CHESAPEAKE UTILITIES CORP
Form 10-Q
May 03, 2017
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended: March 31, 2017
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number: 001-11590

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

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

909 Silver Lake Boulevard, Dover, Delaware 19904
(Address of principal executive offices, including Zip Code)
(302) 734-6799
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x 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 x 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	x	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 x

Common Stock, par value $0.4867 — 16,335,052 shares outstanding as of April 30, 2017.

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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
CDD: Cooling 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 above 65 degrees Fahrenheit
Chesapeake or Chesapeake Utilities: Chesapeake Utilities Corporation, and its direct and indirect 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
CGC: Consumer Gas Cooperative, an Ohio natural gas cooperative
CHP: Combined heat and power plant
Columbia Gas: Columbia Gas of Ohio, an unaffiliated local distribution company based in Ohio
Company: Chesapeake Utilities Corporation, and its direct and indirect 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
Degree-Day: A degree-day is the measure of the variation in the weather based on the extent to which the average daily temperature (from 10:00 am to 10:00 am) falls above or below 65 degrees Fahrenheit.
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, which owns and operates a CHP plant on Amelia Island, Florida
EPA: United States Environmental Protection Agency
ESG: Eastern Shore Gas Company and its affiliates
FASB: Financial Accounting Standards Board

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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
FGT: Florida Gas Transmission Company
Flo-gas: Flo-gas Corporation, a wholly-owned subsidiary of FPU
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, 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, an unaffiliated electric company that supplies electricity to FPU
Gulfstream: Gulfstream Natural Gas System, LLC, an unaffiliated pipeline network that supplies natural gas to FPU
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 unaffiliated community-owned utility located in Jacksonville, Florida, formerly known as Jacksonville Electric Authority
Lenders: PNC, Bank of America N.A., Citizens Bank N.A., Royal Bank of Canada, and Wells Fargo Bank, National Association, which are collectively the lenders that entered into the Credit Agreement with Chesapeake Utilities on October 8, 2015
MDE: Maryland Department of Environment
MGP: Manufactured gas plant, which is a site where coal was previously used to manufacture gaseous fuel for industrial, commercial and residential use
MWH: Megawatt hour, which is a unit of measurement for electricity
OPT ≤ 90 Service: Off Peak ≤ 90 Firm Transportation Service, a tariff associated with Eastern Shore's firm transportation service that enables Eastern Shore to forgo scheduling service for up to 90 days during the peak months of November through April each year
OTC: Over-the-counter
Peninsula Pipeline: Peninsula Pipeline Company, Inc., Chesapeake Utilities' wholly-owned Florida intrastate pipeline subsidiary
PESCO: Peninsula Energy Services Company, Inc., Chesapeake Utilities' wholly-owned natural gas marketing subsidiary
PNC: PNC Bank, National Association, the administrative agent and primary lender for our Revolver
Prudential: Prudential Investment Management Inc., an institutional investment management firm, with which we have entered into the Shelf Agreement
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

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Rayonier: Rayonier Performance Fibers, LLC, the company that owns the property on which Eight Flags' CHP plant is located and that supplies electricity to FPU
Retirement Savings Plan: Chesapeake Utilities' qualified 401(k) retirement savings plan
Revolver: Our unsecured revolving credit facility with the Lenders
Rights Plan: A plan designed to protect against abusive or coercive takeover attempts or tactics that are contrary to the best interests of Chesapeake Utilities' stockholders
Sandpiper: Sandpiper Energy, Inc., Chesapeake Utilities' wholly-owned subsidiary, which provides a tariff-based distribution service to customers in Worcester County, Maryland
Sanford Group: FPU and other responsible parties involved with the Sanford environmental site
SCO: Standard Choice Offer, a program offered by Columbia Gas in which PESCO was selected as a natural gas supplier pursuant to a competitive auction to serve a pool of customers within Columbia Gas' service territory from April 2016 through March 2017
SEC: Securities and Exchange Commission
Senior Notes: Our unsecured long-term debt issued primarily to insurance companies on various dates
Sharp: Sharp Energy, Inc., Chesapeake Utilities' wholly-owned propane distribution subsidiary
Shelf Agreement: An agreement entered into by Chesapeake Utilities and Prudential pursuant to which Chesapeake Utilities may request that Prudential purchase, through October 7, 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
TETLP: Texas Eastern Transmission, LP, an interstate pipeline interconnected with Eastern Shore's pipeline
Xeron: Xeron, Inc., an inactive subsidiary of Chesapeake Utilities, which previously engaged in propane and crude oil trading

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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 March 31,	
	2017	2016
(in thousands, except shares and per share data)		
Operating Revenues		
Regulated Energy	$97,654	$ 89,216
Unregulated Energy and other	87,506	57,080
Total Operating Revenues	185,160	146,296
Operating Expenses		
Regulated Energy cost of sales	40,244	34,905
Unregulated Energy and other cost of sales	60,754	34,024
Operations	32,913	27,159
Maintenance	3,231	2,479
Depreciation and amortization	8,812	7,503
Other taxes	4,530	3,846
Total Operating Expenses	150,484	109,916
Operating Income	34,676	36,380
Other expense, net	(277)	(34)
Interest charges	2,739	2,650
Income Before Income Taxes	31,660	33,696
Income taxes	12,516	13,329
Net Income	$19,144	$ 20,367
Weighted Average Common Shares Outstanding:		
Basic	16,317,224	15,286,842
Diluted	16,363,796	15,331,912
Earnings Per Share of Common Stock:		
Basic	$1.17	$ 1.33
Diluted	$1.17	$ 1.33
Cash Dividends Declared Per Share of Common Stock	$0.3050	$ 0.2875

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

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

	Three Months Ended March 31,	
	2017	2016
(in thousands)		
Net Income	$19,144	$20,367
Other Comprehensive Income (Loss), net of tax:		
Employee Benefits, net of tax:		
Amortization of prior service cost, net of tax of $(8) and $(8), respectively	(11)	(12)
Net gain, net of tax of $77 and $67, respectively	93	101
Cash Flow Hedges, net of tax:		
Unrealized gain on commodity contract cash flow hedges, net of tax of $192 and $0, respectively	338	—
Total Other Comprehensive Income	420	89
Comprehensive Income	$19,564	$20,456

