CHESAPEAKE UTILITIES CORP
Form 10-Q
November 05, 2010

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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, 2010

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 o 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 9,510,532 shares outstanding as of October 31, 2010.

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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
ESNG	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
PIPECO	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
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FDEP	Florida Department of Environmental Protection
Florida PSC	Florida Public Service Commission
IASB	International Accounting Standards Board
Maryland PSC	Maryland Public Service Commission
MDE	Maryland Department of the Environment
PSC	Public Service Commission
SEC	Securities and Exchange Commission

Accounting Standards Related

ASC	FASB Accounting Standards Codification™ (Codification)
ASU	FASB Accounting Standards Update
GAAP	Generally Accepted Accounting Principles
IFRS	International Financial Reporting Standards

Other

AS/SVE	Air Sparging and Soil/Vapor Extraction
BS/SVE	Bio-Sparging and Soil/Vapor Extraction
CGS	Community Gas Systems
DSCP	Directors Stock Compensation Plan
Dts	Dekatherms
Dts/d	Dekatherms per day
FRP	Fuel Retention Percentage
GSR	Gas Sales Service Rates
Gulf Power	Gulf Power Corporation
HDD	Heating Degree-Days

Mcf	Thousand Cubic Feet
MWH	Megawatt Hour
MGP	Manufactured Gas Plant
NYSE	New York Stock Exchange
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

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

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

For the Three Months Ended September 30, *(in thousands, except shares and per share data)*	**2010**	2009
Operating Revenues		
Regulated energy	**$ 53,412**	$ 15,372
Unregulated energy	**20,134**	14,011
Other	**2,920**	2,375
Total operating revenues	**76,466**	31,758
Operating Expenses		
Regulated energy cost of sales	**27,148**	2,345
Unregulated energy and other cost of sales	**17,238**	12,071
Operations	**17,993**	11,001
Transaction-related costs	**68**	(675)
Maintenance	**1,899**	600
Depreciation and amortization	**5,058**	2,437
Other taxes	**2,479**	1,722
Total operating expenses	**71,883**	29,501
Operating Income	**4,583**	2,257
Other income (loss), net of expenses	**102**	(26)
Interest charges	**2,256**	1,540
Income Before Income Taxes	**2,429**	691
Income tax expense	**801**	383
Net Income	**$ 1,628**	$ 308
Weighted Average Common Shares Outstanding:		
Basic	**9,493,425**	6,883,070
Diluted	**9,497,696**	6,888,024
Earnings Per Share of Common Stock:		
Basic	**$ 0.17**	$ 0.04
Diluted	**$ 0.17**	$ 0.04

Cash Dividends Declared Per Share of Common Stock	**$**	**0.330**	$	0.315

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

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

For the Nine Months Ended September 30, *(in thousands, except shares and per share data)*	**2010**	2009
Operating Revenues		
Regulated energy	**$ 197,779**	$ 86,422
Unregulated energy	**104,018**	83,236
Other	**7,990**	7,413
Total operating revenues	**309,787**	177,071
Operating Expenses		
Regulated energy cost of sales	**105,322**	39,143
Unregulated energy and other cost of sales	**82,713**	66,962
Operations	**54,848**	34,820
Transaction-related costs	**179**	530
Maintenance	**5,388**	1,932
Depreciation and amortization	**15,719**	7,235
Other taxes	**7,876**	5,371
Total operating expenses	**272,045**	155,993
Operating Income	**37,742**	21,078
Other income, net of expenses	**206**	19
Interest charges	**6,924**	4,755
Income Before Income Taxes	**31,024**	16,342
Income tax expense	**12,082**	6,636
Net Income	**$ 18,942**	$ 9,706
Weighted-Average Common Shares Outstanding:		
Basic	**9,460,462**	6,859,516
Diluted	**9,570,921**	6,981,010
Earnings Per Share of Common Stock:		
Basic	**$ 2.00**	$ 1.41
Diluted	**$ 1.98**	$ 1.40
Cash Dividends Declared Per Share of Common Stock	**$ 0.975**	$ 0.935

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

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

For the Nine Months Ended September 30,	**2010**	2009
(in thousands)		
Operating Activities		
Net Income	**$ 18,942**	$ 9,706
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**15,719**	7,235
Depreciation and accretion included in other costs	**2,428**	1,987
Deferred income taxes, net	**9,847**	2,353
Unrealized loss (gain) on commodity contracts	**(443)**	1,382
Unrealized gain on investments	**(13)**	(161)
Employee benefits	**(594)**	1,394
Share-based compensation	**899**	897
Changes in assets and liabilities:		
Accounts receivable and accrued revenue	**23,337**	25,513
Propane inventory, storage gas and other inventory	**(411)**	2,071
Regulatory assets	**967**	(1,182)
Prepaid expenses and other current assets	**631**	480
Accounts payable and other accrued liabilities	**(13,922)**	(13,409)
Income taxes receivable	**(6,392)**	6,766
Accrued interest	**1,381**	1,160
Customer deposits and refunds	**1,891**	(1,027)
Accrued compensation	**735**	(280)
Regulatory liabilities	**453**	2,179
Other liabilities	**191**	388
Net cash provided by operating activities	**55,646**	47,452
Investing Activities		
Property, plant and equipment expenditures	**(26,953)**	(19,674)
Purchase of investments	**(2,308)**	
Environmental expenditures	**(522)**	(33)
Net cash used in investing activities	**(29,783)**	(19,707)
Financing Activities		
Common stock dividends	**(8,187)**	(5,683)
Issuance (purchase) of stock for Dividend Reinvestment Plan	**405**	(9)
Change in cash overdrafts due to outstanding checks	**7,020**	471
Net repayment under line of credit agreements	**(23,069)**	(23,387)
Other short-term borrowing	**29,100**	
Repayment of long-term debt	**(31,207)**	(20)
Net cash used in financing activities	**(25,938)**	(28,628)

Net Decrease in Cash and Cash Equivalents		**(75)**		(883)
Cash and Cash Equivalents Beginning of Period		**2,828**		1,611
Cash and Cash Equivalents End of Period	**$**	**2,753**	$	728

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

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

Assets	**September 30, 2010**	**December 31, 2009**
(in thousands, except shares and per share data)		
Property, Plant and Equipment		
Regulated energy	**$ 478,048**	$ 463,856
Unregulated energy	**60,614**	61,360
Other	**16,582**	16,054
Total property, plant and equipment	**555,244**	541,270
Less: Accumulated depreciation and amortization	**(118,393)**	(107,318)
Plus: Construction work in progress	**11,029**	2,476
Net property, plant and equipment	**447,880**	436,428
Investments	**3,006**	1,959
Current Assets		
Cash and cash equivalents	**2,753**	2,828
Accounts receivable (less allowance for uncollectible accounts of $1,030 and $1,609, respectively)	**52,166**	70,029
Accrued revenue	**7,410**	12,838
Propane inventory, at average cost	**7,804**	7,901
Other inventory, at average cost	**3,586**	3,149
Regulatory assets	**53**	1,205
Storage gas prepayments	**6,215**	6,144
Income taxes receivable	**9,071**	2,614
Deferred income taxes	**523**	1,498
Prepaid expenses	**5,301**	5,843
Mark-to-market energy assets	**2,290**	2,379
Other current assets	**147**	147
Total current assets	**97,319**	116,575
Deferred Charges and Other Assets		
Goodwill	**35,609**	34,095
Other intangible assets, net	**3,547**	3,951
Long-term receivables	**235**	343
Regulatory assets	**20,835**	19,860
Other deferred charges	**3,844**	3,891

Total deferred charges and other assets		**64,070**		62,140
Total Assets	**$**	**612,275**	$	617,102

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

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

Capitalization and Liabilities *(in thousands, except shares and per share data)*	**September 30, 2010**	**December 31, 2009**
Capitalization		
Stockholders equity		
Common stock, par value $0.4867 per share (authorized 25,000,000 and 12,000,000 shares, respectively)	**$ 4,623**	$ 4,572
Additional paid-in capital	**147,022**	144,502
Retained earnings	**72,858**	63,231
Accumulated other comprehensive loss	**(2,404)**	(2,524)
Deferred compensation obligation	**767**	739
Treasury stock	**(767)**	(739)
Total stockholders equity	**222,099**	209,781
Long-term debt, net of current maturities	**97,491**	98,814
Total capitalization	**319,590**	308,595
Current Liabilities		
Current portion of long-term debt	**7,216**	35,299
Short-term borrowing	**43,073**	30,023
Accounts payable	**34,363**	51,948
Customer deposits and refunds	**26,591**	24,960
Accrued interest	**3,267**	1,887
Dividends payable	**3,135**	2,959
Accrued compensation	**4,261**	3,445
Regulatory liabilities	**9,573**	8,882
Mark-to-market energy liabilities	**1,982**	2,514
Other accrued liabilities	**13,353**	8,683
Total current liabilities	**146,814**	170,600
Deferred Credits and Other Liabilities		
Deferred income taxes	**75,396**	66,923
Deferred investment tax credits	**125**	193
Regulatory liabilities	**3,475**	4,154
Environmental liabilities	**10,946**	11,104
Other pension and benefit costs	**16,257**	17,505
Accrued asset removal cost Regulatory liability	**34,683**	33,214
Other liabilities	**4,989**	4,814

Total deferred credits and other liabilities		**145,871**		137,907
Total Capitalization and Liabilities	**$**	**612,275**	$	617,102

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

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

(in thousands, except shares and per share data)	Common Stock Number of Shares[7]	Common Stock Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total
Balances at December 31, 2008	**6,827,121**	**$ 3,323**	**$ 66,681**	**$ 56,817**	**$ (3,748)**	**$ 1,549**	**$ (1,549)**	**123,073**
Net Income				15,897				15,897
Other comprehensive income, net of tax:								
Employee Benefit Plans, net of tax:								
Amortization of prior service costs [4]					7			7
Net Gain [5]					1,217			1,217
Total comprehensive income								$ 17,121
Dividend Reinvestment Plan	31,607	15	921					936
Retirement Savings Plan	32,375	16	966					982
Conversion of debentures	7,927	4	131					135
Share based compensation [1] [3]	7,374	3	1,332					1,335
Deferred Compensation Plan [6]						(810)	810	
Purchase of treasury stock	(2,411)						(73)	(73)
Sale and distribution of treasury stock	2,411						73	73
Common stock issued in the merger	2,487,910	1,211	74,471					75,682
Dividends on stock-based compensation				(104)				(104)
Cash dividends [2]				(9,379)				(9,379)
Balances at December 31, 2009	**9,394,314**	**4,572**	**144,502**	**63,231**	**(2,524)**	**739**	**(739)**	**209,781**
Net Income				18,942				18,942
Other comprehensive income, net of tax:								
Employee Benefit Plans, net of tax:								
Amortization of prior service costs [4]					6			6
Net Gain [5]					114			114
Total comprehensive income								$ 19,062
Dividend Reinvestment Plan	41,100	20	1,240					1,260
Retirement Savings Plan	21,998	11	675					686
Conversion of debentures	5,636	3	93					96
Tax benefit on share based compensation			73					73
Share based compensation [1] [3]	36,415	17	439					456
Deferred Compensation Plan [6]						28	(28)	
Purchase of treasury stock	(886)						(28)	(28)
Sale and distribution of treasury stock	886						28	28
Dividends on stock-based compensation				(80)				(80)
Cash dividends [2]				(9,235)				(9,235)

Balances at September 30, 2010	**9,499,463**	**$ 4,623**	**$ 147,022**	**$ 72,858**	**$ (2,404)**	**$ 767**	**$ (767)**	**$ 222,099**

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

(2) Cash dividends declared per share for the periods ended September 30, 2010 and December 31, 2009 were $0.975 and $1.250, respectively.

(3) The shares issued under the Performance Incentive Plan (PIP) are net of shares withheld for employee taxes. For the period ended September 30, 2010, the Company withheld 17,695 shares for taxes. We did not issue any shares under the PIP in 2009.

(4) Tax expense recognized on the prior service cost component of employee benefit plans for the periods ended September 30, 2010 and December 31, 2009 were approximately $4

and $5, respectively.

(5) Tax expense recognized on the net gain component of employee benefit plans for the periods ended September 30, 2010 and December 31, 2009 were $77 and $794, respectively.

(6) In May and November 2009, certain participants of the Deferred Compensation Plan received distributions totaling $883. There were no distributions in the first nine months of 2010.

(7) Includes 29,338 and 28,452 shares at September 30, 2010 and December 31, 2009, respectively, held in a Rabbi Trust established by the Company relating to the Deferred Compensation Plan.

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

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Notes to Condensed Consolidated Financial Statements (Unaudited)

1. Summary of Accounting Policies

Basis of Presentation

References in this document to the Company, Chesapeake, we, us and our are intended to mean the Registrant 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, 2010. 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.

As a result of the merger with Florida Public Utilities Company (FPU) in October 2009, we changed our operating segments (see Note 7, Segment Information, for further discussion). We revised the segment information as of and for the three months and nine months ended September 30, 2009, to reflect the new segments. We also revised certain presentations and reclassified certain amounts reported in the condensed consolidated statements of income and cash flows for the three months and nine months ended September 30, 2009 to conform to current period presentations and classifications. These reclassifications are considered immaterial to the overall presentation of our condensed consolidated financial statements.

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.

Recent Accounting Amendments Yet to be Adopted by the Company

In November 2008, the SEC released a proposed roadmap regarding the potential use by U.S. issuers of financial statements prepared in accordance with International Financial Reporting Standards (IFRS), a comprehensive series of accounting standards published by the International Accounting Standards Board (IASB). Under the proposed roadmap, we may be required to prepare our financial statements in accordance with IFRS as early as 2015. The SEC will make a determination in 2011 regarding the mandatory adoption of IFRS. In July 2009, the IASB issued an exposure draft of Rate-regulated Activities, which sets out the scope, recognition and measurement criteria, and accounting disclosures for assets and liabilities that arise in the context of cost-of-service regulation, to which our rate-regulated businesses are subject. Throughout 2010, IASB has continued its deliberation on the exposure draft and comments received on the overall concept of the recognition of assets and liabilities arising out of cost-of-service regulation. We will continue to monitor the development of the potential implementation of IFRS.

