upon the proposed settlement discussed previously, as the services increase in November 2011 to 33,817 Mcfs per day, the new rate under the proposed settlement of these incremental services will negate the gross margin impact from the increase in volumes. In November 2012, as the new services increase to 38,647 Mcfs per day, additional annual gross margin of approximately $263,000 is expected to be generated from these services.
- New transportation services implemented by Eastern Shore in May 2010 and November 2010 as a result of its system expansion projects generated an additional $330,000 of gross margin during the first nine months of 2011, compared to 2010. These expansions added 2,666 Mcfs of capacity per day and an estimated annual gross margin of $606,000 in 2011. These projects generated $216,000 of gross margin in 2010.
- Eastern Shore entered into two additional transportation services agreements with an existing industrial customer, one for the period of May 2011 through April 2021 for an additional 3,290 Mcfs per day and the other for the period of November 2011 through October 2012 for an additional 9,192 Mcfs per day. These services generated additional gross margin of $154,000 in the first nine months of 2011. The 10-year service from May 2011 to April 2021 is expected to generate gross margin of $243,000 in 2011 and $361,000 annually thereafter. The one-year service from November 2011 to October 2012 is expected to generate gross margin of $168,000 in 2011 and $842,000 in 2012.
- The foregoing increases to gross margin were offset by the expiration of two small firm transportation service contracts in April 2010, decreasing gross margin by $40,000 in the first nine months of 2011.

Gross margin for our Florida electric distribution operation decreased by $365,000 in the first nine months of 2011, compared to the same period in 2010, due primarily to lower customer consumption during the heating season. Heating degree-days in Florida decreased by 43 percent, or 408 heating degree-days during the first nine months of 2011, compared to the same period in 2010.

Other Operating Expenses

Other operating expenses for the regulated energy segment increased by $4.0 million in the nine months ended September 30, 2011. Included in this increase are non-recurring items of $503,000 for severance charges and $334,000 for pension charges during the first nine months of 2011. The remaining increase of $3.1 million is due largely to the following factors:

- $820,000 in higher depreciation expense and asset removal costs form capital investments made since the third quarter of 2010;
- Increased regulatory, legal and other costs, including $439,000 of additional costs associated with the electric franchise dispute in Marianna, Florida and $245,000 in costs with respect to the Come-Back filing in Florida, the rate case proceeding for Eastern Shore and other regulatory proceedings;
- $628,000 in additional expenses related to pipeline integrity projects for Eastern Shore to comply with increased pipeline regulatory requirements;
- $202,000 in higher costs related to maintenance of mains, electric lines and facilities;
- a reduction of $139,000 in expense for the nine months ended September 2010, resulting from a reversal of bad debt expense, which was previously reserved for a receivable from a Florida electric customer in bankruptcy; and
- $192,000 in increased payroll costs, due primarily to higher accruals for performance incentive compensation.

Other Development

In June 2011, Allen Family Foods, Inc. and related entities (collectively, Allen) filed for bankruptcy. Our Delmarva natural gas distribution operation serves two of Allen s poultry facilities, one of which is included in our discussion of the 21 new large commercial and industrial services added since July 2010. The total gross margin for 2010 from our natural gas service to these two facilities was approximately $156,000. Since the bankruptcy filing, these two facilities have been sold to another poultry processor. The facilities continue to operate and we continue to serve them. While we cannot predict the future plan for these two facilities by the new purchaser, the level of natural gas consumption at these two facilities has not changed significantly.