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

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

Assets	March 31, 2017	December 31, 2016
(in thousands, except shares and per share data)		
Property, Plant and Equipment		
Regulated Energy	$985,832	$957,681
Unregulated Energy	199,211	196,800
Other businesses and eliminations	21,486	21,114
Total property, plant and equipment	1,206,529	1,175,595
Less: Accumulated depreciation and amortization	(250,574)	(245,207)
Plus: Construction work in progress	62,362	56,276
Net property, plant and equipment	1,018,317	986,664
Current Assets		
Cash and cash equivalents	5,700	4,178
Accounts receivable (less allowance for uncollectible accounts of $815 and $909, respectively)	58,375	62,803
Accrued revenue	16,317	16,986
Propane inventory, at average cost	5,437	6,457
Other inventory, at average cost	3,657	4,576
Regulatory assets	7,527	7,694
Storage gas prepayments	735	5,484
Income taxes receivable	13,388	22,888
Prepaid expenses	4,534	6,792
Mark-to-market energy assets	1,339	823
Other current assets	1,804	2,470
Total current assets	118,813	141,151
Deferred Charges and Other Assets		
Goodwill	15,070	15,070
Other intangible assets, net	1,752	1,843
Investments, at fair value	5,212	4,902
Regulatory assets	76,218	76,803
Receivables and other deferred charges	2,929	2,786
Total deferred charges and other assets	101,181	101,404
Total Assets	$1,238,311	$1,229,219

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

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

Capitalization and Liabilities	March 31, 2017	December 31, 2016
(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)	7,949	7,935
Additional paid-in capital	251,144	250,967
Retained earnings	206,194	192,062
Accumulated other comprehensive loss	(4,458)	(4,878)
Deferred compensation obligation	3,100	2,416
Treasury stock	(3,100)	(2,416)
Total stockholders' equity	460,829	446,086
Long-term debt, net of current maturities	136,537	136,954
Total capitalization	597,366	583,040
Current Liabilities		
Current portion of long-term debt	12,111	12,099
Short-term borrowing	199,333	209,871
Accounts payable	49,500	56,935
Customer deposits and refunds	29,638	29,238
Accrued interest	2,868	1,312
Dividends payable	4,981	4,973
Accrued compensation	5,560	10,496
Regulatory liabilities	7,275	1,291
Mark-to-market energy liabilities	189	773
Other accrued liabilities	9,278	7,063
Total current liabilities	320,733	334,051
Deferred Credits and Other Liabilities		
Deferred income taxes	231,004	222,894
Regulatory liabilities	42,861	43,064
Environmental liabilities	8,535	8,592
Other pension and benefit costs	33,082	32,828
Deferred investment tax credits and other liabilities	4,730	4,750
Total deferred credits and other liabilities	320,212	312,128
Environmental and other commitments and contingencies (Note 4 and 5)		
Total Capitalization and Liabilities	$ 1,238,311	$ 1,229,219

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

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

	Three Months Ended March 31,	
	2017	2016
(in thousands)		
Operating Activities		
Net income	$19,144	$20,367
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	8,812	7,503
Depreciation and accretion included in other costs	1,939	1,646
Deferred income taxes	7,849	4,326
Realized loss on commodity contracts/sale of assets/investments	1,330	479
Unrealized loss on investments/commodity contracts	132	18
Employee benefits and compensation	423	380
Share-based compensation	639	649
Other, net	(4)	24
Changes in assets and liabilities:		
Accounts receivable and accrued revenue	5,095	(3,738)
Propane inventory, storage gas and other inventory	6,688	3,073
Regulatory assets/liabilities, net	6,103	3,941
Prepaid expenses and other current assets	1,136	1,358
Accounts payable and other accrued liabilities	(5,897)	102
Income taxes receivable	9,500	8,841
Customer deposits and refunds	400	(134)
Accrued compensation	(4,966)	(5,943)
Other assets and liabilities, net	1,631	1,242
Net cash provided by operating activities	59,954	44,134
Investing Activities		
Property, plant and equipment expenditures	(42,172)	(37,783)
Proceeds from sales of assets	36	51
Environmental expenditures	(57)	(99)
Net cash used in investing activities	(42,193)	(37,831)
Financing Activities		
Common stock dividends	(4,815)	(4,204)
Issuance of stock for Dividend Reinvestment Plan	222	195
Tax withholding payments related to net settled stock compensation	(692)	(770)
Change in cash overdrafts due to outstanding checks	587	(1,501)
Net (repayment) borrowing under line of credit agreements	(11,125)	839
Repayment of long-term debt and capital lease obligation	(416)	(402)
Net cash used by financing activities	(16,239)	(5,843)
Net Increase in Cash and Cash Equivalents	1,522	460
Cash and Cash Equivalents—Beginning of Period	4,178	2,855
Cash and Cash Equivalents—End of Period	$5,700	$3,315

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

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

	Common Stock [1]							
(in thousands, except shares and per share data)	Number of Shares[2]	Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total [2]
Balance at December 31, 2015	15,270,659	$7,432	$190,311	$166,235	$ (5,840)	$ 1,883	$(1,883)	$358,138
Net income		—	—	44,675	—	—	—	44,675
Other comprehensive income	—	—	—	—	962	—	—	962
Dividend declared ($1.2025 per share)	—	—	—	(18,848)	—	—	—	(18,848)
Retirement savings plan and dividend reinvestment plan	36,253	17	2,225	—	—	—	—	2,242
Stock issuance [3]	960,488	467	56,893	—	—	—	—	57,360
Share-based compensation and tax benefit [4] [5]	36,099	19	1,538	—	—	—	—	1,557
Treasury stock activities	—	—	—	—	—	533	(533)	—
Balance at December 31, 2016	16,303,499	7,935	250,967	192,062	(4,878)	2,416	(2,416)	446,086
Net income	—	—	—	19,144	—	—	—	19,144
Other comprehensive income	—	—	—	—	420	—	—	420
Dividend declared ($0.3050 per share)	—	—	—	(5,012)	—	—	—	(5,012)
Dividend reinvestment plan	5,733	3	376	—	—	—	—	379
Share-based compensation and tax benefit [4] [5]	22,657	11	(199)	—	—	—	—	(188)
Treasury stock activities	—	—	—	—	—	684	(684)	—
Balance at March 31, 2017	16,331,889	$7,949	$251,144	$206,194	$ (4,458)	$ 3,100	$(3,100)	$460,829

(1) 2,000,000 shares of preferred stock at $0.01 par value has been authorized. None has been issued or is outstanding; accordingly, no information has been included in the statements of stockholders' equity.