Other Accounting Amendments Adopted by the Company during the first nine months of 2010

In January 2010, the Financial Accounting Standards Board (FASB) issued FASB Accounting Standards Update (ASU) 2010-06, Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements. This ASU requires certain new disclosures and clarifies certain existing disclosure requirements about fair value measurement, as set forth in FASB Accounting Standards Codification (ASC) Subtopic 820-10. The FASB s objective is to improve these disclosures and, thus, increase the transparency in financial reporting. Specifically, ASU 2010-06 amends ASC Subtopic 820-10 to now require a reporting entity to disclose separately the amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and describe the reasons for the transfers; and, in the reconciliation for fair value measurements using significant unobservable inputs, a reporting entity should present separate information about purchases, sales, issuances, and settlements. In addition, ASU 2010-06 clarifies certain requirements of the existing disclosures. We adopted the disclosures required by this ASU in the first quarter of 2010, except for disclosures about purchases, sales, issuances, and settlements in the roll-forward of activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. We currently do not have any assets or liabilities that would require Level 3 fair value measurements. Adoption of this ASU did not have an impact on our condensed consolidated financial position and results of operations.

In April 2010, the FASB issued FASB ASU 2010-12 Income Taxes (Topic 740), Accounting for Certain Tax effects of the 2010 Health Care Reform Acts. This ASU codifies the SEC staff announcement relating to the accounting for the Health Care and Education Reconciliation Act and the Patient Protection and Affordable Care Act, which allows the two Acts to be considered together for accounting purposes. We adopted this ASU in the first quarter of 2010 and have determined that these Acts did not have a material impact on our income tax accounting (see Note 8, Employee Benefit Plans, to these unaudited condensed consolidated financial statements for further discussion).

2. Acquisitions

FPU

On October 28, 2009, we completed a merger with FPU, pursuant to which FPU became a wholly-owned subsidiary of Chesapeake. The merger was accounted for under the acquisition method of accounting, with Chesapeake treated as the acquirer for accounting purposes.

The merger increased our overall presence in Florida by adding approximately 51,000 natural gas distribution customers and 12,000 propane distribution customers to our existing Florida operations. It also introduced us to the electric distribution business as we incorporated FPU s approximately 31,000 electric customers in northwest and northeast Florida.

In consummating the merger, we issued 2,487,910 shares of Chesapeake common stock at a price per share of $30.42 in exchange for all outstanding common stock of FPU. We also paid approximately $16,000 in lieu of issuing fractional shares in the exchange. There was no contingent consideration in the merger. The total value of consideration transferred by Chesapeake in the merger was approximately $75.7 million.

The assets acquired and liabilities assumed in the merger were recorded at their respective fair values at the completion of the merger. For certain assets acquired and liabilities assumed, such as pension and post-retirement benefit obligations, income taxes and contingencies without readily determinable fair values, for which GAAP provides specific exception to the fair value recognition and measurement, we applied other specified GAAP or accounting treatment as appropriate.

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The following table summarizes the final allocation of the purchase price to the assets acquired and liabilities assumed at the date of the merger.

(in thousands)	October 28, 2009
Purchase price	$ 75,699
Current assets	26,761
Property, plant and equipment	139,709
Regulatory assets	19,899
Investments and other deferred charges	3,659
Intangible assets	4,019
Total assets acquired	194,047
Long term debt	47,812
Borrowings from line of credit	4,249
Other current liabilities	17,427
Pre-merger contingencies	923
Other regulatory liabilities	19,414
Pension and post retirement obligations	14,276
Environmental liabilities	12,414
Deferred income taxes	20,559
Customer deposits and other liabilities	15,467
Total liabilities assumed	152,541
Net identifiable assets acquired	41,506
Goodwill	$ 34,193

During 2010, we adjusted the allocation of the purchase price based on additional information available. The adjustments are related to certain accruals, regulatory assets, deferred and current income tax assets and liabilities, and pre-merger contingencies (see discussion below). These adjustments also resulted in a change in fair value of the propane property, plant and equipment. Goodwill from the merger increased to $34.2 million after incorporating these adjustments, compared to $33.4 million as previously disclosed at December 31, 2009.

None of the $34.2 million in goodwill recorded in connection with the merger is deductible for tax purposes. All of the goodwill recorded in connection with the merger is related to the regulated energy segment. We believe the goodwill recognized is attributable to the synergies and opportunities primarily related to FPU s regulated energy businesses. The intangible assets acquired in connection with the merger are related to propane customer relationships ($3.5 million) and favorable propane supply contracts ($519,000). The intangible value assigned to FPU s existing propane customer relationships is being amortized over a 12-year period based on the expected duration of the benefit arising from the relationships. The intangible value assigned to FPU s favorable propane contracts is being amortized over a period ranging from one to 14 months based on contractual terms.

Current assets of $26.8 million acquired during the merger included notes receivable of approximately $5.8 million, for which we received full payment in March 2010, and accounts receivable of approximately $3.1 million, $6.0 million and $891,000 for FPU s natural gas, electric and propane distribution businesses, respectively.

The pre-merger contingencies of $923,000 included in the final allocation of the purchase price is primarily related to a proposed settlement agreement for a class action complaint against FPU from a FPU propane customer, which is further discussed in Note 6, Other Commitments and Contingencies. The proposed settlement addresses a particular charge by FPU to its propane customers during the period from May 27, 2006 to September 24, 2010, which encompasses both pre-merger and post-merger periods. We used the ratio of such charge made to customers during the pre-merger period to those made during the settlement period to estimate that $835,000 of the $1.1 million total contingency was related to FPU s operations prior to the merger with Chesapeake. The remaining $278,000 of the liability related to FPU s operations after the merger with Chesapeake was expensed in September 2010. Also included in the pre-merger contingencies are liabilities related to FPU s income taxes for periods prior to the merger.

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The financial position and results of operations and cash flows of FPU from the effective date of the merger are included in our condensed consolidated financial statements. The revenue from FPU for the three months and nine months ended September 30, 2010, included in our condensed consolidated statements of income, were $41.4 million and $135.4 million, respectively, and the net income from FPU for the three months and nine months ended September 30, 2010, included in our condensed consolidated statements of income, were $1.1 million and $7.3 million, respectively.

The following table shows the actual results of combined operations for the nine months ended September 30, 2010 and pro forma results of combined operations for the nine months ended September 30, 2009, as if the merger had been completed at January 1, 2009. Since the effects of the merger for the nine months ended September 30, 2010 were already included in the actual results of our consolidated operations, there is no pro forma adjustment for the nine months ended September 30, 2010.

For the Nine Months Ended September 30, *(in thousands, except per share data)*	**2010**	2009
Operating Revenues	**$ 309,787**	$ 291,389
Operating Income	**37,742**	30,106
Net income	**18,942**	13,319
Earnings per share basic	**$ 2.00**	$ 1.43
Earnings per share diluted	**$ 1.98**	$ 1.41

Pro forma results are presented for informational purposes only and are not necessarily indicative of what the actual results would have been had the acquisition actually occurred on January 1, 2009.

The acquisition method of accounting requires acquisition-related costs to be expensed in the period in which those costs are incurred, rather than including them as a component of consideration transferred. It also prohibits an accrual of certain restructuring costs at the time of the merger. As we intend to seek recovery in future rates in Florida of a certain portion of the purchase premium paid and merger-related costs incurred, we also considered the impact of ASC Topic 980, Regulated Operations, in determining the proper accounting treatment for the merger-related costs. As of September 30, 2010, we incurred approximately $3.3 million in costs to consummate the merger, including the cost associated with merger-related litigation and integrating operations following the merger. This includes $369,000 incurred during the nine months ended September 30, 2010. We deferred approximately $1.7 million of the total costs incurred as a regulatory asset at September 30, 2010, which represents our estimate, based on similar proceedings in Florida in the past, of the costs which we expect to be permitted to recover when we complete the appropriate rate proceedings.

Included in the $3.3 million merger-related costs incurred as of September 30, 2010, were approximately $452,000 of severance and other restructuring charges for our efforts to integrate the operations of the two companies.

Virginia LP Gas

On February 4, 2010, Sharp Energy, Inc. (Sharp), our propane distribution subsidiary, purchased the operating assets of Virginia LP Gas, Inc., a propane distributor serving approximately 1,000 retail customers in Northampton and Accomack Counties in Virginia. The total consideration for the purchase was $600,000, of which $300,000 was paid at the closing and the remaining $300,000 will be paid over 60 months. Based on our valuation, we allocated $188,000 of the purchase price to intangible assets, which consist of customer relationship and non-compete agreements. These intangible assets are being amortized over a seven-year period. There was no goodwill recorded in connection with this acquisition. The revenue and net income from this acquisition that were included in our condensed consolidated statement of income for the three months and nine months ended September 30, 2010 were not material.

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Indiantown Gas Company

On August 9, 2010, FPU purchased the natural gas operating assets of Indiantown Gas Company, which provides natural gas distribution services to approximately 700 customers including two large industrial customers in Indiantown, Florida. FPU paid approximately $1.2 million for these assets. FPU recorded $742,000 in goodwill in connection with this acquisition, all of which is deductible for income tax purposes. There was no intangible asset recorded in connection with this acquisition. The revenue and net income from this acquisition that were included in our condensed and consolidated statement of income for the three months and nine months ended September 30, 2010 were not material.

3. Calculation of Earnings Per Share

	Three Months		Nine Months	
For the Periods Ended September 30,	**2010**	**2009**	**2010**	**2009**
(in thousands, except Shares and Per Share Data)				
Calculation of Basic Earnings Per Share:				
Net Income	**$ 1,628**	$ 308	**$ 18,942**	$ 9,706
Weighted average shares outstanding	**9,493,425**	6,883,070	**9,460,462**	6,859,516
Basic Earnings Per Share	**$ 0.17**	$ 0.04	**$ 2.00**	$ 1.41
Calculation of Diluted Earnings Per Share:				
Reconciliation of Numerator:				
Net Income	**$ 1,628**	$ 308	**$ 18,942**	$ 9,706
Effect of 8.25% Convertible debentures (1)			**56**	60
Adjusted numerator Diluted	**$ 1,628**	$ 308	**$ 18,998**	$ 9,766
Reconciliation of Denominator:				
Weighted shares outstanding Basic	**9,493,425**	6,883,070	**9,460,462**	6,859,516
Effect of dilutive securities: (1)				
Share-based Compensation	**4,271**	4,954	**23,708**	27,838
8.25% Convertible debentures			**86,751**	93,656
Adjusted denominator Diluted	**9,497,696**	6,888,024	**9,570,921**	6,981,010
Diluted Earnings Per Share	**$ 0.17**	$ 0.04	**$ 1.98**	$ 1.40

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

calculation.

4. Rates and Other Regulatory Activities

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

Delaware

On September 2, 2008, our Delaware division filed with the Delaware Public Service Commission (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, 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. Accordingly, if the Hearing Examiner s refund recommendation for past capacity releases were 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. We disagreed with the Hearing Examiner s recommendations and filed exceptions to those recommendations on February 18, 2010. 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. Both the Delaware division and the Division of the Public Advocate filed opening briefs with the Delaware Superior Court on September 30, 2010. It is not anticipated that the Court will render a decision prior to the end of the year. Due to the ongoing legal proceeding, the parties have not yet opened a separate docket to determine an alternative pricing methodology for future capacity releases. We did not accrue any contingent liability related to potential refunds for past capacity releases. Since the Delaware PSC s Order on May 18, 2010, the Delaware division has not released any capacity to PESCO.

On September 4, 2009, the Delaware division filed with the Delaware PSC its annual GSR Application, seeking approval to change its GSR, effective November 1, 2009. On October 6, 2009, the Delaware PSC authorized the Delaware division to implement the GSR charges on November 1, 2009, on a temporary basis, subject to refund, pending the completion of full evidentiary hearings and a final decision. The evidentiary hearing in this matter was held on May 19, 2010. At the evidentiary hearing, the parties in this docket, which included the Delaware PSC, the Delaware division and the Division of the Public Advocate, presented a proposed settlement agreement to resolve all issues addressed in this docket. The settlement agreement contemplates that the Delaware division will begin to share interruptible margins with its firm ratepayers when those margins reach a certain level in each twelve-month period ending October 31. Based on the current level of interruptible margins generated by the Delaware division, we do not anticipate that sharing of future interruptible margins will have a significant impact on our results. The Delaware PSC approved the settlement agreement on September 7, 2010.

On December 17, 2009, the Delaware division filed an application with the Delaware PSC, requesting approval for an Individual Contract Rate for service to be rendered to a potential large industrial customer. The Delaware PSC granted approval of the Individual Contract Rate on February 18, 2010.

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 division anticipates a final decision in no later than the third quarter of 2011.

Maryland

On December 1, 2009, the Maryland Public Service Commission (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, 2009. No issues were raised at the hearing, and on December 9, 2009, the Hearing Examiner in this proceeding issued a proposed Order approving the division s four quarterly filings. On January 8, 2010, the Maryland PSC issued an Order substantially affirming the Hearing Examiner s decision in the matter.

On September 14, 2010, the Maryland division filed with the Maryland PSC, its four quarterly gas cost recovery filings for the twelve months ended September 30, 2010. The Maryland PSC is scheduled to hold an evidentiary hearing on December 14, 2010 to determine the reasonableness of the filings. The Maryland division anticipates a final decision in the first quarter of 2011.

Florida

On July 14, 2009, Chesapeake s Florida division filed with the Florida PSC its petition for a rate increase and request for interim rate relief. In the application, the Florida division sought approval of: (a) an interim rate increase of $417,555; (b) a permanent rate increase of $2,965,398, which represented an average base rate increase, excluding fuel costs, of approximately 25 percent for the Florida division s customers; (c) implementation or modification of certain surcharge mechanisms; (d) restructuring of certain rate classifications; and (e) deferral of certain costs and the purchase premium associated with the then pending merger with FPU. On August 18, 2009, the Florida PSC approved the full amount of the Florida division s interim rate request, subject to refund, applicable to all meters read on or after September 1, 2009. On December 15, 2009, the Florida PSC: (a) approved a $2,536,307 permanent rate increase applicable to all meters read on or after January 14, 2010; (b) determined that there is no refund required of the interim rate increase; and (c) ordered Chesapeake s Florida division and FPU s natural gas distribution operations to submit data no later than April 29, 2011 (which is 18 months after the merger) that details all known benefits, synergies, cost savings and cost increases that have resulted from the merger.

Also on December 15, 2009, the Florida PSC approved the settlement agreement for a final natural gas rate increase of $7,969,000 for FPU s natural gas distribution operation. The Florida PSC had approved an annual interim rate increase of $984,054 on February 10, 2009 and approved the permanent rate increase of $8,496,230 in an order issued on May 5, 2009, with the new rates to be effective beginning on June 4, 2009. On June 17, 2009, however, the Office of Public Counsel entered a protest to the Florida PSC s order and its final natural gas rate increase ruling. Subsequent negotiations led to the settlement agreement between the Office of Public Counsel and FPU, which the Florida PSC approved on December 15, 2009. The rates authorized pursuant to the order approving the settlement agreement became effective on January 14, 2010. In February 2010, FPU refunded to its natural gas customers approximately $290,000, representing revenues in excess of the amount provided by the settlement agreement that had been billed to customers from June 2009 through January 14, 2010.

