

CHESAPEAKE UTILITIES CORP

Form 10-Q

November 03, 2016

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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: September 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 (I.R.S. Employer  
of incorporation or organization) Identification No.)  
909 Silver Lake Boulevard, Dover, Delaware 19904  
(Address of principal executive offices, including Zip Code)  
(302) 734-6799  
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes  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 — 16,301,161 shares outstanding as of October 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 on Amelia Island, 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: The Credit Agreement dated October 8, 2015, among 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

Delaware Division: Chesapeake Utilities' natural gas distribution operation serving customers in Delaware

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

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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., a corporation that merged with and into Aspire Energy on April 1, 2015

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

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., a wholly-owned Florida intrastate pipeline subsidiary of Chesapeake Utilities

PESCO: Peninsula Energy Services Company, Inc., a wholly-owned natural gas marketing subsidiary of Chesapeake Utilities

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: Our unsecured revolving credit facility with the Lenders

Retirement Savings Plan: Chesapeake Utilities' qualified 401(k) retirement savings plan

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

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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., a wholly-owned propane distribution subsidiary of Chesapeake Utilities

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 20 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

SIR: A system improvement rate adder designed to fund system expansion costs in Sandpiper Energy's service territories

TETLP: Texas Eastern Transmission, LP

Xeron: Xeron, Inc., a propane wholesale marketing subsidiary of Chesapeake Utilities

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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		Nine Months Ended	
	September 30,		September 30,	
	2016	2015	2016	2015
(in thousands, except shares and per share data)				
Operating Revenues				
Regulated Energy	\$70,019	\$ 63,796	\$226,630	\$ 235,438
Unregulated Energy and other	38,329	28,117	130,356	119,238
Total Operating Revenues	108,348	91,913	356,986	354,676
Operating Expenses				
Regulated Energy cost of sales	24,644	23,161	81,184	101,414
Unregulated Energy and other cost of sales	28,183	17,959	85,142	73,465
Operations	30,126	26,388	85,370	79,522
Maintenance	3,542	2,603	8,925	8,033
Gain from a settlement	—	—	(130	) (1,500 )
Depreciation and amortization	8,209	7,636	23,493	22,155
Other taxes	3,488	3,257	10,725	10,000
Total Operating Expenses	98,192	81,004	294,709	293,089
Operating Income	10,156	10,909	62,277	61,587
Other (expense) income, net	(28	) 36	(68	) (3 )
Interest charges	2,722	2,492	7,996	7,425
Income Before Income Taxes	7,406	8,453	54,213	54,159
Income taxes	2,990	3,334	21,401	21,638
Net Income	\$4,416	\$ 5,119	\$32,812	\$ 32,521
Weighted Average Common Shares Outstanding:				
Basic	15,372,413	15,258,819	15,324,932	15,035,569
Diluted	15,412,783	15,306,843	15,365,955	15,083,641
Earnings Per Share of Common Stock:				
Basic	\$0.29	\$ 0.34	\$2.14	\$ 2.16
Diluted	\$0.29	\$ 0.33	\$2.14	\$ 2.16
Cash Dividends Declared Per Share of Common Stock	\$0.3050	\$ 0.2875	\$0.8975	\$ 0.8450

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

Table of ContentsChesapeake Utilities Corporation and Subsidiaries  
Condensed Consolidated Statements of Comprehensive Income (Unaudited)

	Three Months Ended September 30, 2016		Nine Months Ended September 30, 2016	
	2015		2015	
(in thousands)				
Net Income	\$4,416	\$5,119	\$32,812	\$32,521
Other Comprehensive Income (Loss), net of tax:				
Employee Benefits, net of tax:				
Amortization of prior service cost, net of tax of \$(8), \$(7), \$(23) and \$(20), respectively	(12 )	(10 )	(37 )	(30 )
Net gain, net of tax of \$66, \$62, \$200 and \$187, respectively	100	93	300	278
Cash Flow Hedges, net of tax:				
Unrealized gain (loss) on commodity contract cash flow hedges, net of tax of \$38, \$(51), \$360 and \$(29), respectively	51	(75 )	548	(43 )
Total Other Comprehensive Income	139	8	811	205
Comprehensive Income	\$4,555	\$5,127	\$33,623	\$32,726

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

Table of ContentsChesapeake Utilities Corporation and Subsidiaries  
Condensed Consolidated Balance Sheets (Unaudited)

	September 30, 2016	December 31, 2015
Assets		
(in thousands, except shares and per share data)		
Property, Plant and Equipment		
Regulated Energy	\$ 908,822	\$ 842,756
Unregulated Energy	194,743	145,734
Other businesses and eliminations	20,835	18,999
Total property, plant and equipment	1,124,400	1,007,489
Less: Accumulated depreciation and amortization	(237,434)	(215,313)
Plus: Construction work in progress	49,082	62,774
Net property, plant and equipment	936,048	854,950
Current Assets		
Cash and cash equivalents	1,536	2,855
Accounts receivable (less allowance for uncollectible accounts of \$792 and \$909, respectively)	47,103	41,007
Accrued revenue	9,506	12,452
Propane inventory, at average cost	4,106	6,619
Other inventory, at average cost	3,867	3,803
Regulatory assets	6,045	8,268
Storage gas prepayments	8,192	3,410
Income taxes receivable	13,178	24,950
Prepaid expenses	7,603	7,146
Mark-to-market energy assets	477	153
Other current assets	543	1,044
Total current assets	102,156	111,707
Deferred Charges and Other Assets		
Goodwill	15,070	14,548
Other intangible assets, net	1,938	2,222
Investments, at fair value	4,630	3,644
Regulatory assets	76,343	77,519
Receivables and other deferred charges	4,325	2,831
Total deferred charges and other assets	102,306	100,764
Total Assets	\$ 1,140,510	\$ 1,067,421

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

Table of ContentsChesapeake Utilities Corporation and Subsidiaries  
Condensed Consolidated Balance Sheets (Unaudited)

	September 30, 2016	December 31, 2015
Capitalization and Liabilities		
(in thousands, except shares and per share data)		
Capitalization		
Stockholders' equity		
Preferred stock, par value \$0.01 per share (authorized 2,000,000 shares), no shares issued and outstanding	\$ —	\$ —
Common stock, par value \$0.4867 per share (authorized 25,000,000 shares)	7,932	7,432
Additional paid-in capital	250,202	190,311
Retained earnings	185,195	166,235
Accumulated other comprehensive loss	(5,029	) (5,840
Deferred compensation obligation	2,476	1,883
Treasury stock	(2,476	) (1,883
Total stockholders' equity	438,300	358,138
Long-term debt, net of current maturities	143,525	149,006
Total capitalization	581,825	507,144
Current Liabilities		
Current portion of long-term debt	12,087	9,151
Short-term borrowing	154,490	173,397
Accounts payable	41,297	39,300
Customer deposits and refunds	26,858	27,173
Accrued interest	3,119	1,311
Dividends payable	4,678	4,390
Accrued compensation	7,823	10,014
Regulatory liabilities	2,412	7,365
Mark-to-market energy liabilities	29	433
Other accrued liabilities	10,260	7,059
Total current liabilities	263,053	279,593
Deferred Credits and Other Liabilities		
Deferred income taxes	205,562	192,600
Regulatory liabilities	43,354	43,064
Environmental liabilities	8,682	8,942
Other pension and benefit costs	32,501	33,481
Deferred investment tax credits and other liabilities	5,533	2,597
Total deferred credits and other liabilities	295,632	280,684
Environmental and other commitments and contingencies (Note 5 and 6)		
Total Capitalization and Liabilities	\$ 1,140,510	\$ 1,067,421
The accompanying notes are an integral part of these financial statements.		

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

	Nine Months Ended September 30,	
	2016	2015
(in thousands)		
Operating Activities		
Net income	\$32,812	\$32,521
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	23,493	22,155
Depreciation and accretion included in other costs	5,357	5,280
Deferred income taxes, net	12,004	(1,155 )
Realized gain on commodity contracts/sale of assets/investments	(405 )	(411 )
Unrealized (gain) loss on investments/commodity contracts	(243 )	60
Employee benefits and compensation	1,217	901
Share-based compensation	1,887	1,445
Other, net	42	13
Changes in assets and liabilities:		
Accounts receivable and accrued revenue	(3,835 )	21,898
Propane inventory, storage gas and other inventory	(2,179 )	3,166
Regulatory assets/liabilities, net	(3,326 )	6,467
Prepaid expenses and other current assets	485	(159 )
Accounts payable and other accrued liabilities	3,679	(9,897 )
Income taxes receivable	14,897	14,883
Customer deposits and refunds	(314 )	(1,177 )
Accrued compensation	(2,293 )	(1,406 )
Other assets and liabilities, net	(1,053 )	(652 )
Net cash provided by operating activities	82,225	93,932
Investing Activities		
Property, plant and equipment expenditures	(106,851)	(97,299 )
Proceeds from sales of assets	119	109
Acquisitions, net of cash acquired	—	(20,930 )
Environmental expenditures	(260 )	(113 )
Net cash used in investing activities	(106,992)	(118,233)
Financing Activities		
Common stock dividends	(12,964 )	(11,725 )
Issuance of stock for Dividend Reinvestment Plan	600	633
Stock issuance	57,306	—
Change in cash overdrafts due to outstanding checks	2,466	2,964
Net (repayment) borrowing under line of credit agreements	(21,379 )	35,898
Repayment of long-term debt and capital lease obligation	(2,581 )	(4,262 )
Net cash provided by financing activities	23,448	23,508
Net Decrease in Cash and Cash Equivalents	(1,319 )	(793 )
Cash and Cash Equivalents—Beginning of Period	2,855	4,574
Cash and Cash Equivalents—End of Period	\$1,536	\$3,781

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



Table of ContentsChesapeake Utilities Corporation and Subsidiaries  
Condensed Consolidated Statements of Stockholders' Equity (Unaudited)

(in thousands, except shares and per share data)	Common Stock			Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total <sup>(2)</sup>
	Number of Shares <sup>(1)</sup>	Par Value	Additional Paid-In Capital					
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 <sup>(4)</sup> <sup>(5)</sup>	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	—	—	—	32,812	—	—	—	32,812
Other comprehensive income	—	—	—	—	811	—	—	811
Dividend declared (\$0.8975 per share)	—	—	—	(13,852 )	—	—	—	(13,852 )
Retirement savings plan and dividend reinvestment plan	30,041	15	1,859	—	—	—	—	1,874
Stock issuance <sup>(3)</sup>	960,488	467	56,839	—	—	—	—	57,306
Share-based compensation and tax benefit <sup>(4)</sup> <sup>(5)</sup>	36,099	18	1,193	—	—	—	—	1,211
Treasury stock activities	—	—	—	—	—	593	(593 )	—
Balance at September 30, 2016	16,297,287	\$7,932	\$250,202	\$185,195	\$ (5,029 )	\$ 2,476	\$(2,476)	\$438,300

(1) Includes 80,024 and 70,631 shares at September 30, 2016 and December 31, 2015, respectively, held in a Rabbi Trust related to our Deferred Compensation Plan.