(2) Includes 86,899 and 76,745 shares at March 31, 2017 and December 31, 2016, respectively, held in a Rabbi Trust related to our Deferred Compensation Plan.

(3) 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 $57.4 million.

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

(5) The shares issued under the SICP are net of shares withheld for employee taxes. For the three months ended March 31, 2017, and for the year ended December 31, 2016, we withheld 10,269 and 12,031 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, 2016. In the opinion of management, these financial statements reflect normal recurring adjustments that are necessary for a fair presentation of our results of operations, financial position and cash flows for the interim periods presented.

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

We have revised the unaudited condensed consolidated statement of cash flows for the three months ended March 31, 2016 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 unaudited condensed consolidated financial statements.

FASB Statements and Other Authoritative Pronouncements

Recently Adopted Accounting Standards

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. We adopted ASU 2015-11 on January 1, 2017 on a prospective basis. Adoption of this standard did not have a material impact on our financial position or results of operations.

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 interim and annual financial statements issued beginning January 1, 2018.

In preparation for the adoption of this standard, we have analyzed our existing businesses and revenue streams and have prepared a preliminary gap analysis between our current revenue policies and the requirements under the new revenue recognition standard. We are in the process of evaluating each revenue stream under the new standard, expanding the contract sampling, creating new policies and evaluating the enhanced disclosure requirements. We will provide additional training to our employees and develop processes and system changes associated with the implementation of the new standard, and we will then implement the standard. We plan to utilize the modified retrospective transition method upon adoption of this standard.

Based on our assessment, we do not believe the new standard will impact the recognition of revenue from a majority of our customers. However, we have just begun to evaluate our long-term special contracts, and may find facts and circumstances in those contracts that could impact the timing of the recognition of revenue. As we continue to execute our plan related to this standard, we will be in a better position to quantify the full impact of this standard.

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 the modified retrospective

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transition method 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 this update may have on our financial position and results of operations.
Statement of Cash Flows (ASC 230) - In August 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.
Intangibles-Goodwill (ASC 350) - In January 2017, the FASB issued ASU 2017-04, Simplifying the Test for Goodwill Impairment, which simplifies how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. ASU 2017-04 will be effective for our annual and interim financial statements beginning January 1, 2020, although early adoption is permitted. The amendments included in this ASU are to be applied prospectively. We are evaluating the effect of this ASU on our financial position and results of operations.
Compensation-Retirement Benefits (ASC 715) - In March 2017, the FASB issued ASU 2017-07, Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post Retirement Benefit Cost. Under this guidance employers are required to report the service cost component in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit costs are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The update allows for capitalization of the service cost component when applicable. ASU 2017-07 will be effective for our annual and interim financial statements beginning January 1, 2018, although early adoption is permitted. The presentation of the service cost and other components in this update are to be applied retrospectively and the capitalization of the service cost is to be applied prospectively on or after the effective date. We are evaluating the effect of this update on our financial position and results of operations.

2. Calculation of Earnings Per Share

	Three Months Ended March 31,	
	2017	2016
(in thousands, except shares and per share data)		
Calculation of Basic Earnings Per Share:		
Net Income	$19,144	$ 20,367
Weighted average shares outstanding	16,317,224	15,286,842
Basic Earnings Per Share	$1.17	$ 1.33
Calculation of Diluted Earnings Per Share:		
Reconciliation of Numerator:		
Net Income	$19,144	$ 20,367
Reconciliation of Denominator:		
Weighted shares outstanding—Basic	16,317,224	15,286,842
Effect of dilutive securities—Share-based compensation	46,572	45,070
Adjusted denominator—Diluted	16,363,796	15,331,912
Diluted Earnings Per Share	$1.17	$ 1.33

3. Rates and Other Regulatory Activities
Our natural gas and electric distribution operations in Delaware, Maryland and Florida are subject to regulation by their respective 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: In December 2015, our Delaware Division filed an application with the Delaware PSC for a base rate increase and certain other changes to its tariff. The Delaware Division, Delaware PSC Staff, the Division of the Public Advocate and other intervenors met and reached a settlement agreement in November 2016. The terms of the settlement agreement included an annual increase of $2.25 million in base rates. The order became final in December 2016, and the new rates became effective January 1, 2017. Amounts collected through interim rates in excess of the respective portion of the $2.25 million increase through December 31, 2016 were accrued as of that date. In January 2017, we filed our proposed refund plan with the Delaware PSC and subsequently issued refunds to customers in March 2017.

Florida

Cost Recovery for the Electric Interconnect Project: In September 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 would enable FPU's electric division to negotiate a new power purchase agreement to mitigate fuel costs for its Northeast division. FPU's proposal was approved by the Florida PSC at its Agenda Conference held in December 2015. In January 2016, however, the Office of Public Counsel filed an appeal of the Florida PSC's decision with the Florida Supreme Court. In March 2017, after consideration of the legal briefs filed and oral arguments held in the proceeding, the Supreme Court reversed the Florida PSC decision. As a result, FPU will exclude the recovery of these costs from its 2018 Fuel and Purchased Power Cost Recovery Clause filing.

Surcharge Associated with Modernization of Electric Distribution System Project: In February 2017, FPU’s electric division filed a petition with the Florida PSC requesting a temporary surcharge mechanism to recover costs and generate an appropriate return on investment associated with an essential reliability and modernization project for its electric distribution system. We requested approval to invest approximately $59.8 million over a five-year period associated with this project. In February 2017, the Office of Public Counsel intervened in this petition. The Florida PSC requested that FPU file a limited proceeding to include these investments in base rates instead of seeking approval of a temporary surcharge. In April 2017, FPU voluntarily withdrew its petition. FPU will prepare and file a limited proceeding, as recommended by the Florida PSC, before the end of 2017.

Eastern Shore

White Oak Mainline Expansion Project: In November 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 proposed to construct approximately 7.2 miles of 16-inch diameter pipeline looping in Chester County, Pennsylvania and add additional compression capability at Eastern Shore’s existing Delaware City compressor station in New Castle County, Delaware. In November 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.