Unregulated Energy

For the Nine Months Ended September 30,	**2011**	**2010**	**Increase (decrease)**
(in thousands, except degree-day data)			
Revenue	**$ 112,164**	$ 104,018	$ 8,146
Cost of sales	**84,227**	78,740	5,487
Gross margin	**27,937**	25,278	2,659
Operations & maintenance	**17,475**	16,792	683
Depreciation & amortization	**2,301**	2,660	(359)
Other taxes	**1,114**	1,094	20
Other operating expenses	**20,890**	20,546	344
Operating Income	**$ 7,047**	$ 4,732	$ 2,315

Weather Analysis Delmarva Peninsula

Actual HDD	**2,876**	3,021	(145)
10-year average HDD	**2,905**	2,923	(18)

Table of Contents

Operating income for the unregulated energy segment for the nine months ended September 30, 2011 was $7.0 million, an increase of $2.3 million, or 49 percent, compared to the same period in 2010. An increase in gross margin of $2.7 million was slightly offset by an increase in operating expenses of $344,000.

Gross Margin

Gross margin for our unregulated energy segment increased by $2.7 million, or 11 percent, for the first nine months of 2011, compared to the same period in 2010.

Our Delmarva propane distribution operation experienced an increase in gross margin of $1.6 million for the first nine months of 2011, compared to the same period in 2010. The factors contributing to this increase were as follows:

- Our Delmarva propane distribution operation generated additional gross margin of $1.2 million due to higher margins per gallon during the first nine months of 2011, compared to the same period in 2010, as margins per gallon returned to more normal levels during the current period. Propane margins per gallon during the first half of 2010 were low, compared to historical levels, due to additional spot purchases at increased costs during the peak heating season to meet the weather-related increase in customer consumption. More normal temperatures and fewer spot purchases during 2011 resulted in margins per gallon returning to more normal levels.
- A one-time gain of $575,000 was recorded in the first nine months of 2011, as a result of our share of proceeds received from an antitrust litigation settlement with a major propane supplier.
- An increase in other fees generated additional gross margin of $174,000, due primarily to the continued growth and successful implementation of various customer pricing programs.
- A decline in volumes sold in the first nine months of 2011, compared to the same period in 2010, decreased gross margin by $287,000. This decrease was attributable to timing of deliveries to bulk customers and a decrease in weather-related consumption due to the warmer temperatures on the Delmarva Peninsula.

Our Florida propane distribution operations experienced an increase in gross margin of $428,000 during the first nine months of 2011 compared to the same period in 2010. Higher margins per gallon, as we continued to adjust our retail pricing in response to market conditions, contributed $897,000 additional gross margin. Also generating $195,000 in gross margin during the period was a propane rail terminal agreement with a supplier to provide terminal and storage services from November 2010 to May 2011. A decrease in heating degree-days in the first nine months of 2011, compared to the same period in 2010, and a decrease in propane deliveries to bulk customers due to a decrease in non-weather volumes, resulted in decreased gross margin of $652,000.

Xeron generated a $514,000 increase in gross margin during the first nine months of 2011, compared to the same period in 2010, due primarily to a 40-percent increase in Xeron s trading activity in the first nine months of 2011, compared to the same period in 2010.

Gross margin generated by PESCO increased by $295,000 during the first nine months of 2011, compared to the same period in 2010. This increase was due to favorable imbalance resolutions during the first nine months of 2011 with third-party pipelines, with which PESCO contracts for natural gas supply. Revenues generated from favorable imbalance resolutions with intrastate pipelines are not predictable and, therefore, are not included in our long-term financial plans or forecasts.

Merchandise sales in Florida decreased in the first nine months of 2011, compared to the same period in 2010, resulting in lower gross margin of $218,000.

Table of Contents

Other Operating Expenses

Other operating expenses for the unregulated energy segment increased by $344,000 for the nine months of 2011, compared to the same period in 2010, due primarily to the following factors: (a) increased payroll and benefit costs of $335,000, attributable primarily to higher accruals for performance incentive compensation; (b) increased vehicle expenses of $282,000 resulting from an increase in fuel prices; and (c) one-time charges of $67,000 associated with the voluntary workforce reduction in Florida as we continued to integrate the Florida operations. These increases were partially offset by the absence of a $278,000 non-recurring charge recorded in the third quarter of 2010 for a Florida propane class action settlement.

