CHESAPEAKE UTILITIES CORP
Form 10-Q
August 05, 2011

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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: June 30, 2011

OR

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

For the transition period from __________ to __________

Commission File Number: 001-11590

Chesapeake Utilities Corporation

(Exact name of registrant as specified in its charter)

Delaware	**51-0064146**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

909 Silver Lake Boulevard, Dover, Delaware 19904

(Address of principal executive offices, including Zip Code)

(302) 734-6799

(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

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

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

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

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

Common Stock, par value $0.4867 9,564,197 shares outstanding as of July 31, 2011.

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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
Eastern Shore	Eastern Shore Natural Gas Company, a wholly-owned subsidiary of Chesapeake
FPU	Florida Public Utilities Company, a wholly-owned subsidiary of Chesapeake, effective October 28, 2009
PESCO	Peninsula Energy Services Company, Inc., a wholly-owned subsidiary of Chesapeake
Peninsula Pipeline	Peninsula Pipeline Company, Inc., a wholly-owned subsidiary of Chesapeake
Sharp	Sharp Energy, Inc., a wholly-owned subsidiary of Chesapeake s and Sharp s subsidiary, Sharpgas, Inc.
Xeron	Xeron, Inc., a wholly-owned subsidiary of Chesapeake

Regulatory Agencies

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

Accounting Standards Related

FASB	Financial Accounting Standards Board
GAAP	Generally Accepted Accounting Principles

Other

AS/SVE	Air Sparging and Soil/Vapor Extraction
BS/SVE	Bio-Sparging and Soil/Vapor Extraction
CDD	Cooling Degree-Days
DSCP	Directors Stock Compensation Plan
Dts	Dekatherms
Dts/d	Dekatherms per day
ECCR	Energy Conservation Cost Recovery
FGT	Florida Gas Transmission Company
FRP	Fuel Retention Percentage
GSR	Gas Sales Service Rates
Gulf Power	Gulf Power Corporation
Gulfstream	Gulfstream Natural Gas System, LLC

HDD	Heating Degree-Days
MWH	Megawatt Hour
Mcf	Thousand Cubic Feet
MGP	Manufactured Gas Plant
NYSE	New York Stock Exchange
OCI	Other Comprehensive Income
OTC	Over-the-Counter
PIP	Performance Incentive Plan
RAP	Remedial Action Plan
Sanford Group	FPU and Other Responsible Parties involved with the Sanford Environmental Site
TETLP	Texas Eastern Transmission, LP
TOU	Time-of-Use

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

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

For the Three Months Ended June 30,	2011	2010
(in thousands, except shares and per share data)		
Operating Revenues		
Regulated Energy	**$ 54,327**	$ 52,740
Unregulated Energy	**29,692**	24,615
Other	**2,812**	2,706
Total operating revenues	**86,831**	80,061
Operating Expenses		
Regulated energy cost of sales	**24,882**	24,625
Unregulated energy and other cost of sales	**24,420**	20,384
Operations	**20,401**	18,526
Maintenance	**1,892**	1,789
Depreciation and amortization	**4,937**	4,545
Other taxes	**2,523**	2,431
Total operating expenses	**79,055**	72,300
Operating Income	**7,776**	7,761
Other income (loss), net of expenses	**27**	(11)
Interest charges	**2,114**	2,305
Income Before Income Taxes	**5,689**	5,445
Income tax expense	**2,169**	2,105
Net Income	**$ 3,520**	$ 3,340
Weighted-Average Common Shares Outstanding:		
Basic	**9,557,707**	9,467,222
Diluted	**9,650,887**	9,557,352
Earnings Per Share of Common Stock:		
Basic	**$ 0.37**	$ 0.35
Diluted	**$ 0.37**	$ 0.35

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

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

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

For the Six Months Ended June 30, *(in thousands, except shares and per share data)*	**2011**	2010
Operating Revenues		
Regulated Energy	**$ 139,329**	$ 144,367
Unregulated Energy	**88,442**	83,885
Other	**5,658**	5,069
Total operating revenues	**233,429**	233,321
Operating Expenses		
Regulated energy cost of sales	**72,872**	78,889
Unregulated energy and other cost of sales	**68,711**	65,474
Operations	**40,237**	37,524
Maintenance	**3,595**	3,489
Depreciation and amortization	**9,958**	9,389
Other taxes	**5,441**	5,397
Total operating expenses	**200,814**	200,162
Operating Income	**32,615**	33,159
Other income, net of expenses	**50**	103
Interest charges	**4,265**	4,667
Income Before Income Taxes	**28,400**	28,595
Income tax expense	**11,133**	11,281
Net Income	**$ 17,267**	$ 17,314
Weighted-Average Common Shares Outstanding:		
Basic	**9,546,606**	9,443,708
Diluted	**9,642,374**	9,550,670
Earnings Per Share of Common Stock:		
Basic	**$ 1.81**	$ 1.83
Diluted	**$ 1.79**	$ 1.82
Cash Dividends Declared Per Share of Common Stock	**$ 0.675**	$ 0.645