(2) 2,000 shares of preferred stock at \$0.00001 par value has been authorized. None has been issued or is outstanding; accordingly, no information has been included in the statements of stockholders' equity.

On September 22, 2016, we completed a public offering of 960,488 shares of our common stock at a price per share of \$62.26. The net proceeds from the sale of common stock, after deducting underwriting commissions and expenses, were approximately \$57.3 million.

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

(4) The shares issued under the SICP are net of shares withheld for employee taxes. For the nine months ended September 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.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. Summary of Accounting Policies

Basis of Presentation

References in this document to the “Company,” “Chesapeake 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 nine months ended September 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 revisions are considered immaterial to the overall presentation of our condensed consolidated financial statements.

On September 22, 2016, we completed a public offering of 960,488 shares of our common stock at a price per share of \$62.26. The net proceeds from the sale of common stock, after deducting underwriting commissions and expenses, were approximately \$57.3 million, which were added to our general funds and used primarily to repay a portion of our short-term debt under unsecured lines of credit.

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 \$301,000 and \$333,000 at September 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.

Intangibles-Goodwill and Other-Internal-Use Software (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.

Interest-Imputation of Interest (ASC 835-30) - In August 2015, the FASB issued ASU 2015-15, Presentation and Subsequent Measurement 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 or 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 and requires that the cumulative impact of a measurement-period adjustments (including

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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 or results of operations.

**Income 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. In March 2016, FASB issued ASU 2016-08, Principal versus Agent Considerations (Reporting Revenue Gross versus Net), to clarify the implementation guidance on principal versus agent considerations. For public entities, this standard is effective for 2018 interim and annual financial statements. We have engaged a third party to review our contracts with customers and to aid in 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, Simplifying the Measurement of 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-Stock 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.

**Statement of Cash Flows (ASC 230)** - On August 26, 2016, the FASB issued ASU 2016-15, Classification of Certain Cash Receipts and Cash Payments, which clarifies how certain transactions are classified in the statement of cash

flows. ASU 2016-15 will be effective for our annual and interim financial statements beginning January 1, 2018, although early adoption is permitted. We are assessing the impact of the adoption of this ASU on our statements of cash flows.

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## 2. Calculation of Earnings Per Share

	Three Months Ended		Nine Months Ended	
	September 30, 2016	September 30, 2015	September 30, 2016	September 30, 2015
(in thousands, except shares and per share data)				
Calculation of Basic Earnings Per Share:				
Net Income	\$4,416	\$ 5,119	\$32,812	\$ 32,521
Weighted average shares outstanding	15,372,415	15,258,819	15,324,932	15,035,569
Basic Earnings Per Share	\$0.29	\$ 0.34	\$2.14	\$ 2.16
Calculation of Diluted Earnings Per Share:				
Reconciliation of Numerator:				
Net Income	\$4,416	\$ 5,119	32,812	32,521
Reconciliation of Denominator:				
Weighted shares outstanding—Basic	15,372,415	15,258,819	15,324,932	15,035,569
Effect of dilutive securities:				
Share-based compensation	40,370	48,024	41,023	48,072
Adjusted denominator—Diluted	15,412,785	15,306,843	15,365,955	15,083,641
Diluted Earnings Per Share	\$0.29	\$ 0.33	\$2.14	\$ 2.16

## 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 so that it can maintain service quality and reliability for 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 outstanding Gatherco debt, which we paid off on the closing 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 September 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 September 30, 2016, we are unable to estimate the range of undiscounted contingent liability outcomes at this time.

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We incurred \$1.3 million in transaction costs associated with this merger of which we incurred \$786,000 in 2014 and the remaining \$514,000 in 2015. Transaction costs were included in operations expense in the accompanying condensed consolidated statements of income. The revenue and net loss from this merger for the three months ended September 30, 2016, included in our condensed consolidated statements of income, were \$5.6 million and \$563,000, respectively. The revenue and net income from this merger for the nine months ended September 30, 2016, included in our condensed consolidated statements of income, were \$18.4 million and \$1.1 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 for such period.

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 primarily reflects the value paid 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.

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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 ("Phase I"). We recognized incremental revenue of approximately \$469,000 (\$280,000 net of tax) and \$1.4 million (\$817,000 net of tax) for the three and nine months ended September 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 totaling \$4.7 million (equal to the initial rate increase in our application) annualized for usage on and after August 1, 2016 ("Phase II"). These revised interim rates represent a five-percent increase over Phase I rates. Revenue associated with these rates collected prior to a final Delaware PSC decision is subject to refund and, 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. Consequently, we will not recognize the impact of the potential additional revenue related to the Phase II rate increase until the Delaware PSC issues its approval in a final ruling.

### 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 the Maryland Office of People's Counsel. The parties reached a settlement agreement, which Sandpiper filed with the Commission on August 10, 2016. The terms of the agreement include revenue neutral rates for the first year, followed by a schedule of rate reductions in subsequent years based upon the projected rate of propane to natural gas conversions. A revenue normalization mechanism and stratification of rate classes were also included in the settlement agreement. On September 28, 2016, the Public Utility Law Judge issued a proposed order recommending approval of the settlement terms. The order became final on October 29, 2016 and the new rates will be in effect on December 1, 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 expanded allocation of these costs includes additional customers, primarily transportation customers, benefiting from these costs but not currently paying for them. This petition was approved by the Florida PSC at its Agenda Conference in September 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 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.

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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 in the certificate proceeding. However, FERC's determination is without prejudice to Eastern Shore filing for and fully supporting rolled-in rate treatment of these project facilities in a future general rate case. The certificate required Eastern Shore to comply with 19 environmental conditions.

On July 29, 2016, Eastern Shore accepted the certificate of public convenience and necessity and, on August 2, 2016, filed its Implementation Plan to comply with each environmental condition and to request approval to begin construction. On August 4, 2016, the FERC issued a "Notice to Proceed," and Eastern Shore commenced construction during August 2016. Eastern Shore continues to file weekly status reports in compliance with one of the 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 proposed 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 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 required Eastern Shore to comply with 19 environmental conditions.

On July 29, 2016, Eastern Shore accepted the certificate and on August 5, 2016 filed its Implementation Plan to comply with each environmental condition and to request approval to begin construction. On August 12, 2016, the FERC issued a "Partial Notice to Proceed" approving construction for certain portions of the System Reliability Project. On September 15, 2016, the FERC granted approval to start construction on the remaining portion of the Project. Construction commenced on the Bridgeville Compressor Station and the Porter Road Loop in August 2016, and on the Dover Loop, in September 2016 and is ongoing. Eastern Shore continues to file weekly status reports in compliance with one of the 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, in December 2016, its application for a certificate of public convenience and necessity, seeking authorization to construct the expansion facilities.

Since the time the pre-filing was initiated, Eastern Shore has finalized market participation for the project. Seven of Eastern Shore's existing customers have signed Precedent Agreements. As a result, the project will provide 61,162 Dts/d of additional firm natural gas transportation deliverability on Eastern Shore's pipeline system. To provide this additional capacity, the project's final facilities will consist of approximately 23 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,

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Pennsylvania; and approximately 17 miles of new mainline extension and two pressure control stations in Sussex County, Delaware.

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 discussing with the MDE another former MGP site located in Cambridge, Maryland.

As of September 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 \$10.5 million of which has been recovered as of September 30, 2016, leaving approximately \$3.5 million in regulatory assets for future recovery of environmental costs from FPU's customers.

In addition to the FPU MGP sites, we had \$298,000 in environmental liabilities at September 30, 2016, representing our estimate of future costs associated with Chesapeake Utilities' MGP site in Winter Haven, Florida.

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 September 30, 2016, we had approximately \$156,000 in environmental liabilities and \$267,000 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.



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Sanford, Florida

FPU is the current owner of property in Sanford, Florida, which is the site on which a former MGP that was operated by several other entities before FPU acquired the property. FPU was never an owner or an operator of the MGP previously located on this 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 September 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 paid by FPU under 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 September 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 September 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 September 2016. Natural attenuation default criteria were met at all locations sampled and the semi-annual report was submitted on October 4, 2016 with the recommendation that semi-annual monitoring should continue at this facility. The next semi-annual NAM is scheduled for the first quarter of 2017.

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.

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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.

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. As directed by MDE, additional measures were performed and this last remaining well was redeveloped in September 2016. Depending on future observations, additional testing may be required. We anticipate that the remaining costs for maintaining and monitoring this one remaining well will not exceed \$5,000 annually. We cannot predict at this time when the MDE will grant permission to permanently decommission this 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 the second quarter of 2017. We estimate the cost of potential remedial actions, based on the findings of the DNREC report, to be between \$273,000 and \$465,000.

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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. Under the merger agreement, we are entitled to be indemnified from an escrow fund created at closing for certain matters, including certain claims related to environmental remediation. The costs incurred to date associated with remediation activities for these eight facilities is approximately \$1.6 million. In September 2016, we and the Gatherco shareholder agent resolved certain disputes associated with our claims for indemnification, including claims for environmental matters. After deducting the amount of anticipated tax benefits related to our claims and an indemnification deductible in the amount of \$431,250 in accordance with the merger agreement, we received a total of approximately \$500,000 from the indemnification escrow in payment of our claims with no material impact to our financial statements. We do not anticipate submitting any additional claims for indemnification or receiving any additional indemnification payments related to or arising out of the Gatherco merger.

6. Other Commitments and Contingencies

Natural Gas, Electric and Propane Supply

We 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 ending in 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 ending in 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.

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 September 30, 2016, FPU was in compliance with all of the requirements of its fuel supply contracts.