In the third quarter of 2010, we accrued $500,000 to reserve for FPU natural gas regulatory risk. We recorded this reserve based on our assessment of the regulatory risk related to FPU s current earnings and how they may have been affected by various factors, including the benefits, synergies, cost savings and cost increases resulting from the merger. We are required to submit by April 29, 2011 data that details such known benefits, synergies, cost savings and cost increases.

On September 1, 2009, FPU s electric distribution operation filed its annual Fuel and Purchased Power Recovery Clause, which seeks final approval of its 2008 fuel-related revenues and expenses and new fuel rates for 2010. On January 4, 2010, the Florida PSC approved the proposed 2010 fuel rates, effective on or after January 1, 2010.

On September 11, 2009, Chesapeake s Florida division and FPU s natural gas distribution operation separately filed their respective annual Energy Conservation Cost Recovery Clauses, seeking final approval of their 2008 conservation-related revenues and expenses and new conservation surcharge rates for 2010. On November 2, 2009, the Florida PSC approved the proposed 2010 conservation surcharge rates for both the Florida division and FPU, effective for meters read on or after January 1, 2010.

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Also on September 11, 2009, FPU s natural gas distribution operation filed its annual Purchased Gas Adjustment Clause, seeking final approval of its 2008 purchased gas-related revenues and expenses and new purchased gas adjustment cap rate for 2010. On November 4, 2009, the Florida PSC approved the proposed 2010 purchased gas adjustment cap, effective on or after January 1, 2010.

On September 1, 2010, FPU s electric distribution operation filed its annual Fuel and Purchased Power Cost Recovery Clause, which seeks final approval of the levelized fuel adjustment and purchased power cost recovery factors for 2011. A final decision on the proposed 2011 fuel adjustment factors is expected in December 2010.

On September 13, 2010, Chesapeake s Florida division and FPU s natural gas distribution operation separately filed their annual Energy Conservation Cost Recovery Clauses, seeking final approval of the 2009 conservation-related revenues and expenses and new conservation surcharge rates for 2011. A final decision on the proposed 2011 conservation rates is expected in December 2010.

On September 13, 2010, FPU s natural gas distribution operation filed its annual Purchase Gas Adjustment Clause seeking final approval of its 2009 purchased gas-related revenues and expenses and new purchased gas adjustment cap rate for 2011. A final decision on the proposed 2011 Purchased Gas Adjustment is expected in December 2010.

The City of Marianna Commissioners voted on July 7, 2009 to enter into a new 10-year franchise agreement with FPU, effective February 1, 2010. The agreement provides that new interruptible and time-of-use rates shall become available for certain customers prior to February 2011, or, at the option of the City, the franchise agreement could be voided nine months after that date. The new franchise agreement contains a provision that permits the City to purchase the Marianna portion of FPU s electric system. Should FPU fail to make available the new interruptible and time-of-use rates, and if the franchise agreement is then voided by the City and the City elects to purchase the Marianna portion of the distribution system, the agreement would require the City to pay FPU severance/reintegration costs, the fair market value for the system, and an initial investment in the infrastructure to operate this limited facility. If the City purchased the electric system, FPU would have a gain in the year of the disposition, but ongoing financial results would be negatively impacted from the loss of the Marianna area from FPU s electric operations.

ESNG

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

Energylink Expansion Project: In 2006, ESNG 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 ESNG s existing facilities in Sussex County, Delaware. In April 2009, ESNG terminated this project based on increased construction costs over its original projection and 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 and approved by the FERC. One of the two participating customers is Chesapeake, through its Delaware and Maryland divisions.

Mainline Extension Project: On November 25, 2009, ESNG filed a notice of its intent under its blanket certificate to construct, own and operate new mainline facilities to deliver additional firm service of 1,594 Mcfs per day of natural gas to Chesapeake s Delaware division. The FERC published the notice of this filing on December 7, 2009. No protest was filed during the 60-day period following the notice, and ESNG commenced construction on February 6, 2010. The facilities were completed on April 29, 2010, and ESNG commenced billing for the new service on May 1, 2010.

Mainline Extension and Interconnect Project: On March 5, 2010, ESNG submitted an Application for Certificate of Public Convenience and Necessity to the FERC related to a proposed mainline extension and interconnect project that would tie into the interstate pipeline system of Texas Eastern Transmission, LP (TETLP). ESNG s project involves building and operating an eight-mile mainline extension from ESNG s existing facility in Parkesburg, Pennsylvania to the interconnection with TETLP at Honey Brook, Pennsylvania. The estimated capital cost of this project is approximately $19.4 million. On September 3, 2010, the FERC approved ESNG s application, subject to certain environmental conditions, some of which have to be met prior to the commencement of construction. ESNG accepted the Order Issuing Certificate on October 4, 2010. On October 13, 2010, the FERC issued a Notice to Proceed with the construction of the project s facilities as all conditions that must be met prior to the commencement of construction were satisfied. Construction is anticipated to be completed during the fourth quarter of 2010.

ESNG also had developments in the following FERC matters:

On April 30, 2010, ESNG submitted its annual Interruptible Revenue Sharing Report to the FERC. ESNG reported in this filing that its interruptible revenue was in excess of its annual threshold amount and refunded $90,718, inclusive of interest, in the second quarter of 2010 to its eligible firm customers.

On May 28, 2010, ESNG submitted its annual Fuel Retention Percentage (FRP) and Cash-Out Surcharge filings to the FERC. In these filings, ESNG proposed to implement a FRP rate of 0.00 percent and a zero rate for its Cash-Out Surcharge. ESNG also proposed to refund $310,117, inclusive of interest, to its eligible customers in the second quarter of 2010 as a result of combining its over-recovered Gas Required for Operations and its over-recovered Cash-Out Cost. The FERC approved these proposals on June 29, 2010, and ESNG issued refunds to eligible customers.

On August 16, 2010, ESNG submitted its compliance filing with regard to the FERC s Order on Electronic Tariff Filings (Order No. 714). This Order required all natural gas, oil and electric pipelines subject to FERC jurisdiction to file baseline tariff sheets electronically. All subsequent rate and tariff-related filings are to be made electronically. On October 13, 2010, the FERC approved ESNG s compliance filing for this Order.

On September 1, 2010, ESNG submitted its compliance filing with regard to the FERC s most recent Order adopting Standards for Business Practices for Interstate Natural Gas Pipelines (Order No. 587-U). With this Order, FERC incorporated by reference into its regulations Version 1.9 of the North American Energy Standards Board Wholesale Gas Quadrant s standards. On October 13, 2010, FERC approved ESNG s compliance filing.

5. Environmental Commitments and Contingencies

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

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. The Key West, Pensacola, Sanford and West Palm Beach sites are related to FPU, for which we assumed in the merger any existing and future contingencies.

As of September 30, 2010, we had $381,000 in environmental liabilities related to Chesapeake s MGP sites in Maryland and Florida, representing our estimate of the future costs associated with those sites. As of September 30, 2010, we had approximately $1.4 million in regulatory and other assets for future recovery of environmental costs from Chesapeake s customers through our approved rates. As of September 30, 2010, we had approximately $11.8 million in environmental liabilities related to FPU s MGP sites in Florida, primarily from the West Palm Beach site, which represents our estimate of the future costs associated with those sites. FPU has approval to recover up to $14.0 million of its environmental costs from insurance and from customers through rates. Approximately $7.7 million of FPU s expected environmental costs have been recovered from insurance and customers through rates as of September 30, 2010. We also had approximately $6.3 million in regulatory assets for future recovery of environmental costs from FPU s customers.

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The following discussion provides details on each site.

Salisbury, Maryland

We have substantially completed remediation of this site in Salisbury, Maryland, where it was determined that a former MGP caused localized ground-water contamination. During 1996, we completed construction of an Air Sparging and Soil-Vapor Extraction (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. We have requested and are awaiting a No Further Action determination from the MDE.

Through September 30, 2010, we have incurred and paid approximately $2.9 million for remedial actions and environmental studies. We have recovered approximately $2.2 million through insurance proceeds or in rates and have $696,000 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 Florida Department of Environmental Protection (FDEP), we are obligated to assess and remediate environmental impacts at this former MGP site. In 2001, the FDEP approved a Remedial Action Plan (RAP) requiring construction and operation of a BioSparging 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 Fifteenth Semi-Annual RAP Implementation Status Report was submitted to the FDEP in July 2010. The groundwater sampling results through July 2010 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 may be met for the area being treated by the BS/SVE treatment system in approximately two to three years.

The BS/SVE treatment system 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 the FDEP for review. The FDEP provided comments to the soil excavation interim RAP by letter, dated June 24, 2010. A meeting is proposed with the FDEP in November 2010 to discuss the proposed soil excavation RAP with the prospect of proceeding with actual field work in late 2011 or early 2012.

The 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 the 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, 2010, we have incurred and paid approximately $1.6 million for this site and estimate an additional cost of $381,000 in the future, which has been accrued. We have recovered through rates $1.3 million of the costs and continue to expect that the remaining $715,000, which is included in regulatory assets, will be recoverable from customers through our approved rates.

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. The FDEP has not required any further work at the site as of this time. Our portion of the consulting/remediation costs which may be incurred at this site is projected to be $93,000.

Pensacola, Florida

FPU formerly owned and operated an MGP in Pensacola, Florida. The MGP was also owned by Gulf Power Corporation (Gulf Power). Portions of the site are now owned by the City of Pensacola and the Florida Department of Transportation. In October 2009, the FDEP informed Gulf Power that FDEP would approve a conditional No Further Action determination for the site, which must include a requirement for institutional and engineering controls. The group, consisting of Gulf Power, City of Pensacola, Florida Department of Transportation and FPU, is proceeding with preparation of the necessary documentation to submit the No Further Action justification. Consulting and remediation costs are projected to be $11,000.

Sanford, Florida

FPU is the current owner of property in Sanford, Florida, a former MGP site which 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 U.S. 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 total estimated remediation costs for this site were projected at the time by EPA to be approximately $12.9 million.

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, 2010, FPU has paid $650,000 to the Sanford Group escrow account for its share of 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, 2010, FPU s remaining share of remediation expenses, including attorneys fees and costs, is estimated to be $22,000. 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 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.

West Palm Beach, Florida

We are currently evaluating remedial options 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 FDEP, effective April 8, 1991, FPU completed the delineation of soil and groundwater impacts at the site. On June 30, 2008, FPU transmitted a revised feasibility study, evaluating appropriate remedies for the site, to the FDEP. 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 recently performed additional field work in August 2010, which included the installation of additional groundwater monitoring wells and performance of a comprehensive groundwater sampling event. The results of the field work were submitted to the FDEP for their review and comment. FPU also performed vapor intrusion sampling in October 2010. The total projected cost of this additional field work requested by the FDEP is approximately $750,000.

The revised feasibility study completed in 2008 evaluated a wide range of remedial alternatives based on criteria provided by applicable laws and regulations. Based on the likely acceptability of proven remedial technologies described in the feasibility study and implemented at similar sites, management believes that consulting and remediation costs to address the impacts now characterized at the West Palm Beach site will range from $7.4 million to $19.0 million. This range of costs covers such remedies as in situ solidification for deeper soil impacts, excavation of superficial soil impacts, installation of a barrier wall with a permeable biotreatment zone, monitored natural attenuation of dissolved impacts in groundwater, or some combination of these remedies.

Negotiations between FPU and the FDEP on a final remedy for the site continue. Until those negotiations are concluded, we are unable to determine, to a reasonable degree of certainty, the full extent or cost of remedial action that may be required. As of September 30, 2010, and subject to the limitations described above, we estimate the remediation expenses, including attorneys fees and costs, will range from approximately $7.8 million to $19.4 million for this site.

We continue to expect that all costs related to these activities will be recoverable from customers through 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.

6. Other Commitments and Contingencies

Litigation

In May 2010, a 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 denies any wrongdoing and maintains that the particular charge at issue is customary, proper and fair. Without any admission by FPU of 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 expenses of continued litigation. The settlement agreement has been preliminarily approved by the court. The hearing for final approval of the settlement, after providing notice to the class, is scheduled for February 11, 2011. We recorded $1.1 million as a contingent liability related to this litigation in September 2010 based on the proposed settlement agreement, which includes the proposed settlement payment, attorneys fees and expenses and costs of notice and class administration. As discussed in Note 2, Acquisitions, $835,000 of this contingent liability was determined to be associated with FPU s operations prior to the merger with Chesapeake and was recorded as part of the purchase price allocation. The remaining $278,000 of the liability, which is related to FPU s operations after the merger with Chesapeake, was expensed in September 2010.

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

Natural Gas, Electric and Propane Supply

Our natural gas, electric and propane distribution operations have entered into contractual commitments to purchase gas, electricity and propane from various suppliers. The contracts have various expiration dates. We have a contract with an energy marketing and risk management company to manage a portion of our natural gas transportation and storage capacity. This contract expires on March 31, 2012.

In May 2010, our natural gas marketing subsidiary, PESCO, renewed contracts to purchase natural gas from various suppliers. These contracts expire in May 2011.

FPU s electric fuel supply contracts require FPU to maintain an acceptable standard of creditworthiness based on specific financial ratios. FPU s agreement with JEA (formerly known as Jacksonville Electric Authority) requires FPU to comply with the following ratios based on the results of the prior 12 months: (a) total liabilities to tangible net worth less than 3.75; and (b) fixed charge coverage greater than 1.5. If either ratio is not met by FPU, we have 30 days to cure the default or provide an irrevocable letter of credit if the default is not cured. FPU s agreement with Gulf Power requires FPU to meet the following ratios based on the average of the prior nine quarters: (a) funds from operation interest coverage (minimum of 2 to 1); and (b) total debt to total capital (maximum of 0.65 to 1). If FPU fails to meet the requirements, we have to provide the supplier a written explanation of action taken or proposed to be taken to be compliant. Failure to comply with the ratios specified in the agreement with Gulf Power could result in FPU having to provide an irrevocable letter of credit. FPU was in compliance with these requirements as of September 30, 2010.

Corporate Guarantees

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, 2010 was $23.3 million, with the guarantees expiring on various dates through 2011.

In addition to the corporate guarantees, we have issued a letter of credit to our previous primary insurance company for $725,000, which expires on June 1, 2011. The letter of credit to our previous primary insurance company is provided as security to satisfy the deductibles under our various insurance policies. There have been no draws on this letter of credit as of September 30, 2010. We do not anticipate that this letter of credit will be drawn upon by the counterparty. As a result of the change in our primary insurance company in September 2010, we may be required to provide a separate letter of credit to our new primary insurance company. In addition, we have issued a letter of credit for $978,000 to TETLP related to a Precedent Agreement, which is further described below.