Other

For the Nine Months Ended September 30,		**2011**		**2010**		**Increase (decrease)**
(in thousands)						
Revenue	**$**	**8,757**	$	7,990	$	767
Cost of sales		**4,790**		3,973		817
Gross margin		**3,967**		4,017		(50)
Operations & maintenance		**3,145**		2,672		473
Depreciation & amortization		**316**		216		100
Other taxes		**538**		479		59
Other operating expenses		**3,999**		3,367		632
Operating Income Other		**(32)**		650		(682)
Operating Income Eliminations						
Operating (Loss) Income	**$**	**(32)**	$	650	$	(682)

Note: Eliminations are entries required to eliminate activities between business segments from the consolidated results.

The other segment reported an operating loss of $32,000 for the nine months ended September 30, 2011, compared to operating income of $650,000 for the same period in 2010. The decrease in operating results of $682,000 was attributable primarily to lower operating income of $860,000 from BravePoint, offset partially by the absence in 2011 of $179,000 in merger-related costs expensed in the first nine months of 2010.

Gross margin

The gross margin decrease of $50,000 for our other segment was primarily a result of lower consulting margin and approximately $101,000 in gross margin loss associated with initial implementation of ProfitZoom , which were slightly offset by an increase of product sales and consulting revenue for BravePoint, our advanced information services subsidiary.

Other Operating expenses

Other operating expenses increased by $632,000 in the first nine months of 2011, compared to the same period in 2010. Other operating expenses for BravePoint increased by $860,000, due primarily to $722,000 in additional marketing and development costs, as it began to roll out ProfitZoom , and $287,000 in increased benefit costs. Benefit costs increased for BravePoint as Chesapeake adopted a safe harbor 401(k) plan design on January 1, 2011, which resulted in an increased 401(k) benefit for BravePoint employees in 2011. The increase in BravePoint s other operating expenses was offset partially by the absence in 2011 of $179,000 in merger-related costs in the first half of 2010.

Interest Expense

Interest expense for the nine months ended September 30, 2011 decreased by approximately $270,000, or four percent, compared to the same period in 2010. The decrease is attributable primarily to a decrease of $582,000 in other long-term interest expense as scheduled repayments decreased the outstanding principal balance. Partially offsetting this decrease was additional interest expense of $240,000 related to the $29 million long-term debt issuance in June 2011 to permanently finance two series of FPU mortgage bonds.

Table of Contents

Income Taxes

We recorded an income tax expense of $12.6 million for the first nine months of 2011, compared to $12.1 million for the same period in 2010. The period-over-period increase in income tax expense is primarily a function of higher earnings for the period.

Financial Position, Liquidity and Capital Resources

Our capital requirements reflect the capital-intensive and seasonal nature of our business and are principally attributable to investment in new plant and equipment, retirement of outstanding debt and seasonal variability in working capital. We rely on cash generated from operations, short-term borrowings, and other sources to meet normal working capital requirements and to finance capital expenditures.

Our energy businesses are weather-sensitive and seasonal. We normally generate a large portion of our annual net income and subsequent increases in our accounts receivable in the first and fourth quarters of each year due to significant volumes of natural gas, electricity, and propane delivered by our natural gas, electric, and propane distribution operations to customers during the peak heating season. In addition, our natural gas and propane inventories, which usually peak in the fall months, are largely drawn down in the heating season and provide a source of cash as the inventory is used to satisfy winter sales demand.