In July 2016, the FERC authorized 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 does not prevent Eastern Shore from proposing rolled-in rate treatment of these project facilities in a future general rate case. In August 2016, the FERC issued a “Notice to Proceed,” and Eastern Shore commenced construction.

Upon receiving the FERC's approval in December 2016, the Daleville and Kemblesville Loops commenced operation. Upon receiving the FERC's approval, the Delaware City Compressor Station commenced service in March 2017. As of the end of March 2017, the entire project was placed into service. The total cost to complete the project is approximately $41.0 million.

System Reliability Project: In May 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. 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. In July 2016, the FERC ordered that Eastern Shore's request for a determination of rolled-in rate treatment may be addressed in its next base rate proceeding and required Eastern Shore to comply with 19 environmental conditions.
In September 2016, the FERC granted approval to start construction on all phases 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. In December 2016, Eastern Shore filed a request to place into service the pipeline looping located in New Castle County, Delaware. The FERC granted approval to place the Porter Road Loop into service in December 2016. The

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remaining components of the project, the Bridgeville Compressor Station and the Dover Loop, are anticipated to be completed by the end of May 2017. Eastern Shore continues to file weekly status reports with the FERC in compliance with the environmental conditions. The estimated cost of the project is approximately $37.0 million. We expect that we will begin to recover the project's costs in August 2017, coinciding with the proposed effectiveness of new rates, subject to refund pending final resolution of the base rate case.

2017 Expansion Project: In May 2016, Eastern Shore submitted a request to the FERC to initiate the pre-filing review procedures for Eastern Shore's 2017 expansion project. The project's facilities include approximately 23 miles of pipeline looping in Pennsylvania, Maryland and Delaware; upgrades to existing metering facilities in Lancaster County, Pennsylvania; installation of an additional 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. In May 2016, the FERC approved Eastern Shore's request to commence the pre-filing review process. Eastern Shore entered into Precedent Agreements with four existing customers as well as Chesapeake affiliates, for a total of 61,162 Dts/d of additional firm natural gas transportation service on Eastern Shore's pipeline system with an additional 52,500 Dts/d of firm transportation service at certain Eastern Shore receipt facilities.

In December 2016, Eastern Shore submitted an application for a certificate of public convenience and necessity seeking authorization to construct the expansion facilities. Six of Eastern Shore's existing customers timely intervened to become parties to the docket. In February 2017, Eastern Shore submitted responses to the FERC staff's data requests. The FERC has scheduled issuance of the environmental assessment for this project in May 2017, with approval of the project anticipated in August 2017. The estimated cost of this expansion project is $98.6 million.

2017 Rate Case Filing: In January 2017, Eastern Shore filed a base rate proceeding with the FERC, as required by the terms of its 2012 rate case settlement agreement. Eastern Shore's proposed rates are based on the mainline cost of service of approximately $60.0 million resulting in an overall requested revenue increase of approximately $18.9 million and a requested rate of return on common equity of 13.75 percent. The filing includes incremental rates for the White Oak Mainline Expansion and Lateral projects, each of which benefits a single customer. Eastern Shore is also proposing to revise its depreciation rates and negative salvage rate based on the results of independent, third-party depreciation and negative salvage value studies. The FERC issued a notice of the filing in January 2017, and the comment period ended in February 2017. Fourteen parties intervened in the proceeding with six of those parties filing protests to various aspects of the filing. New rates were proposed to be effective on March 1, 2017; however, the FERC issued an order suspending the tariff rates for the usual five-month period. Accordingly, the new rates are to become effective, subject to refund, on August 1, 2017.

4. Environmental Commitments and Contingencies

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or 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 March 31, 2017, we had approximately $9.8 million in environmental liabilities, related to 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 its MGP sites. Approximately $10.7 million has been recovered as of March 31, 2017, leaving approximately $3.3 million in regulatory assets for future recovery of environmental costs from FPU's customers.

Environmental liabilities for 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.

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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, on which FPU previously operated a MGP. FPU is implementing a remedial plan approved by the FDEP for the east parcel of the site, which includes installation of monitoring test wells, sparging of air into the groundwater system and extraction of vapors from the subsurface. 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.

Sanford, Florida

FPU is the current owner of property in Sanford, Florida, which was a former MGP site that was operated by several other entities before FPU acquired the property. FPU was never an owner or an operator of the MGP at 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 March 31, 2017, 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 has advised the other members of the Sanford Group that it is unwilling at this time to agree to pay any sum in excess of the $650,000 committed and paid by FPU in the Third Participation Agreement. The Sanford Group has not requested that FPU contribute to costs beyond the originally agreed upon $650,000 contribution.

As of March 31, 2017, FPU's remaining remediation expenses, including attorneys' fees and costs, are estimated to be $24,000. However, we are unable to determine to a reasonable degree of certainty whether the other members of the Sanford Group will accept FPU's asserted defense to liability for costs exceeding $13.0 million to implement the final remedy for this site, as provided for in the Third Participation Agreement, or 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 March 31, 2017.

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, in October 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 in January 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. Groundwater monitoring results from testing conducted in October 2016 indicated that natural attenuation default criteria were met at all wells.

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

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corrective measures for lake sediments are not warranted and will not be required by FDEP. We therefore, have not recorded a liability for sediment remediation.

Seaford, Delaware

In December 2013, the 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 required further investigation. In September 2015, DNREC approved our application to enter this site into the voluntary cleanup program. A remedial investigation was conducted in December 2015, which resulted in DNREC requesting additional investigative work be performed prior to approval of potential remedial actions. In December 2016, additional on-site wells were installed, developed and sampled pursuant to a September 2016 request from DNREC. The results of the sampling event and proposed future activities are anticipated to be available 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.

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.

5. 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. In 2017, our Delaware and Maryland divisions entered into asset management agreements with PESCO to manage a portion of their natural gas transportation and storage capacity. The agreements were effective as of April 1, 2017, and each has a three-year term, expiring on March 31, 2020. Previously, the Delaware PSC had approved PESCO to serve as an asset manager.