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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 dekatherms per day (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 30,000 and 10,000 Dts/d, respectively, 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 (f) 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 ESNG s transmission system. The new firm transportation service contracts between our Delaware and Maryland divisions and TETLP will provide us with an additional direct interconnection with ESNG 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 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.

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 $4.7 million by December 31, 2010. 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 2011, our proportionate share could be as much as approximately $45 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 of September 30, 2010, we provided a letter of credit for $978,000 under the Precedent Agreement with TETLP as required. This letter of credit is expected to increase quarterly as TETLP s pre-service costs increase and will not exceed more than the three-month reservation charge under the firm transportation service contracts, which we currently estimate to be $2.1 million.

On March 17, 2010, our Delaware and Maryland divisions entered into a separate Precedent Agreement with ESNG to extend its mainline by eight miles to interconnect with TETLP at Honey Brook, Pennsylvania. The estimated capital cost associated with construction of this mainline extension and interconnection is approximately $19.4 million, and the proposed rate for transmission service on this extension is ESNG s current tariff rate for service in that area. As discussed in Note 4, Rates and Other Regulatory Activities, ESNG obtained the necessary approvals from the FERC to commence construction, which is anticipated to be completed during the fourth quarter of 2010.

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. Our Delaware and Maryland divisions require no regulatory approvals or exemptions to receive transmission service from TETLP or

ESNG.

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Once the ESNG and TETLP firm transportation services commence, our Delaware and Maryland divisions will incur costs from those services based on the agreed reservation rates, which will become an integral component of the costs associated with providing natural gas supplies to our Delaware and Maryland divisions. The costs from the ESNG and TETLP firm transportation services will be included in the annual GSR filings for each of our respective divisions.

7. Segment Information

We use the management approach to identify operating segments, and we organize our business around differences in regulatory environment and/or products or services. 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.

As a result of the merger with FPU in October 2009, we changed our operating segments to better reflect how the chief operating decision maker reviews the various operations of our Company. Our three operating segments are now composed of the following:

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 various PSCs having jurisdiction in each operating territory or by the FERC in the case of ESNG.

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 services.

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

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The following table presents information about our reportable segments.

For the Periods Ended September 30, *(in thousands)*	Three Months Ended 2010	Three Months Ended 2009	Nine Months Ended 2010	Nine Months Ended 2009
Operating Revenues, Unaffiliated Customers				
Regulated Energy	**$ 53,215**	$ 15,098	**$ 196,966**	$ 85,529
Unregulated Energy	**20,134**	14,011	**103,646**	82,982
Other	**3,117**	2,649	**9,175**	8,560
Total operating revenues, unaffiliated customers	**$ 76,466**	$ 31,758	**$ 309,787**	$ 177,071
Intersegment Revenues [1]				
Regulated Energy	**$ 300**	$ 274	**$ 822**	$ 893
Unregulated Energy			**364**	254
Other	**197**	170	**644**	546
Total intersegment revenues	**$ 497**	$ 444	**$ 1,830**	$ 1,693
Operating Income (Loss)				
Regulated Energy	**$ 6,536**	$ 2,971	**$ 32,360**	$ 16,554
Unregulated Energy	**(2,237)**	(1,361)	**4,732**	5,233
Other and eliminations	**284**	647	**650**	(709)
Total operating income	**$ 4,583**	$ 2,257	**$ 37,742**	$ 21,078
Other income (loss), net of other expenses	**102**	(26)	**206**	19
Interest	**2,256**	1,540	**6,924**	4,755
Income taxes	**801**	383	**12,082**	6,636
Net income	**$ 1,628**	$ 308	**$ 18,942**	$ 9,706

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

	September 30,	December 31,

(in thousands)	**2010**	2009
Identifiable Assets		
Regulated energy	**$ 498,483**	$ 480,903
Unregulated energy	**84,046**	101,437
Other	**29,746**	34,724
Total identifiable assets	**$ 612,275**	$ 617,064

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

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8. Employee Benefit Plans

Net periodic benefit costs for our pension and post-retirement benefits plans for the three months and nine months ended September 30, 2010 and 2009 are set forth in the following table:

For the Three Months Ended September 30,	Chesapeake Pension Plan 2010	Chesapeake Pension Plan 2009	FPU Pension Plan 2010	Chesapeake SERP 2010	Chesapeake SERP 2009	Chesapeake Postretirement Plan 2010	Chesapeake Postretirement Plan 2009	FPU Medical Plan 2010
(in thousands)								
Service Cost	**$**	$	**$**	**$**	$	**$**	$	**$ 28**
Interest Cost	**147**	140	**638**	**35**	33	**30**	27	**33**
Expected return on plan assets	**(108)**	(86)	**(618)**					
Amortization of prior service cost	**(1)**	(2)		**5**	3			
Amortization of net loss	**40**	68		**15**	14	**15**	40	
Net periodic cost	**$ 78**	$ 120	**$ 20**	**$ 55**	$ 50	**$ 45**	$ 67	**$ 61**

For the Nine Months Ended September 30,	Chesapeake Pension Plan 2010	Chesapeake Pension Plan 2009	FPU Pension Plan 2010	Chesapeake SERP 2010	Chesapeake SERP 2009	Chesapeake Postretirement Plan 2010	Chesapeake Postretirement Plan 2009	FPU Medical Plan 2010
(in thousands)								
Service Cost	**$**	$	**$**	**$**	$	**$**	$ 1	**$ 83**
Interest Cost	**441**	420	**1,913**	**105**	97	**91**	81	**101**
Expected return on plan assets	**(323)**	(259)	**(1,856)**					
Amortization of prior service cost	**(4)**	(4)		**15**	10			
Amortization of net loss	**119**	205		**45**	44	**44**	119	
Net periodic cost	**$ 233**	$ 362	**$ 57**	**$ 165**	$ 151	**$ 135**	$ 201	**$ 184**

We expect to record pension and postretirement benefit costs of approximately $1.0 million for 2010, $320,000 of which is attributable to FPU s pension and medical plans. In addition, we expect to record $897,000 in expense for 2010 related to continued amortization of the FPU pension regulatory asset of approximately $7.6 million, 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 prior to the merger by FPU to be recovered through rates pursuant to a previous order by the Florida PSC.

During the three and nine months ended September 30, 2010, we contributed $61,000 and $393,000 respectively, to the Chesapeake Pension Plan. We also contributed $382,000 and $1.1 million to the FPU Pension Plan for the three and nine months ended September 30, 2010, respectively. We expect to contribute $81,000 and $24,000 to the Chesapeake and FPU pension plans, respectively, during the fourth quarter of 2010.

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, 2010, were $22,000 and $67,000, respectively; for the year 2010, such benefits paid are expected to be approximately $88,000. Cash benefits paid for the Chesapeake Postretirement Plan, primarily for medical claims for the three and nine months ended September 30, 2010, totaled $14,000 and $49,000, respectively; for the year 2010, we have estimated that approximately $115,000 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, 2010, totaled $25,000 and $79,000, respectively; for the year 2010, we have estimated that approximately $144,000 will be paid for such benefits.

On March 23, 2010, the Patient Protection and Affordable Care Act was signed into law. On March 30, 2010, a companion bill, the Health Care and Education Reconciliation Act of 2010, was also signed into law. Among other things, these new laws, when taken together, reduce the tax benefits available to an employer that receives the Medicare Part D subsidy. The deferred tax effects of the reduced deductibility of the postretirement prescription drug coverage must be recognized in the period these new laws were enacted. The FPU Medical Plan receives the Medicare Part D subsidy. We assessed the deferred tax effects on the reduced deductibility as a result of these new laws and determined that the deferred tax effects were not material to our financial results.

9. Investments

The investment balance at September 30, 2010, 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 an associated liability that is recorded and adjusted each month for the gains and losses incurred by the Rabbi Trusts. At September 30, 2010 and December 31, 2009, total investments had a fair value of $3.0 million and $2.0 million, respectively.

10. Share-Based Compensation

Our non-employee directors and key employees are awarded share-based awards through our Directors Stock Compensation Plan (DSCP) and 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, 2010 and 2009.

	Three Months Ended		Nine Months Ended	
For the periods ended September 30,	**2010**	**2009**	**2010**	**2009**
(in thousands)				
Directors Stock Compensation Plan	**$ 74**	$ 48	**$ 209**	$ 143
Performance Incentive Plan	**213**	264	**690**	754
Total compensation expense	**287**	312	**899**	897
Less: tax benefit	**115**	125	**361**	359
Share-Based Compensation amounts included in net income	**$ 172**	$ 187	**$ 538**	$ 538

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 2010, 9,900 shares were granted to the directors under the DSCP. A summary of stock activity under the DSCP during the nine months ended September 30, 2010, is presented below:

	Number of Shares	**Weighted Average Grant Date Fair Value**
Outstanding December 31, 2009		
Granted	9,900	$ 29.99

Vested	9,900	$	29.99
Forfeited			
Outstanding September 30, 2010			

At September 30, 2010, there was $173,000 of unrecognized compensation expense related to the DSCP awards that is expected to be recognized over the remaining seven months of the directors service period ending April 30, 2011.

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Performance Incentive Plan

The table below presents the summary of the stock activity for the PIP for the nine months ended September 30, 2010:

		Number of Shares		Weighted Average Fair Value
Outstanding	December 31, 2009	123,075	$	28.15
Granted		40,875		28.05
Vested		43,960		27.94
Fortfeited				
Expired		18,840		27.94
Outstanding	September 30, 2010	101,150	$	28.24

In January 2010, the Board of Directors granted awards under the PIP for 40,875 shares. The shares granted in January 2010 are multi-year awards, 8,000 shares of which will vest at the end of the two-year service period, or December 31, 2011. The remaining 32,875 shares will vest at the end of the three-year service period, or December 31, 2012. These awards are based upon the successful achievement of long-term goals, growth and financial results, and they comprise 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 Monte-Carlo pricing model to estimate the fair value of each market-based award granted.

At September 30, 2010, the aggregate intrinsic value of the PIP awards was $2.1 million.

11. Derivative Instruments

We use derivative and non-derivative contracts to engage in trading activities and manage risks related to obtaining adequate supplies and the price fluctuations of natural gas and propane. Our natural gas and propane distribution operations have entered into agreements with suppliers to purchase natural gas 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, 2010, our natural gas and propane distribution operations did not have any outstanding derivative contracts.

Xeron, our propane wholesale and marketing operation, 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, net of future servicing costs, 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, 2010, we had the following outstanding trading contracts which we accounted for as derivatives:

At September 30, 2010	Quantity in Gallons	Estimated Market Prices		Weighted Average Contract Prices
Forward Contracts				
Sale	18,964,932	$0.9925 $1.12150	$	1.1194
Purchase	18,484,200	$1.0100 $1.2475	$	1.1055

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

All contracts expire during or prior to the second quarter of 2011.

We did not have any derivative contracts with a credit-risk-related contingency.
Fair values of the derivative contracts recorded in the condensed consolidated balance sheet as of September 30, 2010 and December 31, 2009, are the following:

(in thousands)	**Balance Sheet Location**	**Asset Derivatives Fair Value September 30, 2010**		**December 31, 2009**	
Derivatives not designated as hedging instruments					
Forward contracts	Mark-to-market energy assets	**$**	**2,290**	$	2,379
Put option [1]	Mark-to-market energy assets				
Total asset derivatives		**$**	**2,290**	$	2,379

(in thousands)	**Balance Sheet Location**	**Liability Derivatives Fair Value September 30, 2010**		**December 31, 2009**	
Derivatives not designated as hedging instruments					
Forward contracts	Mark-to-market energy liabilities	**$**	**1,982**	$	2,514
Total liability derivatives		**$**	**1,982**	$	2,514

(1) We purchased a put option for the Pro-Cap (Propane Price Cap) plan in September 2009. The put option expired on March 31, 2010. The put option had a fair value

of $0 at December 31, 2009.

The effects of gains and losses from derivative instruments on the condensed consolidated statements of income for the three and nine months ended September 30, 2010 and 2009, are as follows:

		Amount of Gain (Loss) on Derivatives:			
	Location of Gain (Loss) on Derivatives	Three months ended September 30,		Nine months ended September 30,	
(in thousands)		**2010**	**2009**	**2010**	**2009**
Derivatives designated as fair value hedges:					
Propane swap agreement [1]	Cost of Sales	**$**	$	**$**	$ (42)
Derivatives not designated as fair value hedges:					
Unrealized gain (loss) on forward contracts	Revenue	**$ 69**	$ (246)	**$ 443**	$ (1,382)
Total		**$ 69**	$ (246)	**$ 443**	$ (1,424)

[1] Our propane distribution operation entered into a propane swap agreement to protect it from the impact that wholesale propane price increases would have on the Pro-Cap (Propane Price Cap) plan that was offered to customers. We terminated this swap agreement in January 2009.

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The effects of trading activities on the condensed consolidated statements of income for the three and nine months ended September 30, 2010 and 2009 are as follows:

(in thousands)	**Location in the Statement of Income**	**Three months ended September 30, 2010**	**Three months ended September 30, 2009**	**Nine months ended September 30, 2010**	**Nine months ended September 30, 2009**
Realized gains on forward contracts	Revenue	**$ 271**	$ 915	**$ 1,010**	$ 2,984
Changes in mark-to-market energy assets	Revenue	**69**	(246)	**443**	(1,382)
Total		**$ 340**	$ 669	**$ 1,453**	$ 1,602

12. Fair Value of Financial Instruments

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

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

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

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

The following table summarizes our financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements, by level, within the fair value hierarchy used at September 30, 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	$ 3,006	$ 3,006	$	$
Mark-to-market energy assets,	$ 2,290	$	$ 2,290	$
Liabilities:				
Mark-to-market energy liabilities	$ 1,982	$	$ 1,982	$

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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, 2009:

		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	$ 1,959	$ 1,959	$	$
Mark-to-market energy assets, including put option	$ 2,379	$	$ 2,379	$
Liabilities:				
Mark-to-market energy liabilities	$ 2,514	$	$ 2,514	$

The following valuation techniques were used to measure fair value assets in the table above on a recurring basis as of September 30, 2010 and December 31, 2009:

<u>Level 1 Fair Value Measurements:</u>

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

<u>Level 2 Fair Value Measurements:</u>

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 valued using market transactions for similar assets and liabilities in either the listed or OTC markets.

At September 30, 2010, 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, 2010, long-term debt, which includes the current maturities of long-term debt, had a carrying value of $104.7 million, compared to a fair value of $122.8 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, 2009, long-term debt, including the current maturities, had a carrying value of $134.1 million, compared to the estimated fair value of $145.5 million.

