UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended: June 30, 2016

OR

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

For the transition period from _________ to _________

Commission File Number: 001-11590

CHESAPEAKE UTILITIES CORPORATION
(Exact name of registrant as specified in its charter)

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

909 Silver Lake Boulevard, Dover, Delaware 19904
(Address of principal executive offices, including Zip Code)

(302) 734-6799
(Registrant's telephone number, including area code)

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

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

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

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐

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

Common Stock, par value $0.4867 — 15,323,102 shares outstanding as of July 31, 2016.

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GLOSSARY OF DEFINITIONS

ASC: Accounting Standards Codification

ASU: Accounting Standards Update

Aspire Energy: Aspire Energy of Ohio, LLC, a wholly-owned subsidiary of Chesapeake Utilities into which Gatherco merged on April 1, 2015

CDD: Cooling degree-day, which is the measure of the variation in weather based on the extent to which the daily average temperature (from 10:00 am to 10:00 am) is above 65 degrees Fahrenheit

Chesapeake or Chesapeake Utilities: Chesapeake Utilities Corporation, its divisions and its subsidiaries, as appropriate in the context of the disclosure

Chesapeake Pension Plan: A defined benefit pension plan sponsored by Chesapeake Utilities

Chesapeake Postretirement Plan: An unfunded postretirement health care and life insurance plan sponsored by Chesapeake Utilities

Chesapeake SERP: An unfunded supplemental executive retirement pension plan sponsored by Chesapeake Utilities

CHP: A combined heat and power plant constructed by Eight Flags in Nassau County, Florida

Columbia Gas: Columbia Gas of Ohio

Company: Chesapeake Utilities Corporation, its divisions and its subsidiaries, as appropriate in the context of the disclosure

Credit Agreement: An agreement between Chesapeake Utilities and the lenders related to the Revolver

Deferred Compensation Plan: A non-qualified, deferred compensation arrangement under which certain of our executives and members of the Board of Directors are able to defer payment of all or a part of certain specified types of compensation, including executive cash bonuses, executive performance shares, and directors' retainers

Delmarva Peninsula: A peninsula on the east coast of the United States of America occupied by Delaware and portions of Maryland and Virginia

DNREC: Delaware Department of Natural Resources and Environmental Control

Dts/d: Dekatherms per day

Eastern Shore: Eastern Shore Natural Gas Company, a wholly-owned natural gas transmission subsidiary of Chesapeake Utilities

EGWIC: Eastern Gas & Water Investment Company, LLC, an affiliate of ESG

Eight Flags: Eight Flags Energy, LLC, a subsidiary of Chesapeake OnSight Services, LLC

EPA: United States Environmental Protection Agency

ESG: Eastern Shore Gas Company and its affiliates

FASB: Financial Accounting Standards Board

FERC: Federal Energy Regulatory Commission, an independent agency of the United States government that regulates the interstate transmission of electricity, natural gas, and oil

FDEP: Florida Department of Environmental Protection

FDOT: Florida Department of Transportation

FGT: Florida Gas Transmission Company

FPU: Florida Public Utilities Company, a wholly-owned subsidiary of Chesapeake Utilities

FPU Medical Plan: A separate unfunded postretirement medical plan for FPU sponsored by Chesapeake Utilities

FPU Pension Plan: A separate defined benefit pension plan for FPU sponsored by Chesapeake Utilities

GAAP: Accounting principles generally accepted in the United States of America

Gatherco: Gatherco, Inc.

GRIP: The Gas Reliability Infrastructure Program is a natural gas pipeline replacement program in Florida, pursuant to which we collect a surcharge from certain of our Florida customers to recover capital and other program-related costs associated with the replacement of qualifying distribution mains and services in Florida

Gulf Power: Gulf Power Company

Gulfstream: Gulfstream Natural Gas System, LLC

HDD: Heating degree-day, which is a measure of the variation in weather based on the extent to which the daily average temperature (from 10:00 am to 10:00 am) is below 65 degrees Fahrenheit

JEA: The community-owned utility located in Jacksonville, Florida, formerly known as Jacksonville Electric Authority

Lenders: PNC, Bank of America N.A., Citizens Bank N.A., Royal Bank of Canada, and Wells Fargo Bank, National Association, which are collectively the lenders that entered into the Credit Agreement with Chesapeake Utilities on October 8, 2015

MDE: Maryland Department of Environment

MGP: Manufactured gas plant, which is a site where coal was previously used to manufacture gaseous fuel for industrial, commercial and residential use

NAM: Natural Attenuation Monitoring

NYSE: New York Stock Exchange

OPT ≤ 90 Service: Off Peak ≤ 90 Firm Transportation Service, an Eastern Shore firm transportation service that allows Eastern Shore not to schedule service for up to 90 days during the peak months of November through April

OTC: Over-the-counter

Peninsula Pipeline: Peninsula Pipeline Company, Inc., our wholly-owned Florida intrastate pipeline subsidiary

PESCO: Peninsula Energy Services Company, Inc., our wholly-owned natural gas marketing subsidiary

PNC: PNC Bank, National Association, the administrative agent and primary lender for our Revolver

Prudential: Prudential Investment Management Inc., an institutional investment management firm, with which we have entered into the Shelf Agreement for the potential future purchase of our Shelf Notes

PSC: Public Service Commission, which is the state agency that regulates the rates and services provided by Chesapeake Utilities' natural gas and electric distribution operations in Delaware, Maryland and Florida and Peninsula Pipeline in Florida

RAP: Remedial Action Plan, which is a plan that outlines the procedures taken or being considered in removing contaminants from a MGP formerly owned by Chesapeake Utilities or FPU

Revolver: The unsecured revolving credit facility issued to us by the Lenders

Sandpiper: Sandpiper Energy, Inc., a wholly-owned subsidiary of Chesapeake Utilities providing a tariff-based distribution service to customers in Worcester County, Maryland

Sanford Group: FPU and other responsible parties involved with the Sanford environmental site

SCO supplier agreement: Standard Choice Offer (SCO) supplier agreement between PESCO and Columbia Gas

SEC: Securities and Exchange Commission

Sharp: Sharp Energy, Inc., our wholly-owned propane distribution subsidiary

Shelf Agreement: An agreement entered into by Chesapeake Utilities and Prudential pursuant to which Chesapeake Utilities may request that Prudential purchase, by October 8, 2018, up to $150.0 million of Shelf Notes at a fixed interest rate and with a maturity date not to exceed twenty years from the date of issuance

Shelf Notes: Unsecured senior promissory notes that we may request Prudential to purchase under the Shelf Agreement

SICP: 2013 Stock and Incentive Compensation Plan

TETLP: Texas Eastern Transmission, LP

Xeron: Xeron, Inc., our propane wholesale marketing subsidiary, based in Houston, Texas

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PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Income (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands, except shares and per share data)	**2016**	**2015**	**2016**	**2015**
Operating Revenues				
Regulated Energy	**$ 67,395**	$ 62,060	**$ 156,611**	$ 171,642
Unregulated Energy and other	**34,947**	30,622	**92,027**	91,121
Total Operating Revenues	**102,342**	92,682	**248,638**	262,763
Operating Expenses				
Regulated Energy cost of sales	**21,635**	21,124	**56,540**	78,253
Unregulated Energy and other cost of sales	**22,934**	20,272	**56,958**	55,507
Operations	**28,087**	26,190	**55,246**	53,133
Maintenance	**2,904**	2,727	**5,383**	5,431
Gain from a settlement	**(130)**	(1,500)	**(130)**	(1,500)
Depreciation and amortization	**7,780**	7,543	**15,283**	14,518
Other taxes	**3,390**	3,156	**7,236**	6,743
Total Operating Expenses	**86,600**	79,512	**196,516**	212,085
Operating Income	**15,742**	13,170	**52,122**	50,678
Other Expense, net	**(8)**	(171)	**(42)**	(38)
Interest charges	**2,624**	2,485	**5,274**	4,933
Income Before Income Taxes	**13,110**	10,514	**46,806**	45,707
Income taxes	**5,081**	4,220	**18,410**	18,304
Net Income	**$ 8,029**	$ 6,294	**$ 28,396**	$ 27,403
Weighted Average Common Shares Outstanding:				
Basic	**15,315,020**	15,235,860	**15,300,931**	14,922,094
Diluted	**15,352,702**	15,280,657	**15,342,287**	14,970,190
Earnings Per Share of Common Stock:				
Basic	**$ 0.52**	$ 0.41	**$ 1.86**	$ 1.84
Diluted	**$ 0.52**	$ 0.41	**$ 1.85**	$ 1.83
Cash Dividends Declared Per Share of Common Stock	**$ 0.3050**	$ 0.2875	**$ 0.5925**	$ 0.5575

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

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Comprehensive Income (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2016**	**2015**	**2016**	**2015**
Net Income	**$ 8,029**	$ 6,294	**$ 28,396**	$ 27,403
Other Comprehensive Income (Loss), net of tax:				
Employee Benefits, net of tax:				
Amortization of prior service cost, net of tax of $(8), $(7), $(16) and $(14), respectively	**(12)**	(10)	**(24)**	(20)
Net gain, net of tax of $67, $62, $133 and $125, respectively	**99**	93	**200**	185
Cash Flow Hedges, net of tax:				
Unrealized gain on commodity contract cash flow hedges, net of tax of $313, $4, $322 and $21, respectively	**496**	6	**496**	32
Total Other Comprehensive Income	**583**	89	**672**	197
Comprehensive Income	**$ 8,612**	$ 6,383	**$ 29,068**	$ 27,600

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

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Balance Sheets (Unaudited)

Assets	**June 30, 2016**	**December 31, 2015**
(in thousands, except shares and per share data)		
Property, Plant and Equipment		
Regulated Energy	**$ 868,016**	$ 842,756
Unregulated Energy	**189,034**	145,734
Other businesses and eliminations	**19,608**	18,999
Total property, plant and equipment	**1,076,658**	1,007,489
Less: Accumulated depreciation and amortization	**(229,826)**	(215,313)
Plus: Construction work in progress	**61,975**	62,774
Net property, plant and equipment	**908,807**	854,950
Current Assets		
Cash and cash equivalents	**3,266**	2,855
Accounts receivable (less allowance for uncollectible accounts of $631 and $909, respectively)	**41,851**	41,007
Accrued revenue	**8,658**	12,452
Propane inventory, at average cost	**4,285**	6,619
Other inventory, at average cost	**4,025**	3,803
Regulatory assets	**7,042**	8,268
Storage gas prepayments	**5,014**	3,410
Income taxes receivable	**7,395**	24,950
Prepaid expenses	**4,184**	7,146
Mark-to-market energy assets	**405**	153
Other current assets	**771**	1,044
Total current assets	**86,896**	111,707
Deferred Charges and Other Assets		
Goodwill	**15,070**	14,548
Other intangible assets, net	**2,033**	2,222
Investments, at fair value	**4,325**	3,644
Regulatory assets	**76,563**	77,519
Receivables and other deferred charges	**3,353**	2,831
Total deferred charges and other assets	**101,344**	100,764
Total Assets	**$ 1,097,047**	$ 1,067,421

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

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Balance Sheets (Unaudited)

Capitalization and Liabilities	**June 30, 2016**	**December 31, 2015**
(in thousands, except shares and per share data)		
Capitalization		
Stockholders' equity		
Common stock, par value $0.4867 per share (authorized 25,000,000 shares)	**$ 7,456**	$ 7,432
Additional paid-in capital	**191,776**	190,311
Retained earnings	**185,490**	166,235
Accumulated other comprehensive loss	**(5,168)**	(5,840)
Deferred compensation obligation	**2,452**	1,883
Treasury stock	**(2,452)**	(1,883)
Total stockholders' equity	**379,554**	358,138
Long-term debt, net of current maturities	**143,865**	149,006
Total capitalization	**523,419**	507,144
Current Liabilities		
Current portion of long-term debt	**12,075**	9,151
Short-term borrowing	**180,042**	173,397
Accounts payable	**35,496**	39,300
Customer deposits and refunds	**27,572**	27,173
Accrued interest	**1,250**	1,311
Dividends payable	**4,673**	4,390
Accrued compensation	**6,742**	10,014
Regulatory liabilities	**6,808**	7,365
Mark-to-market energy liabilities	**256**	433
Other accrued liabilities	**8,978**	7,059
Total current liabilities	**283,892**	279,593
Deferred Credits and Other Liabilities		
Deferred income taxes	**199,623**	192,600
Regulatory liabilities	**43,093**	43,064
Environmental liabilities	**8,765**	8,942
Other pension and benefit costs	**32,695**	33,481
Deferred investment tax credits and other liabilities	**5,560**	2,597
Total deferred credits and other liabilities	**289,736**	280,684
Environmental and other commitments and contingencies (Note 5 and 6)		
Total Capitalization and Liabilities	**$ 1,097,047**	$ 1,067,421

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

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Cash Flows (Unaudited)

	Six Months Ended June 30,	
(in thousands)	**2016**	**2015**
Operating Activities		
Net income	**$ 28,396**	$ 27,403
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**15,283**	14,518
Depreciation and accretion included in other costs	**3,436**	3,486
Deferred income taxes, net	**6,162**	(1,366)
Realized (gain) loss on commodity contracts/sale of assets/investments	**664**	(686)
Unrealized gain on investments/commodity contracts	**(42)**	(187)
Employee benefits and compensation	**760**	601
Share-based compensation	**1,264**	947
Other, net	**24**	8
Changes in assets and liabilities:		
Accounts receivable and accrued revenue	**2,264**	20,194
Propane inventory, storage gas and other inventory	**663**	4,405
Regulatory assets/liabilities, net	**519**	12,728
Prepaid expenses and other current assets	**2,878**	3,261
Accounts payable and other accrued liabilities	**(4,069)**	(16,359)
Income taxes receivable	**20,680**	19,300
Customer deposits and refunds	**399**	(3,748)
Accrued compensation	**(3,340)**	(3,788)
Other assets and liabilities, net	**(1,786)**	(315)
Net cash provided by operating activities	**74,155**	80,402
Investing Activities		
Property, plant and equipment expenditures	**(70,045)**	(57,350)
Proceeds from sales of assets	**89**	49
Acquisitions, net of cash acquired	**—**	(20,930)
Environmental expenditures	**(177)**	(73)
Net cash used in investing activities	**(70,133)**	(78,304)
Financing Activities		
Common stock dividends	**(8,453)**	(7,532)
Issuance of stock for Dividend Reinvestment Plan	**429**	417
Change in cash overdrafts due to outstanding checks	**1,473**	2,367
Net borrowing (repayment) under line of credit agreements	**5,166**	4,114
Repayment of long-term debt and capital lease obligation	**(2,226)**	(3,934)
Net cash used in financing activities	**(3,611)**	(4,568)
Net Increase (Decrease) in Cash and Cash Equivalents	**411**	(2,470)
Cash and Cash Equivalents—Beginning of Period	**2,855**	4,574
Cash and Cash Equivalents—End of Period	**$ 3,266**	$ 2,104

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

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Stockholders' Equity (Unaudited)

(in thousands, except shares and per share data)	Common Stock Number of Shares[1]	Common Stock Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total
Balance at December 31, 2014	**14,588,711**	**$ 7,100**	**$ 156,581**	**$ 142,317**	**$ (5,676)**	**$ 1,258**	**$ (1,258)**	**$ 300,322**
Net income		—	—	41,140	—	—	—	41,140
Other comprehensive loss	—	—	—	—	(164)	—	—	(164)
Dividend declared ($1.1325 per share)	—	—	—	(17,222)	—	—	—	(17,222)
Retirement savings plan and dividend reinvestment plan	43,275	21	2,214	—	—	—	—	2,235
Common stock issued in acquisition	592,970	289	29,876					30,165
Share-based compensation and tax benefit [2] [3]	45,703	22	1,640	—	—	—	—	1,662
Treasury stock activities	—	—	—	—	—	625	(625)	—
Balance at December 31, 2015	**15,270,659**	**7,432**	**190,311**	**166,235**	**(5,840)**	**1,883**	**(1,883)**	**358,138**
Net income	—	—	—	28,396	—	—	—	28,396
Other comprehensive income	—	—	—	—	672	—	—	672
Dividend declared ($0.5925 per share) and dividend reinvestment plan	13,120	6	759	(9,141)	—	—	—	(8,376)
Share-based compensation and tax benefit [2] [3]	36,099	18	706	—	—	—	—	724
Treasury stock activities	—	—	—	—	—	569	(569)	—
Balance at June 30, 2016	**15,319,878**	**$ 7,456**	**$ 191,776**	**$ 185,490**	**$ (5,168)**	**$ 2,452**	**$ (2,452)**	**$ 379,554**

(1) Includes 79,658 and 70,631 shares at June 30, 2016 and December 31, 2015, respectively, held in a Rabbi Trust related to our Deferred Compensation Plan.
(2) Includes amounts for shares issued for Directors' compensation.
(3) The shares issued under the SICP are net of shares withheld for employee taxes. For the six months ended June 30, 2016, and for the year ended December 31, 2015, we withheld 12,031 and 12,620 shares, respectively, for taxes.

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

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. Summary of Accounting Policies

Basis of Presentation

References in this document to the “Company,” “Chesapeake Utilities,” “we,” “us” and “our” are intended to mean Chesapeake Utilities Corporation, its divisions and/or its 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 SEC and 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 for the year ended December 31, 2015. 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 reclassified certain amounts in the condensed consolidated balance sheet as of December 31, 2015. We have revised the condensed consolidated statement of cash flows for the six months ended June 30, 2015 to reflect only property, plant and equipment expenditures paid in cash within the Investing Activities section. The non-cash expenditures previously included in that section have now been included in the change in accounts payable and other accrued liabilities amount within the Operating Activities section. These reclassifications are considered immaterial to the overall presentation of our condensed consolidated financial statements.

FASB Statements and Other Authoritative Pronouncements

Recently Adopted Accounting Standards

Interest - Imputation of Interest (ASC 835-30) - In April 2015, the FASB issued ASU 2015-03, *Simplifying the Presentation of Debt Issuance Costs*. This standard requires debt issuance costs to be presented in the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of a debt discount. ASU 2015-03 became effective for us on January 1, 2016, and we applied the provisions of this standard on a retrospective basis. As a result of the adoption of this standard, debt issuance costs totaling $312,000 and $333,000 at June 30, 2016 and December 31, 2015, respectively, previously presented as other deferred charges, a non-current asset, are now presented as a deduction from long-term debt, net of current maturities in our condensed consolidated balance sheets.

Customer's Accounting for Fees Paid in a Cloud Computing Arrangement (ASC 350-40) - In April 2015, the FASB issued ASU 2015-05, *Customer's Accounting for Fees Paid in a Cloud Computing Arrangement.* Under the new standard, unless a software arrangement includes specific elements enabling customers to possess and operate software on platforms other than that offered by the cloud-based provider, the cost of such arrangements is to be accounted for as an operating expense in the period incurred. ASU 2015-05 became effective for us on January 1, 2016, and has been applied on a prospective basis. The standard did not have a material impact on our financial position or results of operations for the quarter.

Debt Issuance Costs (ASC 835-30) - In August 2015, the FASB issued ASU 2015-15, *Simplifying the Presentation of Debt Issuance Costs Associated with Line-of-Credit Arrangements*. This standard clarifies treatment of debt issuance costs associated with line-of-credit arrangements that were not specifically addressed in ASU 2015-03. Issuance costs incurred in connection with line-of-credit arrangements may be treated as an asset and amortized over the term of the line-of-credit arrangement. ASU 2015-15 became effective for us on January 1, 2016. The standard did not have a material impact on our financial position and results of operations.

Business Combinations (ASC 805) - In September 2015, the FASB issued ASU 2015-16, *Simplifying the Accounting for Measurement-Period Adjustments*. The standard eliminates the requirement to restate prior period financial statements for measurement period adjustments. The guidance requires that the cumulative impact of a measurement-period adjustment (including the impact of prior periods) be recognized in the reporting period in which the adjustment is identified. ASU 2015-16 was effective for our interim and annual financial statements issued after January 1, 2016 and was adopted on a prospective basis. Adoption of this standard did not have a material impact on our financial position and results of operations.

Balance Sheet Classification of Deferred Taxes (ASC 740) - In November 2015, the FASB issued ASU 2015-17, *Balance Sheet Classification of Deferred Taxes,* which requires all deferred assets and liabilities along with any related valuation allowance to be classified as noncurrent on the balance sheet for our annual financial statements beginning January 1, 2017 and for our interim financial statements beginning January 1, 2018; however, early adoption is permitted. We adopted this standard in the first quarter of 2016 on a retrospective basis and adjusted the December 31, 2015 balance sheet by eliminating the current deferred income taxes asset and decreasing the noncurrent deferred income taxes liability by $831,000.

Recent Accounting Standards Yet to be Adopted

Revenue from Contracts with Customers (ASC 606) - In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*. This standard provides a single comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, as well as across industries and capital markets. The standard contains principles that entities will apply to determine the measurement of revenue and when it is recognized. On July 9, 2015, the FASB affirmed its proposal to defer the implementation of this standard by one year. For public entities, this standard is effective for 2018 interim and annual financial statements. We are assessing the impact this standard may have on our financial position and results of operations.

Inventory (ASC 330) - In July 2015, the FASB issued ASU 2015-11, *Inventory*. Under this guidance, inventories are required to be measured at the lower of cost or net realizable value. Net realizable value represents the estimated selling price less costs associated with completion, disposal and transportation. ASU 2015-11 will be effective for our interim and annual financial statements issued beginning January 1, 2017; however, early adoption is permitted. The standard is to be adopted on a prospective basis. We are assessing the impact this standard may have on our financial position and results of operations.

Leases (ASC 842) - In February 2016, the FASB issued ASU 2016-02, *Leases,* which provides updated guidance regarding accounting for leases. This update requires a lessee to recognize a lease liability and a lease asset for all leases, including operating leases, with a term greater than 12 months on its balance sheet. The update also expands the required quantitative and qualitative disclosures surrounding leases. ASU 2016-02 will be effective for our annual and interim financial statements beginning January 1, 2019, although early adoption is permitted. This update will be applied using a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. We are evaluating the effect of this update on our financial position and results of operations.

Compensation (ASC 718) - In March 2016, the FASB issued ASU 2016-09, *Improvements to Employee Share-Based Payment Accounting,* which simplifies several aspects of accounting for employee share-based payment transactions, including accounting for income taxes, forfeitures, and statutory tax withholding requirements, and classification in the statement of cash flows. ASU 2016-09 will be effective for our annual and interim financial statements beginning January 1, 2017, although early adoption is permitted. The amendments included in this update are to be applied prospectively except for changes impacting the presentation of the cash flow statement that can be applied prospectively or retrospectively. We are evaluating the effect of this update on our financial position and results of operations.