We originally budgeted $51.7 million for capital expenditures during 2011. Our current capital spending projection for 2011 is $53.6 million. This amount includes $45.0 million for the regulated energy segment, $2.8 million for the unregulated energy segment and $5.8 million for the other segment. The amount for the regulated energy segment includes estimated capital expenditures for expansion and improvement of facilities for the following: (a) natural gas distribution operation ($23.4 million); (b) natural gas transmission operation ($15.7 million); and (c) electric distribution operation ($5.9 million). The amount for the unregulated energy segment includes estimated capital expenditures for the propane distribution operations for customer growth and replacement of equipment. The amount for the other segment includes an estimated capital expenditure of $292,000 for the advanced information services operation and $2.5 million for a billing system enhancement, with the remaining balance for other general plant, computer software and hardware. We expect to fund the 2011 capital expenditures program from short-term borrowing, cash provided by operating activities, and other sources. The capital expenditures program is subject to continuous review and modification. Actual capital requirements may vary from the above estimates due to a number of factors, including changing economic conditions, customer growth in existing areas, regulation, new growth or acquisition opportunities and availability of capital.

Capital Structure

We are committed to maintaining a sound capital structure and strong credit ratings to provide the financial flexibility needed to access capital markets when required. This commitment, along with adequate and timely rate relief for our regulated operations, is intended to ensure our ability to attract capital from outside sources at a reasonable cost. We believe that the achievement of these objectives will provide benefits to our customers, creditors and investors. The following presents our capitalization, excluding and including short-term borrowings, as of September 30, 2011 and December 31, 2010:

(in thousands)	**September 30, 2011**		**December 31, 2010**	
Long-term debt, net of current maturities	**$ 117,069**	**33%**	$ 89,642	28%
Stockholders equity	**237,548**	**67%**	226,239	72%
Total capitalization, excluding short-term debt	**$ 354,617**	**100%**	$ 315,881	100%

(in thousands)	**September 30, 2011**		**December 31, 2010**	
Short-term debt	**$ 26,591**	**7%**	$ 63,958	16%
Long-term debt, including current maturities	**126,265**	**32%**	98,858	25%
Stockholders equity	**237,548**	**61%**	226,239	59%
Total capitalization, including short-term debt	**$ 390,404**	**100%**	$ 389,055	100%

Short-term Borrowings

Our outstanding short-term borrowings at September 30, 2011 and December 31, 2010 were $26.6 million and $64.0 million, respectively, at weighted average interest rates of 1.53 percent and 1.77 percent, respectively.

We utilize bank lines of credit to provide funds for our short-term cash needs to meet seasonal working capital requirements and to fund temporarily portions of the capital expenditure program. As of September 30, 2011, we had four unsecured bank lines of credit with two financial institutions for a total of $100.0 million. Two of these unsecured bank lines, totaling $60.0 million, are available under committed lines of credit. None of these unsecured bank lines of credit requires compensating balances. Advances offered under the uncommitted lines of credit are subject to the discretion of the banks. We are currently authorized by our Board of Directors to borrow up to $85.0 million of short-term debt, as required, from these unsecured bank lines of credit.

Our outstanding borrowings under these unsecured bank lines of credit at September 30, 2011 and December 31, 2010 were $21.4 million and $30.8 million, respectively, at weighted average interest rates of 1.49 percent and 1.65 percent, respectively. In addition to the four unsecured bank lines of credit, we entered into a new short-term credit facility for $29.1 million with an existing lender in March 2010 to temporarily finance the early redemption of the 6.85 percent and 4.90 percent series of FPU s secured first mortgage bonds. On June 23, 2011, we issued $29.0 million of 5.68 percent Chesapeake s unsecured senior notes to repay the new short-term credit facility and permanently finance the FPU first mortgage bonds.