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13. Long Term Debt

Our outstanding long-term debt is shown below:

(in thousands)	September 30, 2010	December 31, 2009
FPU secured first mortgage bonds:		
9.57% bond, due May 1, 2018	**$ 7,247**	$ 8,156
10.03% bond, due May 1, 2018	**3,986**	4,486
9.08% bond, due June 1, 2022	**7,950**	7,950
6.85% bond, due October 1, 2031		14,012
4.90% bond, due November 1, 2031		13,222
Uncollateralized senior notes:		
6.91% note, due October 1, 2010		909
6.85% note, due January 1, 2012	**2,000**	2,000
7.83% note, due January 1, 2015	**10,000**	10,000
6.64% note, due October 31, 2017	**21,818**	21,818
5.50% note, due October 12, 2020	**20,000**	20,000
5.93% note, due October 31, 2023	**30,000**	30,000
Convertible debentures:		
8.25% due March 1, 2014	**1,424**	1,520
Promissory note	**282**	40
Total long-term debt	**104,707**	134,113
Less: current maturities	**(7,216)**	(35,299)
Total long-term debt, net of current maturities	**$ 97,491**	$ 98,814

In January 2010, we redeemed the 6.85 percent and 4.90 percent series of FPU s secured first mortgage bonds prior to their respective maturity for $29.1 million, which included the outstanding principal balances, interest accrued, premium and fees. The difference between the carrying value of those bonds and the amount paid at redemption, totaling $1.5 million, was deferred as a regulatory asset as allowed by the Florida PSC. We initially used short-term borrowing to finance the redemption of these bonds. On March 16, 2010, we entered into a new $29.1 million term loan credit facility with an existing lender to continue to finance the redemption. We borrowed $29.1 million for a nine-month period under this new facility, which bears interest at 1.88 percent per annum.

On June 29, 2010, we entered into an agreement with Metropolitan Life Insurance Company and New England Life Insurance Company to issue up to $36 million in uncollateralized senior notes. We expect to use $29 million of the uncollateralized senior notes to permanently finance the redemption of the 6.85 percent and 4.90 percent series of FPU bonds. The terms of the agreement require us to issue $29 million of the $36 million in uncollateralized senior notes committed by the lender on or before July 9, 2012, with a 15-year term at a rate ranging from 5.28 percent to 6.13 percent based on the timing of the issuance. The remaining $7 million will be issued 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, when issued, will have similar covenants and default provisions as the existing senior notes and will have an annual principal payment beginning in the sixth year after the issuance.

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

Management s Discussion and Analysis of Financial Condition and Results of Operations is designed to provide a reader of the financial statements with a narrative report on our financial condition, results of operations and liquidity. This discussion and analysis should be read in conjunction with the attached unaudited condensed consolidated financial statements and notes thereto and our Annual Report on Form 10-K for the year ended December 31, 2009, 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. You 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;
- 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, and to address regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, as well as 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.

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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 through expansion 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 natural gas and propane is highest due to colder temperatures.

As a result of the merger with FPU in October 2009, we changed our operating segments to better reflect how the chief operating decision maker (our Chief Executive Officer) reviews the various operations of the Company. Our three operating segments are now composed of the following:

- *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 various PSCs having jurisdiction in each operating territory or by the FERC in the case of ESNG.
- *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 services.
- *Other*. The Other segment consists primarily of the advanced information services operation, unregulated subsidiaries that own real estate leased to Chesapeake and certain corporate costs not allocated to other operations.

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We revised the segment information for the three and nine months ended September 30, 2009 to reflect the new operating segments.

The following discussions and those later in the document on operating income and segment results include 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.

In addition, certain information is presented, which, for comparison purposes, includes only FPU s results of operations or excludes FPU s results from the consolidated results of operations for the periods ended September 30, 2010. Certain other information is presented, which, for comparison purposes, excludes all merger-related costs incurred in connection with the FPU merger. Although non-GAAP measures are not intended to replace the GAAP measures for evaluation of our performance, we believe that the portions of the presentation, which include only the FPU results, or which exclude FPU s financial results for the post-merger period and merger-related costs, provide helpful comparisons for an investor s evaluation purposes.

Results of Operations for the Quarter Ended September 30, 2010

Overview and Highlights

Our net income for the quarter ended September 30, 2010 was $1.6 million, or $0.17 per share (diluted). This represents an increase of $1.3 million, or $0.13 per share (diluted), compared to a net income of $308,000, or $0.04 per share (diluted), as reported in the same period in 2009. Our natural gas distribution and propane distribution operations typically experience seasonal losses or reduced earnings during the third quarter because customers do not require natural gas or propane for heating purposes during the summer months.

For the Three Months Ended September 30,	**2010**	**2009**	**Change**
(in thousands)			
Operating Income (Loss)			
Regulated Energy	**$ 6,536**	$ 2,971	$ 3,565
Unregulated Energy	**(2,237)**	(1,361)	(876)
Other	**284**	647	(363)
Operating Income	**4,583**	2,257	2,326
Other Income (Loss), net of expenses	**102**	(26)	128
Interest Charges	**2,256**	1,540	716
Income Taxes	**801**	383	418
Net Income	**$ 1,628**	$ 308	$ 1,320
Earnings Per Share of Common Stock:			
Basic	**$ 0.17**	$ 0.04	$ 0.13
Diluted	**$ 0.17**	$ 0.04	$ 0.13

Our results for the third quarter of 2010 included approximately $2.4 million of operating income and $1.1 million of net income reported by FPU. Included in the operating income and net income reported by FPU for the period were the effects of transferring propane distribution customers previously served by Chesapeake in Florida to FPU after the merger in an effort to integrate operations and approximately two months of operations from Indiantown Gas Company, whose operating assets were purchased by FPU on August 9, 2010. Pursuant to the acquisition method of accounting, we consolidated FPU s results into our consolidated results from October 28, 2009, which is the effective date of the merger. Therefore, our consolidated results for the third quarter of 2009 did not include any results from FPU.

During the third quarter of 2010, we expensed approximately $68,000 ($41,000 net of tax) of merger-related costs, which are included in the Other segment. Merger-related costs expensed in the third quarter of 2010 primarily reflected our costs to integrate operations of Chesapeake and FPU, including certain termination benefits offered to employees, net of the portion we expect to recover through future rates when we complete the appropriate rate proceedings. During the third quarter of 2009, we reported a net credit of $675,000 ($223,000 net of tax) of merger-related costs as we deferred certain previously expensed merger-related costs, which we will seek to recover through future rates.

The following table illustrates the effect of the merger on our results in the third quarter of 2010 and provides the comparable results for the same period in 2009.

	2010			
For the Three Months Ended September 30,	**Chesapeake, excluding FPU**	**FPU**	**Chesapeake Total**	**2009**
(in thousands)				
Operating Income (Loss)				
Regulated Energy	**$ 3,512**	**$ 3,024**	**$ 6,536**	$ 2,971
Unregulated Energy	**(1,632)**	**(605)**	**(2,237)**	(1,361)
Other	**284**		**284**	647
Operating Income	**2,164**	**2,419**	**4,583**	2,257
Other Income (Loss), net of expenses	**56**	**46**	**102**	(26)
Interest Charges	**1,566**	**690**	**2,256**	1,540
Income Taxes	**98**	**703**	**801**	383
Net Income	**$ 556**	**$ 1,072**	**$ 1,628**	$ 308
Excluding effect of transaction-related costs:				
Net Income	**$ 556**	**$ 1,072**	**$ 1,628**	$ 308
Transaction-related costs	**68**		**68**	(675)
Income tax impact	**(27)**		**(27)**	452
Net Income, excluding transaction-related costs	**$ 597**	**$ 1,072**	**$ 1,669**	$ 85

Key Factors Affecting Our Businesses

The following is a summary of key factors affecting our businesses and their impacts on our results in the third quarter of 2010. More detailed analysis is provided in the following section of our results by segment.

Merger. FPU added $2.4 million of operating income to our consolidated results in the third quarter of 2010. FPU s operating results by business for the quarter ended September 30, 2010 are presented below.

For the Three Months Ended September 30, 2010	Regulated Energy Natural Gas	Regulated Energy Electric	Unregulated Energy Propane	Unregulated Energy Other	Total
(in thousands)					
Revenue	$ 11,457	$ 26,331	$ 3,066	$ 509	$ 41,363
Cost of sales	4,376	21,397	1,548	332	27,653
Gross margin	7,081	4,934	1,518	177	13,710
Other operating expenses	5,726	3,265	2,201	99	11,291
Operating Income (Loss)	$ 1,355	$ 1,669	$ (683)	$ 78	$ 2,419
Average number of residential customers	46,731	23,594	12,877		83,202

FPU s operating results in the third quarter of 2010 were positively affected by the 18-percent warmer-than-normal weather (compared to the 10-year average cooling days) in northern Florida, which increased the demand for electricity.

Weather. The weather on the Delmarva Peninsula typically does not have a significant impact on our operating results in the third quarter because of the small number of heating degree-days in the summer. Temperatures on the Delmarva Peninsula during the third quarter of 2010 were warmer than the same period in 2009 and the normal (10-year average) temperatures for the period (30 and 10 fewer heating degree-days, respectively). The warmer weather on the Delmarva Peninsula reduced gross margin by approximately $185,000 in the third quarter of 2010 compared to the same period in 2009. As our residential natural gas rates in Maryland are normalized for weather, our residential natural gas margin in Maryland is not affected by the weather.

Growth. The average number of Delmarva natural gas residential customers increased by two percent in the third quarter of 2010, compared to the same period in 2009. This growth and an increase in commercial and industrial customers contributed approximately $138,000 in period-over-period additional gross margin. This additional gross margin for the quarter includes $24,000 generated from service to a new industrial customer in southern Delaware, which began in the third quarter of 2010. Additionally, service to another industrial customer is expected to begin in late 2010 or early 2011. Services to these new industrial customers in southern Delaware are expected to add annual margin equivalent to 1,575 average residential heating customers.

New transportation services and new expansion facilities placed in service in late 2009 and during 2010 by our natural gas transmission subsidiary, ESNG, contributed an additional gross margin of $390,000 in the third quarter of 2010 compared to the same period in 2009. Also during the current quarterly period, but not affecting results for the period, ESNG received the approval from the FERC to begin construction of an eight-mile mainline extension to interconnect ESNG s system with TETLP s mainline facilities. ESNG has executed Precedent Agreements with our Delaware and Maryland divisions that will result in 17-year firm transportation services associated with this project. The Precedent Agreements provide a three-year phase-in of service from 20,000 Dts per day in the first year to 40,000 Dts per year by the third year of the service at ESNG s current tariff rate for service in that area. Estimated annualized margin from this project is $2.2 million based on 20,000 Dts per day and $4.3 million based on 40,000 Dts per day. ESNG expects to complete construction in December 2010 and commence service no later than January 2011.

Rates and Regulatory Matters. In December 2009, the Florida PSC approved an annual rate increase of approximately $2.5 million, applicable to all meters read on or after January 14, 2010, for Chesapeake s Florida natural gas distribution division. The rate increase contributed an additional gross margin of $554,000 in the third quarter of 2010 compared to the same period in 2009.

FPU s earnings for the current quarter reflect an accrual of $500,000 to reserve for regulatory risk associated with its natural gas distribution operation. We recorded this reserve based on management s assessment of the regulatory risk related to FPU s current earnings and how they may have been affected by various factors, including the benefits, synergies, cost savings and cost increases resulting from the FPU merger. We are required to submit by April 29, 2011 data that details such known benefits, synergies, cost savings and cost increases.

Propane Prices. Lower price volatility and trading volumes in the wholesale propane market resulted in a 13-percent decrease in Xeron s trading volumes during the third quarter of 2010, compared to the same period in 2009, which contributed to a period-over-period gross margin decrease of $328,000.

Advanced Information Services. Our advanced information services subsidiary, BravePoint, generated $258,000 in operating income in the third quarter of 2010, compared to an operating loss of $103,000 reported in the same period of 2009. Increased billable consulting hours in 2010 and higher revenue from its professional database monitoring, support solution services and product sales contributed to the increased period-over-period operating results.

Other Operating Expenses. Our other operating expenses, excluding expenses reported by FPU, increased by $793,000 in the third quarter of 2010, compared to the same period in 2009, as a result of increased compensation expenses and costs associated with increased capital investments.

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Regulated Energy

For the Three Months Ended September 30,	**2010**	2009	Change
(in thousands)			
Revenue	**$ 53,412**	$ 15,372	$ 38,040
Cost of sales	**27,148**	2,345	24,803
Gross margin	**26,264**	13,027	13,237
Operations & maintenance	**13,620**	6,869	6,751
Depreciation & amortization	**4,092**	1,841	2,251
Other taxes	**2,016**	1,346	670
Other operating expenses	**19,728**	10,056	9,672
Operating Income	**$ 6,536**	$ 2,971	$ 3,565
Statistical Data Delmarva Peninsula			
Heating degree-days (HDD):			
Actual	**50**	80	(30)
10-year average (normal)	**60**	58	2
Estimated gross margin per HDD	**$ 2,429**	$ 1,937	$ 492
Per residential customer added:			
Estimated gross margin	**$ 375**	$ 375	$
Estimated other operating expenses	**$ 105**	$ 103	$ 2
Florida			
HDD:			
Actual			
10-year average (normal)			
Cooling degree-days:			
Actual	**1,654**	1,425	229
10-year average (normal)	**1,405**	1,466	(61)
Residential Customer Information			
Average number of customers [1]:			
Delmarva	**46,908**	45,871	1,037
Florida Chesapeake	**13,388**	13,059	329
Total	**60,296**	58,930	1,366

(1) Average number of residential customers for

FPU are included in the discussions of FPU s results on page 34.

Operating income for the regulated energy segment increased by approximately $3.6 million, or 120 percent, in the third quarter of 2010, compared to the same period in 2009, which was generated from a gross margin increase of $13.2 million offset partially by an increase in operating expenses of $9.6 million.

Gross Margin

Gross margin for our regulated energy segment increased by $13.2 million, or 102 percent, in the third quarter of 2010 compared to the same period in 2009.

The Delmarva natural gas distribution operation generated an increase in gross margin of $175,000 in the third quarter of 2010 compared to the same period in 2009. A two-percent growth in residential customers and an increase in commercial and industrial customers generated $94,000 and $44,000, respectively, in additional gross margin for the quarter. The remaining gross margin change was attributable primarily to changes in negotiated rates and rate classifications, offset partially by a decrease due to warmer weather on the Delmarva Peninsula.