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 3.1 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 3.1 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 either ratio is not met by FPU, it has 30 days to cure the default or, provide an irrevocable letter of credit if the default is not cured. FPU’s electric fuel supply agreement with Gulf Power requires FPU to meet the following ratios based on the average of the prior six quarters: (a) funds from operations interest coverage ratio (minimum of 2 times) and (b) total debt to total capital (maximum of 65 percent). If FPU fails to meet the requirements, it has to provide the supplier a written explanation of actions taken, or proposed to be taken, to become compliant. Failure to comply with the ratios specified in the Gulf Power agreement could also result in FPU having to provide an irrevocable letter of credit. As of March 31, 2017, FPU was in compliance with all of the requirements of its fuel supply contracts.

Eight Flags provides electricity and steam generation services through its CHP plant located on Amelia Island, Florida. In June 2016, Eight Flags began selling power generated from the CHP plant to FPU pursuant to a 20-year power purchase agreement for distribution to its retail electric customers. In July 2016, Eight Flags also started selling steam to Rayonier

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pursuant to a separate 20-year contract. The CHP plant is powered by natural gas transported by FPU through its distribution system and Peninsula Pipeline through its intrastate pipeline.

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 $85.0 million.

We have issued corporate guarantees to certain of our subsidiaries' vendors, the largest of which are for Xeron and PESCO. These corporate guarantees provide for the payment of propane and natural gas purchases in the event that Xeron or PESCO defaults. Neither subsidiary has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded when incurred. The aggregate amount guaranteed at March 31, 2017 was approximately $56.6 million, with the guarantees expiring on various dates through April 2018.

We have notified all of Xeron's counterparties holding parental guarantees that Xeron began winding down operations during the first quarter of 2017. Upon the winding down of Xeron's business, the corporate guarantees were canceled in accordance with their respective terms and conditions.

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 13, Long-Term Debt, for further details).

We issued letters of credit totaling approximately $7.0 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 December 2017. There have been no draws on these letters of credit as of March 31, 2017. 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.

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.

6. Segment Information

We use the management approach to identify operating segments. We organize our business around differences in regulatory environment and/or products or services, and the operating results of each segment are regularly reviewed by the chief operating decision maker (our Chief Executive Officer) in order to make decisions about resources and to assess performance. The segments are evaluated based on their pre-tax operating income. Our operations comprise 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 as well as natural gas marketing, gathering, processing, transportation and supply. These operations are unregulated as to their rates and services. Effective June 2016, this segment includes electricity and steam generation through Eight Flags' CHP plant. As of March 31, 2017, this segment also included the operations of Xeron, our former propane and crude oil trading subsidiary that began winding down operations during the quarter. Lastly, this segment also includes other unregulated energy services, such as energy-related merchandise sales and heating, ventilation and air conditioning, plumbing and electrical services.

Other operations are presented as “Other businesses and eliminations,” which consist 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 March 31,	
	2017	2016
(in thousands)		
Operating Revenues, Unaffiliated Customers		
Regulated Energy segment	$96,446	$88,894
Unregulated Energy segment	88,714	57,402
Total operating revenues, unaffiliated customers	$185,160	$146,296
Intersegment Revenues (1)		
Regulated Energy segment	$1,208	$322
Unregulated Energy segment	4,011	113
Other businesses	228	226
Total intersegment revenues	$5,447	$661
Operating Income		
Regulated Energy segment	$23,017	$24,319
Unregulated Energy segment	11,530	11,936
Other businesses and eliminations	129	125
Total operating income	34,676	36,380
Other expense, net	(277)	(34)
Interest	2,739	2,650
Income before Income Taxes	31,660	33,696
Income taxes	12,516	13,329
Net Income	$19,144	$20,367

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

(in thousands)	March 31, 2017	December 31, 2016
Identifiable Assets		
Regulated Energy segment	$1,000,265	$986,752
Unregulated Energy segment	213,078	226,368
Other businesses and eliminations	24,968	16,099
Total identifiable assets	$1,238,311	$1,229,219

Our operations are entirely domestic.

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7. Stockholder's Equity

Preferred Stock

We had 2,000,000 authorized and unissued shares of $0.01 par value preferred stock as of March 31, 2017 and December 31, 2016. Shares of preferred stock may be issued from time to time, by authorization of our Board of Directors and without the necessity of further action or authorization by stockholders, in one or more series and with such voting powers, designations, preferences and relative, participating, optional or other special rights and qualifications as the Board of Directors may, in its discretion, determine.

Common Stock Public Offering

In September 2016, we completed a public offering of 960,488 shares of our common stock at a public offering price per share of $62.26. The net proceeds from the sale of common stock, after deducting underwriting commissions and expenses, were approximately $57.4 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.

Stockholders' Rights

Our Certificate of Incorporation contains a Rights Plan, pursuant to which our Board of Directors previously declared a dividend of one preferred stock purchase right (each, a "Right," and, collectively, the "Rights") for each outstanding share of our common stock held of record on September 3, 1999, as adjusted for our stock split in September of 2014, and for additional shares of common stock issued since that time. Unless exercised, the Rights trade with our common stock and are evidenced by the common stock certificate. In general, each Right will become exercisable and trade independently from our common stock upon a person or entity acquiring a beneficial ownership of 15 percent or more of our outstanding common stock.

Each Right, if it becomes exercisable, initially entitles the holder to purchase one fiftieth of a share of our Series A Participating Cumulative Preferred Stock, par value $0.01 per share, at a price of $70 per unit, subject to anti-dilution adjustments. Upon a person or entity becoming an Acquiring Person, each Right (other than the Rights held by the Acquiring Person) will become exercisable to purchase a number of shares of our common stock having a market value equal to two times the exercise price of the Right. The Rights expire on August 20, 2019, unless they are redeemed earlier by us at the redemption price of $0.01 per Right. We may redeem the Rights at any time before they become exercisable and thereafter only in limited circumstances.

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 three months ended March 31, 2017 and 2016. All amounts are presented net of tax.