2. Calculation of Earnings Per Share

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
(in thousands, except shares and per share data)				
Calculation of Basic Earnings Per Share:				
Net Income	**$ 8,029**	$ 6,294	**$ 28,396**	$ 27,403
Weighted average shares outstanding	**15,315,020**	15,235,860	**15,300,931**	14,922,094
Basic Earnings Per Share	**$ 0.52**	$ 0.41	**$ 1.86**	$ 1.84
Calculation of Diluted Earnings Per Share:				
Reconciliation of Numerator:				
Net Income	**$ 8,029**	$ 6,294	**28,396**	27,403
Reconciliation of Denominator:				
Weighted shares outstanding—Basic	**15,315,020**	15,235,860	**15,300,931**	14,922,094
Effect of dilutive securities:				
Share-based compensation	**37,682**	44,797	**41,356**	48,096
Adjusted denominator—Diluted	**15,352,702**	15,280,657	**15,342,287**	14,970,190
Diluted Earnings Per Share	**$ 0.52**	$ 0.41	**$ 1.85**	$ 1.83

3. Acquisitions

Gatherco Merger

On April 1, 2015, we completed the merger in which Gatherco merged with and into Aspire Energy, our then newly formed, wholly-owned subsidiary. Aspire Energy is an unregulated natural gas infrastructure company with approximately 2,500 miles of pipeline systems in 40 counties throughout Ohio. The majority of Aspire Energy’s margin is derived from long-term supply agreements with Columbia Gas of Ohio and Consumers Gas Cooperative, which together serve more than 20,000 end-use customers. Aspire Energy sources gas primarily from 300 conventional producers. Aspire Energy also provides gathering and processing services necessary to maintain quality and reliability to its wholesale markets.

At closing, we issued 592,970 shares of our common stock, valued at $30.2 million, based on the closing price of our common stock as reported on the NYSE on April 1, 2015. In addition, we paid $27.5 million in cash and assumed $1.7 million of existing outstanding debt, which we paid off on the same date. We also acquired $6.8 million of cash on hand at closing.

(in thousands)	Net Purchase Price
Chesapeake Utilities common stock	$ 30,164
Cash	27,494
Acquired debt	1,696
Aggregate amount paid in the acquisition	59,354
Less: cash acquired	(6,806)
Net amount paid in the acquisition	$ 52,548

The merger agreement provided for additional contingent cash consideration to Gatherco's shareholders of up to $15.0 million based on a percentage of revenue generated from potential new gathering opportunities during the five-year period following the closing. As of June 30, 2016, there have been no related gathering opportunities developed; therefore, no contingent consideration liability has been recorded. Based on the absence of related gathering opportunities being developed as of June 30, 2016, we are unable to estimate the range of undiscounted contingent liability outcomes at this time.

We incurred $1.3 million in transaction costs associated with this merger, $786,000 of which we incurred in 2014, and the remaining $514,000 we incurred during 2015. Transaction costs were included in operations expense in the accompanying condensed consolidated statements of income. The revenue and net income from this merger for the three months ended June 30, 2016, included in our condensed consolidated statements of income, were $4.8 million and $28,000, respectively. The revenue and net income from this merger for the six months ended June 30, 2016, included in our condensed consolidated statements of income, were $12.8 million and $1.7 million, respectively. This merger was accretive to earnings per share in the first full year of operations, generating $0.03 in additional earnings per share.

The purchase price allocation of the Gatherco merger was as follows:

(in thousands)	Purchase price Allocation
Purchase price	$ 57,658
Property plant and equipment	53,203
Cash	6,806
Accounts receivable	3,629
Income taxes receivable	3,163
Other assets	425
Total assets acquired	67,226
Long-term debt	1,696
Deferred income taxes	13,409
Accounts payable	3,837
Other current liabilities	745
Total liabilities assumed	19,687
Net identifiable assets acquired	47,539
Goodwill	$ 10,119

The excess of the purchase price over the estimated fair values of the assets acquired and the liabilities assumed was recognized as goodwill at the merger date. The goodwill reflects the value paid primarily for opportunities for growth in a new, strategic geographic area. All of the goodwill from this merger was recorded in the Unregulated Energy segment and is not expected to be deductible for income tax purposes.

In December 2015 and during the first quarter of 2016, we adjusted the allocation of the purchase price based on additional information available. The adjustments resulted in a change in the fair value of property, plant and equipment, deferred income tax liabilities, inventory, income taxes receivable and other current liabilities. Goodwill from the merger decreased from $11.1 million to $10.1 million after incorporating these adjustments. The allocation of the purchase price and valuation of assets are final. The valuation of additional contingent cash consideration may be adjusted as additional information becomes available.

4. Rates and Other Regulatory Activities

Our natural gas and electric distribution operations in Delaware, Maryland and Florida are subject to regulation by their respective PSC; Eastern Shore, our natural gas transmission subsidiary, is subject to regulation by the FERC; and Peninsula Pipeline, our intrastate pipeline subsidiary, is subject to regulation by the Florida PSC. Chesapeake Utilities' Florida natural gas distribution division and FPU's natural gas and electric distribution operations continue to be subject to regulation by the Florida PSC as separate entities.

Delaware

Rate Case Filing: On December 21, 2015, our Delaware division filed an application with the Delaware PSC for a base rate increase and certain other changes to its tariff. We proposed an increase of approximately $4.7 million, or nearly ten percent, in our revenue requirement based on the test period ending March 31, 2016. We also proposed new service offerings to promote growth and a revenue normalization mechanism for residential and small commercial customers. We expect a decision on the application during the first quarter of 2017. Pending the decision, our Delaware division increased rates on an interim basis based on the $2.5 million annualized interim rates approved by the Delaware PSC, effective February 19, 2016. We recognized incremental revenue of approximately $555,000 ($332,000 net of tax) and $878,000 ($526,000 net of tax) for the three and six months ended June 30, 2016, respectively. In addition, our Delaware division requested and received approval on July 26, 2016 from the Delaware PSC to implement revised interim rates of $4.7 million annualized for usage on and after August 1, 2016. Revenue collected prior to a final Delaware PSC decision is subject to refund. Although the final decision is expected during the first quarter of 2017, we cannot predict the revenue requirement the Delaware PSC will ultimately authorize or forecast the timing of a final decision. These rates, which are subject to refund, represent a five percent increase over current rates.

Maryland

Sandpiper Rate Case Filing: On December 1, 2015, Sandpiper filed an application with the Maryland PSC for a base rate increase and certain other changes to its tariff. We proposed an increase of $950,000, or approximately five percent, in our revenue requirement, based on the test period ended December 31, 2015. We also proposed a stratification of rate classes, based on cost of service, and a revenue normalization mechanism for residential and small commercial customers. The procedural schedule was suspended in early May 2016 to allow for the continuation of settlement discussions between Sandpiper, Maryland PSC Staff and Maryland Office of People's Counsel. We expect a decision on the application during the third quarter of 2016.

Florida

On September 1, 2015, FPU’s electric division filed to recover the cost of the proposed Florida Power & Light Company interconnect project through FPU's annual Fuel and Purchased Power Cost Recovery Clause filing. The interconnect project will enable FPU's electric division to negotiate a new power purchase agreement that will mitigate fuel costs for its Northeast division. This action was approved by the Florida PSC at its Agenda Conference held on December 3, 2015. On January 22, 2016, the Office of Public Counsel filed an appeal of the Florida PSC's decision with the Florida Supreme Court. Legal briefs have been filed, but no decision has been reached at this time.

On February 2, 2016, FPU’s natural gas division filed a petition with the Florida PSC for approval of an amendment to its existing transportation agreement with the City of Lake Worth, located in Palm Beach County, Florida. The amendment allows the city to resell natural gas distributed by FPU to the city’s compressed natural gas station. The city will then resell the natural gas, after compression, to its customers. The amendment to the transportation agreement was approved by the Florida PSC at its Agenda Conference held April 5, 2016.

On April 11, 2016, FPU’s natural gas divisions and Chesapeake Utilities' Florida division filed a joint petition for approval to allow FPU and Chesapeake Utilities to expand the cost allocation of the intrastate and unreleased capacity-related components currently embedded in the purchased gas adjustment and operational balancing account, which is currently allocated to a limited number of customers. The proposed new allocation of these costs would include additional customers, primarily transportation customers, benefiting from these costs but not currently paying for them. We expect the petition to be approved by the Florida PSC in late 2016.

Eastern Shore

White Oak Mainline Expansion Project: On November 21, 2014, Eastern Shore submitted an application to the FERC seeking authorization to construct, own and operate certain expansion facilities designed to provide 45,000 Dts/d of firm transportation service to an electric power generator in Kent County, Delaware. Eastern Shore proposes to construct approximately 7.2 miles of 16-inch diameter pipeline looping in Chester County, Pennsylvania and 3,550 horsepower of additional compression at Eastern Shore’s existing Delaware City compressor station in New Castle County, Delaware.

On January 22, 2015, the FERC issued a notice of intent to prepare an environmental assessment for this project. In February, April and May 2015, Eastern Shore filed environmental data in response to comments regarding the evaluation of alternate routes for a segment of the pipeline route in the vicinity of the Historic District of Kemblesville, Pennsylvania. On June 2, 2015, a field meeting was conducted to review the proposed route and alternate routes. In response to comments received from the National Park Service and other stakeholders, the FERC requested that Eastern Shore conduct an additional investigation in relation to Eastern Shore's existing right-of-way. On July 9, 2015, the FERC issued a 30-day public scoping notice, in advance of issuing an environmental assessment, in order to solicit comments from the public regarding construction of the Kemblesville loop. On August 18, 2015, Eastern Shore submitted supplemental information to the FERC regarding the results of its investigation of the Kemblesville loop.

On November 18, 2015, Eastern Shore filed an amendment to this application, which indicated the preferred pipeline route and shortened the total miles of the proposed pipeline to 5.4 miles. On February 10, 2016, the FERC issued a notice combining the White Oak Mainline Expansion Project and the System Reliability Project into a single environmental assessment. On March 2, 2016, the FERC issued a revised notice, rescheduling the issuance of the combined environmental assessment to April 25, 2016, with a 90-day authorization decision to be issued no later than July 24, 2016.

On March 28, 2016, subsequent to the issuance of the schedule, the FERC issued another environmental data request concerning the United States Department of Agriculture and an agricultural conservation easement on a tract of land where the White Oak Mainline Project would install a portion of the pipeline in its existing right-of way. On April 4, 2016, Eastern Shore responded to the data request. Subsequently, Eastern Shore revised the construction workspace configuration to mutual agreement of both parties.

On July 21, 2016, the FERC issued a certificate of public convenience and necessity authorizing Eastern Shore to construct and operate the proposed White Oak Mainline Project. The FERC denied Eastern Shore’s request for a pre-determination of rolled-in rate treatment and requires Eastern Shore to comply with 19 environmental conditions.

System Reliability Project: On May 22, 2015, Eastern Shore submitted an application to the FERC seeking authorization to construct, own and operate approximately 10.1 miles of 16-inch pipeline looping and auxiliary facilities in New Castle and Kent Counties, Delaware and a new compressor at its existing Bridgeville compressor station in Sussex County, Delaware. Eastern Shore further proposes to reinforce critical points on its pipeline system. The total project will benefit all of Eastern Shore’s customers by modifying the pipeline system to respond to severe operational conditions experienced during actual winter peak days in 2014 and 2015. Since the project is intended to improve system reliability, Eastern Shore requested a predetermination of rolled-in rate treatment for the costs of the project.

On June 8, 2015, the FERC filed a notice of the application, and the comment period ended on June 29, 2015. Two interested parties filed comments and protests with the FERC. Eastern Shore has filed answers to the comments and protests from the two parties.

On September 4, 2015, the FERC issued a notice of intent to prepare an environmental assessment, and Eastern Shore responded to the FERC Staff's environmental data requests. On February 10, 2016, the FERC issued a notice combining the System Reliability Project and White Oak Mainline Expansion project into a single environmental assessment. On March 2, 2016, the FERC issued a revised notice rescheduling the issuance of the combined environmental assessment to April 25, 2016, with the 90-day authorization decision to be issued no later than July 24, 2016. On July 21, 2016, the FERC issued a certificate of public convenience and necessity authorizing Eastern Shore to construct and operate the proposed System Reliability Project. The FERC granted Eastern Shore’s request for a pre-determination of rolled-in rate treatment in its next rate base proceeding and requires Eastern Shore to comply with 19 environmental conditions.

TETLP Capacity Expansion Project: On October 13, 2015, Eastern Shore submitted an application to the FERC to make certain measurement and related improvements at its TETLP interconnect facilities, which would enable Eastern Shore to increase natural gas receipts from TETLP by 53,000 Dts/d, for a total capacity of 160,000 Dts/d. On December 22, 2015, the FERC authorized Eastern Shore to proceed with the project. On March 11, 2016, the capacity expansion project was placed into service.

2017 Expansion Project: On May 12, 2016, Eastern Shore submitted a request to the FERC to initiate the FERC’s pre-filing review procedures for Eastern Shore's 2017 expansion project. The expansion project consists of approximately 33 miles of pipeline looping in Pennsylvania, Maryland and Delaware; upgrades to existing metering facilities in Lancaster County, Pennsylvania; installation of an additional 3,550 horsepower compressor unit at Eastern Shore’s existing Daleville compressor station in Chester County, Pennsylvania; and approximately 17 miles of new mainline extension and two pressure control stations in Sussex County, Delaware. The expansion project is necessary to provide up to 86,437 Dts/d of additional firm natural gas transportation capacity to meet anticipated market demand. On May 17, 2016, the FERC approved Eastern Shore’s request to commence the pre-filing review process. Eastern Shore is currently working through the pre-filing process and anticipates filing a certificate of public convenience and necessity seeking authorization to construct the project in November 2016.

2017 Rate Case Filing
In January 2017, Eastern Shore intends to file a base rate proceeding with the FERC as required by the terms of its 2012 settlement agreement.

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 remediate, at current and former operating sites, the effect on the environment of the disposal or release of specified substances.

MGP Sites

We have participated in the investigation, assessment or remediation of, and have exposures at, seven former MGP sites. Those sites are located in Salisbury, Maryland, Seaford, Delaware and Winter Haven, Key West, Pensacola, Sanford and West Palm Beach, Florida. We have also been in discussions with the MDE regarding another former MGP site located in Cambridge, Maryland.

As of June 30, 2016, we had approximately $9.9 million in environmental liabilities, representing our estimate of the future costs associated with all of FPU's MGP sites in Florida, which include the Key West, Pensacola, Sanford and West Palm Beach sites. FPU has approval to recover, from insurance and from customers through rates, up to $14.0 million of its environmental costs related to all of its MGP sites, approximately $10.3 million of which has been recovered as of June 30, 2016, leaving approximately $3.7 million in regulatory assets for future recovery of environmental costs from FPU's customers.

In addition to the FPU MGP sites, we had $314,000 in environmental liabilities at June 30, 2016 related to Chesapeake Utilities' MGP sites in Salisbury, Maryland and Winter Haven, Florida, representing our estimate of future costs associated with these sites. As of June 30, 2016, we had approximately $29,000 in regulatory and other assets for future recovery through Chesapeake Utilities' rates.

During the first quarter of 2015, we established $273,000 in environmental liabilities related to Chesapeake Utilities' MGP site in Seaford, Delaware, representing our estimate of future costs associated with this site, and recorded a regulatory asset for the same amount for probable future recovery through Chesapeake Utilities' rates via our environmental rider. On February 23, 2016, the Delaware PSC approved an environmental surcharge for the recovery of Chesapeake Utilities' environmental expenses associated with the Seaford site for the period of October 1, 2014 through September 30, 2015. Chesapeake Utilities will file for recovery of its expenses incurred between October 1, 2015 and September 30, 2016 by October 31, 2016. As of June 30, 2016, we had approximately $177,000 in environmental liabilities and $268,000 in regulatory and other assets related to this site.

Environmental liabilities for all of our MGP sites are recorded on an undiscounted basis based on the estimate of future costs provided by independent consultants. We continue to expect that all costs related to environmental remediation and related activities, including any potential future remediation costs for which we do not currently have approval for regulatory recovery, will be recoverable from customers through rates.

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 a MGP. FPU is implementing a remedial plan approved by the FDEP for the east parcel of the West Palm Beach site, which includes installation of monitoring test wells, sparging of air into the groundwater system and extraction of vapors from the subsurface. The Start-Up and Monitoring Report, dated November 30, 2015, was submitted for review and comment. We received a letter dated January 6, 2016 from FDEP, which provided minor comments. On January 12, 2016, FDEP conducted a facility inspection and found no problems or deficiencies.

We expect that similar remedial actions will ultimately be implemented for other portions of the site. Estimated costs of remediation for the West Palm Beach site range from approximately $4.5 million to $15.4 million, including costs associated with the relocation of FPU's operations at this site, which is necessary to implement the remedial plan, and any potential costs associated with future redevelopment of the properties. We continue to expect that all costs related to these activities will be recoverable from customers through rates.

Sanford, Florida

FPU is the current owner of property in Sanford, Florida, which was a former MGP site that was operated by several other entities before FPU acquired the property. FPU was never an owner or an operator of this former MGP site. In January 2007, FPU and the Sanford Group signed a Third Participation Agreement, which provides for the funding of the final remedy approved by the EPA for the site. FPU's share of remediation costs under the Third Participation Agreement is set at five percent of a maximum of $13.0 million, or $650,000. As of June 30, 2016, FPU has paid $650,000 to the Sanford Group escrow account for its entire share of the funding requirements.

In December 2014, the EPA issued a preliminary close-out report, documenting the completion of all physical remedial construction activities at the Sanford site. Groundwater monitoring and statutory five-year reviews to ensure performance of the approved remedy will continue on this site. The total cost of the final remedy is estimated to be over $20.0 million, which includes long-term monitoring and the settlement of claims asserted by two adjacent property owners to resolve damages that the property owners allege they have incurred and will incur as a result of the implementation of the EPA-approved remediation.

In settlement of these claims, members of the Sanford Group, which in this instance does not include FPU, have agreed to pay specified sums of money to the parties. FPU has refused to participate in the funding of the third-party settlement agreements based on its contention that it did not contribute to the release of hazardous substances at the site giving rise to the third-party claims. FPU advised the other members of the Sanford Group that it is unwilling to pay any sum in excess of the $650,000 committed by FPU in the Third Participation Agreement. The Sanford Group has not requested that FPU contribute to costs beyond the originally agreed upon $650,000 contribution.

As of June 30, 2016, FPU's remaining remediation expenses, including attorneys' fees and costs, are estimated to be $24,000. 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 as to its limited liability for future costs exceeding $13.0 million to implement the final remedy for this site, as provided for in the Third Participation Agreement, or whether the other members of the Sanford Group will pursue a claim against FPU for a sum in excess of the $650,000 that FPU has paid pursuant to the Third Participation Agreement. No such claims have been made as of June 30, 2016.

Key West, Florida

FPU formerly owned and operated a MGP in Key West, Florida. Field investigations performed in the 1990s identified limited environmental impacts at the site, which is currently owned by an unrelated third party. In 2010, after 17 years of regulatory inactivity, FDEP observed that some soil and groundwater standards were exceeded and requested implementation of additional soil and groundwater fieldwork. The scope of work is limited to the installation of two additional monitoring wells and periodic monitoring of the new and existing wells. The two additional monitoring wells were installed in November 2011, and groundwater monitoring began in December 2011. The first semi-annual report from the monitoring program was issued in May 2012. The data from the June 2012 and September 2012 monitoring events were submitted to the FDEP on October, 2012. FDEP responded on October 9, 2012 that, based on the data, NAM appears to be an appropriate remedy for the site.

In October 2012, FDEP issued a RAP approval order, which requires a limited semi-annual NAM. The most recent groundwater-monitoring event was conducted in March 2016. Natural attenuation default criteria were met at all locations sampled and the semi-annual report was submitted on April 18, 2016. FDEP responded with an acceptance letter on April 22, 2016, concurring with FPU's consultant's recommendation that semi-annual monitoring should continue at this facility, with the next semi-annual NAM scheduled for the third quarter of 2016.

Although the duration of the FDEP-required limited NAM cannot be determined with certainty, we anticipate that total costs to complete the remedial action will not exceed $50,000. The annual cost to conduct the limited NAM program is not expected to exceed $8,000.

Pensacola, Florida

FPU formerly owned and operated a 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 FDOT. In October 2009, FDEP informed Gulf Power that it would approve a conditional No Further Action determination for the site with the requirement for institutional and engineering controls. On June 16, 2014, FDEP issued a draft memorandum of understanding between FDOT and FDEP to implement site closure with approved institutional and engineering controls for the site. We anticipate that FPU's share of remaining legal and cleanup costs will not exceed $5,000.

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 FDEP, we are obligated to assess and remediate environmental impacts at this former MGP site. Groundwater monitoring results have shown a continuing reduction in contaminant concentrations from the sparging system, which has been in operation since 2002. On September 12, 2014, FDEP issued a letter approving shutdown of the sparging operations on the northern portion of the site, contingent upon continued semi-annual monitoring.

Groundwater monitoring results on the southern portion of this site indicate that natural attenuation default criteria continue to be exceeded. Plans to modify the monitoring network on the southern portion of the site in order to collect additional data to support the development of a remedial plan were specified in a letter to FDEP, dated October 17, 2014. The well installation and abandonment program was implemented in October 2014, and documentation was reported in the next semi-annual RAP implementation status report, submitted on January 8, 2015. FDEP approved the plan to expand the bio-sparging operations in the southern portion of the site, and additional sparge points were installed and connected to the operating system in the first quarter of 2016.

Although specific remedial actions for the site have not yet been identified, we estimate that future remediation costs for the subsurface soils and groundwater at the site should not exceed $425,000, which includes an estimate of $100,000 to implement additional actions, such as institutional controls, at the site. We continue to believe that the entire amount will be recoverable from customers through rates.

FDEP previously indicated that we could also be required to remediate sediments along the shoreline of Lake Shipp, immediately west of the site. Based on studies performed to date, and our recent meeting with FDEP, we believe that corrective measures for lake sediments are not warranted and will not be required by FDEP. Therefore, we have not recorded a liability for sediment remediation.

Salisbury, Maryland

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

Seaford, Delaware

In a letter dated December 5, 2013, DNREC notified us that it would be conducting a facility evaluation of a former MGP site in Seaford, Delaware. In a report issued in January 2015, DNREC provided the evaluation, which found several compounds within the groundwater and soil that require further investigation. On September 17, 2015, DNREC approved our application to enter this site into the voluntary cleanup program. A remedial investigation was conducted in December 2015, and the resulting remedial investigation report was submitted to DNREC in May 2016. Based on findings from the remedial investigation, DNREC requested additional investigative work be performed prior to approval of potential remedial actions. We anticipate completing this additional investigative work by the end of 2016. We estimate the cost of potential remedial actions, based on the findings of the DNREC report, to be between $273,000 and $465,000. We also believe these costs will be recoverable from customers through rates.

Cambridge, Maryland

We are discussing with the MDE 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.