Our Florida natural gas distribution operation generated an increase in gross margin of $7.7 million in the third quarter of 2010 compared to the same period in 2009. Inclusion of FPU s natural gas distribution operation in our results provided $7.1 million of gross margin, which includes $49,000 of gross margin generated by Indiantown Gas Company, whose operating assets were purchased by FPU on August 9, 2010, which added approximately 700 customers including two large industrial customers in Indiantown, Florida. Also included in gross margin from FPU s natural gas distribution operation is the impact of the $500,000 reserve for regulatory risk previously described. In addition, Chesapeake s Florida division experienced a period-over-period gross margin increase of $662,000, primarily as a result of a $2.5 million annual rate increase approved by the Florida PSC in December 2009 (effective in January 2010).

The natural gas transmission operations achieved gross margin growth of $386,000 in the third quarter of 2010 compared to the same period in 2009. The factors contributing to this increase were as follows:

- New transportation services implemented by ESNG in November 2009 as a result of the completion of its latest expansion program, provided an additional 6,957 Mcfs per day and added $254,000 to gross margin during the third quarter. In addition, a new expansion project, which was completed in May 2010, provided an additional 1,120 Mcfs of service per day, adding $60,000 to gross margin during the third quarter. The new expansion project completed in May 2010 is expected to provide annualized gross margin of $343,000.
- New firm transportation service for an industrial customer for the period from November 2009 to October 2012 provided an additional 2,705 Mcfs per day and added $76,000 to gross margin in the third quarter of 2010.
- Warm temperatures on the Delmarva Peninsula during the third quarter resulted in increased volumes delivered to two electric generation customers, increasing gross margin by $105,000.
- Offsetting the foregoing increases to gross margin, ESNG received notices from two customers of their intentions not to renew their firm transportation service contracts, which expired in November 2009 and April 2010, decreasing gross margin by $97,000 in the third quarter of 2010. Also, a decline in firm deliveries decreased gross margin by $14,000.

Our Florida electric distribution operation, which was acquired in the FPU merger, generated gross margin of $4.9 million in the third quarter of 2010.

Other Operating Expenses

Other operating expenses for the regulated energy segment increased by $9.6 million, or 96 percent, in the third quarter of 2010 compared to the same period in 2009. Other operating expenses of FPU s regulated energy segment during the period were $9.0 million.

Other Developments

The following developments, which are not discussed above, may affect the future operating results of the regulated energy segment:

- In the first half of 2010, we announced two agreements to provide natural gas service to two industrial customers in southern Delaware. The anticipated annual margin from these services equates to approximately 1,575 average residential heating customers. We commenced service to one of the industrial customers in the third quarter of 2010, adding $24,000 to gross margin. Service to the other industrial customer is expected to commence in late 2010 or early 2011. These services further extend our natural gas distribution and transmission infrastructures to serve other potential customers in the same area.

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On April 8, 2010, we entered into a Precedent Agreement with TETLP to secure firm transportation service from TETLP in conjunction with its new expansion project. 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 30,000 and 10,000 Dts/d, respectively, to be effective on the service commencement date of the project, currently projected to occur in November 2012. As a result of this new service, our Delaware and Maryland divisions will have access to new supplies of natural gas, providing increased reliability and diversity of supply. This will also provide them additional upstream transportation capacity, which is essential to meet their current customer demands and to plan for sustainable growth. In conjunction with this project, ESNG will build and operate an eight-mile mainline extension from TETLP s pipeline to ESNG s existing facility to provide transportation services for the Delaware and Maryland divisions at ESNG s current tariff rate for service in that area. ESNG s transportation service is expected to provide a three-year phase-in from 20,000 Dts per day to 40,000 Dts per day, providing estimated annualized margin of $2.2 million (at 20,000 Dts per day) to $4.3 million (at 40,000 Dts per day). This service is expected to begin no later than January 2011.

Unregulated Energy

For the Three Months Ended September 30,		**2010**		**2009**		**Change**
(in thousands)						
Revenue	**$**	**20,134**	$	14,011	$	6,123
Cost of sales		**15,714**		10,711		5,003
Gross margin		**4,420**		3,300		1,120
Operations & maintenance		**5,435**		3,920		1,515
Depreciation & amortization		**896**		521		375
Other taxes		**326**		220		106
Other operating expenses		**6,657**		4,661		1,996
Operating Loss	**$**	**(2,237)**	$	(1,361)	$	(876)
Statistical Data Delmarva Peninsula						
Heating degree-days (HDD):						
Actual		**50**		80		(30)
10-year average (normal)		**60**		58		2
Estimated gross margin per HDD	**$**	**3,083**	$	2,465	$	618

Operating loss for the unregulated energy segment increased by approximately $876,000 in the third quarter of 2010, compared to the same period in 2009, which was attributable to an operating expense increase of $2.0 million, partially offset by a gross margin increase of $1.1 million.

Gross Margin

Gross margin for our unregulated energy segment increased by $1.1 million, or 34 percent, in the third quarter of 2010, compared to the same period in 2009.

Our Delmarva propane distribution operation experienced a decrease in gross margin of $77,000 in the third quarter of 2010 compared to the same period in 2009. Retail margins decreased by $138,000, due primarily to the propane physical inventory adjustment in the third quarter of 2009, which reduced the cost of propane inventory by $118,000 in that period. We did not have a comparable physical inventory adjustment in the third quarter of 2010. Partially offsetting the retail margin decrease were increased fees of $36,000, primarily from increased customer participation in various customer loyalty programs and additional gross margins of $15,000 and $30,000 generated from the addition of 455 community gas system customers and 1,000 customers acquired in February 2010 as part of the purchase of the operating assets of a propane distributor serving Northampton and Accomack Counties in Virginia. Our Florida propane distribution operations experienced an increase in gross margin of $1.2 million in the third quarter of 2010 compared to the same period in 2009, due to the inclusion of FPU s propane distribution operations.

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Xeron, our propane wholesale marketing operation, experienced a decrease in gross margin of $328,000 in the third quarter of 2010, compared to the same period in 2009 as a result of decreased trading activity. Lower price volatility and lower trading volumes in the wholesale propane market reduced Xeron s trading activity. Xeron s trading volumes decreased by 13 percent for the quarter compared to the same period in 2009.

PESCO, our natural gas marketing operation, experienced an increase in gross margin of $109,000 in the third quarter of 2010, due primarily to increased spot sales to an electric generator on the Delmarva Peninsula as a result of warmer-than-normal weather in July and August of 2010 and a growth in commercial customers in Florida.

Other Operating Expenses

Total other operating expenses for the unregulated energy segment increased by $2.0 million in the third quarter of 2010, due primarily to the increase of $1.9 million associated with the inclusion of FPU s propane distribution and other unregulated energy operations. Other operating expenses for FPU s propane distribution operation in the third quarter of 2010 include the accrual of $278,000 in September 2010 for a litigation reserve related to the settlement of a class action complaint (see Note 6, Other Commitments and Contingencies, of the condensed consolidated financial statements).

Other

For the Three Months Ended September 30,	**2010**	**2009**	**Change**
(in thousands)			
Revenue	**$ 2,920**	$ 2,375	$ 545
Cost of sales	**1,524**	1,360	164
Gross margin	**1,396**	1,015	381
Operations & maintenance	**837**	812	25
Transaction-related costs	**68**	(675)	743
Depreciation & amortization	**70**	75	(5)
Other taxes	**137**	156	(19)
Other operating expenses	**1,112**	368	744
Operating Income	**$ 284**	$ 647	$ (363)

Operating income for the Other segment decreased by approximately $363,000 in the third quarter of 2010, compared to the same period in 2009, which was attributable to an operating expense increase of $744,000, partially offset by a gross margin increase of $381,000.

Gross margin

The period-over-period gross margin increase of $381,000 for our Other segment was primarily a result of an increase in consulting revenues by the advanced information services operation as the number of billable consulting hours increased by eight percent. Increased revenue from its professional database monitoring, support solution services and product sales also contributed to this increase.

Operating expenses

Other operating expenses increased by $744,000 in the third quarter of 2010, compared to the same period in 2009, due primarily to the inclusion in this Other segment of the merger-related costs, which we incurred to consummate the merger with FPU and integrate operations of Chesapeake and FPU, including certain termination benefits offered to employees, net of the portion we expect to recover through future rates when we complete the appropriate rate proceedings. During the third quarter of 2009, we deferred certain previously expensed merger-related costs, which we will seek to recover through future rates.

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Interest Expense

Our total interest expense for the third quarter of 2010 increased by approximately $716,000, or 47 percent, compared to the same period in 2009. The primary drivers of the increased interest expense are related to FPU, including:

- An increase in long-term interest expense of $456,000 is related to interest on FPU s first mortgage bonds.
- Interest expense from a new term loan facility during the third quarter of 2010 was $140,000. Two series of FPU bonds, the 4.9 percent and 6.85 percent series, were redeemed by using this new short-term term loan facility at the end of January 2010.
- Additional interest expense of $184,000 is related to interest on deposits from FPU s customers.

Offsetting the increased interest expense from FPU was lower non-FPU-related interest expense from Chesapeake s unsecured senior notes, as the principal balances decreased from scheduled payments, and lower additional short-term borrowings during the quarter as a result of the timing of our capital expenditures and the increased cash flow generated from ordinary operating activities.

Income Taxes

We recorded an income tax expense of $801,000 for the quarter ended September 30, 2010, compared to $383,000 for the quarter ended September 30, 2009. Included in the income tax expense for the quarter ended September 30, 2009 was the tax effect of the merger-related costs, a portion of which were non-deductible for income tax purposes. Excluding the tax effect of the merger-related costs in 2009, we would have had an income tax benefit of $69,000 for the quarter ended September 30, 2009. All of the merger-related costs in 2010 are tax-deductible. The period-over-period increase in income tax expense is primarily a function of higher earnings for the period.

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Results of Operations for the Nine Months Ended September 30, 2010

Overview and Highlights

Our net income for the nine months ended September 30, 2010 was $18.9 million, or $1.98 per share (diluted). This represents an increase of $9.2 million, or $0.58 per share (diluted), compared to a net income of $9.7 million, or $1.40 per share (diluted), as reported in the same period in 2009.

For the Nine Months Ended September 30,	**2010**	**2009**	**Change**
(in thousands)			
Operating Income (Loss)			
Regulated Energy	**$ 32,360**	$ 16,554	$ 15,806
Unregulated Energy	**4,732**	5,233	(501)
Other	**650**	(709)	1,359
Operating Income	**37,742**	21,078	16,664
Other Income, net of expenses	**206**	19	187
Interest Charges	**6,924**	4,755	2,169
Income Taxes	**12,082**	6,636	5,446
Net Income	**$ 18,942**	$ 9,706	$ 9,236
Earnings Per Share of Common Stock:			
Basic	**$ 2.00**	$ 1.41	$ 0.59
Diluted	**$ 1.98**	$ 1.40	$ 0.58

Our results for the nine months ended September 30, 2010 included approximately $14.1 million of operating income and $7.3 million of net income reported by FPU, which included the effects of transferring propane distribution customers previously served by Chesapeake in Florida to FPU after the merger in an effort to integrate operations, and approximately two months of operations from Indiantown Gas Company, whose operating assets were purchased by FPU on August 9, 2010. Pursuant to the acquisition method of accounting, we consolidated FPU s results into our consolidated results from October 28, 2009, which is the effective date of the merger. Therefore, our consolidated results for the nine months ended September 30, 2009 did not include any results from FPU.

During the nine months ended September 30, 2010 and 2009, we expensed approximately $179,000 ($107,000 net of tax) and $530,000 ($500,000 net of tax), respectively, of merger-related costs, which are included in the Other segment. Merger-related costs expensed in the nine months ended September 30, 2010 primarily reflected our costs to integrate operations of Chesapeake and FPU, including certain termination benefits offered to employees, net of the portion we expect to recover through future rates when we complete the appropriate rate proceedings. Merger-related costs expensed in the nine months ended September 30, 2009 included our costs to consummate the merger, net of the portion we expect to recover through future rates.

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The following table illustrates the effect of the merger on our results in the nine months ended September 30, 2010 and provides the comparable results for the same period in 2009.

	2010			
For the Nine Months Ended September 30,	**Chesapeake, excluding FPU**	**FPU**	**Chesapeake Total**	**2009**
(in thousands)				
Operating Income (Loss)				
Regulated Energy	**$ 19,417**	**$ 12,943**	**$ 32,360**	$ 16,554
Unregulated Energy	**3,527**	**1,205**	**4,732**	5,233
Other	**650**		**650**	(709)
Operating Income	**23,594**	**14,148**	**37,742**	21,078
Other Income, net of expenses	**$ 69**	**$ 137**	**$ 206**	$ 19
Interest Charges	**4,488**	**2,436**	**6,924**	4,755
Income Taxes	**7,530**	**4,552**	**12,082**	6,636
Net Income	**$ 11,645**	**$ 7,297**	**$ 18,942**	$ 9,706
Excluding effect of transaction-related costs:				
Net Income	**$ 11,645**	**$ 7,297**	**$ 18,942**	$ 9,706
Transaction-related costs	**179**		**179**	530
Income tax impact	**(72)**		**(72)**	(30)
Net Income, excluding transaction-related costs	**$ 11,752**	**$ 7,297**	**$ 19,049**	$ 10,206

Key Factors Affecting Our Businesses

The following is a summary of key factors affecting our businesses and their impacts on our results in the nine months ended September 30, 2010. More detailed analysis is provided in the following section of our results by segment.

Merger. FPU added $14.1 million of operating income to our consolidated results in the nine months ended September 30, 2010. FPU s operating results by business for the nine months ended September 30, 2010 are presented below.

	Regulated Energy		Unregulated Energy		
For the Nine Months Ended September 30, 2010	**Natural Gas**	**Electric**	**Propane**	**Other**	**Total**
(in thousands)					
Revenue	$ 48,086	$ 72,492	$ 13,130	$ 1,694	$ 135,402
Cost of sales	20,830	58,467	6,393	1,039	86,729
Gross margin	27,256	14,025	6,737	655	48,673
Other operating expenses	18,230	10,108	5,866	321	34,525
Operating Income	$ 9,026	$ 3,917	$ 871	$ 334	$ 14,148

Average number of residential customers	46,970	23,570	12,786	83,326

FPU s operating results during the nine months ended September 30, 2010 were positively affected by the 61-percent colder weather in the winter months based on the number of the heating degree-days (compared to the 10-year average) and 14-percent warmer weather in the summer months based on the number of the cooling degree-days (compared to the 10-year average). Also positively affecting the operating results was the impact of FPU s natural gas annual rate increase of $8.0 million approved by the Florida PSC in 2009, which increased gross margin by $3.6 million during the first nine months of 2010.