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
As of December 31, 2016	$ (5,360)	$ 482	$(4,878)
Other comprehensive (loss)/income before reclassifications	(9)	1,278	1,269
Amounts reclassified from accumulated other comprehensive loss	91	(940)	(849)
Net current-period other comprehensive income	82	338	420
As of March 31, 2017	$ (5,278)	$ 820	$(4,458)

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(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
As of December 31, 2015	$ (5,580)	$ (260)	$(5,840)
Other comprehensive loss before reclassifications	—	(283)	(283)
Amounts reclassified from accumulated other comprehensive loss	89	283	372
Net prior-period other comprehensive income	89	—	89
As of March 31, 2016	$ (5,491)	$ (260)	$(5,751)

The following table presents amounts reclassified out of accumulated other comprehensive loss for the three months ended March 31, 2017 and 2016. Deferred gains or losses for our commodity contracts cash flow hedges are recognized in earnings upon settlement.

	Three Months Ended March 31,	
(in thousands)	2017	2016
Amortization of defined benefit pension and postretirement plan items:		
Prior service credit [1]	$19	$20
Net loss[1]	(170)	(168)
Total before income taxes	(151)	(148)
Income tax benefit	60	59
Net of tax	$(91)	$(89)
Gains and losses on commodity contracts cash flow hedges		
Propane swap agreements [2]	$388	$(322)
Natural gas futures [2]	1,150	(149)
Total before income taxes	1,538	(471)
Income tax (expense) benefit	(598)	188
Net of tax	940	(283)
Total reclassifications for the period	$849	$(372)

[1] These amounts are included in the computation of net periodic costs (benefits). See Note 8, Employee Benefit Plans, for additional details.
[2] These amounts are included in the effects of gains and losses from derivative instruments. See Note 11, 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.

8. Employee Benefit Plans

Net periodic benefit costs for our pension and post-retirement benefits plans for the three months ended March 31, 2017 and 2016 are set forth in the following tables:

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	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP		Chesapeake Postretirement Plan		FPU Medical Plan	
For the Three Months Ended March 31,	2017	2016	2017	2016	2017	2016	2017	2016	2017	2016
(in thousands)										
Interest cost	$103	$105	$623	$630	$ 22	$ 23	$ 10	$ 11	$13	$ 14
Expected return on plan assets	(127)	(131)	(699)	(701)	—	—	—	—	—	—
Amortization of prior service credit	—	—	—	—	—	—	(19)	(20)	—	—
Amortization of net loss	107	104	131	128	22	22	16	18	—	—
Net periodic cost (benefit)	83	78	55	57	44	45	7	9	13	14
Amortization of pre-merger regulatory asset	—	—	191	191	—	—	—	—	2	2
Total periodic cost	$83	$78	$246	$248	$ 44	$ 45	$ 7	$ 9	$15	$ 16

We expect to record pension and postretirement benefit costs of approximately $1.6 million for 2017. 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 $1.9 million and approximately $2.1 million at March 31, 2017 and December 31, 2016, respectively.

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 March 31, 2017 and 2016:

For the Three Months Ended March 31, 2017	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service credit	$ —	$ —	$ —	$ (19)	$ —	$(19)
Net loss	107	131	22	16	—	276
Total recognized in net periodic benefit cost	107	131	22	(3)	—	257
Recognized from accumulated other comprehensive loss (1)	107	25	22	(3)	—	151
Recognized from regulatory asset	—	106	—	—	—	106
Total	$ 107	$ 131	$ 22	$ (3)	$ —	$257

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For the Three Months Ended March 31, 2016	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service credit	$ —	$ —	$ —	$ (20)	$ —	$ (20)
Net loss	104	128	22	18	—	272
Total recognized in net periodic benefit cost	104	128	22	(2)	—	252
Recognized from accumulated other comprehensive loss [1]	104	24	22	(2)	—	148
Recognized from regulatory asset	—	104	—	—	—	104
Total	$ 104	$ 128	$ 22	$ (2)	$ —	$ 252

[1] See Note 7, Stockholder's Equity.

During the three months ended March 31, 2017, we contributed approximately $48,000 to the Chesapeake Pension Plan and approximately $374,000 to the FPU Pension Plan. We expect to contribute a total of approximately $746,000 and approximately $3.0 million to the Chesapeake Pension Plan and FPU Pension Plan, respectively, during 2017, which represents 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 months ended March 31, 2017, were approximately $38,000. We expect to pay total cash benefits of approximately $151,000 under the Chesapeake Pension SERP in 2017. Cash benefits paid under the Chesapeake Postretirement Plan, primarily for medical claims for the three months ended March 31, 2017, were approximately $49,000. We estimate that approximately $83,000 will be paid for such benefits under the Chesapeake Postretirement Plan in 2017. Cash benefits paid under the FPU Medical Plan, primarily for medical claims for the three months ended March 31, 2017, were approximately $26,000. We estimate that approximately $129,000 will be paid for such benefits under the FPU Medical Plan in 2017.

9. Investments

The investment balances at March 31, 2017 and December 31, 2016, consisted of the following:

(in thousands)	March 31, 2017	December 31, 2016
Rabbi trust (associated with the Deferred Compensation Plan)	$5,190	$ 4,881
Investments in equity securities	22	21
Total	$5,212	4,902

We classify these investments as trading securities and report them at their fair value. For the three months ended March 31, 2017 and 2016, we recorded a net unrealized gain of approximately $252,000 and a net unrealized loss of $18,000, respectively, in other income (expense), net 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.

10. 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 months ended March 31, 2017 and 2016:

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	Three Months Ended March 31,	
	2017	2016
(in thousands)		
Awards to non-employee directors	$135	$165
Awards to key employees	504	484
Total compensation expense	639	649
Less: tax benefit	(257)	(261)
Share-based compensation amounts included in net income	$382	$388

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. At March 31, 2017, there was approximately $45,000 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 three months ended March 31, 2017:

	Number of Shares	Weighted Average Fair Value
Outstanding— December 31, 2016	115,091	$ 51.85
Granted	38,517	$ 62.08
Vested	(32,926)	$ 38.88
Expired	(1,878)	$ 39.97
Outstanding— March 31, 2017	118,804	$ 56.03

In January 2017, our Board of Directors granted awards of 38,517 shares of common stock to key employees under the SICP. The shares granted in January 2017 are multi-year awards that will vest at the end of the three-year service period ending December 31, 2019. 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 the election of certain of our executives, in March 2017, we withheld shares with a value at least equivalent to each such executive’s minimum statutory obligation for applicable income and other employment taxes, remitted the cash to the appropriate taxing authorities, and paid the balance of such shares to each such executive. We withheld 10,269 shares, based on the value of the shares on their award date, determined by the average of the high and low prices of our common stock. Total combined payments for the employees’ tax obligations to the taxing authorities were approximately $692,000.