Cash Flows Provided By Operating Activities

Cash flows provided by operating activities were as follows:

For the Nine Months Ended September 30,	**2011**	**2010**
(in thousands)		
Net Income	**$ 19,664**	$ 18,942

Non-cash adjustments to net income		**32,769**		26,901
Changes in assets and liabilities		**341**		8,951
Net cash provided by operating activities	**$**	**52,774**	$	54,794

During the nine months ended September 30, 2011 and 2010, net cash flow provided by operating activities was $52.8 million and $54.8 million, respectively, a period-over-period decrease of $2.0 million. Significant operating activities reflected in the change in cash flows provided by operating activities were as follows:

- Net cash flows related to income taxes, which include deferred income taxes in non-cash adjustments to net income and the change in income taxes receivable, increased by $7.7 million in the first nine months of 2011, compared to the same period in 2010, due primarily to the 100-percent bonus depreciation deduction allowed in 2011, which is reducing our income tax payments in the current period.
- Net cash flows from receivables and payables in the natural gas and propane distribution operations decreased by $6.2 million, offset partially by an increase in net cash flows due primarily to the timing of collections and payments of trading contracts entered into by our propane wholesale marketing operation.
- Net cash flows from accrued compensation decreased by $2.0 million, as a result of a smaller decrease in the change in accrued payroll due to timing of payroll periods and higher incentive compensation and severance payments in the first nine months of 2011.
- Net cash flows from the changes in regulatory assets and liabilities decreased by approximately $2.0 million, primarily as a result of a reduction in fuel costs due and collected from rate payers.

Cash Flows Used in Investing Activities

Net cash flows used in investing activities totaled $33.3 million and $28.9 million during the nine months ended September 30, 2011 and 2010, respectively. Cash utilized for capital expenditures was $33.4 million and $26.2 million for the first nine months of 2011 and 2010, respectively.

Cash Flows Used by Financing Activities

Cash flows used in financing activities totaled $19.4 million and $25.9 million for the first nine months of 2011 and 2010, respectively. Significant financing activities reflected in the change in cash flows used by financing activities were as follows:

- During the first nine months of 2011 we had a net repayment of $9.3 million under our line of credit agreements related to working capital, compared to $23.1 million during the same period in 2010, resulting in a period-over-period net cash increase of $13.7 million. Changes in cash overdrafts decreased by $5.9 million, resulting in a period-over-period net cash increase.
- Net repayments of other short-term debt and long-term debt during the first nine months of 2011 were $1.5 million, compared to net repayments of $2.1 million in the same period in 2010. During the first nine months of 2010, we redeemed the 6.85 and 4.90 percent series of FPU s secured first mortgage bonds prior to their respective maturities by using the proceeds from a new short-term credit facility. During the first nine months of 2011, we issued Chesapeake s unsecured senior notes, using the proceeds to repay the new short-term credit facility and permanently finance the FPU bonds.
- We paid $8.7 million and $8.2 million in cash dividends for the nine months ended September 30, 2011 and 2010, respectively.

Off-Balance Sheet Arrangements

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily the propane wholesale marketing subsidiary and the 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. None of these subsidiaries has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded in our financial statements when incurred. The aggregate amount guaranteed at September 30, 2011 was $26.7 million, with the guarantees expiring on various dates through 2012.

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, 2011, to provide as security to satisfy the deductibles under our various insurance policies. Although we recently changed our primary insurance company, we still have an outstanding letter of credit for $725,000 to our former primary insurance company, which will expire on June 1, 2012. There have been no draws on these letters of credit as of September 30, 2011. 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 under the Precedent Agreement with TETLP, which is the maximum amount required under the agreement.

Contractual Obligations

There has not been any material change in the contractual obligations presented in our 2010 Annual Report on Form 10-K, except for commodity purchase obligations and forward contracts entered into in the ordinary course of our business. The following table summarizes the commodity and forward contract obligations at September 30, 2011.

	Payments Due by Period				
Purchase Obligations	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**	**Total**
(in thousands)					
Commodities [(1)]	$ 19,463	$ 366	$	$	**$ 19,829**
Propane [(2)]	54,115				**54,115**
Total Purchase Obligations	**$ 73,578**	**$ 366**	**$**	**$**	**$ 73,944**

(1) In addition to the obligations noted above, the natural gas distribution, the electric distribution and propane distribution operations have agreements with commodity suppliers that have provisions with no minimum purchase requirements. There are no monetary penalties for reducing the amounts purchased; however, the propane contracts allow the suppliers to reduce the amounts available in the winter season if we do not purchase specified amounts during the summer season. Under these contracts, the commodity prices will fluctuate as market prices fluctuate.