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

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

For the Six Months Ended June 30, *(in thousands)*	**2011**	2010
Operating Activities		
Net Income	**$ 17,267**	$ 17,314
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**9,958**	9,389
Depreciation and accretion included in other costs	**2,473**	2,199
Deferred income taxes, net	**12,449**	3,683
Loss on sale of assets	**94**	71
Unrealized (gain) loss on commodity contracts	**30**	(374)
Unrealized (gain) loss on investments	**(131)**	60
Employee benefits	**309**	(383)
Share-based compensation	**705**	612
Other, net	**(18)**	(105)
Changes in assets and liabilities:		
Sale (purchase) of investments	**258**	(131)
Accounts receivable and accrued revenue	**14,017**	26,485
Propane inventory, storage gas and other inventory	**3,315**	3,382
Regulatory assets	**601**	1,226
Prepaid expenses and other current assets	**1,792**	3,539
Accounts payable and other accrued liabilities	**674**	(14,796)
Income taxes receivable	**(2,666)**	2,201
Accrued interest	**(241)**	(259)
Customer deposits and refunds	**(1,182)**	1,041
Accrued compensation	**(2,234)**	83
Regulatory liabilities	**2,887**	1,194
Other liabilities	**(268)**	583
Net cash provided by operating activities	**60,089**	57,014
Investing Activities		
Property, plant and equipment expenditures	**(21,236)**	(13,600)
Proceeds from sales of assets	**344**	34
Purchase of investments	**(200)**	(310)
Environmental expenditures	**(326)**	(410)
Net cash used in investing activities	**(21,418)**	(14,286)
Financing Activities		
Common stock dividends	**(5,685)**	(5,369)
(Purchase) issuance of stock for Dividend Reinvestment Plan	**(609)**	268
Change in cash overdrafts due to outstanding checks	**(3,193)**	(834)
Net repayment under line of credit agreements	**(27,417)**	(29,188)

Other short-term borrowing		**(29,100)**		29,100
Proceeds from issuance of long-term debt		**29,000**		
Repayment of long-term debt		**(1,482)**		(30,277)
Net cash used in financing activities		**(38,486)**		(36,300)
Net Increase in Cash and Cash Equivalents		**185**		6,428
Cash and Cash Equivalents Beginning of Period		**1,643**		2,828
Cash and Cash Equivalents End of Period	**$**	**1,828**	$	9,256

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

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

Assets *(in thousands, except shares and per share data)*	**June 30, 2011**	**December 31, 2010**
Property, Plant and Equipment		
Regulated energy	**$ 511,008**	$ 500,689
Unregulated energy	**62,399**	61,313
Other	**18,926**	16,989
Total property, plant and equipment	**592,333**	578,991
Less: Accumulated depreciation and amortization	**(129,054)**	(121,628)
Plus: Construction work in progress	**8,317**	5,394
Net property, plant and equipment	**471,596**	462,757
Investments, at fair value	**4,109**	4,036
Current Assets		
Cash and cash equivalents	**1,828**	1,643
Accounts receivable (less allowance for uncollectible accounts of $1,095 and $1,194, respectively)	**80,381**	88,074
Accrued revenue	**8,655**	14,978
Propane inventory, at average cost	**6,790**	8,876
Other inventory, at average cost	**3,266**	3,084
Regulatory assets	**289**	51
Storage gas prepayments	**3,672**	5,084
Income taxes receivable	**9,414**	6,748
Deferred income taxes	**2,170**	2,191
Prepaid expenses	**3,111**	4,613
Mark-to-market energy assets	**335**	1,642
Other current assets	**226**	245
Total current assets	**120,137**	137,229
Deferred Charges and Other Assets		
Goodwill	**35,613**	35,613
Other intangible assets, net	**3,293**	3,459
Long-term receivables	**26**	155
Regulatory assets	**22,300**	23,884
Other deferred charges	**3,415**	3,860
Total deferred charges and other assets	**64,647**	66,971