Corporate Guarantees

The Board of Directors has authorized us 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.

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Chesapeake Utilities has 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 September 30, 2016 was approximately \$53.9 million, with the guarantees expiring on various dates through September 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 \$8.4 million related to the electric transmission services for FPU's 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 September 2017. There have been no draws on these letters of credit as of September 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 September 30, 2016 and December 31, 2015, we maintained a liability of approximately \$50,000 related to unrecognized income tax benefits. As of December 31, 2015, we maintained a liability of approximately \$310,000 related to contingencies for taxes other than income. We did not have a liability related to contingencies for taxes other than income at September 30, 2016.

### 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). Effective June 2016, this segment includes electricity and steam generation through Eight Flags' CHP plant. 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.

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The following table presents financial information about our reportable segments:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2016	2015	2016	2015
(in thousands)				
Operating Revenues, Unaffiliated Customers				
Regulated Energy segment	\$68,899	\$63,526	\$224,382	\$234,608
Unregulated Energy segment	39,449	28,387	132,604	120,068
Total operating revenues, unaffiliated customers	\$108,348	\$91,913	\$356,986	\$354,676
Intersegment Revenues <sup>(1)</sup>				
Regulated Energy segment	\$1,120	\$270	\$2,248	\$830
Unregulated Energy segment	2,593	1,222	3,759	3,095
Other businesses	240	220	705	660
Total intersegment revenues	\$3,953	\$1,712	\$6,712	\$4,585
Operating Income				
Regulated Energy segment	\$13,115	\$11,828	\$52,660	\$47,616
Unregulated Energy segment	(3,080)	(1,022)	9,267	13,666
Other businesses and eliminations	121	103	350	305
Total operating income	10,156	10,909	62,277	61,587
Other (expense) income, net	(28)	36	(68)	(3)
Interest	2,722	2,492	7,996	7,425
Income before Income Taxes	7,406	8,453	54,213	54,159
Income taxes	2,990	3,334	21,401	21,638
Net Income	\$4,416	\$5,119	\$32,812	\$32,521

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

(in thousands)	September	December
	30, 2016	31, 2015
Identifiable Assets		
Regulated Energy segment	\$921,682	\$872,065
Unregulated Energy segment	207,083	171,840
Other businesses and eliminations	11,745	23,516
Total identifiable assets	\$1,140,510	\$1,067,421

Our operations are entirely domestic.

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## 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 nine months ended September 30, 2016 and 2015. All amounts are presented net of tax.

	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
(in thousands)			
As of December 31, 2015	\$ (5,580 )	\$ (260 )	\$(5,840)
Other comprehensive gain before reclassifications	—	641	641
Amounts reclassified from accumulated other comprehensive loss	263	(93 )	170
Net current-period other comprehensive income	263	548	811
As of September 30, 2016	\$ (5,317 )	\$ 288	\$(5,029)

	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
(in thousands)			
As of December 31, 2014	\$ (5,643 )	\$ (33 )	\$(5,676)
Other comprehensive loss before reclassifications	—	(76 )	(76 )
Amounts reclassified from accumulated other comprehensive loss	248	33	281
Net prior-period other comprehensive income	248	(43 )	205
As of September 30, 2015	\$ (5,395 )	\$ (76 )	\$(5,471)

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

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	Three Months Ended September 30, 2016		Nine Months Ended September 30, 2015	
(in thousands)				
Amortization of defined benefit pension and postretirement plan items:				
Prior service cost <sup>(1)</sup>	\$20	\$17	\$60	\$50
Net loss <sup>(1)</sup>	(166)	(155)	(500)	(465)
Total before income taxes	(146)	(138)	(440)	(415)
Income tax benefit	58	55	177	167
Net of tax	\$(88)	\$(83)	\$(263)	\$(248)
Gains and losses on commodity contracts cash flow hedges				
Propane swap agreements <sup>(2)</sup>	\$—	\$—	\$(322)	\$—
Call options <sup>(2)</sup>	—	—	—	(55)
Natural gas futures <sup>(2)</sup>	105	—	464	—
Total before income taxes	105	—	142	(55)
Income tax benefit (expense)	(41)	—	(49)	22
Net of tax	64	—	93	(33)
Total reclassifications for the period	\$(24)	\$(83)	\$(170)	\$(281)

<sup>(1)</sup> These amounts are included in the computation of net periodic costs (benefits). See Note 9, Employee Benefit Plans, for additional details.

<sup>(2)</sup> 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 nine months ended September 30, 2016 and 2015 are set forth in the following tables:

	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP		Chesapeake Postretirement Plan		FPU Medical Plan	
For the Three Months Ended September 30, (in thousands)	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015
Interest cost	\$105	\$102	\$635	\$626	\$23	\$23	\$11	\$11	\$14	\$15
Expected return on plan assets	(131)	(135)	(625)	(777)	—	—	—	—	—	—
Amortization of prior service cost	—	—	—	—	—	2	(20)	(19)	—	—
Amortization of net loss	103	91	133	114	22	25	16	17	—	2
Net periodic cost (benefit)	77	58	143	(37)	45	50	7	9	14	17
Amortization of pre-merger regulatory asset	—	—	191	191	—	—	—	—	2	2
Total periodic cost	\$77	\$58	\$334	\$154	\$45	\$50	\$7	\$9	\$16	\$19



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	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP		Chesapeake Postretirement Plan		FPU Medical Plan	
	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015
For the Nine Months Ended September 30, (in thousands)										
Interest cost	\$315	\$306	\$1,894	\$1,877	\$68	\$68	\$32	\$33	\$41	\$45
Expected return on plan assets	(392)	(405)	(2,027)	(2,330)	—	—	—	—	—	—
Amortization of prior service cost	—	—	—	—	—	8	(60)	(58)	—	—
Amortization of net loss	309	272	389	341	66	74	51	53	—	5
Net periodic cost (benefit)	232	173	256	(112)	134	150	23	28	41	50
Amortization of pre-merger regulatory asset	—	—	571	571	—	—	—	—	6	6
Total periodic cost	\$232	\$173	\$827	\$459	\$134	\$150	\$23	\$28	\$47	\$56

We expect to record pension and postretirement benefit costs of approximately \$1.7 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 \$2.3 million and approximately \$2.9 million at September 30, 2016 and December 31, 2015, respectively. The amortization included in pension expense is also being added to a net periodic loss of approximately \$917,000, which will increase our total expected benefit costs to approximately \$1.7 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 tables present 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 months ended September 30, 2016 and 2015:

	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP	Chesapeake Postretirement Plan		FPU Medical Plan		Total
	2016	2015	2016	2015		2016	2015	2016	2015	
For the Three Months Ended September 30, 2016 (in thousands)										
Prior service credit	\$ —	\$ —	\$ —	\$ —	\$ —	\$ (20)	\$ —	\$ —	\$ —	\$ (20)
Net loss	103	133	22	16	—	—	—	—	—	274
Total recognized in net periodic benefit cost	\$ 103	\$ 133	\$ 22	\$ (4)	\$ —	\$ (4)	\$ —	\$ —	\$ —	\$ (254)
Recognized from accumulated other comprehensive loss <sup>(1)</sup>	\$ 103	\$ 25	\$ 22	\$ (4)	\$ —	\$ (4)	\$ —	\$ —	\$ —	\$ (146)
Recognized from regulatory asset	—	108	—	—	—	—	—	—	—	108
Total	\$ 103	\$ 133	\$ 22	\$ (4)	\$ —	\$ (4)	\$ —	\$ —	\$ —	\$ (254)

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For the Three Months Ended September 30, 2015	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
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 <sup>(1)</sup>	\$ 91	\$ 22	\$ 27	\$ (2 )	\$ —	\$138
Recognized from regulatory asset	—	92	—	—	2	94
Total	\$ 91	\$ 114	\$ 27	\$ (2 )	\$ 2	\$232

The following tables present the amounts included in the regulatory asset and accumulated other comprehensive loss that were recognized as components of net periodic benefit cost during the nine months ended September 30, 2016 and 2015:

For the Nine Months Ended September 30, 2016	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service credit	\$ —	\$ —	\$ —	\$ (60 )	\$ —	\$(60 )
Net loss	309	389	66	51	—	\$815
Total recognized in net periodic benefit cost	\$ 309	\$ 389	\$ 66	\$ (9 )	\$ —	—\$755
Recognized from accumulated other comprehensive loss <sup>(1)</sup>	\$ 309	\$ 74	\$ 66	\$ (9 )	\$ —	—\$440
Recognized from regulatory asset	—	315	—	—	—	315
Total	\$ 309	\$ 389	\$ 66	\$ (9 )	\$ —	—\$755

For the Nine Months Ended September 30, 2015	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service cost (credit)	\$ —	\$ —	\$ 8	\$ (58 )	\$ —	\$(50 )
Net loss	272	341	74	53	5	745
Total recognized in net periodic benefit cost	\$ 272	\$ 341	\$ 82	\$ (5 )	\$ 5	\$695
Recognized from accumulated other comprehensive loss <sup>(1)</sup>	\$ 272	\$ 65	\$ 82	\$ (5 )	\$ 1	\$415
Recognized from regulatory asset	—	276	—	—	4	280
Total	\$ 272	\$ 341	\$ 82	\$ (5 )	\$ 5	\$695

<sup>(1)</sup> See Note 8, Accumulated Other Comprehensive Loss.