(2) We have also entered into forward sale contracts in the aggregate amount of $32.5 million. See Part I, Item 3, Quantitative and Qualitative Disclosures about Market Risk, below, for further information.

Environmental Matters

As more fully described in Note 4, Environmental Commitments and Contingencies, to the unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q, we continue to work with federal and state environmental agencies to assess the environmental impact and explore corrective action at seven environmental sites. We believe that future costs associated with these sites will be recoverable in rates or through sharing arrangements with, or contributions by, other responsible parties.

Other Matters

Rates and Regulatory Matters

Our natural gas distribution operations in Delaware, Maryland and Florida and electric distribution operation in Florida are subject to regulation by their respective PSC; Eastern Shore is subject to regulation by the FERC; and Peninsula Pipeline is subject to regulation by the Florida PSC. At September 30, 2011, we were involved in rate filings and/or regulatory matters in each of the jurisdictions in which we operate. Each of these rate filings and/or regulatory matters is fully described in Note 3, Rates and Other Regulatory Activities, to the unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q.

Table of Contents

Competition

Our natural gas and electric distribution operations and our natural gas transmission operation compete with other forms of energy, including natural gas, electricity, oil and propane. The principal competitive factors are price and, to a lesser extent, accessibility. Our natural gas distribution operations have several large-volume industrial customers that are able to use fuel oil as an alternative to natural gas. When oil prices decline, these interruptible customers may convert to oil to satisfy their fuel requirements, and our interruptible sales volumes may decline. Oil prices, as well as the prices of other fuels, fluctuate for a variety of reasons; therefore, future competitive conditions are not predictable. To address this uncertainty, we use flexible pricing arrangements on both the supply and sales sides of this business to compete with alternative fuel price fluctuations. As a result of the transmission operation s conversion to open access and Chesapeake s Florida natural gas distribution division s restructuring of its services, these businesses have shifted from providing bundled transportation and sales service to providing only transmission and contract storage services.

Our electric distribution operation currently does not face substantial competition because the electric utility industry in Florida has not been deregulated. In addition, natural gas is the only viable alternative fuel to electricity in our electric service territories and is available only in a small area.

Our natural gas distribution operations in Delaware, Maryland and Florida offer unbundled transportation services to certain commercial and industrial customers. In 2002, Chesapeake s Florida natural gas distribution division, Central Florida Gas, extended such service to residential customers. With such transportation service available on our distribution systems, we are competing with third-party suppliers to sell gas to industrial customers. With respect to unbundled transportation services, our competitors include interstate transmission companies, if the distribution customers are located close enough to a transmission company s pipeline to make connections economically feasible. The customers at risk are usually large volume commercial and industrial customers with the financial resources and capability to bypass our existing distribution operations in this manner. In certain situations, our distribution operations may adjust services and rates for these customers to retain their business. We expect to continue to expand the availability of unbundled transportation service to additional classes of distribution customers in the future. We have also established a natural gas marketing operation in Florida, Delaware and Maryland to provide such service to customers eligible for unbundled transportation services.

Our propane distribution operations compete with several other propane distributors in their respective geographic markets, primarily on the basis of service and price, emphasizing responsive and reliable service. Our competitors generally include local outlets of national distributors and local independent distributors, whose proximity to customers entails lower costs to provide service. Propane competes with electricity as an energy source, because it is typically less expensive than electricity, based on equivalent BTU value. Propane also competes with home heating oil as an energy source. Since natural gas has historically been less expensive than propane, propane is generally not distributed in geographic areas served by natural gas pipeline or distribution systems.