Ohio

We have completed the investigation, assessment and remediation of eight natural gas pipeline facilities in Ohio that Aspire Energy acquired from Gatherco pursuant to the merger. Gatherco's indemnification obligations for environmental matters apply to remediation costs in excess of a $431,250 deductible and are capped at $1.7 million. Pursuant to the merger agreement, an escrow was established to fund certain claims by Chesapeake Utilities and Aspire Energy for indemnification by Gatherco, including environmental claims. The costs incurred to date associated with remediation activities for these eight facilities is approximately $1.6 million. We have recorded a receivable for the costs incurred, net of the deductible amount, and have submitted our request for reimbursement to the escrow agent. Negotiations are currently underway.

6. Other Commitments and Contingencies

Natural Gas, Electric and Propane Supply

Our natural gas, electric and propane distribution operations have entered into contractual commitments to purchase natural gas, electricity and propane from various suppliers. The contracts have various expiration dates. For our Delaware and Maryland natural gas distribution divisions, we have a contract with an unaffiliated energy marketing and risk management company to manage a portion of their natural gas transportation and storage capacity, which expires on March 31, 2017.

In May 2013, Sandpiper entered into a capacity, supply and operating agreement with EGWIC to purchase propane over a six-year term, or until May 2019. Sandpiper's current annual commitment is estimated at approximately 6.5 million gallons. Sandpiper has the option to enter into either a fixed per-gallon price for some or all of the propane purchases or a market-based price utilizing one of two local propane pricing indices.

Also in May 2013, Sharp entered into a separate supply and operating agreement with EGWIC. Under this agreement, Sharp has a commitment to supply propane to EGWIC over a six-year term, or until May 2019. Sharp's current annual commitment is estimated at approximately 6.5 million gallons. The agreement between Sharp and EGWIC is separate from the agreement between Sandpiper and EGWIC, and neither agreement permits the parties to set off the rights and obligations specified in one agreement against those specified in the other agreement.

Chesapeake Utilities' Florida natural gas distribution division has firm transportation service contracts with FGT and 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 Utilities is contingently liable to FGT and Gulfstream should any party that acquired the capacity through release fail to pay the capacity charge.

In May 2015, PESCO renewed contracts to purchase natural gas from various suppliers for a one-year term, expiring May 2016, with the total monthly purchase commitment ranging from 9,982 to 13,423 Dts/d. PESCO has renewed these contracts for an additional six-month term, expiring October 2016.

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) a fixed charge coverage ratio greater than 1.5 times. If FPU fails to comply with either of these ratios, it has 30 days to cure the default or, if the default is not cured, to provide an irrevocable letter of credit. 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 either of these ratios, 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 also result in FPU having to provide an irrevocable letter of credit. As of June 30, 2016, FPU was in compliance with all of the requirements of its fuel supply contracts.

Corporate Guarantees

The Board of Directors has authorized the Company to issue corporate guarantees and to obtain letters of credit securing our subsidiaries' obligations. The maximum authorized liability under such guarantees and letters of credit is $65.0 million.

We have issued corporate guarantees to certain of our subsidiaries' vendors, the largest of which are for Xeron and PESCO. These corporate guarantees provide for the payment of propane and natural gas purchases in the event that Xeron or PESCO defaults. Neither subsidiary has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded when incurred. The aggregate amount guaranteed at June 30, 2016 was approximately $53.6 million, with the guarantees expiring on various dates through June 2017.

Chesapeake Utilities also guarantees the payment of FPU’s first mortgage bonds. The maximum exposure under this guarantee is the outstanding principal plus accrued interest balances. The outstanding principal balances of FPU’s first mortgage bonds approximate their carrying values (see Note 14*, Long-Term Debt*, for further details).

We issued letters of credit totaling approximately $8.1 million related to the electric transmission services for FPU's northwest electric division, the firm transportation service agreement between TETLP and our Delaware and Maryland divisions, and to our current and previous primary insurance carriers. These letters of credit have various expiration dates through March 2017. There have been no draws on these letters of credit as of June 30, 2016. 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.

Tax-related Contingencies

We are subject to various audits and reviews by the federal, state, local and other governmental authorities regarding income taxes and taxes other than income. As of June 30, 2016, we maintained a liability of approximately $50,000 related to unrecognized income tax benefits and approximately $72,000 related to contingencies for taxes other than income. As of December 31, 2015, we maintained a liability of approximately $50,000 related to unrecognized income tax benefits and approximately $310,000 related to contingencies for taxes other than income.

Other

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

7. Segment Information

We use the management approach to identify operating segments. We organize our business around differences in regulatory environment and/or products or services, and the operating results of each segment are regularly reviewed by the chief operating decision maker (our Chief Executive Officer) in order to make decisions about resources and to assess performance. The segments are evaluated based on their pre-tax operating income. Our operations comprise two reportable segments:

- *Regulated Energy*. The Regulated Energy segment includes natural gas distribution, natural gas transmission and electric distribution operations. All operations in this segment are regulated, as to their rates and services, by the PSC having jurisdiction in each operating territory or by the FERC in the case of Eastern Shore.
- *Unregulated Energy*. The Unregulated Energy segment includes propane distribution and wholesale marketing operations, and natural gas marketing operations, which are unregulated as to their rates and services. Effective April 1, 2015, this segment includes Aspire Energy, whose services include natural gas gathering, processing, transportation and supply (See Note 3, *Acquisitions*, regarding the merger with Gatherco). Also included in this segment are other unregulated energy services, such as energy-related merchandise sales and heating, ventilation and air conditioning, plumbing and electrical services.

The remainder of our operations is presented as “Other businesses and eliminations”, which consists of unregulated subsidiaries that own real estate leased to Chesapeake Utilities, as well as certain corporate costs not allocated to other operations.

The following table presents financial information about our reportable segments:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	**2015**	**2016**	**2015**
(in thousands)				
Operating Revenues, Unaffiliated Customers				
Regulated Energy segment	**$ 66,590**	$ 61,790	**$ 155,483**	$ 171,082
Unregulated Energy segment	**35,752**	30,892	**93,155**	91,681
Total operating revenues, unaffiliated customers	**$ 102,342**	$ 92,682	**$ 248,638**	$ 262,763
Intersegment Revenues [1]				
Regulated Energy segment	**$ 805**	$ 270	**$ 1,128**	$ 560
Unregulated Energy segment	**1,052**	1,666	**1,165**	1,873
Other businesses	**240**	220	**466**	440
Total intersegment revenues	**$ 2,097**	$ 2,156	**$ 2,759**	$ 2,873
Operating Income				
Regulated Energy segment	**$ 15,226**	$ 13,605	**$ 39,545**	$ 35,788
Unregulated Energy segment	**412**	(540)	**12,347**	14,689
Other businesses and eliminations	**104**	105	**230**	201
Total operating income	**15,742**	13,170	**52,122**	50,678
Other Expense, net	**(8)**	(171)	**(42)**	(38)
Interest	**2,624**	2,485	**5,274**	4,933
Income before Income Taxes	**13,110**	10,514	**46,806**	45,707
Income taxes	**5,081**	4,220	**18,410**	18,304
Net Income	**$ 8,029**	$ 6,294	**$ 28,396**	$ 27,403

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

(in thousands)	**June 30, 2016**	**December 31, 2015**
Identifiable Assets		
Regulated Energy segment	**$ 892,513**	$ 872,065
Unregulated Energy segment	**192,654**	171,840
Other businesses and eliminations	**11,880**	23,516
Total identifiable assets	**$ 1,097,047**	$ 1,067,421

Our operations are entirely domestic.

8. Accumulated Other Comprehensive Loss

Defined benefit pension and postretirement plan items, unrealized gains (losses) of our propane swap agreements, call options and natural gas futures contracts, designated as commodity contracts cash flow hedges, are the components of our accumulated comprehensive income (loss). The following tables present the changes in the balance of accumulated other comprehensive loss for the six months ended June 30, 2016 and 2015. All amounts are presented net of tax.

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
As of December 31, 2015	**$ (5,580)**	**$ (260)**	**$ (5,840)**
Other comprehensive gain before reclassifications	**—**	**525**	**525**
Amounts reclassified from accumulated other comprehensive loss	**176**	**(29)**	**147**
Net current-period other comprehensive income	**176**	**496**	**672**
As of June 30, 2016	**$ (5,404)**	**$ 236**	**$ (5,168)**

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
As of December 31, 2014	$ (5,643)	$ (33)	$ (5,676)
Other comprehensive loss before reclassifications	—	(1)	(1)
Amounts reclassified from accumulated other comprehensive loss	165	33	198
Net prior-period other comprehensive income	165	32	197
As of June 30, 2015	$ (5,478)	$ (1)	$ (5,479)

The following table presents amounts reclassified out of accumulated other comprehensive loss for the three and six months ended June 30, 2016 and 2015. Deferred gains or losses for our commodity contracts cash flow hedges are recognized in earnings upon settlement.

(in thousands)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Amortization of defined benefit pension and postretirement plan items:				
Prior service cost [1]	**$ 20**	$ 17	**$ 40**	$ 34
Net loss [1]	**(166)**	(155)	**(333)**	(310)
Total before income taxes	**(146)**	(138)	**(293)**	(276)
Income tax benefit	**58**	55	**117**	111
Net of tax	**$ (88)**	$ (83)	**$ (176)**	$ (165)
Gains and losses on commodity contracts cash flow hedges				
Propane swap agreements [2]	**$ —**	$ (10)	**$ (322)**	$ 2
Call options [2]	**—**	—	**—**	(55)
Natural gas futures [2]	**211**	—	**359**	—
Total before income taxes	**211**	(10)	**37**	(53)
Income tax benefit (expense)	**(81)**	4	**(8)**	21
Net of tax	**130**	(6)	**29**	(32)
Total reclassifications for the period	**$ 42**	$ (89)	**$ (147)**	$ (197)

[1] These amounts are included in the computation of net periodic costs (benefits). See Note 9, *Employee Benefit Plans*, for additional details.
[2] These amounts are included in the effects of gains and losses from derivative instruments. See Note 12, *Derivative Instruments*, for additional details.

Amortization of defined benefit pension and postretirement plan items is included in operations expense, and gains and losses on propane swap agreements and call options are included in cost of sales in the accompanying condensed consolidated statements of income. The income tax benefit is included in income tax expense in the accompanying condensed consolidated statements of income.

9. Employee Benefit Plans

Net periodic benefit costs for our pension and post-retirement benefits plans for the three and six months ended June 30, 2016 and 2015 are set forth in the following table:

	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP		Chesapeake Postretirement Plan		FPU Medical Plan	
For the Three Months Ended June 30,	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**
(in thousands)										
Interest cost	**$ 105**	$ 102	**$ 630**	$ 626	**$ 23**	$ 23	**$ 11**	$ 11	**$ 14**	$ 15
Expected return on plan assets	**(131)**	(135)	**(701)**	(777)	**—**	—	**—**	—	**—**	—
Amortization of prior service cost	**—**	—	**—**	—	**—**	2	**(20)**	(19)	**—**	—
Amortization of net loss	**103**	91	**128**	114	**22**	25	**17**	17	**—**	2
Net periodic cost (benefit)	77	58	**57**	(37)	**45**	50	**8**	9	**14**	17
Amortization of pre-merger regulatory asset	—	—	**191**	191	**—**	—	**—**	—	**2**	2
Total periodic cost	**$ 77**	$ 58	**$ 248**	$ 154	**$ 45**	$ 50	**$ 8**	$ 9	**$ 16**	$ 19

For the Six Months Ended June 30,	Chesapeake Pension Plan 2016	Chesapeake Pension Plan 2015	FPU Pension Plan 2016	FPU Pension Plan 2015	Chesapeake SERP 2016	Chesapeake SERP 2015	Chesapeake Postretirement Plan 2016	Chesapeake Postretirement Plan 2015	FPU Medical Plan 2016	FPU Medical Plan 2015
(in thousands)										
Interest cost	**$ 210**	$ 204	**$ 1,259**	$ 1,251	**$ 46**	$ 46	**$ 21**	$ 22	**$ 28**	$ 30
Expected return on plan assets	**(261)**	(270)	**(1,402)**	(1,554)	**—**	—	**—**	—	**—**	—
Amortization of prior service cost	**—**	—	**—**	—	**—**	5	**(40)**	(39)	**—**	—
Amortization of net loss	**206**	181	**257**	227	**44**	50	**34**	35	**—**	3
Net periodic cost (benefit)	**155**	115	**114**	(76)	**90**	101	**15**	18	**28**	33
Amortization of pre-merger regulatory asset	**—**	—	**381**	381	**—**	—	**—**	—	**4**	4
Total periodic cost	**$ 155**	$ 115	**$ 495**	$ 305	**$ 90**	$ 101	**$ 15**	$ 18	**$ 32**	$ 37

We expect to record pension and postretirement benefit costs of approximately $1.6 million for 2016. Included in these costs is approximately $769,000 related to continued amortization of the FPU pension regulatory asset, which represents the portion attributable to FPU's regulated energy operations for the changes in funded status that occurred, but were not recognized, as part of net periodic benefit costs prior to the FPU merger in 2009. This was deferred as a regulatory asset by FPU prior to the merger, to be recovered through rates pursuant to a previous order by the Florida PSC. The unamortized balance of this regulatory asset was approximately $2.5 million and approximately $2.9 million at June 30, 2016 and December 31, 2015, respectively. The amortization included in pension expense is also being added to a net periodic loss of approximately $802,000, which will increase our total expected benefit costs to approximately $1.6 million.

Pursuant to a Florida PSC order, FPU continues to record as a regulatory asset a portion of the unrecognized pension and postretirement benefit costs related to its regulated operations after the FPU merger. The portion of the unrecognized pension and postretirement benefit costs related to FPU's unregulated operations and Chesapeake Utilities' operations is recorded to accumulated other comprehensive loss. The following table presents the amounts included in the regulatory asset and accumulated other comprehensive loss that were recognized as components of net periodic benefit cost during the three and six months ended June 30, 2016 and 2015:

For the Three Months Ended June 30, 2016	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service credit	$ —	$ —	$ —	$ (20)	$ —	$ (20)
Net loss	103	128	22	17	—	270
Total recognized in net periodic benefit cost	$ 103	$ 128	$ 22	$ (3)	$ —	$ 250
Recognized from accumulated other comprehensive loss [(1)]	$ 103	$ 24	$ 22	$ (3)	$ —	$ 146
Recognized from regulatory asset	—	104	—	—	—	104
Total	$ 103	$ 128	$ 22	$ (3)	$ —	$ 250

For the Three Months Ended June 30, 2015 *(in thousands)*	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service cost (credit)	$ —	$ —	$ 2	$ (19)	$ —	$ (17)
Net loss	91	114	25	17	2	249
Total recognized in net periodic benefit cost	$ 91	$ 114	$ 27	$ (2)	$ 2	$ 232
Recognized from accumulated other comprehensive loss [1]	$ 91	$ 22	$ 27	$ (2)	$ —	$ 138
Recognized from regulatory asset	—	92	—	—	2	94
Total	$ 91	$ 114	$ 27	$ (2)	$ 2	$ 232

For the Six Months Ended June 30, 2016 *(in thousands)*	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service credit	$ —	$ —	$ —	$ (40)	$ —	$ (40)
Net loss	206	257	44	34	—	$ 541
Total recognized in net periodic benefit cost	$ 206	$ 257	$ 44	$ (6)	$ —	$ 501
Recognized from accumulated other comprehensive loss [1]	$ 206	$ 49	$ 44	$ (6)	$ —	$ 293
Recognized from regulatory asset	—	208	—	—	—	208
Total	$ 206	$ 257	$ 44	$ (6)	$ —	$ 501

For the Six Months Ended June 30, 2015 *(in thousands)*	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service cost (credit)	$ —	$ —	$ 5	$ (39)	$ —	$ (34)
Net loss	181	227	50	35	3	496
Total recognized in net periodic benefit cost	$ 181	$ 227	$ 55	$ (4)	$ 3	$ 462
Recognized from accumulated other comprehensive loss [1]	$ 181	$ 43	$ 55	$ (4)	$ 1	$ 276
Recognized from regulatory asset	—	184	—	—	2	186
Total	$ 181	$ 227	$ 55	$ (4)	$ 3	$ 462

(1) See Note 8, *Accumulated Other Comprehensive Loss*.

During the three and six months ended June 30, 2016, we contributed approximately $170,000 and $274,000, respectively, to the Chesapeake Pension Plan and approximately $548,000 and approximately $885,000, respectively, to the FPU Pension Plan. We expect to contribute a total of approximately $508,000 and approximately $1.6 million to the Chesapeake Pension Plan and FPU Pension Plan, respectively, during 2016, which represent the minimum annual contribution payments required.

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 six months ended June 30, 2016, were approximately $38,000 and approximately $76,000, respectively. We expect to pay total cash benefits of approximately $151,000 under the Chesapeake Pension SERP in 2016. Cash benefits paid under the Chesapeake Postretirement Plan, primarily for medical claims for the three and six months ended June 30, 2016, were approximately $15,000 and approximately $36,000, respectively. We estimate that approximately $82,000 will be paid for such benefits under the Chesapeake Postretirement Plan in 2016. Cash benefits paid under the FPU Medical Plan, primarily for medical claims for the three and six months ended June 30, 2016, were approximately $27,000 and approximately $67,000, respectively. We estimate that approximately $149,000 will be paid for such benefits under the FPU Medical Plan in 2016.

10. Investments

The investment balances at June 30, 2016 and December 31, 2015, consisted of the following:

(in thousands)	June 30, 2016	December 31, 2015
Rabbi trust (associated with the Deferred Compensation Plan)	**$ 4,304**	$ 3,626
Investments in equity securities	**21**	18
Total	**$ 4,325**	$ 3,644

We classify these investments as trading securities and report them at their fair value. For the three months ended June 30, 2016 and 2015, we recorded a net unrealized gain of approximately $71,000 and approximately $4,000, respectively, in other income in the condensed consolidated statements of income related to these investments. For the six months ended June 30, 2016 and 2015, we recorded an unrealized gain of approximately $53,000 and approximately $107,000, respectively, in other income in the condensed consolidated statements of income related to these investments. For the investment in the Rabbi Trust, we also have recorded an associated liability, which is included in other pension and benefit costs in the condensed consolidated balance sheets and is adjusted each month for the gains and losses incurred by the investments in the Rabbi Trust.

11. Share-Based Compensation

Our non-employee directors and key employees are granted share-based awards through our SICP. We record these share-based awards as compensation costs over the respective service period for which services are received in exchange for an award of equity or equity-based compensation. The compensation cost is based primarily on the fair value of the shares awarded, using the estimated fair value of each share on the date it was granted and the number of shares to be issued at the end of the service period.

The table below presents the amounts included in net income related to share-based compensation expense for the three and six months ended June 30, 2016 and 2015:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2016	2015	2016	2015
Awards to non-employee directors	**$ 145**	$ 160	**$ 310**	$ 311
Awards to key employees	**470**	250	**954**	636
Total compensation expense	**615**	410	**1,264**	947
Less: tax benefit	**(248)**	(165)	**(509)**	(381)
Share-based compensation amounts included in net income	**$ 367**	$ 245	**$ 755**	$ 566

Non-employee Directors

Shares granted to non-employee directors are issued in advance of the directors' service periods and are fully vested as of the grant date. We record a prepaid expense equal to the fair value of the shares issued and amortize the expense equally over a service period of one year. In May 2016, each of our non-employee directors received an annual retainer of 953 shares of common stock under the SICP for service as a director through the 2017 Annual Meeting of Stockholders.

A summary of the stock activity for our non-employee directors during the six months ended June 30, 2016 is presented below:

	Number of Shares	Weighted Average Fair Value
Outstanding— December 31, 2015	—	$ —
Granted	8,577	$ 62.90
Vested	(8,577)	$ 62.90
Outstanding— June 30, 2016	—	$ —

At June 30, 2016, there was approximately $450,000 of unrecognized compensation expense related to these awards. This expense will be recognized over the directors' remaining service period ending April 30, 2017.

Key Employees

The table below presents the summary of the stock activity for awards to key employees for the six months ended June 30, 2016:

	Number of Shares	Weighted Average Fair Value
Outstanding— December 31, 2015	110,398	$ 38.34
Granted	46,571	$ 67.90
Vested	(39,553)	$ 31.79
Expired	(2,325)	$ 42.25
Outstanding— June 30, 2016	115,091	$ 51.85

In February 2016, our Board of Directors granted awards of 46,571 shares of common stock to key employees under the SICP. The shares granted in February 2016 are multi-year awards that will vest at the end of the three-year service period ending December 31, 2018. All of these stock awards are earned based upon the successful achievement of long-term goals, growth and financial results, which 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 grant date of each award. For the market-based conditions, we used the Black-Scholes pricing model to estimate the fair value of each market-based award granted.

At June 30, 2016, the aggregate intrinsic value of the SICP awards granted to key employees was approximately $7.6 million. At June 30, 2016, there was approximately $3.2 million of unrecognized compensation cost related to these awards, which is expected to be recognized from 2016 through 2018.

12. Derivative Instruments

We use derivative and non-derivative contracts to engage in trading activities and manage risks related to obtaining adequate supplies and the price fluctuations of natural gas, electricity and propane. Our natural gas, electric and propane distribution operations have entered into agreements with suppliers to purchase natural gas, electricity and propane for resale to their customers. Aspire Energy has entered into contracts with producers to secure natural gas to meet its obligations. Purchases under these contracts typically either do not meet the definition of derivatives or are considered “normal purchases and normal sales” and are accounted for on an accrual basis. Our propane distribution and natural gas marketing operations may also enter into fair value hedges of their inventory or cash flow hedges of their future purchase commitments in order to mitigate the impact of wholesale price fluctuations. As of June 30, 2016, our natural gas and electric distribution operations did not have any outstanding derivative contracts.

Hedging Activities in 2016

In June 2016, Sharp entered into a swap agreement to mitigate the risk of fluctuations in wholesale propane index prices associated with 630,000 gallons expected to be purchased for the upcoming heating season. Under the swap agreement, Sharp will receive the difference between the index prices (Mont Belvieu prices in December 2016 through February 2017) and the swap price of $0.5525 per gallon, to the extent the index prices exceed the swap price. If the index prices are lower than the swap price, Sharp will pay the difference. The swap agreement essentially fixes the price of the 630,000 gallons that we expect to purchase for the upcoming heating season. We accounted for the swap agreement as a cash flow hedge, and there is no ineffective portion of this hedge. At June 30, 2016, the swap agreement had a fair value of approximately $23,000. The change in the fair value of the swap agreement is recorded as unrealized gain/loss in other comprehensive income (loss).

In January 2016, PESCO entered into a SCO supplier agreement with Columbia Gas to provide natural gas supply for Columbia Gas to service one of its local distribution customer tranches. PESCO also assumed the obligation to store natural gas inventory to satisfy its obligations under the SCO supplier agreement, which terminates on March 31, 2017.