Total Assets	**$**	**660,489**	$	670,993

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

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

Capitalization and Liabilities *(in thousands, except shares and per share data)*	**June 30, 2011**	**December 31, 2010**
Capitalization		
Stockholders equity		
Common stock, par value $0.4867 per share (authorized 25,000,000 shares)	**$ 4,654**	$ 4,635
Additional paid-in capital	**148,796**	148,159
Retained earnings	**87,549**	76,805
Accumulated other comprehensive loss	**(2,999)**	(3,360)
Deferred compensation obligation	**796**	777
Treasury stock	**(796)**	(777)
Total stockholders equity	**238,000**	226,239
Long-term debt, net of current maturities	**117,123**	89,642
Total capitalization	**355,123**	315,881
Current Liabilities		
Current portion of long-term debt	**9,196**	9,216
Short-term borrowing	**4,248**	63,958
Accounts payable	**64,427**	65,541
Customer deposits and refunds	**25,135**	26,317
Accrued interest	**1,548**	1,789
Dividends payable	**3,299**	3,143
Accrued compensation	**4,623**	6,784
Regulatory liabilities	**11,960**	9,009
Mark-to-market energy liabilities	**216**	1,492
Other accrued liabilities	**12,081**	10,393
Total current liabilities	**136,733**	197,642
Deferred Credits and Other Liabilities		
Deferred income taxes	**92,700**	80,031
Deferred investment tax credits	**203**	243
Regulatory liabilities	**3,670**	3,734
Environmental liabilities	**9,414**	10,587
Other pension and benefit costs	**17,816**	18,199
Accrued asset removal cost Regulatory liability	**35,919**	35,092
Other liabilities	**8,911**	9,584
Total deferred credits and other liabilities	**168,633**	157,470

Other commitments and contingencies (Note 4 and 5)

Total Capitalization and Liabilities	**$ 660,489**	$ 670,993

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)

	Common Stock		Additional		Accumulated Other			
usands, except shares and per share data)	Number of Shares[6]	Par Value	Paid-In Capital	Retained Earnings	Comprehensive Loss	Deferred Compensation	Treasury Stock	To
ces at December 31, 2009	**9,394,314(6)**	**$ 4,572**	**$ 144,502**	**$ 63,231**	**$ (2,524)**	**$ 739**	**$ (739)**	**$ 209**
come				26,056				26
comprehensive income, net of tax:								
yee Benefit Plans, net of tax:								
ization of prior service costs [4]					8(4)			
ss [5]					(844)[5]			
comprehensive income								25
end Reinvestment Plan	53,806	26	1,699					1
ment Savings Plan	27,795	14	889					
rsion of debentures	11,865	6	196					
enefit on share based compensation			253					
based compensation [1] [3]	36,415(1)(3)	17(1)(3)	620(1)(3)					
red Compensation Plan						38	(38)	
ase of treasury stock	(1,144)						(38)	
nd distribution of treasury stock	1,144						38	
ends on stock-based compensation				(104)				
lividends [2]				(12,378)[2]				(12
ces at December 31, 2010	**9,524,195(6)**	**4,635**	**148,159**	**76,805**	**(3,360)**	**777**	**(777)**	**226**
come				17,267				17
comprehensive income, net of tax:								
yee Benefit Plans, net of tax:								
ization of prior service costs [4]					4(4)			
ain [5]					357(5)			
comprehensive income								17
end Reinvestment Plan			(11)					
ment Savings Plan	2,002	1	79					
rsion of debentures	5,691	3	94					
based compensation [1] [3]	30,430	15(1)(3)	475(1)(3)					
red Compensation Plan						19	(19)	
ase of treasury stock	(473)						(19)	
nd distribution of treasury stock	473						19	
ends on stock-based compensation				(73)				
lividends [2]				(6,450)[2]				(6
ces at June 30, 2011	**9,562,318**	**$ 4,654**	**$ 148,796**	**$ 87,549**	**$ (2,999)**	**$ 796**	**$ (796)**	**$ 238**

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

(2) Cash dividends declared per share for the periods ended June 30, 2011 and December 31, 2010 were $0.675 and $1.305, respectively.

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

(4) Tax expense recognized on the prior service cost component of employees benefit plans for the periods ended June 30, 2011 and December 31, 2010 were approximately $3 and $5, respectively.

(5) Tax expense (benefit) recognized on the net gain (loss) component of employees benefit plans for the periods ended June 30, 2011 and December 31, 2010, were $239 and ($541), respectively.

(6) Includes 30,078 and 29,596 shares at June 30, 2011 and December 31, 2010, 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, 2011. In the opinion of management, these financial statements reflect normal recurring adjustments that are necessary for a fair presentation of our results of operations, financial position and cash flows for the interim periods presented.