At March 31, 2017, the aggregate intrinsic value of the SICP awards granted to key employees was approximately $8.2 million. At March 31, 2017, there was approximately $3.7 million of unrecognized compensation cost related to these awards, which is expected to be recognized from 2017 through 2020.

Stock Options

We did not have any stock options outstanding at March 31, 2017 or 2016, nor were any stock options issued during these periods.

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11. Derivative Instruments

We use derivative and non-derivative contracts to engage in trading activities and manage risks related to obtaining adequate supplies and the price fluctuations of natural gas, electricity and propane. Our natural gas, electric and propane distribution operations have entered into agreements with suppliers to purchase natural gas, electricity and propane for resale to 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 March 31, 2017, our natural gas and electric distribution operations did not have any outstanding derivative contracts.

Hedging Activities in 2017

PESCO enters into natural gas futures contracts associated with the purchase and sale of natural gas to other specific customers. These contracts have a two-year term, and we have accounted for them as cash flow hedges. There is no ineffective portion of these hedges. At March 31, 2017, PESCO had a total of 2.7 million Dts hedged under natural gas futures contracts, with an asset fair value of approximately $1.2 million. The change in fair value of the natural gas futures contracts is recorded as unrealized gain (loss) in other comprehensive income (loss).

The impact of financial instruments that have not been designated as hedges on our condensed consolidated financial statements for the quarter ended March 31, 2017 was $189,000, which was recorded as an increase in gas costs and is associated with 813,000 Dts of natural gas. This presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments.

Hedging Activities in 2016

In 2016, Sharp entered into swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with 4.8 million gallons expected to be purchased through September 2017, of which 1.4 million gallons were outstanding at March 31, 2017. Under the swap agreements, Sharp will receive the difference between the index prices (Mont Belvieu prices in October 2016 through September 2017) and the swap prices of $0.5225 and $0.5650 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. We accounted for these swap agreements as cash flow hedges, and there is no ineffective portion of these hedges. At March 31, 2017, the remaining swap agreements had a fair value of approximately $137,000. The change in the fair value of the swap agreements is recorded as unrealized gain (loss) in other comprehensive income (loss).

In December 2016, Sharp paid a total of $33,000 to purchase a put option to protect against a decline in propane prices and related potential inventory losses associated with 630,000 gallons for its propane price cap program in the 2016-2017 heating season. The put option expired without being exercised because the propane prices did not fall below the strike price of $0.5650 per gallon in December 2016, January 2017, or February 2017. We accounted for the put option as a fair value hedge, and there was no ineffective portion of this hedge.

In January 2016, PESCO entered into a SCO supplier agreement with Columbia Gas to provide natural gas supply for one of its local distribution customer pools. PESCO also assumed the obligation to store natural gas inventory to satisfy its obligations under the SCO supplier agreement, which terminated 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. 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 discontinued hedge accounting as the hedges were no longer highly effective. As of March 31, 2017, these contracts have all expired and are no longer reported on the balance sheet.

Commodity Contracts for Trading Activities

During the first quarter of 2017, Xeron began winding down operations. Prior to March 31, 2017, Xeron engaged in trading activities using forward and futures contracts for propane and crude oil. These contracts were considered derivatives and were 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 were recognized as unrealized gains or losses in the statements of income for the period of change. As of March 31, 2017, Xeron had no outstanding contracts that were accounted for as derivatives.

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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 March 31, 2017 and December 31, 2016, are as follows:

	Asset Derivatives		
		Fair Value As Of	
(in thousands)	Balance Sheet Location	March 31, 2017	December 31, 2016
Derivatives not designated as hedging instruments			
Propane swap agreements	Mark-to-market energy assets	$4	$ 8
Put options	Mark-to-market energy assets	—	9
Derivatives designated as cash flow hedges			
Natural gas futures contracts	Mark-to-market energy assets	1,198	113
Propane swap agreements	Mark-to-market energy assets	137	693
Total asset derivatives		$1,339	$ 823

	Liability Derivatives		
		Fair Value As Of	
(in thousands)	Balance Sheet Location	March 31, 2017	December 31, 2016
Derivatives not designated as hedging instruments			
Natural gas futures contracts	Mark-to-market energy liabilities	$189	$ 773
Total liability derivatives		$189	$ 773

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

		Amount of Gain (Loss) on Derivatives: For the Three Months Ended March 31,	
(in thousands)	Location of Gain (Loss) on Derivatives	2017	2016
Derivatives not designated as hedging instruments			
Realized (loss) gain on forward contracts and options [1]	Revenue	$ 112	$ 187
Unrealized gain on forward contracts [1]	Revenue	—	1
Natural gas futures contracts	Cost of sales	124	—
Propane swap agreements	Cost of sales	(4)	—
Derivatives designated as fair value hedges			
Put /Call option [2]	Cost of sales	(9)	73
Derivatives designated as cash flow hedges			
Propane swap agreements	Cost of sales	388	(364)
Propane swap agreements	Other Comprehensive Loss	(557)	—
Natural gas futures contracts	Cost of sales	1,150	149
Natural gas futures contracts		1,087	(462)

	Other Comprehensive Income (Loss)		
Total		$ 2,291	$ (416)

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

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

12. Fair Value of Financial Instruments

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

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

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

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

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 March 31, 2017 and December 31, 2016:

		Fair Value Measurements Using:		
As of March 31, 2017	Fair Value	Quoted- Prices- in Active Markets (Level 1)	Significant- Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(in thousands)				
Assets:				
Investments—equity securities	$ 22	$22	$ —	$ —
Investments—guaranteed income fund	565	—	—	565
Investments—mutual funds and other	4,625	4,625	—	—
Total investments	5,212	4,647	—	565
Mark-to-market energy assets, incl. natural gas futures contracts and swap agreements	1,339	—	1,339	—
Total assets	$ 6,551	$4,647	$ 1,339	$ 565
Liabilities:				
Mark-to-market energy liabilities including natural gas futures contracts	$ 189	$—	$ 189	$ —