In conjunction with the SCO supplier agreement, PESCO entered into natural gas futures contracts during the second quarter of 2016 in order to protect its natural gas inventory against market price fluctuations. The contracts expire within one year. We have accounted for these contracts as fair value hedges, and any ineffective portion is reported directly in earnings. We believe these contracts are highly effective at hedging inventory. At June 30, 2016, PESCO had a total of 1,065,000 Dts/d hedged under natural gas futures contracts, with a liability fair value of approximately $233,000. The change in fair value of the natural gas futures contracts is recorded as unrealized gain (loss) in earnings and is offset by any associated gain (loss) in the value of the inventory being hedged.

Beginning in October 2015, PESCO entered into natural gas futures contracts associated with the purchase and sale of natural gas to other specific customers. These contracts expire within two years, and we have accounted for them as cash flow hedges. There is no ineffective portion of these hedges. At June 30, 2016, PESCO had a total of 6,090,000 Dts/d hedged under natural gas futures contracts, with an asset fair value of approximately $357,000. The change in fair value of the natural gas futures contracts is recorded as unrealized gain (loss) in other comprehensive income (loss).

Fair Value Hedges
The impact of our natural gas futures commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three and six months ended June 30, 2016 is presented below:

(in thousands)	Three Months Ended June 30, 2016(1)	Six Months Ended June 30, 2016(1)
Commodity contracts	$ (233)	$ (233)
Fair value adjustment for natural gas inventory designated as the hedged item	681	681
Total increase in purchased gas cost	$ 448	$ 448
The increase in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$ (83)	$ (83)
Timing ineffectiveness	531	531
Total ineffectiveness	$ 448	$ 448

(1) There were no natural gas futures commodity contracts designated as fair value hedges in 2015.

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedging instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot-to-forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on purchased gas cost. To the extent that our natural gas inventory does not qualify as a hedged item in a fair-value hedge, or has not been designated as such, the natural gas inventory is valued at the lower of cost or market.

Hedging Activities in 2015
In March, May and June 2015, Sharp paid a total of approximately $143,000 to purchase put options to protect against a decline in propane prices and related potential inventory losses associated with 2.5 million gallons for the propane price cap program in the 2015-2016 heating season. We exercised the put options as propane prices fell below the strike prices of $0.4950, $0.4888 and $0.4500 per gallon in December 2015 through February 2016 and $0.4200 per gallon in January through March 2016. We received approximately $239,000, which represents the difference between the market prices and the strike prices during those months. We accounted for the put options as fair value hedges.

In March, May and June 2015, Sharp entered into swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with 2.5 million gallons purchased in December 2015 through March 2016. Under these swap agreements, Sharp would have received the difference between the index prices (Mont Belvieu prices in December 2015 through March 2016) and the swap prices, which ranged from $0.5200 to $0.5950 per gallon, for each swap agreement, to the extent the index prices exceeded the swap prices. If the index prices were lower than the swap prices, Sharp would pay the difference. These swap agreements essentially fixed the price of the 2.5 million gallons that we purchased during this period. We accounted for the swap agreements as cash flow hedges. Sharp paid approximately $484,000, which represents the difference between the index prices and swap prices during those months of the swap agreements.

Commodity Contracts for Trading Activities
Xeron engages in trading activities using forward and futures contracts for propane and crude oil. These contracts are considered derivatives and have been accounted for using the mark-to-market method of accounting. Under this method, the trading contracts are recorded at fair value, and the changes in fair value of those contracts are recognized as unrealized gains or losses in the statements of income for the period of change. As of June 30, 2016, we had the following outstanding propane and crude oil trading contracts, which we accounted for as derivatives:

At June 30, 2016	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts - Propane			
Purchase	421,000	$ 0.5375	$ 0.5388

At June 30, 2016	Quantity in Barrels	Estimated Market Prices	Weighted Average Contract Prices
Futures Contracts - Crude Oil			
Purchase	20,000	$ 48.3300	$ 47.9000

Estimated market prices and weighted average contract prices are in dollars per gallon and barrel. All contracts expire by the end of the third quarter of 2016.

Xeron entered into master netting agreements with two counterparties to mitigate exposure to counterparty credit risk. The master netting agreements enable Xeron to net these two counterparties' outstanding accounts receivable and payable, which are presented on a gross basis in the accompanying condensed consolidated balance sheets. At June 30, 2016, Xeron had no accounts receivable or accounts payable balances to offset with these two counterparties. At December 31, 2015, Xeron had a right to offset $431,000 of accounts payable with these two counterparties. At December 31, 2015, Xeron did not have outstanding accounts receivable with these two counterparties.

The following tables present information about the fair value and related gains and losses of our derivative contracts. We did not have any derivative contracts with a credit-risk-related contingency. The fair values of the derivative contracts recorded in the condensed consolidated balance sheets as of June 30, 2016 and December 31, 2015, are as follows:

	Asset Derivatives		
		Fair Value As Of	
(in thousands)	Balance Sheet Location	June 30, 2016	December 31, 2015
Derivatives not designated as hedging instruments			
Forward & Future contracts	Mark-to-market energy assets	**$ 25**	$ 1
Derivatives designated as fair value hedges			
Put options	Mark-to-market energy assets	—	152
Derivatives designated as cash flow hedges			
Natural gas futures contracts	Mark-to-market energy assets	**357**	—
Propane swap agreements	Mark-to-market energy assets	**23**	—
Total asset derivatives		**$ 405**	$ 153

(in thousands)	Liability Derivatives Balance Sheet Location	Fair Value As Of June 30, 2016	December 31, 2015
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy liabilities	**$ 23**	$ 1
Derivatives designated as fair value hedges			
Natural gas futures contracts	Mark-to-market energy liabilities	**233**	—
Derivatives designated as cash flow hedges			
Propane swap agreements	Mark-to-market energy liabilities	**—**	323
Natural gas futures contracts	Mark-to-market energy liabilities	**—**	109
Total liability derivatives		**$ 256**	$ 433

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

		Amount of Gain (Loss) on Derivatives:			
	Location of Gain	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
(in thousands)	(Loss) on Derivatives	2016	2015	2016	2015
Derivatives not designated as hedging instruments					
Realized gain on forward contracts (1)	Revenue	**$ 88**	$ (71)	**275**	206
Unrealized gain (loss) on forward contracts (1)	Revenue	**1**	203	**2**	78
Propane swap agreements	Cost of sales	**—**	—	**—**	18
Derivatives designated as fair value hedges					
Put /Call options	Cost of sales	**—**	—	**73**	506
Put /Call options (2)	Propane Inventory	—	(30)		(34)
Natural gas futures contracts	Natural Gas Inventory	**(233)**	—	**(233)**	—
Derivatives designated as cash flow hedges					
Propane swap agreements	Cost of sales	**—**	—	**(364)**	—
Propane swap agreements	Other Comprehensive Gain (Loss)	**23**	10	**23**	(2)
Call options	Cost of sales	**—**	—	**—**	(81)
Natural gas futures contracts	Cost of sales	**211**	—	**359**	—
Natural gas futures contracts	Other Comprehensive Gain	**786**	—	**472**	—
Total		**$ 876**	$ 112	**$ 607**	$ 691

(1) All of the realized and unrealized gain (loss) on forward contracts represents the effect of trading activities on our condensed consolidated statements of income.

(2) As a fair value hedge with no ineffective portion, the unrealized gains and losses associated with this call option are recorded in cost of sales, offset by the corresponding change in the value of propane inventory (hedged item), which is also recorded in cost of sales. The amounts in cost of sales offset to zero, and the unrealized gains and losses of this put option effectively changed the value of propane inventory.

13. 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).

Financial Assets and Liabilities Measured at Fair Value

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 as of June 30, 2016 and December 31, 2015:

		Fair Value Measurements Using:		
As of June 30, 2016 *(in thousands)*	**Fair Value**	**Quoted- Prices- in Active Markets (Level 1)**	**Significant- Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Assets:				
Investments—equity securities	$ 21	$ 21	$ —	$ —
Investments—guaranteed income fund	$ 475	$ —	$ —	$ 475
Investments—mutual funds and other	$ 3,829	$ 3,829	$ —	$ —
Mark-to-market energy assets, incl. put options and swap agreements	$ 405	$ —	$ 405	$ —
Liabilities:				
Mark-to-market energy liabilities incl. swap agreements	$ 256	$ —	$ 256	$ —

		Fair Value Measurements Using:		
As of December 31, 2015 *(in thousands)*	**Fair Value**	**Quoted- Prices- in Active Markets (Level 1)**	**Significant- Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Assets:				
Investments—equity securities	$ 18	$ 18	$ —	$ —
Investments—guaranteed income fund	$ 279	$ —	$ —	$ 279
Investments—mutual funds and other	$ 3,347	$ 3,347	$ —	$ —
Mark-to-market energy assets, incl. put/call options	$ 153	$ —	$ 153	$ —
Liabilities:				
Mark-to-market energy liabilities, incl. swap agreements	$ 433	$ —	$ 433	$ —

The following valuation techniques were used to measure fair value assets in the tables above on a recurring basis as of June 30, 2016 and December 31, 2015:

Level 1 Fair Value Measurements:

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

Investments - mutual funds and other — The fair values of these investments, comprised of money market and mutual funds, are recorded at fair value based on quoted net asset values of the shares.

Level 2 Fair Value Measurements:

Mark-to-market energy assets and liabilities — These forward contracts are valued using market transactions in either the listed or OTC markets.

Propane put/call options, swap agreements and natural gas futures contracts – The fair value of the propane put/call options, swap agreements and natural gas futures contracts are measured using market transactions for similar assets and liabilities in either the listed or OTC markets.

Level 3 Fair Value Measurements:

Investments- guaranteed income fund — The fair values of these investments are recorded at the contract value, which approximates their fair value.

The following table sets forth the summary of the changes in the fair value of Level 3 investments for the six months ended June 30, 2016 and 2015:

	Six Months Ended June 30,	
(in thousands)	**2016**	**2015**
Beginning Balance	**$ 279**	$ 287
Purchases and adjustments	**112**	49
Transfers	**88**	(3)
Distribution	**(8)**	—
Investment income	**4**	2
Ending Balance	**$ 475**	$ 335

Investment income from the Level 3 investments is reflected in other income (expense) in the accompanying condensed consolidated statements of income.

At June 30, 2016, there were no non-financial assets or liabilities required to be reported at fair value. We review our non-financial assets for impairment at least on an annual basis, as required.

Other Financial Assets and Liabilities

Financial assets with carrying values approximating fair value include cash and cash equivalents and accounts receivable. Financial liabilities with carrying values approximating fair value include accounts payable and other accrued liabilities and short-term debt. The fair value of cash and cash equivalents is measured using the comparable value in the active market and approximates its carrying value (Level 1 measurement). The fair value of short-term debt approximates the carrying value due to its short maturities and because interest rates approximate current market rates (Level 3 measurement).

At June 30, 2016, long-term debt, including current maturities but excluding a capital lease obligation, had a carrying value of approximately $151.8 million. This compares to a fair value of approximately $174.3 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, and with adjustments for duration, optionality, and risk profile. At December 31, 2015, long-term debt, including the current maturities but excluding a capital lease obligation, had a carrying value of approximately $153.7 million, compared to the estimated fair value of approximately $165.1 million. The valuation technique used to estimate the fair value of long-term debt would be considered a Level 3 measurement.

14. Long-Term Debt

Our outstanding long-term debt is shown below:

(in thousands)	June 30, 2016	December 31, 2015
FPU secured first mortgage bonds [1]:		
9.08% bond, due June 1, 2022	**$ 7,976**	$ 7,973
Uncollateralized senior notes:		
6.64% note, due October 31, 2017	**5,455**	5,455
5.50% note, due October 12, 2020	**10,000**	10,000
5.93% note, due October 31, 2023	**22,500**	24,000
5.68% note, due June 30, 2026	**29,000**	29,000
6.43% note, due May 2, 2028	**7,000**	7,000
3.73% note, due December 16, 2028	**20,000**	20,000
3.88% note, due May 15, 2029	**50,000**	50,000
Promissory notes	**168**	238
Capital lease obligation	**4,153**	4,824
Total long-term debt	**156,252**	158,490
Less: current maturities	**(12,075)**	(9,151)
Less: debt issuance costs	**(312)**	(333)
Total long-term debt, net of current maturities	**$ 143,865**	$ 149,006

[1] FPU secured first mortgage bonds are guaranteed by Chesapeake Utilities.

Shelf Agreement

On October 8, 2015, we entered into a Shelf Agreement with Prudential. Under the terms of the Shelf Agreement, we may request that Prudential purchase, over the next three years, up to $150.0 million of our Shelf Notes at a fixed interest rate and with a maturity date not to exceed 20 years from the date of issuance. Prudential is under no obligation to purchase any of the Shelf Notes. The interest rate and terms of payment of any series of Shelf Notes will be determined at the time of purchase. We currently anticipate the proceeds from the sale of any series of Shelf Notes will be used for general corporate purposes, including refinancing of short-term borrowing and/or repayment of outstanding indebtedness and financing capital expenditures on future projects; however, actual use of such proceeds will be determined at the time of a purchase, and each request for purchase with respect to a series of Shelf Notes will specify the exact use of the proceeds.

On May 13, 2016, we formally requested that Prudential purchase $70.0 million of 3.25 percent Shelf Notes under the Shelf Agreement. On May 20, 2016, Prudential formally accepted and confirmed our request. The closing of the sale and issuance of the Shelf Notes is expected to occur on or before April 28, 2017.

The Shelf Agreement sets forth certain business covenants to which we are subject when any Shelf Note is outstanding, including covenants that limit or restrict our ability, and the ability of our subsidiaries, to incur indebtedness or incur liens and encumbrances on any of our property or the property of our subsidiaries.

15. Short-Term Borrowing

On October 8, 2015, we entered into the Credit Agreement with the Lenders for a $150.0 million Revolver for a term of five years, subject to the terms and conditions of the Credit Agreement. Borrowings under the Revolver will be used for general corporate purposes, including repayments of short-term borrowings, working capital requirements and capital expenditures.

Borrowings under the Revolver will bear interest at: (i) the LIBOR Rate plus an applicable margin of 1.25 percent or less, with such margin based on total indebtedness as a percentage of total capitalization, both as defined by the Credit Agreement, or (ii) the base rate plus 0.25 percent or less. Interest will be payable quarterly, and the Revolver is subject to a commitment fee on the unused portion of the facility. We may extend the expiration date for up to two years on any anniversary date of the Revolver, with such extension subject to the Lenders' approval. We may also request the Lenders to increase the Revolver to $200.0 million, with any increase at the sole discretion of each Lender. At June 30, 2016 and December 31, 2015, we had borrowed $40.0 million and $35.0 million, respectively, under the Revolver.

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, 2015, including the audited consolidated financial statements and notes thereto.

Safe Harbor for Forward-Looking Statements

We make statements in this Quarterly Report on Form 10-Q that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. One can typically identify forward-looking statements by the use of forward-looking words, such as "project," "believe," "expect," "anticipate," "intend," "plan," "estimate," "continue," "potential," "forecast" or other similar words, or future or conditional verbs such as "may," "will," "should," "would" or "could." These statements represent our intentions, plans, expectations, assumptions and beliefs about future financial performance, business strategy, projected plans and objectives of the Company. These statements are subject to many risks, uncertainties and other important factors that could cause actual results to differ materially from those expressed in the forward-looking statements. Such factors include, but are not limited to:

- state and federal legislative and regulatory initiatives (including deregulation) that affect cost and investment recovery, have an impact on rate structures and affect the speed at, and the degree to, which competition enters the electric and natural gas industries;
- the outcomes of regulatory, tax, environmental and legal matters, including whether pending matters are resolved within current estimates and whether the costs associated with such matters are adequately covered by insurance or recoverable in rates;
- the timing of certification authorizations;
- the loss of customers due to a government-mandated sale of our utility distribution facilities;
- industrial, commercial and residential growth or contraction in our markets or service territories;
- the weather and other natural phenomena, including the economic, operational and other effects of hurricanes, ice storms and other damaging weather events;
- the timing and extent of changes in commodity prices and interest rates;
- general economic conditions, including any potential effects arising from terrorist attacks and any hostilities or other external factors over which we have no control;
- changes in environmental and other laws and regulations to which we are subject and environmental conditions of property that we now or may in the future own or operate;
- the capital-intensive nature of our regulated energy businesses;
- 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;
- the impact on our cost and funding obligations under our pension and other post-retirement benefit plans of potential downturns in the financial markets, lower discount rates, and costs associated with the Patient Protection and Affordable Care Act;
- the creditworthiness of counterparties with which we are engaged in transactions;
- the extent of our success in connecting natural gas and electric supplies to transmission systems and in expanding natural gas and electric markets;
- the ability to continue to hire, train and retain appropriately qualified personnel;
- conditions of the capital markets and equity markets during the periods covered by the forward-looking statements;
- the ability to successfully execute, manage and integrate merger, acquisition or divestiture plans; regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, and the success of the business following a merger, acquisition or divestiture;
- the ability to establish and maintain new key supply sources;
- the effect of spot, forward and future market prices on our various energy businesses;
- the effect of competition on our businesses;
- the ability to construct facilities at or below estimated costs;
- possible increased federal, state and local regulation of the safety of our operations;
- the inherent hazards and risks involved in our energy businesses;

- the effect of accounting pronouncements issued periodically by accounting standard-setting bodies; and
- risks related to cyber-attacks that could disrupt our business operations or result in failure of information technology systems.

Introduction

We are a diversified energy company engaged, directly or through our operating divisions and subsidiaries, in various energy and other businesses.

Our strategy is focused on growing earnings from a stable utility foundation and investing in related businesses and services that provide opportunities for returns greater than traditional utility returns. The key elements of this strategy include:

- executing a capital investment program in pursuit of organic growth opportunities that generate returns equal to or greater than our cost of capital;
- expanding the regulated energy distribution and transmission businesses into new geographic areas and providing new services in our current service territories;
- expanding the propane distribution business in existing and new markets through leveraging our community gas system services, our vehicular fuel offerings and our bulk delivery capabilities;
- expanding both our regulated and unregulated energy businesses through strategic acquisitions;
- utilizing our expertise across our various businesses to improve overall performance;
- pursuing and entering new unregulated energy markets and business lines that will complement our existing strategy and operating units;
- enhancing marketing channels to attract new customers;
- providing reliable and responsive customer service to existing customers so they become our best promoters;
- engaging our customers through a distinctive service excellence initiative;
- developing and retaining a high-performing team that advances our goals;
- empowering and engaging our employees at all levels to live our brand and vision;
- demonstrating community leadership and engaging our local communities and governments in a cooperative and mutually beneficial way;
- maintaining a capital structure that enables us to access capital as needed;
- continuing to build a branded culture that drives a shared mission, vision, and values;
- maintaining a consistent and competitive dividend for stockholders; and
- creating and maintaining a diversified customer base, energy portfolio and utility foundation.

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

The following discussions and those elsewhere in the document on operating income and segment results include the use of the term "gross margin." "Gross margin" is determined by deducting the cost of sales from operating revenue. Cost of sales includes the purchased fuel cost for 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. Chesapeake Utilities believes that gross margin, although a non-GAAP measure, is meaningful in the Company's regulated operations because the cost of natural gas and electricity are passed through and changes in commodity prices can cause revenue to go up and down in ways that are not indicative of volumes sold or tied to profitability. Gross margin provides investors with information that demonstrates the profitability achieved by the Company under its allowed rates for regulated operations and under its competitive pricing structure for non-regulated segments. Chesapeake Utilities' management uses gross margin in measuring its business units' performance and has historically analyzed and reported gross margin information publicly. Other companies may calculate gross margin in a different manner.

Unless otherwise noted, earnings per share information is presented on a diluted basis.

Results of Operations for the Three and Six Months ended June 30, 2016

Overview and Highlights

Our net income for the quarter ended June 30, 2016 was $8.0 million, or $0.52 per share. This represents an increase of $1.7 million, or $0.11 per share, compared to net income of $6.3 million, or $0.41 per share, as reported for the same quarter in 2015. Excluding the non-recurring gain associated with the billing system settlement, operating income increased $3.9 million for the three months ended June 30, 2016.

	Three Months Ended June 30,		Increase
	2016	**2015**	**(decrease)**
(in thousands except per share)			
Business Segment:			
Regulated Energy segment	**$ 15,226**	$ 13,605	$ 1,621
Unregulated Energy segment	**412**	(540)	952
Other businesses and eliminations	**104**	105	(1)
Operating Income	**$ 15,742**	$ 13,170	$ 2,572
Other Expense, net	**(8)**	(171)	163
Interest Charges	**2,624**	2,485	139
Pre-tax Income	**13,110**	10,514	2,596
Income Taxes	**5,081**	4,220	861
Net Income	**$ 8,029**	$ 6,294	$ 1,735
Earnings Per Share of Common Stock			
Basic	**$ 0.52**	$ 0.41	$ 0.11
Diluted	**$ 0.52**	$ 0.41	$ 0.11

Key variances included:

(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
Second Quarter of 2015 Reported Results	$ 10,514	$ 6,294	$ 0.41
Adjusting for Unusual Items:			
Net gain from settlement agreement associated with customer billing system	(1,370)	(820)	(0.05)
	(1,370)	(820)	(0.05)
Increased (Decreased) Gross Margins:			
Service expansions (See Major Projects and Initiatives table)	1,992	1,192	0.08
GRIP	1,040	623	0.04
Natural gas growth (excluding service expansions)	820	491	0.03
Aspire Energy	708	424	0.03
Implementation of Delaware division interim rates	555	332	0.02
Eight Flags	551	330	0.02
Natural gas marketing	464	278	0.02
Increase in customer consumption	345	207	0.01
	6,475	3,877	0.25
Decreased (Increased) Other Operating Expenses:			
Higher payroll and benefit costs	(1,100)	(658)	(0.04)
Higher service contractor costs	(786)	(470)	(0.03)
Higher depreciation, asset removal, amortization and property tax costs due to recent capital investments	(493)	(295)	(0.02)
	(2,379)	(1,423)	(0.09)
Interest Charges	(139)	(83)	(0.01)
Net Other Changes	9	184	0.01
Second Quarter of 2016 Reported Results	$ 13,110	$ 8,029	$ 0.52

Our net income for the six months ended June 30, 2016 was $28.4 million, or $1.85 per share. This represents an increase of $993,000, or $0.02 per share, compared to net income of $27.4 million, or $1.83 per share, as reported for the same period in 2015. Excluding the non-recurring gain associated with the billing system settlement, operating income increased by $2.8 million for the six months ended June 30, 2016.