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

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

Reclassifications

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

Recent Accounting Amendments Yet to be Adopted by the Company

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

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

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2. Calculation of Earnings Per Share

For the Periods Ended June 30,	Three Months 2011	Three Months 2010	Six Months 2011	Six Months 2010
(in thousands, except shares and per share data)				
Calculation of Basic Earnings Per Share:				
Net Income	**$ 3,520**	$ 3,340	**$ 17,267**	$ 17,314
Weighted average shares outstanding	**9,557,707**	9,467,222	**9,546,606**	9,443,708
Basic Earnings Per Share	**$ 0.37**	$ 0.35	**$ 1.81**	$ 1.83
Calculation of Diluted Earnings Per Share:				
Reconciliation of Numerator:				
Net Income	**$ 3,520**	$ 3,340	**$ 17,267**	$ 17,314
Effect of 8.25% Convertible debentures	**15**	19	**31**	37
Adjusted numerator Diluted	**$ 3,535**	$ 3,359	**$ 17,298**	$ 17,351
Reconciliation of Denominator:				
Weighted shares outstanding Basic	**9,557,707**	9,467,222	**9,546,606**	9,443,708
Effect of dilutive securities:				
Share-based Compensation	**20,699**	3,347	**21,958**	19,437
8.25% Convertible debentures	**72,481**	86,783	**73,810**	87,525
Adjusted denominator Diluted	**9,650,887**	9,557,352	**9,642,374**	9,550,670
Diluted Earnings Per Share	**$ 0.37**	$ 0.35	**$ 1.79**	$ 1.82

3. Rates and Other Regulatory Activities

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

Delaware

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

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

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

On June 29, 2011, the Delaware Attorney General filed an appeal with the Delaware Supreme Court, asking it to review the Delaware Superior Court s decision affirming the Delaware PSC decision with regard to refunds for past capacity releases. The Delaware Attorney General was substituted in the case for the Division of the Public Advocate in the period between when the former Public Advocate retired and a new Public Advocate was appointed by the Governor. On July 12, 2011, the Delaware division filed a Notice of Cross Appeal with the Delaware Supreme Court, asking it to overturn the Superior Court s decision with regard to the Delaware PSC s decision on future capacity releases to PESCO. We have not accrued any contingent liability related to potential refunds for past capacity releases. We anticipate that the Delaware Supreme Court will render a decision sometime in the first half of 2012. In addition, due to the ongoing legal proceedings, the parties have not yet opened a separate docket to determine an alternative pricing methodology for future capacity releases. Since the Delaware PSC s Order on May 18, 2010, the Delaware division has not released any capacity to PESCO.

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

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

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

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Maryland

On December 14, 2010, 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, 2010. No issues were raised at the hearing, and on December 20, 2010, the Hearing Examiner in this proceeding issued a proposed Order approving the division s four quarterly filings. This proposed Order became a final Order of the Maryland PSC on January 20, 2011.

On March 2, 2011, the Maryland division filed with the Maryland PSC an application for the approval of a franchise executed between the Maryland division and the Board of County Commissioners of Cecil County, Maryland. In this franchise agreement, the County granted the Maryland division a 50-year, non-exclusive, franchise to construct and operate natural gas distribution facilities within the present and future jurisdictional boundaries of Cecil County. On April 11, 2011, the Maryland PSC issued an Order approving the franchise between the Maryland division and Cecil County, subject to no adverse comments being received within 30 days after the issuance of the Order. On May 10, 2011, comments opposing the application were filed by Pivotal Utility Holdings, Inc. d/b/a Elkton Gas (Pivotal). Pivotal also provides natural gas service to customers in a portion of Cecil County. On June 8, 2011, the Maryland PSC granted the Maryland division the authority to exercise its franchise in a majority of the area requested in the Maryland division s application. The approval for a small portion of the area within the requested franchise area, which is closest to the area served by Pivotal, has been withheld until an evidentiary hearing is convened. It is anticipated that the Maryland PSC will render a decision on the remaining area in the fourth quarter of 2011 or the first quarter of 2012.

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

Florida

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

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

Our earnings may be reduced by as much as $1.6 million annually for the amortization expense (approximately $1.3 million is non-tax-deductible) until 2014 and $1.1 million annually (non-tax deductible) thereafter until 2039. This amortization expense would be a non-cash charge, and the net effect of the recovery would be positive cash flow. Over the long-term, however, the inclusion of the acquisition adjustment and merger-related costs in our rate base and the recovery of these regulatory assets through amortization expense will increase our earnings and cash flows above what we would have otherwise been able to achieve.