The propane wholesale marketing operation competes against various regional and national marketers, many of which have significantly greater resources and are able to obtain price or volumetric advantages.

Our advanced information services subsidiary faces significant competition from a number of larger competitors having substantially greater resources available to them than does our subsidiary. In addition, changes in the advanced information services business are occurring rapidly and could adversely affect the markets for the products and services offered by these businesses. This segment competes on the basis of technological expertise, reputation and price.

Inflation

Inflation affects the cost of supply, labor, products and services required for operations, maintenance and capital improvements. While the impact of inflation has remained low in recent years, natural gas and propane prices are subject to rapid fluctuations. In the regulated natural gas and electric distribution operations, fluctuations in natural gas and electricity prices are passed on to customers through the fuel cost recovery mechanism in our tariffs. To help cope with the effects of inflation on our capital investments and returns, we seek rate increases from regulatory commissions for our regulated operations and closely monitor the returns of our unregulated business operations. To compensate for fluctuations in propane gas prices, we adjust propane selling prices to the extent allowed by the market.

Recent Authoritative Pronouncements on Financial Reporting and Accounting

Recent accounting developments applicable to us and their impact on our financial position, results of operations and cash flows are described in Note 1, Summary of Accounting Policies, to the unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Market risk represents the potential loss arising from adverse changes in market rates and prices. Long-term debt is subject to potential losses based on changes in interest rates. Our long-term debt consists of fixed-rate senior notes, secured debt and convertible debentures. All of our long-term debt is fixed-rate debt and was not entered into for trading purposes. The carrying value of long-term debt, including current maturities, was $126.3 million at September 30, 2011, as compared to a fair value of $150.4 million, based on a discounted cash flow methodology that incorporates a market interest rate that is based on published corporate borrowing rates for debt instruments with similar terms and average maturities with adjustments for duration, optionality, credit risk, and risk profile. We evaluate whether to refinance existing debt or permanently refinance existing short-term borrowing, based in part on the fluctuation in interest rates.

Our propane distribution business is exposed to market risk as a result of propane storage activities and entering into fixed price contracts for supply. We can store up to approximately six million gallons of propane (including leased storage and rail cars) during the winter season to meet our customers peak requirements and to serve metered customers. Decreases in the wholesale price of propane may cause the value of stored propane to decline. To mitigate the impact of price fluctuations, we have adopted a Risk Management Policy that allows the propane distribution operation to enter into fair value hedges or other economic hedges of our inventory.

In August 2011, our Delmarva 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 is exercised if the propane prices fall below the strike price of $1.445 per gallon in January through March of 2012 and we will receive the difference between the market price and the strike price during those months. We paid $91,000 to purchase the put option. We account for this put option as a fair value hedge. As of September 30, 2011, the put option had a fair value of $92,000. The change in the fair value of the put option reduced our propane inventory balance.

Our propane wholesale marketing operation is a party to natural gas liquids forward contracts, primarily propane contracts, with various third parties. These contracts require that the propane wholesale marketing operation purchase or sell natural gas liquids at a fixed price at fixed future dates. At expiration, the contracts are settled by the delivery of natural gas liquids to us or the counter-party or booking out the transaction. Booking out is a procedure for financially settling a contract in lieu of the physical delivery of energy. The propane wholesale marketing operation also enters into futures contracts that are traded on the New York Mercantile Exchange. In certain cases, the futures contracts are settled by the payment or receipt of a net amount equal to the difference between the current market price of the futures contract and the original contract price; however, they may also be settled by physical receipt or delivery of propane.