	Six Months Ended June 30,		Increase (decrease)
	2016	**2015**	
(in thousands except per share)			
Business Segment:			
Regulated Energy segment	**$ 39,545**	$ 35,788	$ 3,757
Unregulated Energy segment	**12,347**	14,689	(2,342)
Other businesses and eliminations	**230**	201	29
Operating Income	**$ 52,122**	$ 50,678	1,444
Other Expense, net	**(42)**	(38)	(4)
Interest Charges	**5,274**	4,933	341
Pre-tax Income	**46,806**	45,707	1,099
Income Taxes	**18,410**	18,304	106
Net Income	**$ 28,396**	$ 27,403	$ 993
Earnings Per Share of Common Stock			
Basic	**$ 1.86**	$ 1.84	$ 0.02
Diluted	**$ 1.85**	$ 1.83	$ 0.02

(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
Six months ended June 30, 2015 Reported Results	$ 45,707	$ 27,403	$ 1.83
Adjusting for Unusual Items:			
Weather impact, primarily in the first quarter	(6,596)	(3,954)	(0.26)
Net gain from settlement agreement associated with customer billing system	(1,370)	(821)	(0.05)
	(7,966)	(4,775)	(0.31)
Increased (Decreased) Gross Margins:			
Service expansions (See Major Projects and Initiatives table)	3,939	2,361	0.16
GRIP	2,148	1,288	0.09
Lower retail propane margins	(1,737)	(1,041)	(0.07)
Natural gas growth (excluding service expansions)	1,579	947	0.06
Natural gas marketing	905	543	0.04
Implementation of Delaware division interim rates	878	526	0.03
Eight Flags	551	330	0.02
	8,263	4,954	0.33
Decreased (Increased) Other Operating Expenses:			
Higher payroll and benefit costs	(1,339)	(803)	(0.05)
Higher depreciation, asset removal and property tax costs due to recent capital investments	(1,253)	(751)	(0.05)
Lower bad debt, sales and advertising	482	289	0.02
Decreased incentive compensation	466	279	0.02
	(1,644)	(986)	(0.06)
Net contribution from Aspire Energy, including impact of shares issued	2,978	1,892	0.09
Interest Charges	(341)	(204)	(0.01)
Net Other Changes	(191)	112	(0.02)
Six months ended June 30, 2016 Reported Results	$ 46,806	$ 28,396	$ 1.85

Summary of Key Factors

Major Projects and Initiatives

The following table summarizes gross margin for our existing and future major projects and initiatives. Gross margin reflects operating revenue less cost of sales, excluding depreciation, amortization and accretion (dollars in thousands):

	Gross Margin for the Period							
	Three Months Ended June 30,		Six Months Ended June 30,		Total 2015	Estimate for		
	2016	2015	2016	2015	Margin	2016	2017	2018
Completed major projects and initiatives effected since 2014	$ 10,487	$ 5,642	$ 22,256	$ 9,791	$ 25,270	$ 47,769	$ 53,991	$ 54,646
Major projects and initiatives underway [1]	—	—	—	—	—	—	2,250	4,500
	$ 10,487	$ 5,642	$ 22,256	$ 9,791	$ 25,270	$ 47,769	$ 56,241	$ 59,146

[1] This represents gross margin for the 2017 System Reliability Project.

Completed Major Projects and Initiatives

The following table summarizes gross margin generated by our major projects and initiatives completed since 2014 (dollars in thousands):

	Gross Margin for the Period									
	Three Months Ended June 30,			Six Months Ended June 30,			Total 2015	Estimate for		
	2016	2015	Variance	2016	2015	Variance	Margin	2016	2017	2018
Acquisition:										
Aspire Energy	$ 2,331	$ 1,624	$ 707	$ 6,573	$ 1,624	$ 4,949	$ 6,324	$ 12,824	$ 14,198	$ 15,415
Natural Gas Transmission Expansions and Contracts:										
Short-term contracts										
New Castle County, Delaware	$ 616	$ 523	$ 93	$ 1,375	$ 1,491	$ (116)	$ 2,682	$ 2,707	$ 1,885	$ 677
Kent County, Delaware [1]	2,032	398	1,634	3,815	398	3,417	$ 2,270	7,965	1,534	—
Total short-term contracts	$ 2,648	$ 921	$ 1,727	$ 5,190	$ 1,889	$ 3,301	$ 4,952	$ 10,672	$ 3,419	$ 677
Long-term contracts										
Kent County, Delaware	$ 455	$ 463	$ (8)	$ 911	$ 926	$ (15)	$ 1,844	$ 1,815	$ 7,629	$ 7,605
Polk County, Florida	407	134	273	814	161	653	908	1,627	1,627	1,627
Total long-term contracts	$ 862	$ 597	$ 265	$ 1,725	$ 1,087	$ 638	$ 2,752	$ 3,442	$ 9,256	$ 9,232
Total Expansions & Contracts	$ 3,510	$ 1,518	$ 1,992	$ 6,915	$ 2,976	$ 3,939	$ 7,704	$ 14,114	$ 12,675	$ 9,909
Florida GRIP	$ 2,809	$ 1,769	$ 1,040	$ 5,396	$ 3,248	$ 2,148	$ 7,508	$ 11,405	$ 13,756	$ 15,960
Florida Electric Rate Case	$ 731	$ 731	$ —	$ 1,943	$ 1,943	$ —	$ 3,734	$ 3,562	$ 3,562	$ 3,562
Delaware Division Rate Case [2]	$ 555	$ —	$ 555	$ 878	$ —	$ 878	$ —	$ 2,164	$ 2,500	$ 2,500
Eight Flags CHP Plant [3]	$ 551	$ —	$ 551	$ 551	$ —	$ 551	$ —	$ 3,700	$ 7,300	$ 7,300
Total Completed Major Projects and Initiatives	$ 10,487	$ 5,642	$ 4,845	$ 22,256	$ 9,791	$ 12,465	$ 25,270	$ 47,769	$ 53,991	$ 54,646

[1] In April 2015, Eastern Shore commenced interruptible service to an electric power generator in Kent County, Delaware. The interruptible service concluded in December 2015 and was replaced by a short-term OPT ≤ 90 Service. The short-term OPT ≤ 90 Service is expected to be replaced by a 20-year contract for OPT ≤ 90 Service in the first quarter of 2017.

[2] In December 2015, our Delaware division submitted a rate case filing with the Delaware PSC. A decision on this application is expected during the first quarter of 2017. Pending the decision, our Delaware division implemented interim rates effective February 19, 2016. These rates are subject to refund. We cannot predict the revenue requirement the Delaware PSC will ultimately authorize or forecast timing of the decision.

(3) This amount includes gross margin of $432,000 for the three and six months ended June 30, 2016, attributed to natural gas distribution and transportation services provided by our affiliates.

Aspire Energy
On April 1, 2015, we completed the merger of Gatherco with and into Aspire Energy, a then newly-formed, wholly-owned subsidiary of Chesapeake Utilities. Aspire Energy is an unregulated natural gas infrastructure company with approximately 2,500 miles of pipeline systems in 40 counties throughout Ohio. The majority of Aspire Energy's margin is derived from long-term sales agreements with Columbia Gas and Consumers Gas Cooperative, which together serve more than 20,000 end-use customers. Aspire Energy sources gas primarily from 300 conventional producers in Ohio. Aspire Energy also provides gathering and processing services necessary to maintain quality and reliability to its wholesale markets.

Aspire Energy generated $707,000 and $4.9 million in additional gross margin for the three and six months ended June 30, 2016, and incurred $363,000 and $2.0 million in other operating expenses for the same periods, respectively. As projected, this merger was accretive to our earnings per share in the first full year of operations, generating $0.03 in additional earnings per share.

Service Expansions
On January 16, 2015, the Florida PSC approved a firm transportation agreement between Peninsula Pipeline and our Florida natural gas distribution division. Under this agreement, Peninsula Pipeline provides natural gas transmission service to support our expansion of natural gas distribution service in Polk County, Florida. Peninsula Pipeline began the initial phase of its service to Chesapeake Utilities' Florida natural gas distribution division in March 2015. This new service generated $273,000 and $653,000 of additional gross margin for the three and six months ended June 30, 2016, respectively, compared to the same periods in 2015. When all phases of this service are complete, this expansion will generate an estimated annual gross margin of $1.6 million.

In April 2015, Eastern Shore commenced interruptible service to an electric power generator in Kent County, Delaware. The interruptible service concluded in December 2015 and was replaced by a short-term OPT ≤ 90 Service, which generated additional gross margin of $1.6 million and $3.4 million during the three and six months ended June 30, 2016, respectively. The short-term OPT ≤ 90 Service is expected to be replaced by a 20-year contract for OPT ≤ 90 Service in the first quarter of 2017.

On October 13, 2015, Eastern Shore submitted an application to the FERC to make certain measurement and related improvements at its TETLP interconnect facilities, which will enable Eastern Shore to increase natural gas receipts from TETLP by 53,000 Dts/d, for a total capacity of 160,000 Dts/d. In December 2015, the FERC authorized Eastern Shore to proceed with this project, which was completed and placed in service in March 2016. Approximately, 80 percent of the increased capacity has been subscribed on a short-term firm service basis. This service generated an additional gross margin of $108,000 and $128,000 for the three and six months ended June 30, 2016, respectively, and will generate approximately $1.4 million in additional gross margin through 2016. The remaining capacity is available for firm or interruptible service.

GRIP
GRIP is a natural gas pipe replacement program approved by the Florida PSC, designed to expedite the replacement of qualifying distribution mains and services (any material other than coated steel or plastic) to enhance reliability and integrity of the Florida natural gas distribution systems. This program allows recovery, through regulated rates, of capital and other program-related costs, inclusive of a return on investment, associated with the replacement of the mains and services. Since the program's inception in August 2012, we have invested $91.5 million to replace 191 miles of qualifying distribution mains, including $14.7 million during the first six months of 2016. We expect to invest an additional $6.4 million in this program during the remainder of 2016. The increased investment in GRIP generated additional gross margin of $1.0 million and $2.1 million for the three and six months ended June 30, 2016, respectively, compared to the same periods in 2015.

Eight Flags
In June 2016, Eight Flags, one of our unregulated energy subsidiaries, substantially completed construction of a CHP plant in Nassau County, Florida. This CHP plant, which consists of a natural-gas-fired turbine and associated electric generator, can produce approximately 20 megawatts of base load power and includes a heat recovery steam generator capable of providing approximately 75,000 pounds per hour of unfired steam. Beginning June 13, 2016, Eight Flags began selling power generated from the CHP plant to FPU, our wholly-owned subsidiary, for distribution to its retail electric customers pursuant to a 20-year power purchase agreement. On July 1, 2016, it also started selling steam to an industrial customer pursuant to a separate 20-year contract. FPU will be transporting natural gas through its distribution system to Eight Flags' CHP plant, which will be used to power the CHP plant. Eight Flags and other affiliates of Chesapeake Utilities generated $551,000 in additional gross margin as a result of these new services, including natural gas and distribution services, for the three and six months ended June 30, 2016. On a consolidated basis, this project is expected to generate approximately $7.3 million in annual gross margin, which could fluctuate based upon various factors, including, but not limited to, the quantity of steam delivered and the CHP plant's hours of operations.

Major Projects and Initiatives Underway

White Oak Mainline Expansion Project: In December 2014, Eastern Shore entered into a precedent agreement with an electric power generator in Kent County, Delaware, to provide a 20-year natural gas transmission service for 45,000 Dts/d for the customer's facility, upon the satisfaction of certain conditions. This new service will be provided as a long-term OPT ≤ 90 Service and is expected to generate at least $5.8 million in annual gross margin. In November 2014, Eastern Shore requested authorization by the FERC to construct 5.4 miles of 16-inch pipeline looping and 3,550 horsepower of new compression in Delaware to provide this service. As previously discussed, during the three and six months ended June 30, 2016, we generated $1.6 million and $3.4 million, respectively, in additional gross margin by providing interruptible service and short-term OPT ≤ 90 Service to this customer. The estimated annual gross margin contribution from this project, once it is placed in service, is approximately $5.8 million. On July 21, 2016, the FERC issued a certificate of public convenience and necessity authorizing Eastern Shore to construct and operate the proposed White Oak Mainline Project.

System Reliability Project: On May 22, 2015, Eastern Shore submitted an application to the FERC seeking authorization to construct, own and operate approximately 10.1 miles of 16-inch pipeline looping and auxiliary facilities in New Castle and Kent Counties, Delaware and a new compressor at its existing Bridgeville compressor station in Sussex County, Delaware. Eastern Shore further proposes to reinforce critical points on its pipeline system. The total project will benefit all of Eastern Shore's customers by modifying the pipeline system to respond to severe operational conditions experienced during actual winter peak days. Since the project is intended to improve system reliability, Eastern Shore requested a predetermination of rolled-in rate treatment for the costs of the project and an order granting the requested authorization. This project will be included in Eastern Shore's upcoming 2017 rate case filing. The estimated annual gross margin associated with this project, assuming recovery in the 2017 rate case, is approximately $4.5 million. On July 21, 2016, the FERC issued a certificate of public convenience and necessity authorizing Eastern Shore to construct and operate the proposed System Reliability Project.

2017 Expansion Project: On May 12, 2016, Eastern Shore submitted a request to the FERC to initiate the FERC's pre-filing procedures for its proposed 2017 expansion project. The 2017 expansion project consists of approximately 33 miles of pipeline looping in Pennsylvania, Maryland and Delaware; upgrades to existing facilities; installation of an additional 3,550 horsepower compressor unit at the existing Daleville compressor station in Chester County, Pennsylvania; approximately 17 miles of new mainline extension; and the addition of two pressure control stations in Sussex County, Delaware. The proposed 2017 expansion project would provide up to 86,437 Dts/d of additional firm natural gas transportation capacity to meet anticipated market demand. Eastern Shore is currently negotiating precedent agreements with customers who have expressed an interest in this service.

Other factors influencing gross margin

Weather and Consumption

Weather was not a significant factor in the second quarter. Temperatures on the Delmarva Peninsula and in Florida during the first quarter of 2016 were significantly warmer than the first quarter of 2015, which negatively affected the Company's year-to-date results in 2016. Lower customer consumption, directly attributable to warmer than normal temperatures during the six months ended June 30, 2016, reduced gross margin by $6.6 million compared to the same period in 2015. The following tables summarize the HDD and CDD information for the three and six months ended June 30, 2016 and 2015 resulting from weather fluctuations in those periods.

HDD and CDD Information

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	**2015**	**Variance**	**2016**	**2015**	**Variance**
Delmarva						
Actual HDD	**485**	386	99	**2,579**	3,208	(629)
10-Year Average HDD ("Delmarva Normal")	**452**	443	9	**2,854**	2,843	11
Variance from Delmarva Normal	**33**	(57)		**(275)**	365	
Florida						
Actual HDD	**49**	—	49	**646**	501	145
10-Year Average HDD ("Florida Normal")	**19**	24	(5)	**553**	557	(4)
Variance from Florida Normal	**30**	(24)		**93**	(56)	
Ohio						
Actual HDD	**830**	632	198	**3,683**	4,413	(730)
10-Year Average HDD ("Ohio Normal")	**666**	669	(3)	**3,842**	3,778	64
Variance from Ohio Normal	**164**	(37)		**(159)**	635	
Florida						
Actual CDD	**1,028**	1,114	(86)	**1,214**	1,236	(22)
10-Year Average CDD ("Florida CDD Normal")	**948**	909	39	**1,025**	982	43
Variance from Florida CDD Normal	**80**	205		**189**	254	

Propane prices

For the quarter ended June 30, 2016, retail propane margins per gallon generated additional gross margin of $185,000, compared to the same period last year. For the six months ended June 30, 2016, compared to the same period in 2015, margins per retail gallon returned to more normal levels, which resulted in a year-to-date decline in gross margin of $1.9 million, driven principally by lower propane prices and local market conditions. The level of retail margins per gallon generated during 2015 were not expected to be sustained over the long term; accordingly, the Company has assumed more normal levels of margins in its long-term financial plans and forecasts.

In Florida, higher retail propane margins per gallon, resulting from local market conditions, generated $6,000 and $131,000 of additional gross margin for the three and six months ended June 30, 2016, respectively, compared to the same periods in 2015.

These market conditions, which are influenced by competition with other propane suppliers as well as the availability and price of alternative energy sources, may fluctuate based on changes in demand, supply and other energy commodity prices.

Other Natural Gas Growth - Distribution Operations

In addition to service expansions, the natural gas distribution operations on the Delmarva Peninsula generated $509,000 and $854,000 in additional gross margin for the three and six months ended June 30, 2016, respectively, compared to the same periods in 2015, due to an increase in residential, commercial and industrial customers served. The average number of residential customers on the Delmarva Peninsula during the three and six months ended June 30, 2016, increased by 3.8 percent and 3.2 percent, respectively, compared to the same periods in 2015. The natural gas distribution operations in Florida generated $406,000 and $652,000 in additional gross margin for the three and six months ended June 30, 2016, respectively, compared to the same periods in 2015, due primarily to an increase in commercial and industrial customers in Florida.

Delaware division rate case

On December 21, 2015, our Delaware division filed an application with the Delaware PSC for a base rate increase and certain other changes to its tariff. We proposed an increase of approximately $4.7 million, or nearly ten percent, in our revenue requirement based on the test period ending March 31, 2016. See *Note 4, Rates and Other Regulatory Activities*, to the condensed consolidated financial statements for additional details. We expect a decision on the application during the first quarter of 2017. Pending the decision, our Delaware division increased rates on an interim basis based on the $2.5 million annualized interim rates approved by the Delaware PSC, effective February 19, 2016. We generated additional gross margin of approximately $555,000 ($332,000 net of tax) and $878,000 ($526,000 net of tax) for the three and six months ended June 30, 2016, respectively, from the implementation of interim rates. In addition, the Company's Delaware division requested and received approval on July 26, 2016 from the Delaware PSC to implement revised interim rates of $4.7 million annualized for usage on and after August 1, 2016. These rates, are subject to refund. Although a final decision is expected during the first quarter of 2017, we cannot predict the revenue requirement the Delaware PSC will ultimately authorize or forecast the timing of a final decision.

Regulated Energy Segment

For the quarter ended June 30, 2016 compared to the quarter ended June 30, 2015

	Three Months Ended June 30,		Increase
	2016	**2015**	**(decrease)**
(in thousands)			
Revenue	**$ 67,395**	$ 62,060	$ 5,335
Cost of sales	**21,635**	21,124	511
Gross margin	**45,760**	40,936	4,824
Operations & maintenance	**21,301**	18,484	2,817
Depreciation & amortization	**6,267**	6,080	187
Other taxes	**2,966**	2,767	199
Other operating expenses	**30,534**	27,331	3,203
Operating income	**$ 15,226**	$ 13,605	$ 1,621

Operating income for the Regulated Energy segment for the quarter ended June 30, 2016 was $15.2 million, an increase of $1.6 million, or 11.9 percent, compared to the same quarter in 2015. The increased operating income was primarily due to an increase in gross margin of $4.8 million, partially offset by an increase in operating expenses of $3.2 million.

Gross Margin

Items contributing to the quarter-over-quarter increase of $4.8 million, or 11.8 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended June 30, 2015	$ 40,936
Factors contributing to the gross margin increase for the three months ended June 30, 2016:	
Service expansions	1,992
Additional revenue from GRIP in Florida	1,040
Natural gas growth (excluding service expansions)	820
Implementation of Delaware division interim rates	555
Eight Flags	432
Other	(15)
Gross margin for the three months ended June 30, 2016	$ 45,760

The following is a narrative discussion of the significant items, which we believe is necessary to understand the information disclosed in the foregoing table.

Service Expansions

Increased gross margin from natural gas service expansions was generated primarily from the following:

- $1.6 million from the short-term OPT ≤ 90 Service that commenced in December 2015 to an electric power generator in Kent County, Delaware following the conclusion of an interruptible service Eastern Shore had provided this customer. The short-term OPT ≤ 90 Service is expected to be replaced by a 20-year OPT ≤ 90 Service in the first quarter of 2017.
- $273,000 from natural gas transmission service as part of the major expansion initiative in Polk County, Florida.

Additional Revenue from GRIP in Florida

Additional GRIP investments during 2015 and 2016 by our Florida natural gas distribution operations generated $1.0 million in additional gross margin

Natural Gas Growth (excluding service expansions)

Increased gross margin from other growth in natural gas (excluding service expansions) was generated primarily from the following:

- $509,000 from a 3.8 percent increase in the average number of residential customers in the Delmarva natural gas distribution operations, as well as growth in the number of commercial and industrial customers; and
- $406,000 from Florida natural gas customer growth due primarily to new services to commercial and industrial customers.

Implementation of Delaware Division Interim Rates

Delaware division generated additional gross margin of $555,000 from the implementation of interim rates as a result of its rate case filing. See *Note 4, Rates and Other Regulatory Activities*, to the condensed consolidated financial statements for additional details.

Eight Flags

We generated additional gross margin of $432,000 during the quarter, from new natural gas transmission and distribution services provided to or by Eight Flags' CHP plant.

Other Operating Expenses

Other operating expenses increased by $3.2 million. The significant components of the increase in other operating expenses included:

- The absence of a $1.5 million gain from a customer billing system settlement, recorded in 2015, which was partially offset by an associated gain of $130,000 during the second quarter of 2016, representing an additional current portion of the settlement recovery;
- $724,000 in higher payroll and benefits costs for additional personnel to support growth;
- $722,000 in higher service contractor and consulting costs; and
- $385,000 in higher depreciation, asset removal and property tax costs associated with recent capital investments.

For the six months ended June 30, 2016 compared to the six months ended June 30, 2015

	Six Months Ended June 30,		Increase
(in thousands)	**2016**	**2015**	**(decrease)**
Revenue	**$ 156,611**	$ 171,642	$ (15,031)
Cost of sales	**56,540**	78,253	(21,713)
Gross margin	**100,071**	93,389	6,682
Operations & maintenance	**41,761**	39,768	1,993
Depreciation & amortization	**12,563**	11,979	584
Other taxes	**6,202**	5,854	348
Other operating expenses	**60,526**	57,601	2,925
Operating income	**$ 39,545**	$ 35,788	$ 3,757

Operating income for the Regulated Energy segment for the six months ended June 30, 2016 was $39.5 million, an increase of $3.8 million, or, 10.5 percent, compared to the same period in 2015. The increased operating income was due primarily to an increase in gross margin of $6.7 million partially offset by a $2.9 million increase in operating expenses.

Gross Margin

Items contributing to the period-over-period increase of $6.7 million, or 7.2 percent, in gross margin are listed in the following table:

(in thousands)		
Gross margin for the six months ended June 30, 2015	$	93,389
Factors contributing to the gross margin increase for the six months ended June 30, 2016:		
Service expansions		3,939
Decreased customer consumption - weather and other		(2,456)
Additional revenue from GRIP in Florida		2,148
Natural Gas Growth (excluding service expansions)		1,579
Implementation of Delaware division interim rates		878
Eight Flags		432
Other		162
Gross margin for the six months ended June 30, 2016	$	100,071

The following is a narrative discussion of the significant items, which we believe is necessary to understand the information disclosed in the foregoing table.