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

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

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

In accordance with the terms of the Franchise Agreement, FPU developed reasonable TOU and interruptible rates and on December 14, 2010, FPU filed a petition with the Florida PSC for authority to implement such proposed TOU and interruptible rates on or before February 17, 2011. On February 11, 2011, the Florida PSC issued an Order approving FPU s petition for authority to implement the proposed TOU and interruptible rates, which became effective on February 8, 2011. The City of Marianna has objected to the proposed rates and has filed a petition protesting the entry of the Florida PSC s Order. On March 17, 2011, FPU filed a Motion to Dismiss the petition by the City of Marianna and requested oral argument. On June 14, 2011, the Florida PSC granted FPU s request for oral argument and on July 5, 2011, issued an Order approving FPU s Motion to Dismiss the protest by the City of Marianna, without prejudice. On July 25, 2011, the City of Marianna filed an amended petition protesting the entry of the Florida PSC s Order.

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

On April 7, 2011, FPU filed a petition for approval of a mid-course reduction to its Northwest Division fuel rates based on two factors: 1) the previously discussed amendment to the Generation Services Agreement with Gulf Power; and 2) a weather-related increase in sales resulting in an accelerated collection of prior year s under-recovered costs. Pursuant to its Order dated July 5, 2011, the Florida PSC approved the petition, which is projected to reduce customers fuel rates by approximately 10 percent per month.

As disclosed in Note 5, Other Commitments and Contingencies, to the unaudited condensed consolidated financial statements, the City of Marianna, on March 2, 2011, filed a complaint against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida, alleging breaches of the Franchise Agreement by FPU and seeking a declaratory judgment that the City of Marianna has the right to exercise its option to purchase FPU s property in the City of Marianna in accordance with the terms of the Franchise Agreement. On March 28, 2011, FPU filed its answer to the declaratory action by the City of Marianna, in which it denied the material allegation by the City of Marianna and asserted several affirmative defenses.

Eastern Shore

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

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

Rate Case Filing: On December 30, 2010, Eastern Shore filed with the FERC a base rate proceeding in compliance with the terms of the settlement in its prior base rate proceeding. The rate filing reflects increases in operating and maintenance expenses, depreciation expense, and a return on existing and new gas plant facilities expected to be placed into service before June 30, 2011. The FERC issued a notice of the filing on January 3, 2011. Protests were received from several interested parties, and other parties intervened in the proceeding. On January 31, 2011, the FERC issued its Order accepting the filing and suspending its effectiveness for the full five-month period permitted under the Natural Gas Act. The discovery process commenced on February 22, 2011, and FERC Staff performed an on-site audit on March 16-17, 2011. Settlement conferences involving Eastern Shore, FERC Staff and other interested parties were held beginning in April and have extended through early August 2011. Eastern Shore expects the base rate proceeding to be resolved in 2011.

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

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

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

Eastern Shore also had developments in the following FERC matters:

On March 7, 2011, Eastern Shore filed certain tariff sheets to amend the creditworthiness provisions contained in its FERC Gas Tariff. On April 6, 2011, the FERC issued an Order accepting and suspending Eastern Shore s filed tariff revisions for an effective date of April 1, 2011, subject to Eastern Shore submitting certain clarifications with regard to several proposed revisions.

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

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

4. Environmental Commitments and Contingencies

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

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

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As of June 30, 2011, we had approximately $11.2 million in environmental liabilities related to all of FPU s MGP sites in Florida, which include the Key West, Pensacola, Sanford and West Palm Beach sites, representing our estimate of the future costs associated with those sites. FPU has approval to recover up to $14.0 million of its environmental costs related to all of its MGP sites from insurance and from customers through rates. Approximately $8.1 million of FPU s expected environmental costs have been recovered from insurance and customers through rates as of June 30, 2011. We also had approximately $5.9 million in regulatory assets for future recovery of environmental costs from FPU s customers.

West Palm Beach, Florida

Remedial options are being evaluated to respond to environmental impacts to soil and groundwater at and in the immediate vicinity of a parcel of property owned by FPU in West Palm Beach, Florida, where FPU previously operated an MGP. Pursuant to a Consent Order between FPU and the Florida Department of Environmental Protection (FDEP), effective April 8, 1991, FPU is required to complete the delineation of soil and groundwater impacts at the site, and implement an effective remedy.