During the three and nine months ended September 30, 2016, we contributed approximately \$116,000 and \$390,000, respectively, to the Chesapeake Pension Plan and approximately \$374,000 and approximately \$1.3 million, 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 nine months ended September 30, 2016, were approximately \$38,000 and approximately \$114,000, 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 nine months ended September 30, 2016, were approximately \$23,000 and approximately \$59,000, respectively. We estimate that approximately \$82,000 will be paid

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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 nine months ended September 30, 2016, were approximately \$32,000 and approximately \$97,000, 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 September 30, 2016 and December 31, 2015, consisted of the following:

(in thousands)	September 30,		December 31,	
	2016	2015	2016	2015
Rabbi trust (associated with the Deferred Compensation Plan)	\$4,609	\$ 3,626		
Investments in equity securities	21	18		
Total	\$4,630	3,644		

We classify these investments as trading securities and report them at their fair value. For the three months ended September 30, 2016 and 2015, we recorded a net unrealized gain of approximately \$193,000 and \$238,000, respectively, in other income in the condensed consolidated statements of income related to these investments. For the nine months ended September 30, 2016 and 2015, we recorded an unrealized gain of approximately \$246,000 and a net unrealized loss of approximately \$131,000, 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 nine months ended September 30, 2016 and 2015:

(in thousands)	Three Months Ended		Nine Months Ended	
	September 30, 2016	September 30, 2015	September 30, 2016	September 30, 2015
Awards to non-employee directors	\$135	\$165	\$445	\$475
Awards to key employees	488	334	1,442	970
Total compensation expense	623	499	1,887	1,445
Less: tax benefit	(251)	(201)	(760)	(582)
Share-based compensation amounts included in net income	\$372	\$298	\$1,127	\$863
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 nine months ended September 30, 2016 is presented below:

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

At September 30, 2016, there was approximately \$314,000 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 nine months ended September 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— September 30, 2016	115,091	\$ 52.36

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 September 30, 2016, the aggregate intrinsic value of the SICP awards granted to key employees was approximately \$7.0 million. At September 30, 2016, there was approximately \$2.7 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. We have entered into agreements with suppliers to purchase natural gas, electricity and propane for resale to our 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 September 30, 2016, our natural gas and electric distribution operations did not have any outstanding derivative contracts.

## Hedging Activities in 2016

In 2016, Sharp entered into swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with 4.1 million gallons expected to be purchased for the upcoming heating season. Under the swap agreements, Sharp will receive the difference between the index prices (Mont Belvieu prices in December 2016 through September 2017) and the swap prices of \$0.5250 and \$0.5525 per gallon, to the extent the index prices exceed the swap prices. If the index prices are lower than the swap price, Sharp will pay the difference. The swap agreement

essentially fixes the price of the 4.1 million gallons that we expect to purchase for the upcoming heating season. We accounted for these swap

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agreements as cash flow hedges, and there is no ineffective portion of these hedges. At September 30, 2016, the swap agreements had a fair value of approximately \$237,000. The change in the fair value of the swap agreements 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 had previously accounted for these contracts as fair value hedges with any ineffective portion being reported directly in earnings and offset by any associated gain (loss) on the inventory value being hedged. During the third quarter of 2016, we de-designated the hedges as they were no longer highly effective. We are now accounting for them as derivatives on a mark-to-market basis with the change in fair value reflected as unrealized gain (loss) in current period earnings, and these are no longer offset by any associated gain (loss) in the value of the inventory previously hedged. As of September 30, 2016, we had a total of 1.8 million Dts/d in natural gas futures contracts with a mark-to-market liability of \$29,000.

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 September 30, 2016, PESCO had a total of 6.0 million Dts/d hedged under natural gas futures contracts, with an asset fair value of approximately \$240,000. 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 previously designated as fair value hedges and the related hedged item on our condensed consolidated income statements for the three and nine months ended September 30, 2016 is presented below:

	Three Months Ended September 30, 2016 (1)	Nine Months Ended September 30, 2016 (1)
Commodity contracts	\$	—\$ (233 )
Fair value adjustment for natural gas inventory designated as the hedged item	—	681
Total increase in purchased gas cost	\$	—\$ 448

The increase in purchased gas cost is comprised of the following:

Basis ineffectiveness	\$	—\$ (83 )
Timing ineffectiveness	—	531
Total ineffectiveness	\$	—\$ 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

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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 September 30, 2016, Xeron had no outstanding contracts that were accounted for as derivatives.

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 September 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 September 30, 2016 and December 31, 2015, are as follows:

(in thousands)	Asset Derivatives Balance Sheet Location	Fair Value As	
		Of September 30, 2016	December 31, 2015
Derivatives not designated as hedging instruments			
Forward & Future contracts	Mark-to-market energy assets	\$—	\$ 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	240	—
Propane swap agreements	Mark-to-market energy assets	237	—
Total asset derivatives		\$477	\$ 153

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(in thousands)	Liability Derivatives Balance Sheet Location	Fair Value As Of	
		September 30, 2016	December 31, 2015
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy liabilities	\$—	\$ 1
Natural gas futures contracts	Mark-to-market energy liabilities	29	—
Derivatives designated as fair value hedges			
Natural gas futures contracts	Mark-to-market energy liabilities	—	—
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		\$29	\$ 433

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

(in thousands)	Location of Gain (Loss) on Derivatives	Amount of Gain (Loss) on Derivatives:			
		For the Three Months Ended September 30, 2016		For the Nine Months Ended September 30, 2015	
Derivatives not designated as hedging instruments					
Realized gain (loss) on forward contracts <sup>(1)</sup>	Revenue	\$ (231 )	\$ 187	\$ 44	\$ 393
Unrealized gain (loss) on forward contracts <sup>(1)</sup>	Revenue	(2 )	(7 )	—	71
Natural gas futures contracts	Cost of sales	205	—	205	—
Propane swap agreements	Cost of sales	—	—	—	18
Derivatives designated as fair value hedges					
Put /Call options	Cost of sales	—	—	73	506
Put /Call options <sup>(2)</sup>	Propane Inventory	—	(46 )	—	(79 )
Natural gas futures contracts	Natural Gas Inventory	—	—	(233 )	—
Derivatives designated as cash flow hedges					
Propane swap agreements	Cost of sales	—	—	(364 )	—
Propane swap agreements	Other Comprehensive Gain (Loss)	213	(126 )	559	(128 )
Call options	Cost of sales	—	—	—	(81 )
Natural gas futures contracts	Cost of sales	105	—	464	—
Natural gas futures contracts	Other Comprehensive Gain (Loss)	(123 )	—	349	—
Total		\$ 167	\$ 8	\$ 1,097	\$ 700

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

<sup>(2)</sup> 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

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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 September 30, 2016 and December 31, 2015:

As of September 30, 2016	Fair Value	Fair Value Measurements Using:		
		Quoted-Active Markets (Level 1)	Prices- in Significant-Observable Inputs (Level 2)	Other Significant Unobservable Inputs (Level 3)
(in thousands)				
Assets:				
Investments—equity securities	\$ 21	\$21	\$ —	\$ —
Investments—guaranteed income fund	\$ 485	\$—	\$ —	\$ 485
Investments—mutual funds and other	\$ 4,124	\$4,124	\$ —	\$ —
Mark-to-market energy assets, incl. put options and swap agreements	\$ 477	\$—	\$ 477	\$ —
Liabilities:				
Mark-to-market energy liabilities incl. swap agreements	\$ 29	\$—	\$ 29	\$ —

As of December 31, 2015	Fair Value	Fair Value Measurements Using:		
		Quoted-Active Markets (Level 1)	Prices- in Significant-Observable Inputs (Level 2)	Other Significant Unobservable Inputs (Level 3)
(in thousands)				
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 September 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.

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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 nine months ended September 30, 2016 and 2015:

	Nine Months Ended September 30, 2016 2015	
(in thousands)		
Beginning Balance	\$279	\$287
Purchases and adjustments	120	(11 )
Transfers	88	(3 )
Distribution	(8 )	—
Investment income	6	3
Ending Balance	\$485	\$276

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

At September 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 September 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 \$173.5 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.



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## 14. Long-Term Debt

Our outstanding long-term debt is shown below:

(in thousands)	September 30, 2016	December 31, 2015
FPU secured first mortgage bonds <sup>(1)</sup> :		
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	3,814	4,824
Total long-term debt	155,913	158,490
Less: current maturities	(12,087 )	(9,151 )
Less: debt issuance costs	(301 )	(333 )
Total long-term debt, net of current maturities	\$143,525	\$ 149,006

<sup>(1)</sup> 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, through October 8, 2018, we may request that Prudential purchase 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.

On May 13, 2016, we submitted a request that Prudential purchase \$70.0 million of 3.25 percent Shelf Notes under the Shelf Agreement. On May 20, 2016, Prudential accepted and confirmed our request. The proceeds received from the issuances of the Shelf Notes will be used to reduce short-term borrowings under the Company's revolving credit facility, lines of credit and/or to fund capital expenditures. 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, place or permit 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

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to increase the Revolver to \$200.0 million, with any increase at the sole discretion of each Lender. At September 30, 2016 and December 31, 2015, we had outstanding borrowings of \$50.0 million and \$35.0 million, respectively, under the Revolver.

The net proceeds from the sale of our common stock on September 22, 2016, of approximately \$57.3 million, after deducting underwriting commissions and expenses, were added to our general funds and used to repay a portion of our short-term debt under unsecured lines of credit.

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 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 weather and other natural phenomena, including the economic, operational and other effects of hurricanes, ice storms and other damaging weather events;
- industrial, commercial and residential growth or contraction in our markets or service territories;
- the timing and extent of changes in commodity prices and interest rates;
- the capital-intensive nature of our regulated energy businesses;
- the extent of our success in connecting natural gas and electric supplies to transmission systems and in expanding natural gas and electric markets;
- 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 ability to establish and maintain new key supply sources;
- 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;
- general economic conditions, including any potential effects arising from terrorist attacks and any hostilities or other external factors over which we have no control;
- conditions of the capital markets and equity markets during the periods covered by the forward-looking statements;
- the ability to continue to hire, train and retain appropriately qualified personnel;
- the creditworthiness of counterparties with which we are engaged in transactions;
- the effect of spot, forward and future market prices on our various energy 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 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 inherent hazards and risks involved in our energy businesses;  
risks related to cyber-attacks that could disrupt our business operations or result in failure of information technology  
systems.

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- the effect of competition on our businesses;
- 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 effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- the timing of regulatory and other governmental approvals, authorizations, and permits; and
- the loss of customers due to a government-mandated sale of our utility distribution facilities.

### 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 our regulated operations because the cost of natural gas and electricity are passed through to customers 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 Chesapeake Utilities 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.

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

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## Results of Operations for the Three and Nine Months ended September 30, 2016

## Overview and Highlights

Our net income for the quarter ended September 30, 2016 was \$4.4 million, or \$0.29 per share. This represents a decrease of \$703,000, or \$0.04 per share, compared to the net income of \$5.1 million, or \$0.33 per share, as reported for the same quarter in 2015. Operating income decreased \$753,000 for the three months ended September 30, 2016. Gross margin increased by \$4.7 million, although other operating expenses increased by \$5.5 million. The increase in other operating expenses, in part, reflects the fact that the higher expenses to support growth of our businesses are largely recognized equally across the year, while the margin from this growth is more concentrated in the heating season during the fourth and first quarters.