Service Expansions

Increased gross margin from natural gas service expansions was generated primarily from the following:

- $3.4 million from the short-term OPT ≤ 90 Service that commenced in December 2015 to an electric power generator in Kent County, Delaware following the conclusion of an interruptible service Eastern Shore had provided this customer. The short-term OPT ≤ 90 Service is expected to be replaced by a 20-year OPT ≤ 90 Service in the first quarter of 2017; and
- $653,000 from natural gas transmission service as part of the major expansion initiative in Polk County, Florida.

Decreased Customer Consumption—Weather and Other

In the first six months of 2016, customer consumption of natural gas and electricity decreased primarily due to significantly warmer weather on the Delmarva Peninsula, which reduced gross margin by approximately $2.5 million.

Additional Revenue from GRIP in Florida

Additional GRIP investments during 2015 and 2016 by our Florida natural gas distribution operations generated $2.1 million in additional gross margin.

Natural Gas Growth (excluding service expansions)

Increased gross margin from other growth in natural gas (excluding service expansions) was generated primarily from the following:

- $854,000 from a 3.2 percent increase in the average number of residential customers in the Delmarva natural gas distribution operations, as well as growth in the number of commercial and industrial customers; and
- $652,000 from Florida natural gas customer growth due primarily to new services to commercial and industrial customers.

Implementation of Delaware Division Interim Rates

Delaware division generated additional gross margin of $878,000 from the implementation of interim rates as a result of its rate case filing. See *Note 4, Rates and Other Regulatory Activities*, to the condensed consolidated financial statements for additional details.

Eight Flags

We generated additional gross margin of $432,000 from new natural gas transmission and distribution services provided to or by Eight Flags' CHP plant, commencing in June of 2016.

Other Operating Expenses

Other operating expenses increased by $2.9 million. The significant components of the increase in other operating expenses included:

- The absence of a $1.5 million gain from a customer billing system settlement, recorded in 2015, which was partially offset by an associated gain of $130,000 during the second quarter of 2016, representing an additional current portion of the settlement recovery;
- $1.0 million in higher depreciation, asset removal and property tax costs associated with recent capital investments; and
- $565,000 in higher payroll and benefits costs for additional personnel to support growth.

Unregulated Energy Segment

For the quarter ended June 30, 2016 compared to the quarter ended June 30, 2015

	Three Months Ended June 30,		Increase
(in thousands)	**2016**	**2015**	**(decrease)**
Revenue	**$ 36,803**	$ 32,559	$ 4,244
Cost of sales	**24,726**	22,156	2,570
Gross margin	**12,077**	10,403	1,674
Operations & maintenance	**9,771**	9,130	641
Depreciation & amortization	**1,490**	1,439	51
Other taxes	**404**	374	30
Other operating expenses	**11,665**	10,943	722
Operating Income	**$ 412**	$ (540)	$ 952

Operating income for the Unregulated Energy segment increased by $952,000 to $412,000 in the second quarter of 2016, compared to an operating loss of $540,000 in the same quarter of 2015. The results for the second quarter include an increase in gross margin of $708,000 and other operating expenses of $363,000 from Aspire Energy. Excluding these impacts from Aspire Energy, gross margin increased by $966,000, offset by a $359,000 increase in other operating expenses.

Gross Margin

Items contributing to the quarter-over-quarter increase of $1.7 million, or 16.1 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended June 30, 2015	$ 10,403
Factors contributing to the gross margin increase for the three months ended June 30, 2016:	
Aspire Energy	708
Natural gas marketing	464
Increased customer consumption - weather and other	370
Other	132
Gross margin for the three months ended June 30, 2016	$ 12,077

The following is a discussion of the significant items, which we believe is necessary to understand the information disclosed in the foregoing table.

Aspire Energy

Aspire Energy generated $708,000 in additional gross margin for the quarter ended June 30, 2016 as a result of additional margins generated by pricing amendments to long-term sales agreements, the elimination of gas retainage volume credits associated with shrinkage for gas processing activities, and the optimization of gathering system receipts and deliveries through improved management and monitoring of system volumes and imbalance positions.

Natural Gas Marketing

PESCO generated $464,000 in additional gross margin due primarily to customer growth, which includes a new SCO supplier agreement with Columbia Gas, and the positive impact from favorable supply management and hedging activities, which generated additional gross margin as a result of a decrease in inventory costs. The increase in gross margin as a result of favorable supply management and hedging activities is not predictable and, therefore, is not included in our long-term financial plans or forecasts.

Increased Customer Consumption - Weather and Other

Gross margin increased by $370,000 due to increased deliveries of propane as a result of weather and the timing of bulk deliveries.

Other Operating Expenses

The increase in other operating expenses was due primarily to $481,000 in higher payroll and benefits costs for additional personnel to support growth.

For the six months ended June 30, 2016 compared to the six months ended June 30, 2015

	Six Months Ended June 30,		Increase
(in thousands)	**2016**	**2015**	**(decrease)**
Revenue	**$ 94,319**	93,555	$ 764
Cost of sales	**59,141**	57,833	1,308
Gross margin	**35,178**	35,722	(544)
Operations & maintenance	**19,162**	17,687	1,475
Depreciation & amortization	**2,672**	2,490	182
Other taxes	**997**	856	141
Other operating expenses	**22,831**	21,033	1,798
Operating Income	**$ 12,347**	$ 14,689	$ (2,342)

Operating income for the Unregulated Energy segment decreased by $2.4 million, to $12.3 million, in the first six months of 2016, compared to $14.7 million in the same period of 2015. The results for the first six months include an increase in gross margin of $4.9 million and other operating expenses of $2.0 million from Aspire Energy. Excluding these impacts from Aspire Energy, gross margin and other operating expenses decreased by $5.5 million, and $174,000, respectively.

Gross Margin

Items contributing to the period-over-period decrease of $544,000 or 1.5 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the six months ended June 30, 2015	$ 35,722
Factors contributing to the gross margin decrease for the six months ended June 30, 2016:	
Aspire Energy	4,949
Decreased customer consumption - weather and other	(3,867)
Decrease in retail propane margins	(1,737)
Natural gas marketing	905
Propane wholesale sales	(452)
Other	(342)
Gross margin for the six months ended June 30, 2016	$ 35,178

The following is a discussion of the significant items, which we believe is necessary to understand the information disclosed in the foregoing table.

Aspire Energy

Aspire Energy generated $6.6 million in gross margin compared to $1.6 million in the same period of 2015. Results for the first six months of 2015 reflect only three months of margin for Aspire Energy, which became a wholly-owned subsidiary of Chesapeake Utilities on April 1, 2015. In addition, Aspire Energy generated additional margins as a result of pricing amendments to long-term gas sales agreements, the elimination of gas retainage volume credits associated with shrinkage for gas processing activities, and the optimization of gathering system receipts and deliveries through improved management and monitoring of system volumes and imbalance positions.

Decreased Customer Consumption - Weather and Other

Gross margin decreased by $3.9 million due to lower customer consumption of propane. The decrease was driven mainly by weather as a result of warmer temperatures on the Delmarva Peninsula during the first six months of 2016 compared to significantly colder temperatures during the first six months of 2015.

Decrease in Retail Propane Margins

Lower retail propane margins for our Delmarva propane distribution operation decreased gross margin by $1.9 million, as margins per retail gallon returned to more normal levels. The decline in margin was driven principally by lower propane prices and local market conditions. The level of retail margins per gallon generated during 2015 were not expected to be sustained over the long term; accordingly, we have assumed more normal levels of margins in our long-term financial plans and forecasts.

This decrease was partially offset by $131,000 in higher retail propane margins per gallon for our Florida propane distribution operation as a result of local market conditions.

Natural Gas Marketing

PESCO generated $905,000 in additional gross margin due to customer growth, which includes its SCO supplier agreement with Columbia Gas, and the positive impact from favorable supply management and hedging activities, which generated additional gross margin as a result of a decrease in inventory costs. The increase in gross margin as a result of favorable supply management and hedging activities is not predictable and, therefore, is not included in our long-term financial plans or forecasts.

Propane wholesale sales

Gross margin decreased by $452,000 as a result of lower propane wholesale sales associated with the sales agreement with an affiliate of ESG, that has a propane supply agreement with Sandpiper Energy. The lower sales are expected as more customers in Ocean City, Maryland and surrounding areas are converted from propane to natural gas. Lower sales due to significantly warmer weather in the first six months of 2016 compared to the same period in 2015, also contributed to this decrease.

Other Operating Expenses

The increase in other operating expenses was due primarily to $2.0 million in other operating expenses incurred by Aspire Energy, given the additional quarter's results included in 2016, compared to only three months of results in the six months ended June 30, 2015. This increase in expenses was partially offset by $161,000 in lower accruals for incentive compensation as a result of the lower financial results, due to the impact of significantly warmer weather on financial results.

Interest Charges

For the quarter ended June 30, 2016 compared to the quarter ended June 30, 2015

Interest charges for the three months ended June 30, 2016 increased slightly by approximately $139,000, compared to the same quarter in 2015.

For the six months ended June 30, 2016 compared to the six months ended June 30, 2015

Interest charges for the six months ended June 30, 2016 increased slightly by approximately $341,000, compared to the same period in 2015.

Income Taxes

For the quarter ended June 30, 2016 compared to the quarter ended June 30, 2015
Income tax expense was $5.1 million in the second quarter of 2016, compared to $4.2 million in the same quarter in 2015. The increase in income tax expense was due primarily to higher taxable income. Our effective income tax rate was 38.8 percent and 40.1 percent, for the second quarter of 2016 and 2015, respectively.

For the six months ended June 30, 2016 compared to the six months ended June 30, 2015
Income tax expense was $18.4 million in the six months ended June 30, 2016, compared to $18.3 million in the same period in 2015. The decrease in income tax expense was due primarily to lower taxable income. Our effective income tax rate was 39.3 percent and 40.0 percent, for the first six months of 2016 and 2015, respectively.

FINANCIAL POSITION, LIQUIDITY AND CAPITAL RESOURCES

Our capital requirements reflect the capital-intensive and seasonal nature of our business and are principally attributable to investment in new plant and equipment, retirement of outstanding debt and seasonal variability in working capital. We rely on cash generated from operations, short-term borrowings, and other sources to meet normal working capital requirements and to temporarily finance capital expenditures. We may also issue long-term debt and equity to fund capital expenditures and to more closely align our capital structure to target.

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

Our capital expenditures for the six months ended June 30, 2016 were approximately $70.3 million. We currently project capital expenditures of $179.3 million in 2016. Our current forecast by segment and business line is shown below:

(dollars in thousands)		
Regulated Energy:		
Natural gas distribution	$	73,285
Natural gas transmission		66,938
Electric distribution		7,566
Total Regulated Energy		147,789
Unregulated Energy:		
Propane distribution		11,141
Other unregulated energy		13,504
Total Unregulated Energy		24,645
Other		6,871
Total 2016 capital expenditures	$	179,305

The 2016 forecast includes expenditures for the following projects: Eight Flags' CHP plant; anticipated new facilities to serve an electric power generator in Kent County, Delaware under the OPT ≤ 90 Service; Eastern Shore's system reliability project; additional expansions of our natural gas distribution and transmission systems; continued natural gas infrastructure improvement activities; expenditures for continued replacement under the Florida GRIP; replacement of several facilities and systems; and other strategic initiatives and investments. In addition, we included $30.0 million in the 2016 forecast for projects that are in the early development stage.

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. Historically, actual capital expenditures have typically lagged behind the budgeted amounts.

The timing of capital expenditures can vary based on securing environmental approvals and other permits. The regulatory application and approval process has lengthened, and we expect this trend to continue.

Capital Structure

We are committed to maintaining a sound capital structure and strong credit ratings to provide the financial flexibility needed to access capital markets when required. This commitment, along with adequate and timely rate relief for our regulated operations, is intended to ensure our ability to attract capital from outside sources at a reasonable cost. We believe that the achievement of these objectives will provide benefits to our customers, creditors and investors. The following table presents our capitalization, excluding and including short-term borrowings, as of June 30, 2016 and December 31, 2015:

(in thousands)	June 30, 2016		December 31, 2015	
Long-term debt, net of current maturities	**$ 143,865**	**27%**	$ 149,006	29%
Stockholders' equity	**379,554**	**73%**	358,138	71%
Total capitalization, excluding short-term debt	**$ 523,419**	**100%**	$ 507,144	100%

(in thousands)	June 30, 2016		December 31, 2015	
Short-term debt	**$ 180,042**	**25%**	$ 173,397	25%
Long-term debt, including current maturities	**155,940**	**22%**	158,157	23%
Stockholders' equity	**379,554**	**53%**	358,138	52%
Total capitalization, including short-term debt	**$ 715,536**	**100%**	$ 689,692	100%

Included in the long-term debt balances at June 30, 2016 and December 31, 2015, was a capital lease obligation associated with Sandpiper's capacity, supply and operating agreement ($2.8 million and $3.5 million, respectively, net of current maturities, and $4.2 million and $4.8 million, respectively, including current maturities). Sandpiper entered into this six-year agreement at the closing of the ESG acquisition in May 2013. The capacity portion of this agreement is accounted for as a capital lease.

Our target ratio of equity to total capitalization, including short-term borrowings, is between 50 and 60 percent. We have maintained a ratio of equity to total capitalization, including short-term borrowings, between 52 percent and 54 percent during the past three years. Our equity as a percent of total capitalization declined in 2015 as we financed several large revenue generating capital projects with short-term borrowings. As we continue to construct these projects in 2016, the ratio of equity to total capitalization, including short-term borrowings, will further decline temporarily.

As described below under "Short-term Borrowings," we entered into a new Revolver with the Lenders on October 8, 2015, which increased our borrowing capacity by $150.0 million. To facilitate the refinancing of a portion of the short-term borrowings into long-term debt, as appropriate, we also entered into a long-term private placement Shelf Agreement with Prudential that is further described below under the heading "Shelf Agreement."

For larger capital projects, we will seek to align, as much as feasible, any such long-term debt or equity issuance(s) with the earnings associated with the commencement of long-term service for larger revenue-generating capital projects. The exact timing of any long-term debt or equity issuance(s) will be based on market conditions.

Short-term Borrowings

Our outstanding short-term borrowings at June 30, 2016 and December 31, 2015 were $180.0 million and $173.4 million, respectively. The weighted average interest rates for our short-term borrowings were 1.39 percent and 1.08 percent, for the six months ended June 30, 2016 and 2015, respectively.

We utilize bank lines of credit to provide funds for our short-term cash needs to meet seasonal working capital requirements and to temporarily fund portions of the capital expenditure program. As of June 30, 2016, we had four unsecured bank credit facilities with three financial institutions totaling $170.0 million in total available credit. In addition, since October 2015, we have $150.0 million of additional short-term debt capacity available under a Revolver with five participating Lenders. The terms of the Revolver are described in further detail below. We also had access to two credit facilities, which totaled $40.0 million; however, these credit facilities expired on October 31, 2015 and were not renewed given the addition of the new Revolver. None of the unsecured bank lines of credit requires compensating balances. We are currently authorized by our Board of Directors to borrow up to $275.0 million of short-term borrowing.

The $150.0 million Revolver has a five-year term and is subject to the terms and conditions set forth in the Credit Agreement. Borrowings under the Revolver will be used for general corporate purposes, including repayments of short-term borrowings, working capital requirements and capital expenditures. Borrowings under the Revolver will bear interest at: (i) the LIBOR Rate plus an applicable margin of 1.25 percent or less, with such margin based on total indebtedness as a percentage of total capitalization, both as defined by the Credit Agreement, or (ii) the base rate plus 0.25% or less. Interest is payable quarterly, and the Revolver is subject to a commitment fee on the unused portion of the facility. We may extend the expiration date for up to two years on any anniversary date of the Revolver, with such extension subject to the Lenders' approval. We may also request the Lenders to increase the Revolver to $200.0 million, with any increase at the sole discretion of each Lender. At June 30, 2016 and December 31, 2015, we had borrowed $40.0 million and $35.0 million, respectively, under the Revolver.

Shelf Agreement

On October 8, 2015, we entered into a committed Shelf Agreement with Prudential and other purchasers that may become a party to the Shelf Agreement. Under the terms of the Shelf Agreement, we may request that Prudential purchase, over the next three years, up to $150.0 million of our Shelf Notes at a fixed interest rate and with a maturity date not to exceed twenty years from the date of issuance. Prudential and its affiliates are under no obligation to purchase any of the Shelf Notes. The interest rate and terms of payment of any series of Shelf Notes will be determined at the time of purchase. We currently anticipate that the proceeds from the sale of any series of Shelf Notes will be used for general corporate purposes, including refinancing of short-term borrowings and/or repayment of outstanding indebtedness and financing of capital expenditures on future projects; however, actual use of such proceeds will be determined at the time of a purchase, and each request for purchase with respect to a series of Shelf Notes will specify the use of the proceeds.

On May 13, 2016, we formally requested that Prudential purchase $70.0 million of 3.25 percent Shelf Notes under the Shelf Agreement. On May 20, 2016, Prudential formally accepted and confirmed our request. The closing of the sale and issuance of our Shelf Notes is expected to occur on or before April 28, 2017.

The Shelf Agreement sets forth certain business covenants to which we are subject when any Shelf Note is outstanding, including covenants that limit or restrict us and our subsidiaries from incurring indebtedness and incurring liens and encumbrances on any of our property.

Cash Flows

The following table provides a summary of our operating, investing and financing cash flows for the six months ended June 30, 2016 and 2015:

	Six Months Ended June 30,	
	2016	**2015**
(in thousands)		
Net cash provided by (used in):		
Operating activities	**$ 74,155**	$ 80,402
Investing activities	**(70,133)**	(78,304)
Financing activities	**(3,611)**	(4,568)
Net increase (decrease) in cash and cash equivalents	**411**	(2,470)
Cash and cash equivalents—beginning of period	**2,855**	4,574
Cash and cash equivalents—end of period	**$ 3,266**	$ 2,104

Cash Flows Provided By Operating Activities

Changes in our cash flows from operating activities are attributable primarily to changes in net income, non-cash adjustments for depreciation, deferred income taxes and working capital. Changes in working capital are determined by a variety of factors, including weather, the prices of natural gas, electricity and propane, the timing of customer collections, payments for purchases of natural gas, electricity and propane, and deferred fuel cost recoveries.

During the six months ended June 30, 2016 and 2015, net cash provided by operating activities was $74.2 million and $80.4 million, respectively, resulting in a decrease in cash flows of $6.2 million. Significant operating activities generating the cash flows change were as follows:

- Net income, adjusted for reconciling activities, increased cash flows by $11.2 million, due primarily to an increase in deferred income taxes as a result of the availability and utilization of bonus depreciation in the first six months of 2016, which resulted in a higher book-to-tax timing difference and higher non-cash adjustments for depreciation and amortization.

- The changes in net regulatory assets and liabilities decreased cash flows by $12.2 million, due primarily to the change in fuel costs collected through the various fuel cost recovery mechanisms.
- The changes in net accounts receivable and payable decreased cash flows by $5.6 million, due primarily to the timing of the receipt of customer payments as well as the timing of payments to vendors.
- Changes in customer deposits and refunds increased cash flows by $4.1 million.
- Net cash flows from changes in propane, natural gas and materials inventories decreased by approximately $3.7 million.

Cash Flows Used in Investing Activities

Net cash used in investing activities totaled $70.1 million and $78.3 million during the six months ended June 30, 2016 and 2015, respectively, resulting in an increase in cash flows of $8.2 million. The decrease in net cash used in investing activities was due primarily to a decrease in cash used for acquisitions. The cash expended in 2015 was associated with the Gatherco merger.

Cash Flows Used in Financing Activities

Net cash used in financing activities totaled $3.6 million in the first six months of 2016, compared to $4.6 million in the same period in 2015, resulting in an increase in cash flows of $1.0 million.

Off-Balance Sheet Arrangements

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily Xeron and PESCO, which provide for the payment of propane and natural gas purchases in the event that the subsidiary defaults. 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, 2016 was $53.6 million, with the guarantees expiring on various dates through June 2017.

We have issued letters of credit totaling $8.1 million related to the electric transmission services for FPU's northwest electric division, the firm transportation service agreement between TETLP and our Delaware and Maryland divisions, and to our current and previous primary insurance carriers. These letters of credit have various expiration dates through March 2017. There have been no draws on these letters of credit as of June 30, 2016. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that they will be renewed to the extent necessary in the future. Additional information is presented in Item 1*, Financial Statements,* Note 6*, Other Commitments and Contingencies* in the Condensed Consolidated Financial Statements.

Contractual Obligations

There has been no material change in the contractual obligations presented in our 2015 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 commodity and forward contract obligations at June 30, 2016.

	Payments Due by Period				
(in thousands)	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
Purchase obligations - Commodity [1]	$ 46,383	$ 5,903	$ —	$ —	**$ 52,286**
Forward purchase contracts - Propane [2]	227	—	—	—	**227**
Total	**$ 46,610**	**$ 5,903**	**$ —**	**$ —**	**$ 52,513**

(1) In addition to the obligations noted above, the natural gas, electric 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. See Item 3, *Quantitative and Qualitative Disclosures About Market Risk* for further information.

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 the respective state PSC; Eastern Shore is subject to regulation by the FERC; and Peninsula Pipeline is subject to regulation by the Florida PSC. At June 30, 2016, we were involved in regulatory matters in each of the jurisdictions in which we operate. Our significant regulatory matters are fully described in Note 4, *Rates and Other Regulatory Activities*, to the unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q.

Recent Authoritative Pronouncements on Financial Reporting and Accounting

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Market risk represents the potential loss arising from adverse changes in market rates and prices. Long-term debt is subject to potential losses based on changes in interest rates. Our long-term debt consists of fixed-rate senior notes and secured debt. All of our long-term debt, excluding a capital lease obligation, is fixed-rate debt and was not entered into for trading purposes. The carrying value of our long-term debt, including current maturities, but excluding a capital lease obligation, was $151.8 million at June 30, 2016, as compared to a fair value of $174.3 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, credit risk, and risk profile. We evaluate whether to refinance existing debt or permanently refinance existing short-term borrowing, based in part on the fluctuation in interest rates.

Our propane distribution business is exposed to market risk as a result of our propane storage activities and entering into fixed price contracts for supply. We can store up to approximately 6.8 million gallons of propane (including leased storage and rail cars) during the winter season to meet our customers' peak requirements and to serve metered customers. Decreases in the wholesale price of propane may cause the value of stored propane to decline. To mitigate the impact of price fluctuations, we have adopted a Risk Management Policy that allows the propane distribution operation to enter into fair value hedges or other economic hedges of our inventory.

Our propane wholesale marketing operation is a party to natural gas liquids (primarily propane) forward contracts, with various third parties, which 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 typically settled financially without taking physical delivery of propane. The propane wholesale marketing operation also enters into futures contracts that are traded on the Intercontinental Exchange, Inc. 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 future contracts at June 30, 2016 is presented in the following table:

At June 30, 2016	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts - Propane			
Purchase	421,000	$ 0.5375	$ 0.5388

At June 30, 2016	Quantity in Barrels	Estimated Market Prices	Weighted Average Contract Prices
Futures Contracts - Crude Oil			
Purchase	20,000	$ 48.33	$ 47.90

Estimated market prices and weighted average contract prices are in dollars per gallon and barrel. All contracts expire by the end of the third quarter of 2016.