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

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

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

FPU is currently implementing the interim RAP for the east parcel of the West Palm Beach site, including the incorporation of FDEP s conditions for approval. The operations on the east parcel have been relocated, and the structures removed. New monitoring wells and Air Sparging and Soil-Vapor Extraction (AS/SVE) test wells were installed on the east parcel in May of 2011. The initial round of SVE and sparging pilot testing was completed in July of 2011 and the results of the testing are currently being analyzed.

Estimated costs of remediation for the West Palm Beach site range from approximately $4.9 million to $13.1 million. This estimate does not include any costs associated with relocation of FPU s operations at this site, which is necessary to implement the remedial plan, and any potential costs associated with future redevelopment of the properties.

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

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Sanford, Florida

FPU is the current owner of property in Sanford, Florida, which was a former MGP site that was operated by several other entities before FPU acquired the property. FPU was never an owner or an operator of the MGP. In late September 2006, the United States Environmental Protection Agency (EPA) sent a Special Notice Letter, notifying FPU, and the other responsible parties at the site (Florida Power Corporation, Florida Power & Light Company, Atlanta Gas Light Company, and the city of Sanford, Florida, collectively with FPU, the Sanford Group), of EPA s selection of a final remedy for OU1 (soils), OU2 (groundwater), and OU3 (sediments) for the site. The EPA projected the total estimated remediation costs for this site to be approximately $12.9 million.

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 June 30, 2011, FPU has paid $650,000 to the Sanford Group escrow account for its share of the funding requirements.

The Sanford Group, EPA and the U.S. Department of Justice agreed to a Consent Decree in March 2008, which was entered by the Federal Court in Orlando, Florida on January 15, 2009. The Consent Decree obligates the Sanford Group to implement the remedy approved by EPA for the site. The total cost of the final remedy is now estimated at approximately $18 million. FPU has advised the other members of the Sanford Group that it is unwilling at this time to agree to pay any sum in excess of the $650,000 committed by FPU in the Third Participation Agreement.

Several members of the Sanford Group have concluded negotiations with two adjacent property owners to resolve damages that the property owners allege they have and will incur as a result of the implementation of the EPA-approved remediation. In settlement of these claims, members of the Sanford Group, which in this instance does not include FPU, have agreed to pay specified sums of money to the parties. FPU has refused to participate in the funding of the third-party settlement agreements based on its contention that it did not contribute to the release of hazardous substances at the site giving rise to the third-party claims.

As of June 30, 2011, FPU s remaining share of remediation expenses, including attorneys fees and costs, is estimated to be $20,000. However, we are unable to determine, to a reasonable degree of certainty, whether the other members of the Sanford Group will accept FPU s asserted defense to liability for costs exceeding $13.0 million to implement the final remedy for this site or will pursue a claim against FPU for a sum in excess of the $650,000 that FPU has paid under the Third Participation Agreement. No such claims have been made as of June 30, 2011.

Key West, Florida

FPU formerly owned and operated an MGP in Key West, Florida. Field investigations performed in the 1990s identified limited environmental impacts at the site, which is currently owned by an unrelated third party. In September 2010, FDEP issued a Preliminary Contamination Assessment Report, for additional soil and groundwater investigation work that was undertaken by FDEP in November 2009 and January 2010, after 17 years of regulatory inactivity. Because FDEP observed that some soil and groundwater standards were exceeded, FDEP is requesting implementation of additional fieldwork which FDEP believes is warranted for the site.

FPU and the current site owner have had several discussions regarding the approach to be taken with FDEP and the proposed scope of work. Representatives of FPU, FDEP and the current site owner participated in a teleconference on July 7, 2011. During that call, the scope of work was tentatively agreed upon, and FDEP agreed to proceed without using a consent order. FPU and the current site owner will submit a work plan and schedule to FDEP in August of 2011. Total potential costs for investigation and remediation are projected to be $153,000.

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Pensacola, Florida

FPU formerly owned and operated an MGP in Pensacola, Florida, which was subsequently owned by Gulf Power. Portions of the site are now owned by the City of Pensacola and the Florida Department of Transportation (FDOT). In October 2009, FDEP informed Gulf Power that FDEP would approve a conditional No Further Action (NFA) determination for the site, which must include a requirement for institutional and engineering controls. On November 9, 2010, an NFA Proposal was submitted to FDEP, along with a draft restrictive covenant for that portion of the property currently owned by FDOT. FPU, FDOT and the City of Pensacola are working together to obtain a restrictive covenant that is acceptable to FDEP to complete closure of the site, and it is anticipated that no further monitoring will be required on the site. FPU s total remaining consulting and remediation costs for this site are projected to be $5,000.