	Three Months Ended		Increase (decrease)
	September 30, 2016	2015	
(in thousands except per share)			
Business Segment:			
Regulated Energy segment	\$13,115	\$11,828	\$ 1,287
Unregulated Energy segment	(3,080 )	(1,022 )	(2,058 )
Other businesses and eliminations	121	103	18
Operating Income	\$10,156	\$10,909	\$ (753 )
Other (expense) income, net	(28 )	36	(64 )
Interest charges	2,722	2,492	230
Pre-tax Income	7,406	8,453	(1,047 )
Income taxes	2,990	3,334	(344 )
Net Income	\$4,416	\$5,119	\$ (703 )
Earnings Per Share of Common Stock			
Basic	\$0.29	\$0.34	\$ (0.05 )
Diluted	\$0.29	\$0.33	\$ (0.04 )



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Key variances, between the third quarter of 2015 and the third quarter of 2016, included:

(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
Third Quarter of 2015 Reported Results	\$8,453	\$5,119	\$ 0.33
Increased (Decreased) Gross Margins:			
Eight Flags*	2,033	1,212	0.08
Service expansions*	1,577	940	0.06
Natural gas growth (excluding service expansions)	943	562	0.04
GRIP*	920	549	0.04
Implementation of Delaware Division interim rates*	469	280	0.02
Lower retail propane margins	(414 )	(247 )	(0.02 )
Lower margins for Xeron	(413 )	(246 )	(0.02 )
Aspire Energy*	(407 )	(243 )	(0.02 )
	4,708	2,807	0.18
Decreased (Increased) Other Operating Expenses:			
Higher payroll and benefits costs	(1,830 )	(1,091 )	(0.07 )
Eight Flags operating expenses	(1,065 )	(635 )	(0.04 )
Higher outside services costs	(928 )	(553 )	(0.04 )
Higher facility maintenance	(601 )	(358 )	(0.02 )
Higher depreciation, asset removal and property tax costs	(466 )	(278 )	(0.02 )
	(4,890 )	(2,915 )	(0.19 )
Interest charges	(230 )	(137 )	(0.01 )
Net Other Changes	(635 )	(458 )	(0.02 )
Third Quarter of 2016 Reported Results	\$7,406	\$4,416	\$ 0.29

\*See the Major Projects and Initiatives table.

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Our net income for the nine months ended September 30, 2016 was \$32.8 million, or \$2.14 per share. This represents an increase of \$291,000 or a decrease of \$0.02 per share, compared to net income of \$32.5 million, or \$2.16 per share, as reported for the same period in 2015. Our growth projects and initiatives generated earnings that were offset by the effect of warmer weather, primarily in the normally colder first quarter, as well as the \$1.4 million lower net settlement gain associated with the customer billing system. The warmer weather reduced year-to-date earnings per share by \$0.31 compared to the same period last year.

	Nine Months Ended September 30, 2016		2015	Increase (decrease)
(in thousands except per share)				
Business Segment:				
Regulated Energy segment	\$52,660	\$47,616		\$ 5,044
Unregulated Energy segment	9,267	13,666		(4,399 )
Other businesses and eliminations	350	305		45
Operating Income	\$62,277	\$61,587		690
Other (expense) income, net	(68 )	(3 )		(65 )
Interest charges	7,996	7,425		571
Pre-tax Income	54,213	54,159		54
Income taxes	21,401	21,638		(237 )
Net Income	\$32,812	\$32,521		\$ 291
Earnings Per Share of Common Stock				
Basic	\$2.14	\$2.16		\$ (0.02 )
Diluted	\$2.14	\$2.16		\$ (0.02 )

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Key variances, between the first nine months of 2015 and the first nine months of 2016, included:

(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
Nine months ended September 30, 2015 Reported Results	\$54,159	\$32,521	\$ 2.16
Adjusting for Unusual Items:			
Weather impact, primarily in the first quarter	(7,548 )	(4,533 )	(0.31 )
Net gain from settlement agreement associated with customer billing system	(1,367 )	(821 )	(0.06 )
	(8,915 )	(5,354 )	(0.37 )
Increased (Decreased) Gross Margins:			
Service expansions*	5,516	3,312	0.22
GRIP*	3,069	1,843	0.12
Natural gas growth (excluding service expansions)	2,630	1,579	0.11
Eight Flags*	2,581	1,550	0.10
Lower retail propane margins	(2,204 )	(1,324 )	(0.09 )
Implementation of Delaware Division interim rates*	1,350	811	0.05
Natural gas marketing	1,062	638	0.04
Sandpiper SIR	618	371	0.03
	14,622	8,780	0.58
Decreased (Increased) Other Operating Expenses:			
Higher payroll and benefits costs	(2,144 )	(1,287 )	(0.09 )
Higher depreciation, asset removal and property tax costs	(1,705 )	(1,024 )	(0.07 )
Eight Flags operating expenses	(1,136 )	(682 )	(0.05 )
Higher outside services costs	(1,100 )	(661 )	(0.04 )
Higher facility maintenance	(787 )	(473 )	(0.03 )
Lower bad debt, sales and advertising	427	256	0.02
	(6,445 )	(3,871 )	(0.26 )
Net contribution from Aspire Energy, including impact of shares issued*	2,069	1,274	0.08
Interest Charges	(571 )	(343 )	(0.02 )
Net Other Changes	(706 )	(195 )	(0.03 )
Nine months ended September 30, 2016 Reported Results	\$54,213	\$32,812	\$ 2.14

\*See the Major Projects and Initiatives table.



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Major Projects and Initiatives

The following table summarizes gross margin for our major projects and initiatives completed since 2014 and our major projects and initiatives currently underway, but which will be completed in the future. 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		September 30,			Nine Months Ended			September 30,	
	2016	2015	2016	2015	2016	2015	2016	2015	2015	Estimate for
							Margin	2016	2017	2018
Major projects and initiatives completed since 2014	\$12,083	\$7,490	\$34,086	\$17,030	\$25,270	\$47,603	\$54,258	\$54,727		
Major projects and initiatives underway <sup>(1)</sup>	—	—	—	—	—	—	5,255	20,238		
	\$12,083	\$7,490	\$34,086	\$17,030	\$25,270	\$47,603	\$59,513	\$74,965		

<sup>(1)</sup> This represents gross margin for the System Reliability and 2017 Expansion projects.

## Major Projects and Initiatives Completed Since 2014

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

	Gross Margin for the Period												
	Three Months Ended			September 30,			Nine Months Ended			September 30,		Total	Estimate for
	2016	2015	Variance	2016	2015	Variance	2015	Margin	2016	2017	2018		
Acquisition:													
Aspire Energy Natural Gas	\$1,630	\$2,037	\$(407)	\$8,203	\$3,661	\$4,542	\$6,324	\$12,674	\$13,376	\$14,302			
Transmission Expansions and Contracts:													
Short-term contracts													
New Castle County, Delaware	\$664	\$507	\$157	\$2,040	\$1,998	\$42	\$2,682	\$2,910	\$2,275	\$714			
Kent County, Delaware	2,416	1,055	1,361	6,231	1,453	4,778	2,270	7,982	1,377	—			
Total short-term contracts	\$3,080	\$1,562	\$1,518	\$8,271	\$3,451	\$4,820	\$4,952	\$10,892	\$3,652	\$714			
Long-term contracts													
Kent County, Delaware	455	463	(8)	1,366	1,389	(23)	1,844	1,815	7,629	7,605			
Polk County, Florida	407	340	67	1,221	501	720	908	1,627	1,627	1,627			
Total long-term contracts	\$862	\$803	\$59	\$2,587	\$1,890	\$697	\$2,752	\$3,442	\$9,256	\$9,232			
Total Expansions & Contracts	\$3,942	\$2,365	\$1,577	\$10,858	\$5,341	\$5,517	\$7,704	\$14,334	\$12,908	\$9,946			
Florida GRIP	\$2,987	\$2,067	\$920	\$8,383	\$5,314	\$3,069	\$7,508	\$11,405	\$13,756	\$15,960			
Florida Electric Rate Case	\$1,021	\$1,021	\$—	\$2,714	\$2,714	\$—	\$3,734	\$3,562	\$3,562	\$3,562			
Delaware Division Rate Case	\$469	\$—	\$469	\$1,347	\$—	\$1,347	\$—	\$2,164	\$2,500	\$2,500			
Eight Flags CHP Plant	\$2,034	\$—	\$2,034	\$2,581	\$—	\$2,581	\$—	\$3,464	\$8,156	\$8,457			

Total Completed Major Projects and Initiatives	\$12,083	\$7,490	\$4,593	\$34,086	\$17,030	\$17,056	\$25,270	\$47,603	\$54,258	\$54,727
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Aspire Energy

Aspire Energy's gross margin decreased by \$407,000 for the three months ended September 30, 2016, partly due to increased deliveries and imbalance positions that favorably impacted Aspire Energy in the third quarter of 2015, which are non-recurring. Lower margin associated with system volumes and imbalance positions in third quarter of 2016 also contributed to the decrease.

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For the nine months ended September 30, 2016, Aspire Energy generated \$4.5 million in additional gross margin compared to the same period in 2015. Aspire Energy's gross margin for the same period in 2015 was lower due in part to the fact that the period included only six months of results commencing on April 1, 2015. Aspire Energy also generated additional gross margin primarily as a result of pricing amendments to long-term gas sales agreements, additional management fees and the optimization of gathering system receipts and deliveries. As projected, this merger was accretive to earnings per share in the first full year of operations.

**Service Expansions**

On January 16, 2015, the Florida PSC approved a firm transportation agreement between Peninsula Pipeline and our Florida natural gas distribution division. Pursuant to 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 \$67,000 and \$720,000 of additional gross margin for the three and nine months ended September 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  $\leq$  90 Service, which generated additional gross margin of \$901,000 and \$4.3 million during the three and nine months ended September 30, 2016, respectively, compared to the same periods in 2015. The short-term OPT  $\leq$  90 Service is expected to be replaced by a 20-year contract for OPT  $\leq$  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 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. In December 2015, the FERC authorized Eastern Shore to proceed with this project, which was completed and placed in service in March 2016. Approximately 85 percent of the increased capacity has been subscribed on a short-term firm service basis. This service generated an additional gross margin of \$617,000 and \$744,000 for the three and nine months ended September 30, 2016, respectively, compared to the same periods in 2015, and is expected to generate approximately \$1.4 million in additional gross margin for the year. 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 inception of the program in August 2012, we have invested \$97.3 million to replace 209 miles of qualifying distribution mains, including \$20.4 million during the first nine months of 2016. We expect to invest an additional \$650,000 in this program during the remainder of 2016. The increased investment in GRIP generated additional gross margin of \$920,000 and \$3.1 million for the three and nine months ended September 30, 2016, respectively, compared to the same periods in 2015.