Table of Contents

The forward and futures contracts are entered into for trading and wholesale marketing purposes. The propane wholesale marketing business is subject to commodity price risk on its open positions to the extent that market prices for natural gas liquids deviate from fixed contract settlement prices. Market risk associated with the trading of futures and forward contracts is monitored daily for compliance with our Risk Management Policy, which includes volumetric limits for open positions. To manage exposures to changing market prices, open positions are marked up or down to market prices and reviewed daily by our oversight officials. In addition, the Risk Management Committee reviews periodic reports on markets and the credit risk of counter-parties, approves any exceptions to the Risk Management Policy (within limits established by the Board of Directors) and authorizes the use of any new types of contracts. Quantitative information on forward and futures contracts at September 30, 2011 is presented in the following tables.

At September 30, 2011	Quantity in Gallons	Estimated Market Prices		Weighted Average Contract Prices
Forward Contracts				
Sale	21,361,200	$ 1.3900	$1.6200	$ 1.5231
Purchase	21,193,200	$ 1.3344	$1.6047	$ 1.5149

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

All contracts expire during or prior to the first quarter of 2012.

At September 30, 2011 and December 31, 2010, we marked these forward and other contracts to market, using market transactions in either the listed or OTC markets, which resulted in the following assets and liabilities:

(in thousands)	September 30, 2011	December 31, 2010
Mark-to-market energy assets, including put option	**$ 1,229**	$ 1,642
Mark-to-market energy liabilities	**$ 956**	$ 1,492

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer and Chief Financial Officer of the Company, with the participation of other Company officials, have evaluated our disclosure controls and procedures (as such term is defined under Rules 13a-15(e) and 15d-15(e), promulgated under the Securities Exchange Act of 1934, as amended) as of September 30, 2011. Based upon their evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2011.

Changes in Internal Control over Financial Reporting

During the quarter ended September 30, 2011, there was no change in our internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

PART II OTHER INFORMATION

Item 1. Legal Proceedings

As disclosed in Note 5, Other Commitments and Contingencies, of the unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q, we are involved in certain legal actions and claims arising in the normal course of business. We are also involved in certain legal and administrative proceedings before various governmental or regulatory agencies concerning rates and other regulatory actions. In the opinion of management, the ultimate disposition of these proceedings and claims will not have a material effect on our condensed consolidated financial position, results of operations or cash flows.

Item 1A. Risk Factors

Our business, operations, and financial condition are subject to various risks and uncertainties. The risk factors described in Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2010, should be carefully considered, together with the other information contained or incorporated by reference in this Quarterly Report on Form 10-Q and in our other filings with the SEC in connection with evaluating the Company, our business and the forward-looking statements contained in this Report. Additional risks and uncertainties not presently known to us or that we currently deem immaterial also may affect the Company. The occurrence of any of these known or unknown risks could have a material adverse impact on our business, financial condition, and results of operations.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (2)	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs (2)
July 1, 2011 through July 31, 2011 (1)	260	$ 40.06		
August 1, 2011 through August 31, 2011		$		
September 1, 2011 through September 30, 2011		$		
Total	260	$ 40.06		

(1) Chesapeake purchased shares of stock on the open market for the purpose of reinvesting the dividend on deferred stock units held in the Rabbi Trust accounts for certain Directors and Senior Executives under the Deferred Compensation Plan. The Deferred Compensation Plan is discussed in detail in Item 8 under the heading Notes to the Consolidated Financial Statements Note M, Employee Benefit Plans of our Form 10-K filed with the SEC on March 8, 2011. During the quarter, 260 shares were purchased through the reinvestment of dividends on deferred stock units.

(2) Except for the purposes described in Footnote (1), Chesapeake has no publicly announced plans or programs to repurchase its shares.

Item 3. Defaults upon Senior Securities

None.

Item 5. Other Information

None.

Table of Contents

Item 6. Exhibits

31.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, dated November 4, 2011.
31.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, dated November 4, 2011.
32.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated November 4, 2011.
32.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated November 4, 2011.

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Chesapeake Utilities Corporation

/s/ Beth W. Cooper

Beth W. Cooper
Senior Vice President and Chief Financial Officer

Date: November 4, 2011

- 60 -