In addition, we had $284,000 in environmental liabilities at June 30, 2011, related to Chesapeake s MGP sites in Maryland and Florida, representing our estimate of future costs associated with these sites. As of June 30, 2011, we had approximately $1.2 million in regulatory and other assets for future recovery through rates. The following discussion provides details on MGP sites for Chesapeake s Maryland and Florida divisions:

Salisbury, Maryland

We have substantially completed remediation of a site in Salisbury, Maryland, where it was determined that a former MGP caused localized ground-water contamination. During 1996, we completed construction of an AS/SVE system and began remediation procedures. We have reported the remediation and monitoring results to the MDE on an ongoing basis since 1996. In February 2002, the MDE granted permission to permanently decommission the AS/SVE system and to discontinue all on-site and off-site well monitoring, except for one well, which is being maintained for periodic product monitoring and recovery.

Through June 30, 2011, we have incurred and paid approximately $2.9 million for remedial actions and environmental studies related to this site. We have recovered approximately $2.3 million through insurance proceeds or in rates, and $609,000 is expected to be recovered through future rates.

Winter Haven, Florida

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

The BS/SVE treatment system at the Winter Haven site does not address impacted soils in the southwest corner of the site. On April 16, 2010, a soil excavation interim RAP describing the proposed excavation of approximately 4,000 cubic yards of impacted soils from the southwest corner of the site was submitted to FDEP for review. On June 24, 2010, FDEP provided comments on the soil excavation interim RAP by letter, to which we responded, and a subsequent conditional approval letter was issued by FDEP on August 27, 2010. The cost to implement this excavation plan has been estimated at $250,000; however, this estimate does not include costs associated with dewatering or shoreline stabilization, which would be required to complete the excavation. Because the costs associated with shoreline stabilization and dewatering (including treatment and discharge of the pumped water) are likely to be substantial, alternatives to this excavation plan are being evaluated. One alternative currently being evaluated involves sparging into the southwest portion of the property to treat soils rather than excavating the soils.
Two new sparge points were installed in the southwest portion of the property in February of 2011. Sparging into these points has been initiated and operational and monitoring data over the next few quarters should provide the information needed to make this evaluation.

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

Through June 30, 2011, we have incurred and paid approximately $1.7 million for remedial activities at this site, and we have estimated and accrued for additional future costs of $284,000. We have recovered through rates $1.4 million of the costs to remediate the Winter Haven site and continue to expect that the remaining $542,000, which is included in regulatory assets, will be recoverable from customers through our approved rates.

Other

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

5. Other Commitments and Contingencies

Litigation

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

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On March 2, 2011, the City of Marianna, Florida filed a complaint against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida, alleging that FPU breached its obligations under its franchise with the City of Marianna to provide electric service to customers within and without the City of Marianna by failing: (i) to develop and implement TOU and interruptible rates that were mutually agreed to by the City of Marianna and FPU; (ii) to have such mutually agreed upon rates in effect by February 17, 2011; and (iii) to have such rates available to all of FPU s customers located within and without the corporate limits of the City of Marianna. The City of Marianna is seeking a declaratory judgment allowing it to exercise its option under the Franchise Agreement to purchase FPU s property (consisting of the electric distribution assets) within the City of Marianna. Any such purchase would be subject to approval by the Marianna Commission, which would also need to approve the presentation of a referendum to voters in the City of Marianna related to the purchase and the operation by the City of Marianna of an electric distribution facility. If the purchase is approved by the Marianna Commission and the referendum is approved by the voters, the closing of the purchase must occur within 12 months after the referendum is approved. On March 28, 2011, FPU filed its answer to the declaratory action by the City of Marianna, in which it denied the material allegations by the City of Marianna and asserted several affirmative defenses. FPU intends to vigorously contest this litigation and intends to oppose the adoption of any proposed referendum to approve the purchase of the FPU property in the City of Marianna.

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.

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

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

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

FPU s electric fuel supply contracts require FPU to maintain an acceptable standard of creditworthiness based on specific financial ratios. FPU s agreement with JEA requires FPU to comply with the following ratios based on the results of the prior 12 months: (a) total liabilities to tangible net worth less than 3.75 times, and (b) fixed charge coverage ratio greater than 1.5 times. If either ratio is not met by FPU, it has 30 days to cure the default or provide an irrevocable letter of credit if the default is not cured. FPU s electric fuel supply agreement with Gulf Power requires FPU to meet the following ratios based on the average of the prior six quarters: (a) funds from operations interest coverage ratio (minimum of 2 times), and (b) total debt to total capital (maximum of 65 percent). If FPU fails to meet the requirements, it has to provide the supplier a written explanation of actions taken or proposed to be taken to become compliant. Failure to comply with the ratios specified in the Gulf Power agreement could result in FPU providing an irrevocable letter of credit. As of June 30, 2011, FPU was in compliance with all of the requirements of its fuel supply contracts.