Our natural gas distribution, electric distribution and natural gas marketing operations have entered into agreements with various suppliers to purchase natural gas, electricity and propane for resale to their customers. Purchases under these contracts either do not meet the definition of derivatives or are considered “normal purchases and sales” and are accounted for on an accrual basis.

At June 30, 2016 and December 31, 2015, we marked these forward and other contracts to market, using market transactions in either the listed or OTC markets, which resulted in the following assets and liabilities:

(in thousands)	June 30, 2016	December 31, 2015
Mark-to-market energy assets, including call options, swap agreements and futures	**$ 405**	$ 153
Mark-to-market energy liabilities, including swap agreements and futures	**$ 256**	$ 433

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 June 30, 2016. Based upon their evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2016.

Changes in Internal Control over Financial Reporting

During the quarter ended June 30, 2016, 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.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

As disclosed in Note 6, *Other Commitments and Contingencies*, of the unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q, we are involved in certain legal actions and claims arising in the normal course of business. We are also involved in certain legal and administrative proceedings before various governmental or regulatory agencies concerning rates and other regulatory actions. In the opinion of management, the ultimate disposition of these proceedings and claims will not have a material effect on our condensed consolidated financial position, results of operations or cash flows.

Item 1A. Risk Factors

Our business, operations, and financial condition are subject to various risks and uncertainties. The risk factors described in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K, for the year ended December 31, 2015, 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 Quarterly Report on Form 10-Q. Additional risks and uncertainties not known to us at present, 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)
April 1, 2016 through April 30, 2016 (1)	364	$ 60.00	—	—
May 1, 2016 through May 31, 2016	—	$ —	—	—
June 1, 2016 through June 30, 2016	—	$ —	—	—
Total	364	$ 60.00	—	—

(1) Chesapeake Utilities 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 16, *Employee Benefit Plans*" in our latest Annual Report on Form 10-K for the year ended December 31, 2015. During the quarter ended June 30, 2016, 364 shares were purchased through the reinvestment of dividends on deferred stock units.

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

Item 3. Defaults upon Senior Securities

None.

Item 5. Other Information

None.

Item 6. Exhibits

10.1	Executive Employment Agreement dated May 10, 2016, between Chesapeake Utilities Corporation and James F. Moriarty, 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.
31.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
32.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350.
32.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

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: August 4, 2016

Initials ____

EXECUTIVE EMPLOYMENT AGREEMENT

This Executive Employment Agreement (the "Agreement") dated this 10th day of May 2016, is hereby made by and between Chesapeake Utilities Corporation, a Delaware corporation (the "Company"), and James F. Moriarty (the "Executive").

Recitals

WHEREAS, the Company is currently obtaining the benefit of Executive's services as a full-time executive employee in the capacity of Vice-President, General Counsel and Corporate Secretary;

WHEREAS, the Company's Board of Directors (the "Board") has authorized the Company to provide for the Executive's continued employment pursuant to the terms of this Agreement; and

WHEREAS, Executive is willing, in consideration of the covenants and consideration hereinafter provided, to continue to be employed by the Company in the capacity of Vice-President, General Counsel and Corporate Secretary and to render services incident to such position during the term of this Agreement.

Agreement

In consideration of the mutual promises and covenants contained herein, the Company and Executive hereby agree as follows:

1. Employment. The Company agrees to employ Executive, and Executive agrees to accept employment, as an executive officer of the Company in the capacity of Vice-President, General Counsel and Corporate Secretary, with such authority, duties and responsibilities as are customarily assigned to such position, including such reasonable duties and responsibilities as may be requested of the Executive by the Board of Directors and which are consistent with the By-laws of the Company as in effect from time to time including, but not limited to, responsibility for direction of the corporate legal function, serving as the chief legal advisor on regulatory, transactional, corporate matters, and governmental relations, advising management and the Board on corporate governance matters and serving as Secretary of the Company.

2. Term.

(a) Term of Agreement. The term of this Agree-ment ("Term") shall be the Current Term (as defined in Paragraph 2(b)), and, if applicable, the Extended Term (as defined in Paragraph 2(c)).

(b) Current Term. Subject to Paragraph 2(c), the Current Term of this Agreement shall extend for two (2) years commencing on January 1, 2016. If the Current Term of this Agreement expires without there having been a Change in Control (as hereinafter defined), this Agreement may be renewed for successive one (1) year terms, as of the day following such expiration, by the Company through action of the Compensation Committee of the Board of Directors, unless, during the period beginning ninety (90) days prior and ending thirty (30) days prior to such day, either the Company or Executive shall have given notice to the other that this Agreement will not be renewed. If the Company determines to extend or renew this Agreement as provided under this Paragraph, the new Agreement shall be identical to this Agreement (except insofar as the Company and Executive may otherwise agree in writing) except that the date of the new Agreement shall be as of the day following the expiration of the Current Term of this Agreement or any renewal term.

(c) Extended Term. Upon the occurrence of a Change in Control (as defined in Paragraph 2(d)), the Current Term shall end and the Term of this Agreement shall thereupon automatically be extended, commencing on the date of such Change in Control, for a period of two (2) years (the "Extended Term").

(d) Change In Control. For the purposes of this Agreement, "Change in Control" shall mean a change in the control of the Company during the Term of this Agreement, which shall be deemed to have occurred upon the first of the following events:

(i) any one person, or group of owners of another corporation who acting together through a merger, consolidation, purchase, acquisition of stock or the like (a "Group"), acquires ownership of stock of the Company (or a majority-controlled subsidiary of the Company) that, together with the stock held by such person or Group, constitutes more than fifty percent (50%) of the total fair market value or total voting power of the stock of the Company. However, if such person or Group is considered to own more than fifty percent (50%) of the total fair market value or total voting power of the stock of the corporation before this transfer of the Company's stock, the acquisition of additional stock by the same person or Group shall not be considered to cause a Change in Control of the Company; or

(ii) any one person or Group acquires (or has acquired during the twelve (12) month period ending on the date of the most recent acquisition by such person or persons) ownership of stock of the Company (or a majority-controlled subsidiary of the Company) possessing thirty-five percent (35%) or more of the total voting power of the stock of the Company where such person or Group is not merely acquiring additional control of the Company; or

(iii) a majority of members of the Company's Board (other than the Board of a majority-controlled subsidiary of the Company) is replaced during any twelve (12) month period by directors whose appointment or election is not endorsed by a majority of the members of the Company's Board prior to the date of the appointment or election (the “Incumbent Board”), but excluding, for purposes of determining whether a majority of the Incumbent Board has endorsed any candidate for election to the Board, any individual whose initial assumption of office occurs as a result of an actual or threatened election contest with respect to the election or removal of directors or other actual or threatened solicitation of proxies or consents by or on behalf of a person or Group other than the Company’s Board; or

(iv) any one person or Group acquires (or has acquired during the twelve (12) month period ending on the date of the most recent acquisition by such person or Group) assets from the Company (or a majority-controlled subsidiary of the Company) that have a total gross fair market value equal to or more than forty percent (40%) of the total fair market value of all assets of the Company immediately prior to such acquisition or acquisitions. For this purpose, gross fair market value means the value of the assets of the Company, or the value of the assets being disposed of, determined without regard to any liabilities associated with such assets. A transfer of assets by the Company will not result in a Change in Control if the assets are transferred to:

(A) a stockholder of the Company (immediately before the asset transfer) in exchange for or with respect to its stock;

(B) an entity, fifty percent (50%) or more of the total value or voting power of which is owned, directly or indirectly, by the Company immediately after the transfer of assets;

(C) a person or Group that owns, directly or indirectly, fifty percent (50%) or more of the total value or voting power of all the outstanding stock of the Company; or

(D) an entity, at least fifty percent (50%) of the total value or voting power of which is owned directly or indirectly, by a person described in subparagraph (d)(i), above.

However, no Change in Control shall be deemed to have occurred with respect to the Executive by reason of (1) any event involving a transaction in which the Executive or a group of persons or entities with which the Executive acts in concert, acquires, directly or indirectly, more than thirty percent (30%) of the Common Stock of the business or assets of the Company; or (2) any event involving or arising out of a proceeding under Title 11 of the United States Code (or the provisions of any future United States bankruptcy law), or an assignment for the benefit of creditors or an insolvency proceeding under state or local law.

3. <u>Time</u>. Executive agrees to devote all reasonable full time and best efforts for the benefit of the Company and any subsidiary of the Company, and not to serve any other business enterprise or organization in any capacity during the Term of this Agreement without the prior written consent of the Company, which consent shall not be unreasonably with held.

4. <u>Office</u>.

(a) <u>Current Term</u>. During the Current Term, the Executive shall serve as the Company's Vice-President, General Counsel and Corporate Secretary and the parties agree that the Company shall elect the Executive to these offices, on an annual basis if necessary, during the Current Term of this Agreement.

(b) <u>Extended Term</u>. During the Extended Term of this Agreement the Executive shall hold and perform an office with the responsibility, importance and scope within the Company at least equal to that of the office described and contemplated in Paragraph 1. Further, Executive's office shall be located in Dover, Delaware and Executive shall not be required, without his written consent, to change the office location or to be absent therefrom on business for more than sixty (60) working days in any year.

5. <u>Compensation and Benefits</u>.

(a) <u>Base Compensation; Current Term</u>. The Company shall compensate Executive for his services hereunder during the Current Term at a rate of $250,000 per annum, or such amount as the Board may from time to time determine ("Base Compensation"), payable in installments on the Company's regular payroll dates for salaried executives. The Base Compensation rate shall be reviewed annually and may be increased or decreased, from time to time, provided, however, that Base Compensation shall only be decreased by the Board on a good faith basis and with reasonable justification for the same, and provided further, that in the event of a Change in Control, Base Compensation shall not at any time thereafter be decreased.

(b) <u>Base Compensation; Extended Term</u>. During the Extended Term, the Company shall compensate Executive for his services hereun-der at a rate per annum, payable in installments on the Company's regular payroll dates for salaried executives, equal to his Base Compensation at the time the Extended Term commences, which may be increased, but not decreased by such additional amounts as the Board may determine from time to time based, in part, on an annual review of the Executive's compensation and performance.

(c) Incentive Plans. During the Term of this Agreement, Executive shall be entitled to participate in all bonus, incentive compensation and performance based compensation plans, and other similar policies, practices, programs and arrangements of the Company, now in effect or as hereafter amended or established, on a basis that is commensurate with his position and no less favorable than those generally applicable or made available to other executives of the Company. The Executive's participation shall be in accordance with the terms and provisions of such plans and programs. Participation shall include, but not be limited to:

(i) Chesapeake Utilities Corporation Long-Term Incentive Program. Executive shall be eligible for a performance incentive compensation award as determined on an annual basis by the Compensation Committee of the Board in its discretion and in accordance with and subject to the terms of the Company's 2013 Stock and Incentive Compensation Plan (the "Equity Plan") during the Term of this Agreement. The Equity Plan's Target Bonus as a percent of base salary shall be reviewed annually and may be increased or decreased, from time to time, provided, however, that Target shall only be decreased by the Board on a good faith basis and with reasonable justification for the same, and provided further, that in the event of a Change in Control, Target shall not at any time thereafter be decreased.

(ii) Chesapeake Utilities Corporation Cash Bonus Incentive Plan. Executive shall be eligible for an annual cash bonus award with a target award amount equal to thirty percent (30%) of Executive's Base Compensation, as determined on an annual basis by the Compensation Committee of the Board in its discretion and in accordance with and subject to the terms of the Company's Cash Bonus Incentive Plan during the Term of this Agreement.

(d) Recovery of Compensation. The Executive acknowledges and agrees that all or any portion of an incentive award under the above described bonus and incentive compensation plans or any future arrangement established by the Company to provide incentive or bonus compensation, whether payable in cash, Company common stock or other property, ("Award") is subject to an obligation of repayment by the Executive to the Company if the amount of the Award was calculated based upon the achievement of certain financial results (as reflected in the financial statement of the Company or otherwise) or other performance metrics that, in either case, were subsequently found to be materially inaccurate. The amount that shall be repaid by the Executive to the Company shall be based on the excess amount paid or awarded to the Executive under the Award as compared to the amount that would have been paid or awarded had the material inaccuracy not occurred. If the Compensation Committee of the Board of Directors determines that the Executive engaged in misconduct, malfeasance or gross negligence in the performance of his duties that either caused or significantly contributed to the material inaccuracy in financial statements or other performance metrics, there shall be no time limit on this right of recovery, which shall apply to all future Awards as well as to any and all pre-existing Awards that have not yet been determined and paid as of the date of this Agreement. In all other circumstances, this right of recovery shall apply to all future Awards as well as to any and all pre-existing Awards that have not yet been determined and paid as of the date of this agreement for a period not exceeding one year after the date of payment of each such Award. In addition, the Executive hereby agrees that, if he does not promptly repay the amount recoverable hereunder within thirty (30) days of a demand therefore, such amount may be withheld from compensation of any type not yet due and payable to the Executive, including, but not limited to, the cancellation of future Awards, as determined by the Compensation Committee in its sole discretion. In addition, the Compensation Committee is granted the discretionary authority to interpret and enforce this provision as it determines to be in the best interest of the Company and equitable to the parties. Notwithstanding anything herein, this provision shall not be the Company's exclusive remedy with respect to such matters. In addition, the parties agree that the Company may unilaterally amend this provision at any time to comply with applicable law or securities exchange listing rules, as the same may be in effect from time to time, during the Current Term or the Extended Term of this Agreement.

(e) Retirement Plans. During the Term of this Agreement, Executive shall be entitled to participate in all profit-sharing, savings and retirement benefit plans, plans that are supplemental to any tax-qualified savings and retirement plans, and other similar policies, practices, programs and arrangements of the Company, now in effect or as hereafter amended or established, on a basis that is commensurate with his position and no less favorable than those generally applicable or made available to other executives of the Company. The Executive's participation shall be in accordance with the terms and provisions of such plans and programs.

(f) Welfare Benefits. During the Term of this Agreement, Executive, and his family, as applicable, shall be entitled to participate in all insurance, medical, health and welfare, and similar plans and arrangements, as well as all vacation and other employee fringe benefit plans, perquisite plans, and other policies, practices, programs and arrangements of the Company, now in effect or as hereafter amended or established, on a basis that is commensurate with his position and no less favorable than those generally applicable or made available to other executives of the Company. The Executive's participation shall be in accordance with the terms and provisions of such plans.

(g) Other Benefits. During the Term of this Agreement, the Company shall furnish Executive with a suitable office, necessary administrative support and customary furniture and furnishings for such office. The Company further agrees that Executive shall have the use of a Company-owned or Company-leased and Company-maintained automobile, new every three (3) years, of a kind and model appropriate to his position with the Company.

(h) Expenses. During the Term of this Agreement, the Company shall pay all necessary and reasonable business expenses incurred by Executive on behalf of the Company in the course of his employment hereunder, including, without limitation, expenses incurred in the conduct of the Company's business while away from his domicile and properly substantiated expenses for travel, meals, lodging, entertainment and related expenses that are for the benefit of the Company. All expense reimbursements shall comply with applicable rules or guidelines of the Company in effect at the time the expense is incurred.

If any reimbursements under this or any other provision of this Agreement are taxable to the Executive, such reimbursements shall be paid on or before the end of the calendar year following the calendar year in which the reimbursable expense was incurred, and the Company shall not be obligated to pay any such reimbursement amount for which Executive fails to submit an invoice or other documented reimbursement request at least 10 business days before the end of the calendar year next following the calendar year in which the expense was incurred. Such expenses shall be reimbursable only to the extent they were incurred during the term of the Agreement. In addition, the amount of such reimbursements that the Company is obligated to pay in any given calendar year shall not affect the amount the Company is obligated to pay in any other calendar year. In addition, Executive may not liquidate or exchange the right to reimbursement of such expenses for any other benefits.

(i) Nothing in this Agreement shall preclude the Company from amending or terminating any employee benefit plan or practice, but, it being the intent of the parties that the Executive shall continue to be entitled during the Extended Term to compensation, benefits, reimbursements and perquisites as set forth in Paragraphs 5(a) through 5(c) and 5(e) through 5(h) at least equal to those attached to his position on the date of this Agreement, and nothing in this Agreement shall operate as, or be construed to authorize, a reduction during the Extended Term without Executive's written consent in the level of such compensation, benefits, reimbursements or perquisites as in effect on the date of a Change in Control. If and to the extent that such compensation, benefits, reimbursements or perquisites are not payable or provided to Executive under any such plan or practice by reason of an amendment thereto or termination thereof during the Extended Term, the Company shall nevertheless pay or provide such compensation, benefits, reimbursements or perquisites to Executive, either directly or through alternative arrangements.

6. Termination.

(a) Payment Upon Termination During Current Term. In the event that the Company terminates this Agreement during the Current Term, or elects not to renew this Agreement at the end of the Current Term, for any reason other than Cause, as defined below, or the Executive’s death, the Company shall continue to pay to Executive his (or in the event of his death following such termination, his legal representative), as a severance benefit Base Compensation under Paragraph 5(a), at the rate in effect immediately prior to the date of such termination ("Termination Date"), on the regular payroll dates occurring during the period of one (1) year following the Termination Date. In addition, and notwithstanding the foregoing provisions of this Paragraph 6(a), to the extent required in order to comply with Section 409A of the Internal Revenue Code of 1986, as amended (the "Code"), Termination Date shall be determined based on the date the Executive has a “separation from service” within the meaning of Code Section 409A and regulations thereunder, using the default rule under such regulations (“Separation from Service”), and cash amounts that would otherwise be payable under this Paragraph 6(a) during the six-month period immediately following the Termination Date shall instead be paid, with interest on any delayed payment at the applicable federal rate under Code Section 7872(f)(2)(A), on the first business day after the date that is six (6) months following the Executive’s Separation from Service. Payment of the severance benefit under this Paragraph is subject to the Executive’s compliance with the covenants of Paragraph 9 and the execution and delivery (and non-revocation) of a release of claims (the “Release”) against the Company and its officers, directors, employees and affiliates, which Release must be delivered to the Company not later than 45 days after the Termination Date. If the Executive fails to comply with any of the covenants of Paragraph 9 or fails to deliver the Release within 45 days after the Termination Date, or if the Executive revokes such Release within 7 days after its delivery to the Company, payment of the severance benefits shall cease and any unpaid amounts shall be forfeited. Payment commencement shall not be delayed, however, pending delivery of the Release.

(b) Termination for Cause. This Agreement and Executive's employment hereunder may be terminated by the Company at any time for Cause. In the event of termination for Cause, the Executive shall not be entitled to any severance benefits under this Agreement. Termination of the Executive's employment shall be deemed to have been "for Cause" only if it shall have been the result of:

(i) Executive’s conviction of a felony under the laws of the United States or a state in which Executive works or resides, or a guilty or no contest plea by the Executive with respect thereto;

(ii) a willful or deliberate act or acts of dishonesty by Executive resulting or intended to result directly or indirectly in material gain to or personal enrichment of Executive at the Company's expense;

(iii) a deliberate and intentional refusal by Executive (except by reason of incapacity due to illness or accident) to comply with the provisions of Paragraph 1, provided that such breach shall have resulted in demonstrably material injury to the Company and the Executive shall have failed to remedy such breach within thirty (30) days after notice from the Secretary of the Company demanding that the Executive remedy such breach; or

(iv) conduct by Executive that is materially injurious to the Company if such conduct was undertaken without good faith and the reasonable belief that such conduct was in the best interest of the Company.

(c) Payment Upon Termination During Extended Term. In the event of a Termination Without Cause, as defined below, during the Extended Term, the Company shall pay to Executive (or, in the event of his death following the termination, his legal representative) in cash, the first business day that falls on or after the sixtieth (60th) day after the date of such termination (the "Extended Termination Date") the sum of all accrued but unpaid salary, bonus, vacation pay, expense reimbursements and any other amounts due, plus the following:

(i) an amount equal to the product of multiplying the monthly rate of Base Compensation to which Executive was entitled under Paragraph 5(a) on the day immediately prior to the Extended Termination Date by Twenty-four (24) months ("Covered Period");

(ii) an amount equal to the aggregate of the Company's contributions to the Company's savings plan (including, but not limited to, the Chesapeake Utilities Corporation Retirement Savings Plan, and any related excess benefit plans) in respect of Executive that were not vested on the day immediately prior to the Extended Termination Date but that would have been vested at the end of the Covered Period if Executive had remained employed by the Company for the duration of that period; and

(iii) an amount equal to the product of multiplying the average of the annual aggregate benefits awarded to the Executive under all annual bonus program(s) of the Company in which the Executive was a participant in each of the three (3) calendar years immediately preceding the calendar year in which the Extended Termination Date occurs by two (2) years.

Payment of the severance benefit under this Paragraph is subject to the Executive's compliance with the covenants of Paragraph 9 and the execution and delivery (and non-revocation) of a release of claims (the "Release") against the Company and its officers, directors, employees and affiliates, which Release must be delivered to the Company not later than 45 days after the Termination Date. If the Executive fails to comply with any of the covenants of Paragraph 9 or fails to deliver the Release within 45 days after the Termination Date, or if the Executive revokes such Release within 7 days after its delivery to the Company, payment of the severance benefits shall cease (if commenced) or shall not be made, and any unpaid amounts shall be forfeited.

In addition, the Company shall continue to provide medical, prescription drug, vision, dental and other Company welfare benefits to the Executive and his eligible dependents during the Covered Period as if the Executive remained an active employee of the Company (but, with respect to any such benefits provided through insurance, only if and to the extent it is permissible to extend such benefits to a former employee of the Company under the terms of the applicable plan and insurance contracts). Executive further acknowledges that the cost of the coverage afforded to Executive and his eligible dependents under self-funded medical expense reimbursement plans of the Company during the Covered Period shall be treated as additional taxable income to the Executive to the extent necessary to avoid a violation of the nondiscrimination provisions of Section 105(h) of the Code. Should the continuation of any medical or similar coverages be through fully insured plans, and should such continuation violate the nondiscrimination requirements for such plans under the Patient Protection and Affordable Care Act of 2010, then the Executive shall receive additional cash severance benefits rather than continued coverage under such plans of the Company in an amount based on the premium cost of such coverage that the Company would otherwise pay under this paragraph. In addition, the applicable period of health benefit continuation under Code Section 4980B shall begin at the end of the Covered Period.