Weather. Temperatures on the Delmarva Peninsula during the nine months ended September 30, 2010 were one-percent colder than the same period in 2009 and three-percent colder than normal (10-year average) for the period. The slightly colder weather on the Delmarva Peninsula increased gross margin by approximately $274,000 in the nine months ended September 30, 2010 compared to the same period in 2009. As our residential rates in Maryland are normalized for weather, our residential margin in Maryland is not affected by the weather. Temperatures in Florida during the nine months ended September 30, 2010 were 53-percent colder than the same period in 2009 and 60-percent colder than normal (10-year average), which increased gross margin of Chesapeake s Florida natural gas distribution division by $245,000 in the nine months ended September 30, 2010 compared to the same period in 2009.

Growth. The average number of Delmarva natural gas residential customers increased by two percent in the nine months ended September 30, 2010, compared to the same period in 2009. This growth and an increase in commercial and industrial customers contributed approximately $798,000 in period-over-period additional gross margin. This additional gross margin for the quarter includes $24,000 generated from service to a new industrial customer in southern Delaware, which began in the third quarter of 2010. Additionally, service to another industrial customer is expected to begin in late 2010 or early 2011. Services to these new industrial customers in southern Delaware are expected to add annual margin equivalent to 1,575 average residential heating customers.

New transportation services and new expansion facilities placed in service in late 2009 and during 2010 by our natural gas transmission subsidiary, ESNG, contributed an additional gross margin of $1.2 million in the nine months ended September 30, 2010 compared to the same period in 2009. Also during the third quarter of 2010, but not affecting results for the current period, ESNG received the approval from the FERC to begin construction of an eight-mile mainline extension to interconnect ESNG s system with TETLP s mainline facilities. ESNG has executed Precedent Agreements with our Delaware and Maryland divisions that will result in 17-year firm transportation services associated with this project. The Precedent Agreements provide a three-year phase-in of service from 20,000 Dts per day in the first year to 40,000 Dts per year by the third year of the service at ESNG s current tariff rate for service in that area. Estimated annualized margin from this project is $2.2 million based on 20,000 Dts per day and $4.3 million based on 40,000 Dts per day. ESNG expects to complete construction in December 2010 and commence service no later than January 2011.

Rates and Regulatory Matters. In December 2009, the Florida PSC approved an annual rate increase of approximately $2.5 million, applicable to all meters read on or after January 14, 2010, for Chesapeake s Florida natural gas distribution division. The rate increase contributed an additional gross margin of $1.7 million in the nine months ended September 30, 2010 compared to the same period in 2009. The operating results of FPU s natural gas distribution operation for the first nine months of 2010 also reflect an increase of $3.6 million in gross margin from its annual rate increase of approximately $8.0 million approved by the Florida PSC in 2009.

FPU s earnings for the current nine-month period reflect an accrual of $500,000 to reserve for regulatory risk associated with its natural gas distribution operation. We recorded this reserve based on management s assessment of the regulatory risk related to FPU s current earnings and how they may have been affected by various factors, including the benefits, synergies, cost savings and cost increases resulting from the FPU merger. We are required to submit by April 29, 2011 data that details such known benefits, synergies, cost savings and cost increases.

Propane Prices. During the first half of 2009, our Delmarva propane distribution operation experienced higher retail margins, which were benefited from the $939,000 loss recorded in late 2008 on a swap agreement for the 2008/2009 winter Pro-Cap (Propane Price Cap) program. This loss lowered the propane inventory costs and, therefore, increased retail margins during the first half of 2009. During the first nine months of 2010, the retail margins returned to more normal levels, resulting in a lower retail margin per gallon and, therefore, decreasing gross margin of the Delmarva propane distribution operation by $1.0 million. Lower volatility in wholesale propane prices and lower trading volumes in the wholesale propane market during the second and third quarters of 2010 reduced Xeron s trading volume by 14 percent in the nine months ended September 30, 2010, which resulted in a gross margin decrease of $149,000.

Natural Gas Spot Sale Opportunities. During the first nine months of 2009, our unregulated natural gas marketing subsidiary, PESCO, benefited from increased spot sales on the Delmarva Peninsula. PESCO executed fewer spot sales in the first nine months of 2010, largely due to reduced sales to one industrial customer. These decreased spot sales resulted in a decrease in gross margin of $579,000 in the nine months ended September 30, 2010 compared to the same period in 2009. Spot sales are not predictable, and, therefore, are not included in our long-term financial plans or forecasts.

Advanced Information Services. Our advanced information services subsidiary, BravePoint, generated $523,000 in operating income in the first nine months of 2010, compared to an operating loss of $448,000 reported in the same period of 2009. Increased billable consulting hours in 2010 and cost containment actions implemented throughout 2009 contributed to the increased period-over-period operating results.

Other Operating Expenses. Our other operating expenses, excluding FPU s expenses, increased by $836,000 in the nine months ended September 30, 2010 compared to the same period in 2009. Increased compensation expenses and higher costs associated with increased capital investments were partially offset by lower expenses related to collections and allowance for doubtful accounts receivable and cost containment actions implemented throughout 2009 for the advanced information services business.

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Regulated Energy

For the Nine Months Ended September 30,	**2010**	**2009**	**Change**
(in thousands)			
Revenue	**$ 197,779**	$ 86,422	$ 111,357
Cost of sales	**105,322**	39,143	66,179
Gross margin	**92,457**	47,279	45,178
Operations & maintenance	**40,951**	21,144	19,807
Depreciation & amortization	**12,843**	5,453	7,390
Other taxes	**6,303**	4,128	2,175
Other operating expenses	**60,097**	30,725	29,372
Operating Income	**$ 32,360**	$ 16,554	$ 15,806
Statistical Data Delmarva Peninsula			
Heating degree-days (HDD):			
Actual	**3,021**	3,003	18
10-year average (normal)	**2,923**	2,889	34
Estimated gross margin per HDD	**$ 2,429**	$ 1,937	$ 492
Per residential customer added:			
Estimated gross margin	**$ 375**	$ 375	$
Estimated other operating expenses	**$ 103**	$ 103	$
Florida			
HDD			
Actual	**942**	614	328
10-year average (normal)	**587**	547	40
Cooling degree-days:			
Actual	**2,693**	2,434	259
10-year average (normal)	**2,365**	2,418	(53)
Residential Customer Information			
Average number of customers [(1)]:			
Delmarva	**47,508**	46,669	839
Florida Chesapeake	**13,423**	13,291	132
Total	**60,931**	59,960	971

(1) Heating degree-days and average number

of residential customers for FPU are included in the discussions of FPU s results on page 42.

Operating income for the regulated energy segment increased by approximately $15.8 million, or 95 percent, in the first nine months of 2010, compared to the same period in 2009, which was generated from a gross margin increase of $45.2 million, offset partially by an operating expense increase of $29.4 million.

Gross Margin

Gross margin for our regulated energy segment increased by $45.2 million, or 96 percent in the first nine months of 2010 compared to the same period in 2009.

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The natural gas distribution operations for the Delmarva Peninsula generated an increase in gross margin of $811,000 during the period. The factors contributing to this increase are as follows:

The Delmarva natural gas distribution operations experienced growth in residential, commercial and industrial customers, which contributed $798,000 to the gross margin increase. Residential, commercial and industrial growth by our Delaware division contributed $418,000, $145,000 and $137,000, respectively, to the gross margin increase, and the customer growth by our Maryland division contributed $98,000 to the gross margin increase in Maryland. We experienced a two-percent increase in average residential customers in the Delmarva natural gas distribution operation.

Colder weather on the Delmarva Peninsula generated an additional $219,000 to the gross margin as heating degree-days increased by one percent for the first nine months of 2010 compared to the same period in 2009. Residential heating rates for our Maryland division are weather-normalized, and we typically do not experience an impact on gross margin from the weather for our residential customers in Maryland.

A decline in non-weather-related customer consumption, primarily by residential customers of our Delaware division, decreased gross margin by $310,000.

The remaining gross margin change is due primarily to changes in negotiated rates for a commercial customer in Delaware and two industrial customers in Maryland, which increased gross margin by $241,000 for the first nine months of 2010. These increases were offset by a change in rate classifications for certain residential customers in Delaware, which decreased gross margin by $190,000 during the period.

Our Florida natural gas distribution operation experienced an increase in gross margin of $29.4 million for the first nine months of 2010 compared to the same period in 2009. The factors contributing to this increase are as follows:

FPU s natural gas distribution operation contributed $27.3 million in gross margin in the nine months ended September 30, 2010, which includes $49,000 of gross margin generated by Indiantown Gas Company, whose operating assets were purchased by FPU on August 9, 2010. Gross margin from FPU s natural gas distribution operation in the first half of 2010 was positively affected by an annual rate increase of approximately $8.0 million approved by the Florida PSC on December 15, 2009, and colder temperatures during the first quarter of 2010.

Included in gross margin from FPU s natural gas distribution operation is the impact of the $500,000 reserve for its regulatory risk previously described.

Chesapeake s Florida division also experienced an increase in gross margin of $1.7 million from an annual rate increase of approximately $2.5 million approved by the Florida PSC on December 15, 2009 (applicable to all meters read on or after January 14, 2010).

During the first nine months of 2010, Chesapeake s Florida division experienced an increase in customer consumption, which was heavily affected by the colder temperatures in Florida during the first quarter of 2010. We estimate that the colder temperatures contributed an additional $245,000 to gross margin in the first nine months of 2010 compared to the same period in 2009.

The natural gas transmission operations achieved gross margin growth of $949,000 during the first nine months of 2010 compared to the same period in 2009. The factors contributing to this increase are as follows:

New transportation services, implemented by ESNG in November 2009 as a result of the completion of its latest expansion program, provided an additional 6,957 Mcfs per day and added $762,000 to gross margin during the first nine months in 2010. In addition, a new expansion project, which was completed in May 2010, provided an additional 1,120 Mcfs of service per day, adding $101,000 to gross margin during the nine months ended September 30, 2010. The new expansion project completed in May 2010 is expected to provide an annualized gross margin of $343,000.

New firm transportation service for an industrial customer for the period from November 2009 to October 2012 provided an additional 9,662 Mcfs per day for the period January 1, 2010 through February 5, 2010, and an additional 2,705 Mcfs per day for the period February 6, 2010 through September 30, 2010. These new services added $304,000 to gross margin for the first nine months of 2010. During the second quarter of 2009, the same customer temporarily increased the service, which further increased ESNG s gross margin by $61,000. This temporary increase in service did not occur in 2010.

Offsetting the foregoing increases to gross margin, ESNG received notices from two customers of their intentions not to renew their firm transportation service contracts, which expired in November 2009 and April 2010, decreasing gross margin by $284,000 for the first nine months of 2010. A change in certain customer rates offset these decreases.

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Our Florida electric distribution operation, which was acquired in the FPU merger, generated gross margin of $14.0 million in the nine months ended September 30, 2010.

Other Operating Expenses

Other operating expenses for the regulated energy segment increased by $29.4 million, or 96 percent, in the first nine months of 2010, compared to the same period in 2009, $28.3 million of which was related to other operating expenses of FPU s regulated energy segment during the period.

Other Developments

The following developments, which are not discussed above, may affect the future operating results of the regulated energy segment:

In the first half of 2010, we announced two agreements to provide natural gas service to two industrial customers in southern Delaware. The anticipated annual margin from these services equates to approximately 1,575 average residential heating customers. We commenced service to one of the industrial customers in the third quarter of 2010, adding $24,000 to gross margin. Service to the other industrial customer is expected to commence in late 2010 or early 2011. These services further extend our natural gas distribution and transmission infrastructures to serve other potential customers in the same area.

On April 8, 2010, we entered into a Precedent Agreement with TETLP to secure firm transportation service from TETLP in conjunction with its new expansion project. 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 30,000 and 10,000 Dts/d, respectively, to be effective on the service commencement date of the project, currently projected to occur in November 2012. As a result of this new service, our Delaware and Maryland divisions will have access to new supplies of natural gas, providing increased reliability and diversity of supply. This will also provide them additional upstream transportation capacity, which is essential to meet their current customer demands and to plan for sustainable growth. In conjunction with this project, ESNG will build and operate an eight-mile mainline extension from TETLP s pipeline to ESNG s existing facility to provide transportation services for the Delaware and Maryland divisions at ESNG s current tariff rate for service in that area. ESNG s transportation service is expected to provide a three-year phase-in from 20,000 Dts per day to 40,000 Dts per day, providing estimated annualized margin of $2.2 million (at 20,000 Dts per day) to $4.3 million (at 40,000 Dts per day). This service is expected to begin no later than January 2011.

Unregulated Energy

For the Nine Months Ended September 30,	**2010**	**2009**	**Change**
(in thousands)			
Revenue	**$ 104,018**	$ 83,236	$ 20,782
Cost of sales	**78,740**	62,943	15,797
Gross margin	**25,278**	20,293	4,985
Operations & maintenance	**16,792**	12,788	4,004
Depreciation & amortization	**2,660**	1,552	1,108
Other taxes	**1,094**	720	374
Other operating expenses	**20,546**	15,060	5,486
Operating Income	**$ 4,732**	$ 5,233	$ (501)
Statistical Data Delmarva Peninsula			
Heating degree-days (HDD):			
Actual	**3,021**	3,003	18

10-year average (normal)		**2,923**		2,889		34
Estimated gross margin per HDD	**$**	**3,083**	$	2,465	$	618

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Operating income for the unregulated energy segment decreased by $501,000 in the nine months ended September 30, 2010, compared to the same period in 2009, which was attributable to an operating expense increase of $5.5 million, partially offset by a gross margin increase of $5.0 million.

Gross Margin

Gross margin for our unregulated energy segment increased by $5.0 million, or 25 percent, in the first nine months of 2010, compared to the same period in 2009.

Our Delmarva propane distribution operation experienced a decrease in gross margin of $641,000, as a result of the following factors:

A lower margin per gallon during the first nine months of 2010 compared to the same period in 2009 decreased gross margin by $1.0 million. Retail margins for the first half of 2009 benefited from the $939,000 loss recorded in late 2008 on a swap agreement for the 2008/2009 winter Pro-Cap (Propane Price Cap) program. This loss lowered the propane inventory costs and, therefore, increased retail margins during the first half of 2009. Retail margins for the first half of 2010 returned to more normal levels.

Non-weather-related volumes sold increased in the first nine months of 2010, compared to the same period in 2009, adding $143,000 to gross margin. The addition of 433 community gas system customers and 1,000 other customers acquired in February 2010 as part of the purchase of the operating assets of a propane distributor serving Northampton and Accomack Counties in Virginia contributed $141,000 and $114,000, respectively, to this increase.

The remaining change was primarily related to an increase in other fees of $165,000, as a result of increased customer participation in various customer loyalty programs, and the impact of the colder weather of $55,000.