**Eight Flags**

In June 2016, Eight Flags, completed construction of a CHP plant on Amelia Island, Florida. This CHP plant, which consists of a natural-gas-fired turbine and associated electric generator, produces approximately 20 megawatts of base load power and includes a heat recovery steam generator capable of providing approximately 75,000 pounds per hour of residual steam. On June 13, 2016, Eight Flags began selling power generated from the CHP plant to FPU, our wholly-owned subsidiary, pursuant to a 20-year power purchase agreement for distribution to its retail electric customers. On July 1, 2016, it also started selling steam to an industrial customer pursuant to a separate 20-year contract. The CHP plant is powered by natural gas transported by FPU through its distribution system. Eight Flags and other affiliates of Chesapeake Utilities generated \$2.0 million and \$2.6 million in additional gross margin as a result of these new services, for the three and nine months ended September 30, 2016 in which the CHP was operational. This amount includes gross margin of \$464,000 and \$892,000, for the three and nine months ended September 30,

2016, attributed to natural gas distribution and transportation services provided by our affiliates. On a consolidated basis, this project is expected to generate approximately \$8.2 million in annual gross margin in 2017, 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.

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## Major Projects and Initiatives Underway

**White Oak Mainline Expansion Project:** In August 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  $\leq$  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 nine months ended September 30, 2016, compared to the same periods in 2015, we generated \$901,000 and \$4.3 million, respectively, in additional gross margin by providing interruptible service and short-term OPT  $\leq$  90 Service to this customer. 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. Construction of the project is underway.

**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. Construction of the project is underway.

**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. Since the time the pre-filing was initiated, Eastern Shore has finalized market participation for the project. Seven of Eastern Shore's existing customers have signed Precedent Agreements. As a result, the project will provide 61,162 Dts/d of additional firm natural gas transportation deliverability on Eastern Shore's pipeline system. To provide this additional capacity, the project's final facilities will consist of approximately 23 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 project will generate approximately \$15.7 million in the first full year after the new transportation services go into effect.

## Other factors influencing gross margin

## Weather and Consumption

Although weather was not a significant factor in the second and third quarters, warmer temperatures during the first three months of the year, compared to temperatures in 2015, had a significant impact on our earnings. Lower customer consumption, directly attributable to warmer temperatures during the nine months ended September 30, 2016, reduced gross margin by \$7.5 million compared to the same period in 2015. The following tables summarize the HDD and CDD information for the three and nine months ended September 30, 2016 and 2015 resulting from weather fluctuations in those periods.

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## HDD and CDD Information

	Three Months			Nine Months		
	Ended			Ended		
	September 30,	2015	Variance	September 30,	2015	Variance
	2016			2016		
Delmarva						
Actual HDD	11	41	(30 )	2,590	3,249	(659 )
10-Year Average HDD ("Delmarva Normal")	65	65	—	2,919	2,908	11
Variance from Delmarva Normal	(54 )	(24 )		(329 )	341	
Florida						
Actual HDD	—	—	—	646	501	145
10-Year Average HDD ("Florida Normal")	—	—	—	553	557	(4 )
Variance from Florida Normal	—	—		93	(56 )	
Ohio <sup>(1)</sup>						
Actual HDD	65	78	(13 )	3,747	710	3,037
10-Year Average HDD ("Ohio Normal")	137	143	(6 )	3,979	811	3,168
Variance from Ohio Normal	(72 )	(65 )		(232 )	(101 )	
Florida						
Actual CDD	1,523	1,591	(68 )	2,737	2,827	(90 )
10-Year Average CDD ("Florida CDD Normal")	1,523	1,524	(1 )	2,548	2,506	42
Variance from Florida CDD Normal	—	67		189	321	

<sup>(1)</sup> HDD for Ohio is presented from April 1, 2015 through September 30, 2015.

## Propane prices

Lower retail propane margins per gallon on the Delmarva Peninsula decreased gross margin by \$344,000 and \$2.2 million, for the three and nine months ended September 30, 2016, respectively, compared to the same periods in 2015. Margins per retail gallon returned to more normal levels, 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 continued to assume more normal levels of margins in our long-term financial plans and forecasts.

In Florida, retail propane margins per gallon, generated \$70,000 of lower margin and \$61,000 of additional gross margin for the three and nine months ended September 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 \$253,000 and \$1.1 million in additional gross margin for the three and nine months ended September 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 nine months ended September 30, 2016, increased by 4.2 percent and 3.5 percent, respectively, compared to the same periods in 2015. The natural gas distribution operations in Florida generated \$350,000 and \$1.1 million in additional gross margin for the three and nine months ended September 30, 2016, respectively, compared to the same periods in 2015, due primarily to an increase in commercial and industrial customers in Florida.



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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. 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 ("Phase I"). We recognized incremental revenue of approximately \$469,000 (\$280,000 net of tax) and \$1.4 million (\$817,000 net of tax) for the three and nine months ended September 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 totaling \$4.7 million (equal to the initial rate increase in our application) annualized for usage on and after August 1, 2016 ("Phase II"). These revised interim rates represent a five percent increase over Phase I rates. Revenue associated with these rates collected prior to a final Delaware PSC decision is subject to refund and, 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. Consequently, we will not recognize the impact of the potential additional revenue related to the Phase II rate increase until the Delaware PSC issues its approval in a final ruling.

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## Regulated Energy Segment

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

	Three Months Ended		Increase (decrease)
	September 30, 2016	2015	
(in thousands)			
Revenue	\$70,019	\$63,796	\$ 6,223
Cost of sales	24,644	23,161	1,483
Gross margin	45,375	40,635	4,740
Operations & maintenance	22,912	19,882	3,030
Depreciation & amortization	6,346	6,129	217
Other taxes	3,002	2,796	206
Other operating expenses	32,260	28,807	3,453
Operating income	\$13,115	\$11,828	\$ 1,287

Operating income for the Regulated Energy segment for the quarter ended September 30, 2016 was \$13.1 million, an increase of \$1.3 million, or 10.9 percent, compared to the same quarter in 2015. The increased operating income was due primarily to an increase in gross margin of \$4.7 million, partially offset by an increase in operating expenses of \$3.4 million.

## Gross Margin

Items contributing to the quarter-over-quarter increase of \$4.7 million, or 11.7 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended September 30, 2015	\$40,635
Factors contributing to the gross margin increase for the three months ended September 30, 2016:	
Service expansions	1,577
Natural gas growth (excluding service expansions)	943
Additional revenue from GRIP in Florida	920
Implementation of Delaware Division interim rates	469
Margin from service to Eight Flags	464
Sandpiper SIR	226
Other	141
Gross margin for the three months ended September 30, 2016	\$45,375

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:

\$901,000 attributable to \$1.9 million from the short-term OPT  $\leq$  90 Service that commenced in December 2015 to an electric power generator in Kent County, Delaware and offset by a \$1.0 million decrease in gross margin from the conclusion of the interruptible service Eastern Shore provided this customer in 2015. The short-term OPT  $\leq$  90 Service is expected to be replaced by a 20-year OPT  $\leq$  90 Service in the first quarter of 2017.

\$617,000 from short-term firm service that commenced in March 2016, following certain measurement and related improvements to Eastern Shore's interconnect with TETLP that increased its natural gas receipt capacity from TETLP by 53,000 Dts/d, for a total capacity of 160,000 Dts/d. This service will generate approximately \$1.4 million in additional gross margin in 2016. The remaining capacity is available for firm or interruptible service.



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Natural Gas Growth (excluding service expansions)

Increased gross margin of \$943,000 from other growth in natural gas (excluding service expansions) was generated primarily from the following:

\$368,000 from Eastern Shore interruptible service provided to customers;

\$350,000 from Florida natural gas customer growth due primarily to new services to commercial and industrial customers; and

\$253,000 from a 4.2 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.

Additional Revenue from GRIP in Florida

Additional GRIP investments during 2015 and 2016 by our Florida natural gas distribution operations generated \$920,000 in additional gross margin in the third quarter of 2016, compared to the same period in 2015.

Implementation of Delaware Division Interim Rates

Delaware Division generated additional gross margin of \$469,000 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.

Margin from service to Eight Flags

We generated additional gross margin of \$464,000 in the third quarter of 2016, compared to the same period in 2015, from new natural gas transmission and distribution services provided to our Eight Flags' CHP plant.

Sandpiper SIR

Sandpiper generated additional gross margin of \$226,000, in the third quarter of 2016, compared to the same period in 2015, from a higher system improvement rate resulting from the continuing conversion of the Sandpiper system from propane service to natural gas service.

Other Operating Expenses

Other operating expenses increased by \$3.4 million. The significant components of the increase in other operating expenses included:

\$1.3 million in higher payroll and benefits costs for additional personnel to support growth;

\$702,000 in higher outside services costs primarily associated with growth and ongoing compliance activities;

\$517,000 in higher facilities costs to support growth; and

\$401,000 in higher depreciation, asset removal and property tax costs associated with recent capital investments to support growth and system integrity.

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For the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015

	Nine Months Ended		Increase (decrease)
	September 30, 2016	2015	
(in thousands)			
Revenue	\$226,630	\$235,438	\$(8,808 )
Cost of sales	81,184	101,414	(20,230 )
Gross margin	145,446	134,024	11,422
Operations & maintenance	64,673	59,648	5,025
Depreciation & amortization	18,909	18,109	800
Other taxes	9,204	8,650	554
Other operating expenses	92,786	86,407	6,379
Operating income	\$52,660	\$47,617	\$ 5,043

Operating income for the Regulated Energy segment for the nine months ended September 30, 2016 was \$52.7 million, an increase of \$5.0 million, or, 10.6 percent, compared to the same period in 2015. The increased operating income was primarily due to an increase in gross margin of \$11.4 million partially offset by a \$6.4 million increase in operating expenses to support growth.