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Corporate Guarantees

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

We have issued corporate guarantees to certain vendors of our subsidiaries, the largest portion of which are for our propane wholesale marketing subsidiary and our natural gas marketing subsidiary. These corporate guarantees provide for the payment of propane and natural gas purchases in the event of the respective subsidiary s default. Neither subsidiary has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded in our financial statements when incurred. The aggregate amount guaranteed at June 30, 2011 was $25.6 million, with the guarantees expiring on various dates through December 2011.

Chesapeake guarantees the payment of FPU s first mortgage bonds. The maximum exposure under the guarantee is the outstanding principal and accrued interest balances. The outstanding principal balances of FPU s first mortgage bonds approximate their carrying values (see Note 12, Long-Term Debt, to the unaudited condensed consolidated financial statements for further details).

In addition to the corporate guarantees, we have issued a letter of credit to our primary insurance company for $441,000, which expires on December 2, 2011. The letter of credit is provided as security to satisfy the deductibles under our various outstanding insurance policies. As a result of a change in our primary insurance company in 2010, we renewed the letter of credit for $725,000 to our former primary insurance company, which will expire on June 1, 2012. There have been no draws on these letters of credit as of June 30, 2011. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future.

We provided a letter of credit for $2.5 million to Texas Eastern Transmission, LP (TETLP) related to the Precedent Agreement, which is further described below.

Agreements for Access to New Natural Gas Supplies

On April 8, 2010, our Delaware and Maryland divisions entered into a Precedent Agreement with TETLP to secure firm transportation service from TETLP in conjunction with its new expansion project, which is expected to expand TETLP s mainline system by up to 190,000 Dts/d. The Precedent Agreement provides that, upon satisfaction of certain conditions, the parties will execute two firm transportation service contracts, one for our Delaware division and one for our Maryland division, for 34,100 and 15,900 Dts/d, respectively, including the additional volume subscribed in a subsequent agreement, to be effective on the service commencement date of the project, which is currently projected to occur in November 2012. Each firm transportation service contract shall, among other things, provide for: (a) the maximum daily quantity of Dts/d described above; (b) a term of 15 years; (c) a receipt point at Clarington, Ohio; (d) a delivery point at Honey Brook, Pennsylvania; and (e) certain credit standards and requirements for security. Commencement of service and TETLP s and our rights and obligations under the two firm transportation service contracts are subject to satisfaction of various conditions specified in the Precedent Agreement.

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

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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 $8.6 million as of June 30, 2011. If we were to terminate the Precedent Agreement after TETLP completed its construction of all facilities, which is expected to be in the fourth quarter of 2011, our proportionate share could be as much as approximately $50 million. The actual amount of our proportionate share of such costs could differ significantly and would ultimately be based on the level of pre-service costs at the time of any potential termination. As our Delaware and Maryland divisions have now executed the required reservation rate agreements with TETLP, we believe that the likelihood of terminating the Precedent Agreement and having to reimburse TETLP for our proportionate share of TETLP s pre-service costs is remote.

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

On March 17, 2010, our Delaware and Maryland divisions entered into a separate Precedent Agreement with Eastern Shore to extend its mainline by eight miles to interconnect with TETLP at Honey Brook, Pennsylvania. As discussed in Note 3, Rates and Other Regulatory Activities, to the unaudited condensed consolidated financial statements, Eastern Shore completed the extension project in December 2010 and commenced the service in January 2011. The rate for the transportation service on this extension is Eastern Shore s current tariff rate for service in that area.

TETLP is proceeding with obtaining the necessary approvals, authorizations or exemptions for construction and operation of its portion of the project, including, but not limited to, approval by the FERC. TETLP is expecting the FERC approval by the end of 2011. Our Delaware and Maryland divisions require no regulatory approvals or exemptions to receive transmission service from TETLP or Eastern Shore.

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

Non-income-based Taxes

From time to time, we are subject to various audits and reviews by the states and other regulatory authorities regarding non-income-based taxes. We are currently undergoing a sales tax audit in Florida. As of June 30, 2011, we maintained an accrual of $698,000 related to additional sales taxes and gross receipts taxes owed to various states, all of which were recorded in 2010.

Other Contingency

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

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6. Segment Information

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