Our Florida propane distribution operations experienced an increase in gross margin of $5.7 million due to inclusion of FPU s propane distribution operations.

Xeron, our propane wholesale marketing operation, experienced a decrease in gross margin of $149,000 during the first nine months of 2010 compared to the same period in 2009. Xeron s trading volumes decreased by 14 percent in the nine months ended September 30, 2010 compared to the same period in 2009, as lower price volatility and lower trading volumes in the wholesale propane market reduced Xeron s trading activity, particularly during the second and third quarters. Lower margins from the decreased trading volume were partially offset by increased margins from larger propane price fluctuations in early 2010.

During the first nine months of 2009, our unregulated natural gas marketing subsidiary, PESCO, benefited from increased spot sales on the Delmarva Peninsula. Although PESCO continued to identify spot sale opportunities on the Delmarva Peninsula during the first nine months of 2010, spot sales decreased, due primarily to one industrial customer, resulting in a decrease in gross margin of $579,000 in the first nine months of 2010 compared to the same period in 2009. Spot sales are not predictable and, therefore, are not included in our long-term financial plans or forecasts.

Other Operating Expenses

Total other operating expenses for the unregulated energy segment increased by $5.5 million for the nine months ended September 30, 2010, compared to the same period in 2009, due primarily to the increase of $5.3 million associated with the inclusion of FPU s propane distribution and other unregulated energy operations. Other operating expenses for FPU s propane distribution operation in the first nine months of 2010 include the accrual of $278,000 in September 2010 for a litigation reserve related to the settlement of a class action complaint (see Note 6, Other Commitments and Contingencies, of the condensed consolidated financial statements).

Other

For the Nine Months Ended September 30,	2010	2009	Change
(in thousands)			
Revenue	**$ 7,990**	$ 7,413	$ 577
Cost of sales	**3,973**	4,019	(46)
Gross margin	**4,017**	3,394	623
Operations & maintenance	**2,493**	2,820	(327)
Transaction-related costs	**179**	530	(351)
Depreciation & amortization	**216**	230	(14)
Other taxes	**479**	523	(44)
Other operating expenses	**3,367**	4,103	(736)
Operating Income (Loss)	**$ 650**	$ (709)	$ 1,359

Operating income for the Other segment increased by approximately $1.4 million in the first nine months of 2010, compared to the same period in 2009, which was attributable to a gross margin increase of $623,000 and an operating expense decrease of $736,000. Increased operating income from our advanced information services operation of $971,000 and decreased merger-related transaction costs of $351,000 contributed to the operating income increase.

Gross margin

The period-over-period increase in gross margin of $623,000 for our Other segment was contributed by our advanced information services operation s increase in revenue and gross margin from its professional database monitoring and support solution services and higher consulting revenues as a result of a nine-percent increase in the number of billable consulting hours for the first nine months of 2010 compared to the same period in 2009.

Operating expenses

Other operating expenses decreased by $736,000 in the first nine months of 2010 compared to the same period in 2009. The decrease in operating expenses was attributable primarily to the lower merger-related costs expensed in the first nine months of 2010 compared to the same period in 2009 by $351,000 and cost containment actions, including layoffs and compensation adjustments, implemented by the advanced information services operation in March, September and October 2009.

Interest Expense

Our total interest expense increased by approximately $2.2 million or 46 percent, during the first nine months of 2010, compared to the same period in 2009. The primary drivers of the increased interest expense are related to FPU, including:

- An increase in long-term interest expense of $1.5 million is related to interest on FPU s first mortgage bonds.
- Interest expense from a new term loan credit facility during the first nine months of 2010 was $356,000. Two series of FPU bonds, the 4.9 percent and 6.85 percent series, were redeemed by using this new short-term term loan facility at the end of January 2010.
- Additional interest expense of $553,000 is related to interest on deposits from FPU s customers.

Offsetting the increased interest expense from FPU was lower non-FPU-related interest expense from Chesapeake s unsecured senior notes, as the principal balances decreased from scheduled payments, and lower additional short-term borrowings as a result of the timing of our capital expenditures and the increased cash flow generated from ordinary operating activities.

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Income Taxes

We recorded an income tax expense of $12.1 million for the nine months ended September 30, 2010, compared to $6.6 million for the same period in 2009. The effective income tax rate for the first nine months of 2010 is 38.9 percent, compared to 40.6 percent in the same period in 2009. Included in the income tax expense for the nine months ended September 30, 2009 was the tax effect of the merger-related costs, a portion of which were non-deductible for income tax purposes. Excluding the tax effect of the merger-related costs in 2009, the effective income tax rate for the nine months ended September 30, 2009 would have been 39.5 percent. All of the merger-related costs in 2010 are tax-deductible. The period-over-period decrease in the effective income tax rate is due primarily to higher earnings generated from operations in states with lower income tax rates largely as a result of our expansion in Florida operations through the merger with FPU.

Financial Position, Liquidity and Capital Resources

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

During the first nine months of 2010, net cash provided by operating activities was $55.6 million, cash used in investing activities was $29.8 million, and cash used in financing activities was $25.9 million.

During the first nine months of 2009, net cash provided by operating activities was $47.5 million, cash used in investing activities was $19.7 million, and cash used in financing activities was $28.6 million.

As of September 30, 2010, we had four unsecured bank lines of credit with two financial institutions, for a total of $100.0 million, two of which totaling $60.0 million are available under committed lines of credit. None of the unsecured bank lines of credit requires compensating balances. These bank lines are available 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. We are currently authorized by our Board of Directors to borrow up to $85.0 million of short-term debt, as required, from these short-term lines of credit. Advances offered under the uncommitted lines of credit are subject to the discretion of the banks. In addition to the four unsecured bank lines of credit, we entered into a new credit facility for $29.1 million with an existing lender in March 2010. We borrowed $29.1 million under this new credit facility for a term of nine months to finance the early redemption of two series of FPU s secured first mortgage bonds. The outstanding balance of short-term borrowing at September 30, 2010 and December 31, 2009, was $43.1 and $30.0 million, respectively.

On June 29, 2010, we entered into an agreement with an existing senior note holder to issue up to $36 million in uncollateralized senior notes. We expect to use $29 million of the uncollateralized senior notes to permanently finance the early redemption of the FPU bonds previously discussed. The terms of the agreement require us to issue $29 million of the $36 million in uncollateralized senior notes committed by the lender on or before July 9, 2012, with a 15-year term at a rate ranging from 5.28 percent to 6.13 percent based on the timing of the issuance. The remaining $7 million will be issued prior to May 3, 2013 at a rate ranging from 5.28 percent to 6.43 percent based on the timing of the issuance.

We originally budgeted $53.9 million for capital expenditures during 2010. As a result of continued growth, expansion opportunities and timing of capital projects, we revised our capital spending projection for 2010 to $54.8 million. This amount includes $48.8 million for the regulated energy segment, $3.1 million for the unregulated energy segment and $2.9 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 ($22.8 million); (b) natural gas transmission operation ($22.4 million); and (c) electric distribution operation ($3.6 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 $762,000 for the advanced information services operation, with the remaining balance for other general plant, computer software and hardware. We expect to fund the 2010 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.

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Capital Structure

The following presents our capitalization, excluding short-term borrowing, as of September 30, 2010 and December 31, 2009:

At September 30, 2010, common equity represented 69 percent of total capitalization, excluding short-term borrowing, compared to 68 percent at December 31, 2009. If short-term borrowing and the current portion of long-term debt were included in total capitalization, the equity component of our capitalization would have been 60 percent at September 30, 2010, compared to 56 percent at December 31, 2009.

We remain 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.

Cash Flows Provided By Operating Activities

Cash flows provided by operating activities were as follows:

For the Nine Months Ended September 30,	**2010**	2009
(in thousands)		
Net Income	**$ 18,942**	$ 9,706
Non-cash adjustments to net income	**27,843**	15,087
Changes in assets and liabilities	**8,861**	22,659
Net cash provided by operating activities	**$ 55,646**	$ 47,452

During the nine months ended September 30, 2010 and 2009, net cash flow provided by operating activities was $55.6 million and $47.5 million, respectively, a period-over-period increase of $8.1 million. Significant operating activities reflected in the change in cash flows provided by operating activities are as follows:

Net income increased by $9.2 million. Consolidation of FPU and organic growth of existing Chesapeake businesses contributed to this increase.

Non-cash adjustments to net income increased by $12.8 million due primarily to higher depreciation and amortization, changes in deferred income taxes and changes in unrealized gains/losses on commodity contracts. Higher depreciation and amortization is due to inclusion of FPU and an increase in capital investments. The increase in deferred income taxes is a result of bonus depreciation in 2010, which significantly reduces our income tax payment obligations in 2010.

Net cash flows from income taxes receivable decreased by $13.8 million due to low income tax payments and large refunds received in 2009 as a result of bonus depreciation authorized for 2008 and 2009. Prior to the extension of bonus depreciation to include 2010, we made approximately $8.5 million in income tax payments for 2010. We expect to receive refunds for a significant portion of those payments in late 2010 or early 2011.

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Cash Flows Used in Investing Activities

Net cash flows used in investing activities totaled $29.8 million and $19.7 million during the nine months ended September 30, 2010 and 2009, respectively. Cash utilized for capital expenditures was $27.0 million and $19.7 million for the first nine months of 2010 and 2009, respectively. Additions to property, plant and equipment in the first nine months of 2010 included $7.2 million of FPU s capital expenditures. We also paid $2.3 million during the nine months ended September 30, 2010 to purchase certain assets from a propane distributor and a natural gas distribution company and equity securities during the nine months ended September 30, 2010.

Cash Flows Used by Financing Activities

Cash flows used in financing activities totaled $25.9 million and $28.6 million for the first nine months of 2010 and 2009, respectively. Significant financing activities reflected in the change in cash flows used by financing activities are as follows:

- During the first nine months of 2010 we had a net repayment of $23.1 million under our line of credit agreements related to working capital compared to $23.4 million in the same period in 2009. Changes in cash overdrafts increased by $6.5 million.
- During the first nine months of 2010 we issued $29.1 million in short-term term notes and used the proceeds to finance the redemption, in January 2010, of two series of FPU s secured first mortgage bonds prior to their respective maturities.
- We repaid $31.2 million of long-term debt during the first nine months of 2010, primarily related to early redemption of FPU s long-term debt described above.
- We paid $8.2 million and $5.7 million in cash dividends for the nine months ended September 30, 2010 and 2009, respectively. Dividends paid in the first nine months of 2010 increased as a result of an increase in our annualized dividend rate and in the number of shares outstanding.

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 have 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, 2010 was $23.3 million, with the guarantees expiring on various dates in 2011.

In addition to the corporate guarantees, we have issued a letter of credit to our previous primary insurance company for $725,000, which expires on June 1, 2011. The letter of credit is provided as security to satisfy the deductibles under our various insurance policies. There have been no draws on this letter of credit as of September 30, 2010, and we do not anticipate that this letter of credit will be drawn upon by the counterparty in the future. As a result of the change in our primary insurance company in September 2010, we may be required to provide a separate letter of credit to our new primary insurance company.

We provided a letter of credit for $978,000 under the Precedent Agreement with TETLP. The letter of credit is expected to increase quarterly as TETLP s pre-service costs increases. The letter of credit will not exceed the three-month reservation charge under the firm transportation service contracts, which we currently estimate to be $2.1 million.

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Contractual Obligations

There have not been any material changes in the contractual obligations presented in our 2009 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, 2010.

	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] [3]	$ 27,711	$ 197	$	$	**$ 27,908**
Propane [2]	35,103				**35,103**
Total Purchase Obligations	$ 62,814	$ 197	$	$	**$ 63,011**

(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 $21.2 million. See Part I, Item 3, Quantitative and Qualitative Disclosures about Market Risk, below, for further information.

(3) In March 2009, we renewed our contract with an energy marketing and risk management company to manage a portion of our natural gas transportation and storage capacity. There were no material changes to the contract s terms, as reported in our 2009 Annual Report on Form 10-K.

Environmental Matters

As more fully described in Note 5, Environmental Commitments and Contingencies, to these 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; ESNG is subject to regulation by the FERC; and Peninsula Pipeline Company, Inc. (PIPECO) is subject to regulation by the Florida PSC. At September 30, 2010, 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 4, Rates and Other Regulatory Activities, to these unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q.

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 natural gas 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 as 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.

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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 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.

The advanced information services business faces significant competition from a number of larger competitors having substantially greater resources available to them than does the Company. 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 and their impact on our financial position, results of operations and cash flows are described in the Recent Accounting Pronouncements section of Note 1, Summary of Accounting Policies, to these 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 $104.7 million at September 30, 2010, as compared to a fair value of $122.8 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.

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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 four million gallons (including leased storage and rail cars) of propane 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.

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.

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, 2010 is presented in the following tables.

At September 30, 2010	**Quantity in Gallons**	**Estimated Market Prices**		**Weighted Average Contract Prices**
Forward Contracts				
Sale	18,964,932	$ 0.9925	$1.2150	$ 1.1194
Purchase	18,484,200	$ 1.0100	$1.2475	$ 1.1055

Estimated market prices and weighted average contract prices are in dollars per gallon.
All contracts expire prior to or during the second quarter of 2011.

At September 30, 2010 and December 31, 2009, we marked these forward 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, 2010**	**December 31, 2009**
Mark-to-market energy assets	**$ 2,290**	$ 2,379
Mark-to-market energy liabilities	**$ 1,982**	$ 2,514

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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, 2010. 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, 2010.

Changes in Internal Control Over Financial Reporting

During the quarter ended September 30, 2010, 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.

On October 28, 2009, the merger between Chesapeake and FPU was consummated. We are currently in the process of integrating FPU s operations and have not included FPU s activity in our evaluation of internal control over financial reporting. FPU s operations will be included in our assessment and report on internal control over financial reporting as of December 31, 2010.

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PART II OTHER INFORMATION

Item 1. Legal Proceedings

As disclosed in Note 6, Other Commitments and Contingencies, of these 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, 2009 and in Part II, Item 1A, Risk Factors in our Quarterly Reports on Form 10-Q for the quarters ended March 31 and June 30, 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, 2010 through July 31, 2010 [1]	306	$ 31.23		
August 1, 2010 through August 31, 2010		$		
September 1, 2010 through September 30, 2010		$		
Total	306	$ 31.23		

[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 Securities and Exchange Commission on March 8, 2010. During the quarter, 306 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.

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Item 5. Other Information

None.

Item 6. Exhibits

10.1	First Amendment to the Chesapeake Utilities Corporation Supplemental Executive Retirement Savings Plan, dated October 28, 2010, is filed herewith.
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, 2010.
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, 2010.
32.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated November 4, 2010.
32.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated November 4, 2010.

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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, 2010