**Gross Margin**

Items contributing to the period-over-period increase of \$11.4 million, or 8.5 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the nine months ended September 30, 2015	\$ 134,024
Factors contributing to the gross margin increase for the nine months ended September 30, 2016:	
Service expansions	5,516
Additional revenue from GRIP in Florida	3,069
Natural gas growth (excluding service expansions)	2,630
Implementation of Delaware Division interim rates	1,350
Margin from service to Eight Flags	892
Sandpiper SIR	618
Decreased customer consumption - weather and other	(2,141 )
Other	(512 )
Gross margin for the nine months ended September 30, 2016	\$ 145,446

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:

\$4.3 million attributable to \$5.6 million from the short-term OPT  $\leq$  90 Service that commenced in December 2015 to an electric power generator in Kent County, Delaware and offset by a \$1.3 million decrease in gross margin from the conclusion of the interruptible service Eastern Shore provided this customer in 2015. The short-term OPT  $\leq$  90 Service is expected to be replaced by a 20-year OPT  $\leq$  90 Service in the first quarter of 2017.

\$744,000 from short-term firm service that commenced in March 2016, following certain measurement and related improvements to Eastern Shore's interconnect with TETLP that increased its natural gas receipt capacity from TETLP by 53,000 Dts/d, for a total capacity of 160,000 Dts/d. This service will generate approximately \$1.4 million in additional gross margin in 2016. The remaining capacity is available for firm or interruptible service.

\$720,000 from natural gas transmission service as part of the major expansion initiative in Polk County, Florida.



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The foregoing gross margin increases were offset by a gross margin decrease of \$243,000 resulting from a reduction in rates for a long-term firm service to an industrial customer in New Castle County, Delaware.

Additional Revenue from GRIP in Florida

Additional GRIP investments during 2015 and 2016 by our Florida natural gas distribution operations generated \$3.1 million in additional gross margin during the first nine months of 2016, compared to the same period in 2015.

Natural Gas Growth (excluding service expansions)

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

- \$1.1 million from a 3.5 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.

\$1.1 million from Florida natural gas customer growth due primarily to new services to commercial and industrial customers.

\$348,000 from Eastern Shore interruptible service provided to other customers.

Implementation of Delaware Division Interim Rates

Our Delaware Division generated additional gross margin of \$1.4 million from the implementation of interim rates as a result of its rate case filing, during the first nine months of 2016. See Note 4, Rates and Other Regulatory Activities, to the condensed consolidated financial statements for additional details.

Margin from service to Eight Flags

We generated additional gross margin of \$892,000 from new natural gas transmission and distribution services provided to our Eight Flags' CHP plant, commencing in June of 2016.

Sandpiper SIR Rates

Sandpiper generated additional gross margin of \$618,000 from a higher system improvement rate resulting from the continuing conversion of the Sandpiper system from propane service to natural gas service.

Decreased Customer Consumption - Weather and Other

The above increases were partially offset by \$2.1 million in lower gross margin due to reduced consumption of natural gas and electricity, largely as a result of warmer weather during the first quarter of 2016, compared to the same period in 2015.

Other Operating Expenses

Other operating expenses increased by \$6.4 million. The significant components of the increase in other operating expenses included:

\$2.0 million in higher payroll and benefits costs for additional personnel to support growth;

\$1.4 million due to 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 third quarter of 2016, representing an additional current portion of the contingent settlement recovery;

\$1.4 million in higher depreciation, asset removal and property tax costs associated with recent capital investments to support growth and system integrity; and

\$817,000 in higher outside services costs primarily associated with growth and ongoing compliance activities.

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## Unregulated Energy Segment

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

	Three Months		Increase (decrease)
	Ended		
	September 30, 2016	2015	
(in thousands)			
Revenue	\$42,042	\$29,609	\$ 12,433
Cost of sales	31,840	19,402	12,438
Gross margin	10,202	10,207	(5 )
Operations & maintenance	10,975	9,305	1,670
Depreciation & amortization	1,840	1,483	357
Other taxes	467	441	26
Other operating expenses	13,282	11,229	2,053
Operating Loss	\$(3,080 )	\$(1,022 )	\$(2,058 )

Operating loss for the Unregulated Energy segment for the quarter ended September 30, 2016 was \$3.1 million, an increase of \$2.1 million compared to the same quarter of 2015. The Unregulated Energy segment typically reports an operating loss in the third quarter due to the seasonal nature the businesses included in this segment. Gross margin for the quarter was \$10.2 million, which was more than offset by operating expenses of \$13.3 million, to generate the operating loss of \$3.1 million.

## Gross Margin

Items contributing to the quarter-over-quarter decrease of \$5,000 in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended September 30, 2015	\$ 10,207
Factors contributing to the gross margin decrease for the three months ended September 30, 2016:	
Eight Flags	1,570
Aspire Energy	(407 )
Lower margins for Xeron	(413 )
Decreased retail propane margins	(414 )
Other	(341 )
Gross margin for the three months ended September 30, 2016	\$ 10,202

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

## Eight Flags

Eight Flags' CHP plant, which commenced operations in June 2016, generated \$1.6 million in additional gross margin.

## Aspire Energy

\$407,000 of decreased gross margin from Aspire Energy as a result of increased deliveries and imbalance positions that favorably impacted Aspire Energy in the third quarter of 2015, which are non-recurring. Lower margin associated with system volumes and imbalance positions in third quarter of 2016, also contributed to the decrease.

## Lower Margins for Xeron

Xeron's gross margin decreased by \$413,000 resulting from lower margins on executed trades.

Decreased Retail Propane Margins

Lower retail propane margins for our Delmarva and Florida propane distribution operations decreased gross margin by \$414,000, of which \$344,000 is associated with the Delmarva Peninsula propane distribution operation, as retail margins per gallon returned

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to more normal levels; accordingly, we have continued to assume more normal levels of margins in our long-term financial plans and forecasts. 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.

## Other Operating Expenses

Other operating expenses increased by \$2.1 million. The significant components of the increase in other operating expenses included:

\$1.1 million in other operating expenses incurred by the Eight Flags CHP plant;

\$545,000 in higher payroll and benefits costs for additional personnel to support growth; and

\$225,000 in higher outside services costs primarily associated with growth and ongoing compliance activities.

For the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015

	Nine Months		Increase (decrease)
	Ended September 30, 2016	2015	
(in thousands)			
Revenue	\$136,361	123,164	\$13,197
Cost of sales	90,981	77,235	13,746
Gross margin	45,380	45,929	(549 )
Operations & maintenance	30,136	26,993	3,143
Depreciation & amortization	4,512	3,973	539
Other taxes	1,465	1,297	168
Other operating expenses	36,113	32,263	3,850
Operating Income	\$9,267	\$13,666	\$(4,399 )

Operating income for the Unregulated Energy segment for the nine months ended September 30, 2016 was \$9.3 million, a decrease of \$4.4 million, or 32.2 percent for the same period of 2015. The results for the first nine months include an increase in gross margin of \$4.5 million and other operating expenses of \$2.5 million, each associated with Aspire Energy. Excluding these impacts from Aspire Energy, gross margin decreased by \$5.1 million, and other operating expenses increased by \$1.4 million.

## Gross Margin

Items contributing to the period-over-period decrease of \$549,000 in gross margin are listed in the following table:

(in thousands)	
Gross margin for the nine months ended September 30, 2015	\$45,929
Factors contributing to the gross margin decrease for the nine months ended September 30, 2016:	
Aspire Energy	4,542
Eight Flags	1,689
Natural gas marketing	1,062
Lower margins for Xeron	(419 )
Decreased wholesale propane sales	(436 )
Decreased retail propane margins	(2,204 )
Decreased customer consumption - weather and other	(4,059 )
Other	(724 )
Gross margin for the nine months ended September 30, 2016	\$45,380



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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 \$8.2 million in gross margin compared to \$3.7 million in the same period of 2015, an increase of \$4.5 million. Results for the first nine months of 2015 reflect only six 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, additional management fees and the optimization of gathering system receipts and deliveries.

### Eight Flags

Eight Flags' CHP plant, which commenced operations in June 2016, generated \$1.7 million in additional gross margin.

### Natural Gas Marketing

PESCO generated \$1.1 million in additional gross margin due to customer growth and the positive impact from favorable supply management and hedging activities, which generated additional gross margin.

### Lower Margins for Xeron

Xeron's gross margin decreased by \$419,000 resulting from lower margins on executed trades.

### Decreased Propane Wholesale Sales

Gross margin decreased by \$436,000 as a result of lower propane wholesale sales associated with the supply agreement between an affiliate of ESG and 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 nine months of 2016 compared to the same period in 2015, also contributed to this decrease.

### Decreased Retail Propane Margins

Lower retail propane margins for our Delmarva propane distribution operation decreased gross margin by \$2.2 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 continued to assume more normal levels of margins in our long-term financial plans and forecasts.

This decrease was partially offset by \$61,000 in higher retail propane margins per gallon for our Florida propane distribution operation as a result of local market conditions.

### Decreased Customer Consumption - Weather and Other

Gross margin decreased by \$4.1 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 nine months of 2016 compared to colder temperatures during the first nine months of 2015.

### Other Operating Expenses

Other operating expenses increased by \$3.9 million. The significant components of the increase in other operating expenses included:

\$2.5 million in other operating expenses incurred by Aspire Energy, given the additional quarter's results included in 2016, compared to only six months of results in the nine months ended September 30, 2015; and

\$1.1 million in other operating expenses incurred by Eight Flags, which commenced operations in June 2016.

Interest Charges

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

Interest charges for the three months ended September 30, 2016 increased by approximately \$230,000, compared to the same quarter in 2015, attributable to an increase of \$392,000 in interest from higher short-term borrowings, partially offset by a decrease of \$117,000 in interest from long-term debt.

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For the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015

Interest charges for the nine months ended September 30, 2016 increased by approximately \$571,000, compared to the same period in 2015, attributable to an increase of \$1.1 million in interest from higher short-term borrowings, partially offset by a decrease of \$352,000 in interest from long-term debt.

Income Taxes

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

Income tax expense was \$3.0 million in the third quarter of 2016, compared to \$3.3 million in the same quarter in 2015. The slight decrease in income tax expense was due primarily to lower taxable income. Our effective income tax rate was 40.4 percent and 39.4 percent, for the third quarter of 2016 and 2015, respectively.