To the extent required in order to comply with Code Section 409A, cash amounts that would otherwise be payable under this Paragraph 6(c) during the six-month period immediately following the Extended Termination Date (and which are not eligible for the exception applicable to payments due to involuntary separation under Treas. Reg. Section 1.409A-1(b)(9)(iii)) shall instead be paid, with interest on any delayed payment at the applicable federal rate under Code Section 7872(f)(2)(A), on the first business day after the date that is six (6) months following the Executive's Separation from Service. Further, any taxable welfare benefits provided to Executive pursuant to this Paragraph 6(c) that are not "disability pay" or "death benefits" within the meaning of Treas. Reg. Section 1.409A-1(a)(5) (collectively, the "Applicable Benefits") shall be subject to the following requirements in order to comply with Code Section 409A. The amount of any Applicable Benefits provided during one taxable year shall not affect the amount of the Applicable Benefits provided in any other taxable year, except that with respect to any Applicable Benefits that consist of the reimbursement of expenses referred to in Code Section 105(b), a limitation may be imposed on the amount of such reimbursements over some or all of the Covered Period, as described in Treas. Reg. Section 1.409A-3(i)(1)iv)(B). To the extent that any Applicable Benefits consist of the reimbursement of eligible expenses, such reimbursement must be made on or before the last day of the calendar year following the calendar year in which the expense was incurred. No Applicable Benefits may be liquidated or exchanged for another benefit. During the period of six (6) months immediately following Executive's Separation from Service, Executive shall be obligated to pay the Company the full cost for any Applicable Benefits that do not constitute health benefits of the type required to be provided under the health continuation coverage requirements of Code Section 4980B, and the Company shall reimburse Executive for any such payments on the first business day that is more than six (6) months after Executive's Separation from Service, together with interest on such amount from the date of Separation from Service through the date of payment at the applicable federal rate under Code Section 7872(f)(2)(A).

(d) Termination Without Cause. For purposes of Paragraph 6(c) above, "Termination Without Cause" shall mean a Separation from Service of the Executive that is either a:

(i) Termination by the Company of Executive's employment without Cause (as "Cause" is defined in Paragraph 6(b) above); or

(ii) Termination by Executive of his employ-ment following the occurrence of any of the following events:

(A) failure to elect or re-elect Execu-tive to, or removal of Executive from, the office or offices set forth in Paragraph 1, or failure to nominate Executive for election to the Board if Executive shall have been a member of the Board immedi-ately prior to a Change in Control of the Company;

(B) a significant change in the nature or scope of his authorities, powers, functions, duties or responsibilities attached to the positions contemplated in Paragraph 1 or a reduction in his compensation or in the benefits available to the Executive and his family, as provided in Para-graph 5, which change or reduction is not remedied within thirty (30) days after notice to the Company by the Executive;

(C) any other breach by the Company of any material provision of this Agreement (including, without limitation, relocation of the Executive in material violation of Paragraph 4(b)), which breach is not remedied within thirty (30) days after notice to the Company by Executive; or

(D) the consolidation or merger of the Company or transfer of all or a significant portion of its assets unless a successor or successors (by merger, consolidation or otherwise) to which all or a significant portion of its assets has been transferred shall have assumed all duties and obligations of the Company under this Agreement.

In order to effect a Termination Without Cause in any event set forth in this Paragraph 6(d)(ii), Executive must elect to terminate his employment under this Agreement upon not less than forty (40) days and not more than ninety (90) days' written notice to the Board, attention of the Chief Executive Officer, given, except in the case of a continuing breach, within three (3) calendar months after: (1) failure to be so elected, reelected, or nominated, or such removal, (2) expiration of the 30-day cure period with respect to such event, or (3) the closing date of such consolidation, merger or transfer of assets.

An election by Executive to terminate his employment under the provisions of this Paragraph shall not be deemed a voluntary termination of employment by Executive for the purpose of this Agreement or any plan or practice of the Company. Further, the death of the Executive during the Extended Term but prior to a Termination Without Cause, as defined, shall not constitute Cause or be deemed to be a Termination Without Cause.

7. <u>Maximum Payment Upon Termination</u>.

(a) <u>Determination</u>. Notwithstanding any other provision of this Agreement, if any payment or distribution (a "Payment") by the Company or any other person or entity to or for the benefit of the Executive is determined to be an "excess parachute payment" (within the meaning of Code Section 280G(b)(1) or any successor provision of similar effect), whether paid or payable or distributed or distributable pursuant to Paragraph 6(c) of this Agreement or otherwise, then the Executive’s benefits under this Agreement shall be reduced by the amount necessary so that the Executive’s total "parachute payment" as defined in Code Section 280G(b)(2)(A) under this and all other agreements will be $1.00 less than the amount that would be a "parachute payment". The determination concerning the application of the reduction shall be made by a nationally-recognized firm of independent accountants (together with legal counsel of its choosing) selected by the Company after consultation with the Executive (which may be the Company’s independent auditors), whose determination shall be conclusive and binding on all parties. Any fees and expenses of such independent accountants and counsel (including counsel for the Executive) shall be borne by the Company.

(b) <u>Notices</u>. If it is determined that the benefits under this Agreement must be reduced under this Paragraph, within 10 days of the date of such determination, the Company will apprise the Executive of the amount of the reduction ("Notice of Reduction"). Within 10 days of receiving that information, the Executive may specify how (and against which benefit or payment source) the reduction is to be applied ("Notice of Application"). The Company will be required to implement these directions within 10 days of receiving the Notice of Application. If the Company has not received a Notice of Application from the Executive within 10 days of the date of the Notice of Reduction, the Company will apply this Paragraph proportionately based on the amounts otherwise payable under Paragraph 6(c). If the Company receives a Notice of Application that does not fully implement the requirements of this Paragraph, the Company will apply this Paragraph proportionately on the basis of the reductions specified in the Notice of Application first, then to any remaining reduction based on the amounts otherwise payable under Paragraph 6(c).

Notwithstanding the foregoing, if the exercise of discretion reserved to the Executive in determining the Notice of Application would violate Code Section 409A, then such discretion shall be eliminated and the amounts payable under Paragraph 6(c) shall be reduced proportionately.

8. Mitigation. Executive shall not be required to mitigate the amount of any payment provided for in this Agreement either by seeking other employment or otherwise. The amount of any payment provided for herein shall not be reduced by any remuneration that Executive may earn from employment with another employer or otherwise following his Termination Date or Extended Termination Date, as applicable.

9. Covenants.

(a) Introduction. The parties acknowledge that the provisions and covenants contained in this Paragraph 9 are ancillary and material to this Agreement and that the limitations contained herein are reasonable in geographic and temporal scope and do not impose a greater restriction or restraint than is necessary to protect the goodwill and other legitimate business interests of the Company. The parties also acknowledge and agree that the provisions of this Paragraph 9 do not adversely affect Executive’s ability to earn a living in any capacity that does not violate the covenants contained herein. The parties further acknowledge and agree that the provisions of Paragraph 19 below are accurate and necessary because (i) Delaware is the headquarters state of the Company, which has operations in multiple states and a compelling interest in having its employees treated uniformly, (ii) the use of Delaware law provides certainty to the parties in any covenant litigation in the United States, and (iii) enforcement of the provisions of this Paragraph 9 would not violate any fundamental public policy of Delaware or any other jurisdiction.

(b) Confidential Information. Executive shall hold in a fiduciary capacity for the benefit of the Company, all secret or confidential information, knowledge or data relating to the Company and its businesses (including, but not limited to, any proprietary and not publicly available information concerning any processes, methods, trade secrets, costs, names of users or purchasers of the Company’s products or services, business methods, financial affairs, operating procedures or programs or methods of promotion and sale) that Executive has obtained or obtains during Executive’s employment by the Company and that is not public knowledge (other than as a result of Executive’s violation of this Paragraph 9(b)) ("Confidential Information"). For purposes of this Paragraph 9(b), information shall not be deemed to be publicly available merely because it is embraced by general disclosures or because individual features or combinations thereof are publicly available. Executive shall not communicate, divulge or disseminate Confidential Information at any time during or after Executive’s employment with the Company except:

(i) to employees or agents of the Company that need the Confidential Information to perform their duties on behalf of the Company;

(ii) in the performance of Executive’s duties to the Company;

(iii) as a necessary (and only to the extent necessary) part of any undertaking by Executive to enforce Executive’s rights under this Agreement; or

(iv) as otherwise required by law or legal process.

All confidential records, files, memoranda, reports, customer lists, drawings, plans, documents and the like that Executive uses, prepares or comes into contact with during the course of Executive’s employment shall remain the sole property of the Company and shall be turned over to the Company upon termination of Executive's employment.

(c) Non-solicitation of Company Employees. Executive shall not, at any time during the Restricted Period (as defined below), without the prior written consent of the Company, engage in the following conduct (a "Solicitation"):

(i) directly or indirectly, contact, solicit, recruit or employ (whether as an employee, officer, director, agent, consultant or independent contractor) any person who was or is at any time during the previous six months an employee, representative, officer or director of the Company; or

(ii) take any action to encourage or induce any employee, representative, officer or director of the Company to cease his relationship with the Company for any reason. A "Solicitation" does not include any recruitment of employees for the Company.

The "Restricted Period" means the period including Executive's employment with the Company and one (1) year following the Termination Date or Extended Termination Date, as applicable, and, if the Executive has given a notice pursuant to Paragraph 6(d)(ii), for a period of fifteen (15) months following the giving of such notice.

(d) Non-solicitation of Third Parties. During the Restricted Period, the Executive shall not (either directly or indirectly or as an officer, agent, employee, partner or director of any other company or entity) solicit, service, recruit, induce, influence, or accept on behalf of any competitor of the Company the business of:

(i) any customer of the Company at the time of Executive's employment or Termination Date or Extended Termination Date, as applicable; or

(ii) any potential customer of the Company which Executive knew to be an identified, prospective purchaser of services or products of the Company.

(e) Non-competition. During the Restricted Period, Executive shall not, directly or indirectly, accept employment with, act as a consultant to, or otherwise perform services that are substantially the same or similar to those for which Executive was compensated by the Company (such comparison to be based on job-related functions and responsibilities and not job title) for any business that directly competes with any portion of the Company. This restriction applies to any parent, division, affiliate, newly formed or purchased business(es) and/or successor of a business that competes with the Company. Further, during the Restricted Period, Executive shall not assist any individual or entity other than the Company in acquiring any entity with respect to which a proposal to acquire such entity was presented to the Board during the one (1) year period beginning prior to Executive's Termination Date, Extended Termination Date or notice given by Executive pursuant to Paragraph 6(d)(ii), as applicable.

(f) Post-Termination Cooperation. Executive agrees that during and after employment with the Company and without additional compensation (other than reimbursement for reasonable associated expenses) to cooperate with the Company in the following areas:

(i) Cooperation with the Company. Executive agrees to:

(A) be reasonably available to answer questions for the Company's officers regarding any matter, project, initiative or effort for which

Executive was responsible while employed by the Company; and

(B) cooperate with the Company during the course of all third-party proceedings arising out of the Company's business about which Executive has knowledge or information.

For purposes of this Agreement, "proceeding" includes internal investigations, administrative investigations or proceedings and lawsuits (including pre-trial discovery and trial testimony) and "cooperation" includes (1) Executive being reasonably available for interviews, meetings, depositions, hearings and/or trials without the need for a subpoena or assurances by the Company, (2) providing any and all documents in Executive's possession that relate to the proceeding, and (3) providing assistance in locating any and all relevant notes and/or documents.

(ii) Cooperation with Third Parties. Unless compelled to do so by lawfully-served subpoena or court order, Executive agrees not to communicate with, or give statements or testimony to, any attorney representing an interest opposed to the Company's interest ("Opposing Attorney"), Opposing Attorney's representative (including a private investigator) or current or former employee relating to any matter (including pending or threatened lawsuits or administrative investigations) about which Executive has knowledge or information as a result of employment with the Company. Executive also agrees to notify the Company immediately after being contacted by a third party or receiving a subpoena or court order to appear and testify with respect to any matter that may include a claim opposed to the Company's interest. However, this Paragraph 9(f)(ii) shall not apply to any effort undertaken by Executive to enforce Executive's rights under this Agreement, but only to the extent necessary for that purpose.

(iii) Cooperation with the Media. Executive agrees not to communicate with, or give statements to, any member of the media (including print, television, electronic or radio media) relating to any matter (including pending or threatened lawsuits or administrative investigations) about which Executive has knowledge or information as a result of employment with the Company. Executive also agrees to notify the Company immediately after being contacted by any member of the media with respect to any matter affected by this Paragraph.

(g) Non-Disparagement. Executive and Company shall at all times refrain from taking actions or making statements, written or verbal, that:

(i) denigrate, disparage or defame the goodwill or reputation of Executive or the Company, as the case may be, or any of its trustees, officers, security holders, partners, agents or former or current employees and directors, or

(ii) are intended to, or may be reasonably expected to, adversely affect the morale of the employees of the Company.

Executive further agrees not to make any negative statements to third parties relating to Executive's employment or any aspect of the business of the Company and not to make any statements to third parties about the circumstances of the termination of Executive's employment, or about the Company or its trustees, directors, officers, security holders, partners, agents or former or current employees and directors, except as may be required by a court or governmental body.

(h) Enforcement. The Executive acknowledges and agrees that: (i) the purpose of the foregoing covenants, including, without limitation, the nonsolicitation and noncompetition covenants of Paragraphs 9(d) and (e), is to protect the goodwill, trade secrets and other Confidential Information of the Company; (ii) because of the nature of the business in which the Company is engaged and because of the nature of the Confidential Information to which the Executive has access, the Company would suffer irreparable harm and it would be impractical and excessively difficult to determine the actual damages of the Company in the event the Executive breached any of the covenants of this Paragraph 9; and (iii) remedies at law (such as monetary damages) for any breach of the Executive's obligations under this Paragraph 9 would be inadequate. The Executive therefore agrees and consents that if the Executive commits any breach of a covenant under this Paragraph 9, or threatens to commit any such breach, the Company shall have the right (in addition to, and not in lieu of, any other right or remedy that may be available to it, including but not limited to the right to terminate and forfeit as yet unpaid severance benefits under Paragraphs 6(a) and 6(c) of this Agreement) to temporary and permanent injunctive relief from a court of competent jurisdiction, without posting any bond or other security and without the necessity of proof of actual damage, and that the arbitration provisions of Paragraph 14 shall not apply.

10. Indemnification. The Company shall indemnify Executive to the fullest extent permitted by applicable Delaware law (as may be amended from time to time), includ-ing the advance of expenses permitted herein.

11. Performance. The failure of either party to this Agreement to insist upon strict performance of any provision of this Agreement shall not constitute a waiver of its rights subse-quently to insist upon strict performance of such provision or any other provision of this Agreement.

12. Non-Assignability. Neither party shall have the right to assign this Agreement or any rights or obligations hereunder without the consent of the other party.

13. Invalidity. If any provisions of this Agreement shall be found to be invalid by any court of competent jurisdiction, such finding shall not affect the remaining provisions of this Agreement, all of which shall remain in full force and effect.

14. Arbitration and Legal Fees. In the event of any dispute regarding a refusal or failure by the Company to make payments or provide benefits hereunder for any reason, Executive shall have the right, in addition to all other rights and remedies provided by law, to arbitration of such dispute under the rules of the American Arbitration Asso-ciation, which right shall be invoked by serving upon the Company a notice to arbitrate, stating the place of arbi-tration, within ninety (90) days of receipt of notice in any form (including, without limitation, failure by the Company to respond to a notice from Executive within thirty (30) days) that the Company is withholding or proposes to withhold any payments or the provision of any benefits the Executive, in good faith, believes are called for hereunder. In the event of any such dis-pute, whether or not Executive exercises his right to arbitration, if it shall ultimately be determined that the Company's refusal or failure to make payments or provide benefits hereunder was wrongful or otherwise inconsistent with the terms of this Agreement, the Company shall indemni-fy and hold harmless Executive from and against any and all expenses incurred in connection with such determination, including reasonable legal and other fees and expenses. Accordingly, the Company agrees to pay within 30 days following the Company’s receipt of an invoice from the Executive all legal fees and expenses which the Executive may reasonably incur as a result of any contest by either party of the validity or enforceability of, or liability under, any provision of this Agreement, plus, in each case interest on any delayed payment at the applicable Federal rate provided for in Section 7872(f)(2)(A) of the Code, if the Executive prevails on any material claim made by him and disputed by the Company (or its successors and assigns) under the terms of this

Agreement. Such payments shall be made in accordance with the provisions of Paragraph 20 in order to comply with Section 409A of the Code.

15. Survival of Certain Provisions. Notwithstanding any other provision of this Agreement, the termination of this Agreement for any reason shall not result in the termination of the rights and obligations of the parties under the provisions of Sections 5(d), 6, 7, 9, 10, 14 and 16 hereof, which shall survive any such termination. The right of recovery provisions of Section 5(d) shall cease to apply during the Extended Term and shall be automatically terminated upon a Change in Control of the Company (as defined in Paragraph 2(d)) except with respect to any right of recovery that has been asserted prior to such Change in Control.

16. Successors. This Agreement shall be binding upon and inure to the benefit of the Executive (and his personal representative), the Company and any successor organization or organizations that shall succeed to substantially all of the business and property of the Company and assume the Company's obligations hereunder, whether by means of merger, consolidation, acquisition of substantially all of the assets of the Company, or operation of law. The Company shall require any successor organization or organizations to agree to assume the obligations of this Agreement.

17. Set-off. The Company shall have no right of set-off or counterclaim in respect of any claim, debt or obligation against any payments or benefits provided for in this Agreement except as otherwise provided herein.

18. Amendments. No Amendment to this Agreement shall be effective unless in writing and signed by both the Company and Executive. Notwithstanding the foregoing, if any compensation or benefits provided by this Agreement may result in the application of Code Section 409A, the Company shall, in consultation with the Executive, modify the Agreement in the least restrictive manner necessary in order to exclude such compensation from the definition of "deferred compensation" within the meaning of Code Section 409A or in order to comply with the provisions of Code Section 409A, other applicable provisions of the Code and/or any rules, regulations or other regulatory guidance issued under such statutory provisions, and without any diminution in the value of the payments to the Executive.

19. Governing Law. This Agreement shall be interpret-ed and enforced in accordance with the laws of the State of Delaware. The parties hereto irrevocably agree to submit to the jurisdiction and venue of the courts of the State of Delaware in any action or proceeding brought with respect to or in connection with this Agreement except for an action described in Paragraph 14.

20. Code Section 409A. Notwithstanding any provision of Paragraph 10 or 14 of this Agreement to the contrary, any legal fees and expenses to be paid by the Company pursuant to Paragraph 10 or 14 shall be subject to the following requirements in order to comply with Code Section 409A. Such legal fees and expenses shall be paid by the Company only to the extent incurred during the Term of the Agreement or for a period of ten (10) years after the Executive's Separation from Service. The Company shall pay such legal fees and expenses no later than the end of the calendar year next following the calendar year in which such fees and expenses were incurred, and the Company shall not be obligated to pay any such fees and expenses for which the Executive fails to submit an invoice at least ten (10) business days before the end of the calendar year next following the calendar year in which such fees and expenses were incurred. The amount of such legal fees and expenses that the Company is obligated to pay in any given calendar year shall not affect the legal fees and expenses that the Company is obligated to pay in any other calendar year, and the Executive's right to have the Company pay such legal fees and expenses may not be liquidated or exchanged for any other benefit.

21. Notices. Unless otherwise stated herein, all notices hereunder shall be in writing and

shall be deemed to be given when personally delivered or mailed by United States registered or certified mail, postage prepaid, to, if to the Company, 909 Silver Lake Boulevard, Dover, Delaware 19904, and, if to Executive, the last address therefore shown on the records of the Company. Either the Company or Executive may, by notice to the other, designate an address other than the foregoing for the receipt of subsequent notices.

22. Withholding. The Company may withhold from any amounts payable to Executive hereunder all federal, state, city or other taxes that the Company may reasonably deter-mine are required to be withheld pursuant to any applicable law or regulation.

23. Nature of Payments Upon Termination. All payments to Executive pursuant to Paragraph 6 of this Agree-ment shall be considered as liquidated damages or, in the case of certain payments pursuant to Paragraph 6(c), as severance payments in consideration of Executive's past services to the Company, and no such payment shall be regarded as a penalty to the Company.

24. Prior Agreement. The parties acknowledge and agree that the terms of this Agreement constitute the entire agreement of the parties with respect to the subject matter and supersede all prior agreements and amendments with respect thereto, including, without limitation, the Prior Agreement.

25. Acknowledgment. The parties hereto each acknowl-edge that each has read this Agreement and understands the same and that each enters into this Agreement freely and voluntarily.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the date first above written.

CHESAPEAKE UTILITIES CORPORATION

[CORPORATE SEAL] By: ______________________________

Title:

ATTEST:

____

EXECUTIVE:

EXHIBIT 31.1

**CERTIFICATE PURSUANT TO RULE 13A-14(A)
UNDER THE SECURITIES EXCHANGE ACT OF 1934**

I, Michael P. McMasters, certify that:

1. I have reviewed this quarterly report on Form 10-Q for the quarter ended June 30, 2016 of Chesapeake Utilities Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a–15(e) and 15d–15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a–15(f) and 15d–15(f)) for the registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 4, 2016

/S/ MICHAEL P. MCMASTERS

Michael P. McMasters
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATE PURSUANT TO RULE 13A-14(A)
UNDER THE SECURITIES EXCHANGE ACT OF 1934

I, Beth W. Cooper, certify that:

1. I have reviewed this quarterly report on Form 10-Q for the quarter ended June 30, 2016 of Chesapeake Utilities Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a–15(e) and 15d–15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a–15(f) and 15d–15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 4, 2016

/S/ BETH W. COOPER

Beth W. Cooper
Senior Vice President and Chief Financial Officer

EXHIBIT 32.1

Certificate of Chief Executive Officer

of

Chesapeake Utilities Corporation

(pursuant to 18 U.S.C. Section 1350)

I, Michael P. McMasters, President and Chief Executive Officer of Chesapeake Utilities Corporation, certify that, to the best of my knowledge, the Quarterly Report on Form 10-Q of Chesapeake Utilities Corporation ("Chesapeake") for the period ended June 30, 2016, filed with the Securities and Exchange Commission on the date hereof (i) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Chesapeake.

/S/ MICHAEL P. MCMASTERS

Michael P. McMasters
August 4, 2016

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to Chesapeake Utilities Corporation and will be retained by Chesapeake Utilities Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.2

Certificate of Chief Financial Officer

of

Chesapeake Utilities Corporation

(pursuant to 18 U.S.C. Section 1350)

I, Beth W. Cooper, Senior Vice President and Chief Financial Officer of Chesapeake Utilities Corporation, certify that, to the best of my knowledge, the Quarterly Report on Form 10-Q of Chesapeake Utilities Corporation ("Chesapeake") for the period ended June 30, 2016, filed with the Securities and Exchange Commission on the date hereof (i) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Chesapeake.

/S/ BETH W. COOPER

Beth W. Cooper

August 4, 2016

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to Chesapeake Utilities Corporation and will be retained by Chesapeake Utilities Corporation and furnished to the Securities and Exchange Commission or its staff upon request.