For the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015

Income tax expense was \$21.4 million in the nine months ended September 30, 2016, compared to \$21.6 million in the same period in 2015. The slight decrease in income tax expense was due primarily to lower taxable income. Our effective income tax rate was 39.5 percent and 40.0 percent, for the first nine months of 2016 and 2015, respectively.

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## 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 through 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 nine months ended September 30, 2016 were approximately \$106.3 million. We currently project aggregate capital expenditures between \$150.0 and \$170.0 million in 2016. Our current forecast by segment and business line is shown below:

	Low	High
(dollars in thousands)		
Regulated Energy:		
Natural gas distribution	\$60,000	\$65,000
Natural gas transmission	55,000	60,000
Electric distribution	10,000	13,000
Total Regulated Energy	125,000	138,000
Unregulated Energy:		
Propane distribution	10,000	12,000
Other unregulated energy	10,000	13,000
Total Unregulated Energy	20,000	25,000
Other	5,000	7,000

Total 2016 capital expenditures \$150,000 \$170,000

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  $\leq$  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 information technology systems; and other strategic initiatives and investments. 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.

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## 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 September 30, 2016 and December 31, 2015:

	September 30, 2016	December 31, 2015
(in thousands)		
Long-term debt, net of current maturities	\$143,525 25 %	\$149,006 29 %
Stockholders' equity	438,300 75 %	358,138 71 %
Total capitalization, excluding short-term debt	\$581,825 100%	\$507,144 100%
	September 30, 2016	December 31, 2015
(in thousands)		
Short-term debt	\$154,490 20 %	\$173,397 25 %
Long-term debt, including current maturities	155,612 21 %	158,157 23 %
Stockholders' equity	438,300 59 %	358,138 52 %
Total capitalization, including short-term debt	\$748,402 100%	\$689,692 100%

Included in the long-term debt balances at September 30, 2016 and December 31, 2015, was a capital lease obligation associated with Sandpiper's capacity, supply and operating agreement (\$2.4 million and \$3.5 million, respectively, net of current maturities, and \$3.8 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. On September 22, 2016, we completed a public offering of 960,488 shares of our common stock at a price per share of \$62.26. The net proceeds from the sale of common stock, after deducting underwriting commissions and expenses, were approximately \$57.3 million, which were added to our general funds and used primarily to repay a portion of our short-term debt under unsecured lines of credit. The issuance of equity resulted in our equity to total capitalization ratio representing 59% as of September 30, 2016.

As described below under "Short-term Borrowings," we entered into the Credit Agreement and the 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 Shelf Agreement with Prudential for the potential private placement of Shelf Notes as further described below under the heading "Shelf Agreement."

For larger capital projects, to the extent feasible, we will seek to align any planned long-term debt or equity issuances 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 issuances will be based on market conditions.

## Short-term Borrowings

Our outstanding short-term borrowings at September 30, 2016 and December 31, 2015 were \$154.5 million and \$173.4 million, respectively. The weighted average interest rates for our short-term borrowings were 1.49 percent and 1.09 percent, for the nine months ended September 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 September 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 the Revolver with five participating Lenders. The terms of the Revolver are described in further detail below. We also had

access to two credit facilities with a total of \$40.0 million of available credit. The Revolver replaced these credit facilities when they expired on October 31, 2015. 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

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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 have the right, under certain circumstances, to 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 September 30, 2016 and December 31, 2015, we had outstanding borrowings of \$50.0 million and \$35.0 million, respectively, under the Revolver.

Shelf Agreement

On October 8, 2015, we entered into a Shelf Agreement with Prudential. Under the terms of the Shelf Agreement, through October 8, 2018, we may request that Prudential purchase 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.

On May 13, 2016, we submitted a request that Prudential purchase \$70.0 million of 3.25 percent Shelf Notes under the Shelf Agreement. On May 20, 2016, Prudential accepted and confirmed our request. The proceeds received from the issuances of the Shelf Notes will be used to reduce short-term borrowings under the Company's revolving credit facility, lines of credit and/or to fund capital expenditures. 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, place or permit liens and encumbrances on any of our property or the property of our subsidiaries.

Cash Flows

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

	Nine Months Ended September 30, 2016      2015	
(in thousands)		
Net cash provided by (used in):		
Operating activities	\$82,225	\$93,932
Investing activities	(106,992)	(118,233)
Financing activities	23,448	23,508
Net decrease in cash and cash equivalents	(1,319 )	(793 )
Cash and cash equivalents—beginning of period	2,855	4,574
Cash and cash equivalents—end of period	\$1,536	\$3,781

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 nine months ended September 30, 2016 and 2015, net cash provided by operating activities was \$82.2 million and \$93.9 million, respectively, resulting in a decrease in cash flows of \$11.7 million. Significant operating

activities generating the cash flows change were as follows:

Net income, adjusted for reconciling activities, increased cash flows by \$15.4 million, due primarily to an increase in deferred income taxes as a result of the availability and utilization of bonus depreciation in the first nine months of 2016, which resulted in a higher book-to-tax timing difference and higher non-cash adjustments for depreciation and amortization.

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Changes in net regulatory assets and liabilities decreased cash flows by \$9.8 million, due primarily to changes in fuel costs collected through the various fuel cost recovery mechanisms.

Changes in net accounts receivable and accrued revenue and accounts payable and accrued liabilities decreased cash flows by \$12.2 million, due primarily to higher revenues and the timing of the receipt of customer payments as well as increased operating expenses and the timing of payments to vendors.

Changes in propane, natural gas and materials inventories decreased net cash flows by approximately \$5.3 million.

**Cash Flows Used in Investing Activities**

Net cash used in investing activities totaled \$107.0 million and \$118.2 million during the nine months ended September 30, 2016 and 2015, respectively, resulting in an increase in cash flows of \$11.2 million. This was due primarily to the \$20.7 million net cash (\$27.5 million cash paid, less \$6.8 million of cash acquired) used for the Gatherco acquisition in 2015. An increase in capital investments of \$9.7 million partially offset this decrease.

**Cash Flows Provided by Financing Activities**

Net cash provided by financing activities totaled \$23.4 million in the first nine months of both 2016 and 2015. Net proceeds of \$57.3 million, after deducting underwriting commissions and expenses, from the issuance of common stock during the third quarter of 2016, was used to pay down short-term debt. Net cash provided by financing activities further increased as a result of an increase in a cash overdraft of \$2.5 million and an increase in short-term borrowing of \$35.9 million, partially offset by common stock dividends of \$13.0 million and \$600,000 of stock issued for the Dividend Reinvestment Plan. During the nine months ended September 30, 2015, there were approximately \$31.6 million in net additional borrowings, offset by common stock dividends of \$11.7 million and \$633,000 of stock issued for the Dividend Reinvestment Plan.

**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 September 30, 2016 was \$53.9 million, with the guarantees expiring on various dates through September 2017.

We have issued letters of credit totaling \$8.4 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 September 2017. There have been no draws on these letters of credit as of September 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 September 30, 2016:

	Payments Due by Period				Total
	Less than 2 years	2 - 3 years	3 - 5 years	More than 5 years	
(in thousands)					
Purchase obligations - Commodity <sup>(1)</sup>	\$42,155	\$ 3,417	\$ —	\$ —	\$45,572

In addition to the obligations noted above, we have agreements with commodity suppliers that have provisions with no minimum purchase requirements. There are no monetary penalties for reducing the amounts purchased;

<sup>(1)</sup> 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.



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### 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 September 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 September 30, 2016, as compared to a fair value of \$173.5 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 hedge its inventory.

In 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.

Our propane wholesale marketing operation is a party to propane and crude oil futures and forward contracts, with various third parties, which require that the propane wholesale marketing operation purchase or sell natural gas liquids or crude oil at a fixed price at fixed future dates. At expiration, the contracts are typically settled financially without taking physical delivery of propane or crude oil. 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 or crude oil. 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 dollar 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. As of September 30, 2016, there were no outstanding contracts.

We have entered into agreements with various suppliers to purchase natural gas, electricity and propane for resale to our 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 September 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:

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(in thousands)	September 30, 2016	December 31, 2015
Mark-to-market energy assets, including call options, swap agreements and futures	\$ 477	\$ 153
Mark-to-market energy liabilities, including swap agreements and futures	\$ 29	\$ 433

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer and Chief Financial Officer of Chesapeake Utilities, with the participation of other Company officials, have evaluated our “disclosure controls and procedures” (as such term is defined under Rules 13a-15(e) and 15d-15(e), promulgated under the Securities Exchange Act of 1934, as amended) as of September 30, 2016. Based upon their evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2016.

Changes in Internal Control over Financial Reporting

During the quarter ended September 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.

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## 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 Chesapeake Utilities, 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 Chesapeake Utilities. 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 <sup>(2)</sup>	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs <sup>(2)</sup>
July 1, 2016 through July 30, 2016 <sup>(1)</sup>	366	\$ 66.35	—	—
August 1, 2016 through August 31, 2016	—	\$ —	—	—
September 1, 2016 through September 30, 2016	—	\$ —	—	—
Total	366	\$ 66.35	—	—

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

<sup>(1)</sup> 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 September 30, 2016, 366 shares were purchased through the reinvestment of dividends on deferred stock units.

<sup>(2)</sup> Except for the purposes described in Footnote <sup>(1)</sup>, 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.



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Item 6. Exhibits

- 1.1 Underwriting Agreement entered into by Chesapeake Utilities Corporation and Wells Fargo Securities, LLC, RBC Capital Markets, LLC, Janney Montgomery Scott LLC., Robert W. Baird & Co., Incorporated, J.J.B. Hilliard, W.L. Lyons, LLC, Ladenburg Thalmann & Co. Inc., U.S. Capital Advisors LLC and BB&T Securities, LLC on September 22, 2016, relating to the sale and issuance of 835,207 shares of the Company's common stock, is incorporated herein by reference to Exhibit 1.1 of the Company's current report on Form 8-K, filed on September 28, 2016, File No. 001-11590.
- 3.3 Second Amendment to the Amended and Restated Bylaws of Chesapeake Utilities Corporation, effective November 2, 2016, 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.

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SIGNATURES

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

CHESAPEAKE UTILITIES CORPORATION

/S/ BETH W. COOPER

Beth W. Cooper

Senior Vice President and Chief Financial Officer

Date: November 3, 2016