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		Fair Value Measurements Using:		
As of December 31, 2016	Fair Value	Quoted- Prices- in Active Markets (Level 1)	Significant- Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(in thousands)				
Assets:				
Investments—equity securities	$ 21	$21	$ —	$ —
Investments—guaranteed income fund	561	—	—	561
Investments—mutual funds and other	4,320	4,320	—	—
Total investments	4,902	4,341	—	561
Mark-to-market energy assets, incl. natural gas futures contracts and swap agreements	823	—	823	—
Total assets	$ 5,725	$4,341	$ 823	$ 561
Liabilities:				
Mark-to-market energy liabilities including natural gas futures contracts	$ 773	$—	$ 773	$ —

The following valuation techniques were used to measure the fair value of assets and liabilities in the tables above on a recurring basis as of March 31, 2017 and December 31, 2016:

Level 1 Fair Value Measurements:

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

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

Level 2 Fair Value Measurements:

Mark-to-market energy assets and liabilities — The fair values of forward contracts are measured using market transactions in either the listed or OTC markets. 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 three months ended March 31, 2017 and 2016:

	Three Months Ended March 31,	
	2017	2016
(in thousands)		
Beginning Balance	$561	$279
Purchases and adjustments	2	2
Transfers	—	242
Investment income	2	2
Ending Balance	$565	$525

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

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At March 31, 2017, 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 March 31, 2017, long-term debt, including current maturities but excluding a capital lease obligation, had a carrying value of approximately $145.8 million. This compares to a fair value of approximately $160.5 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, 2016, long-term debt, including the current maturities but excluding a capital lease obligation, had a carrying value of approximately $145.9 million, compared to the estimated fair value of approximately $161.5 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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13. Long-Term Debt

Our outstanding long-term debt is shown below:

(in thousands)	March 31, 2017	December 31, 2016
FPU secured first mortgage bonds [1] :		
9.08% bond, due June 1, 2022	$7,979	$ 7,978
Uncollateralized senior notes:		
6.64% note, due October 31, 2017	2,727	2,727
5.50% note, due October 12, 2020	8,000	8,000
5.93% note, due October 31, 2023	21,000	21,000
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	97	168
Capital lease obligation	3,125	3,471
Less: debt issuance costs	(280)	(291)
Total long-term debt	148,648	149,053
Less: current maturities	(12,111)	(12,099)
Total long-term debt, net of current maturities	$136,537	$ 136,954

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

Shelf Agreement

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

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.

In May 2016, Prudential confirmed and accepted our request that Prudential purchase $70.0 million of 3.25 percent Shelf Notes under the Shelf Agreement. We issued the Shelf Notes on April 21, 2017. The proceeds received from the Shelf Notes were used to reduce short-term borrowings under the Revolver. The balance under the Revolver had accumulated over time as capital expenditures were temporarily financed.

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

Management's Discussion and Analysis of Financial Condition and Results of Operations is designed to provide a reader of the financial statements with a narrative report on our financial condition, results of operations and liquidity. This discussion and analysis should be read in conjunction with the attached unaudited condensed consolidated financial statements and notes thereto and our Annual Report on Form 10-K for the year ended December 31, 2016, 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 wo or conditional verbs such as "may," "will," "should," "would" or "could." These statements represent our intentions, plans, expectations, assumptions and beliefs about future financial performance, business strategy, projected plans and objectives of the Company. These statements are subject to many risks, uncertainties and other important factors that could cause actual results to differ materially from those expressed in the forward-looking statements. Such factors include, but are not limited to:

- state and federal legislative and regulatory initiatives (including deregulation) that affect cost and investment recovery, have an impact on rate structures and affect the speed at, and the degree to, which competition enters the electric and natural gas industries;
- the outcomes of regulatory, tax, environmental and legal matters, including whether pending matters are resolved within current estimates and whether the costs associated with such matters are adequately covered by insurance or recoverable in rates;
- the timing of certificate authorizations associated with new capital projects;
- 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;
- possible increased federal, state and local regulation of the safety of our operations;
- general economic conditions, including any potential effects arising from terrorist attacks and any hostilities or other external factors over which we have no control;
- industrial, commercial and residential growth or contraction in our markets or service territories;
- the weather and other natural phenomena, including the economic, operational and other effects of hurricanes, ice storms and other damaging weather events;
- the timing and extent of changes in commodity prices and interest rates;
- the ability to establish and maintain key supply sources;
- the effect of spot, forward and future market prices on our various energy businesses;
- the effect of competition on our businesses;
- the 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 ability to construct facilities at or below estimated costs and within projected time frames;
- the creditworthiness of counterparties with which we are engaged in transactions;
- 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 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 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 ability to continue to hire, train and retain appropriately qualified personnel;
- the effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- the timing and success of technological improvements;
- risks related to cyber-attacks that could disrupt our business operations or result in failure of information technology systems; and
- the impact of significant changes to current tax regulations and rates.

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Introduction

We are a diversified energy company engaged, directly or through our operating divisions and subsidiaries, in regulated and unregulated energy 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. We are focused on identifying and developing opportunities across the energy value chain, with emphasis on midstream and downstream investments that are accretive to earnings per share and consistent with our long-term growth strategy.

The key elements of this strategy include:

- executing a capital investment program in pursuit of growth opportunities that generate returns equal to or greater than our cost of capital;
- expanding our energy distribution and transmission businesses organically as well as into new geographic areas;
- providing new services in our current service territories;
- expanding our footprint in potential growth markets through strategic acquisitions;
- entering new unregulated energy markets and business lines that will complement our existing operating units and growth strategy while capitalizing on opportunities across the energy value chain; and
- differentiating the Company as a full-service energy supplier/partner/provider through a customer-centric model.

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", which is determined by deducting the cost of sales from operating revenue. Cost of sales includes the purchased cost of natural gas, electricity and propane and the cost of labor spent on direct revenue-producing activities, and excludes depreciation, amortization and accretion. Gross margin should not be considered an alternative to operating income or net income, which are determined in accordance with GAAP. We believe that gross margin, although a non-GAAP measure, is useful and meaningful to investors as a basis for making investment decisions. It provides investors with information that demonstrates the profitability achieved by us under our allowed rates for regulated operations and under our competitive pricing structure for non-regulated segments. Our management uses gross margin in measuring its business units’ performance and has historically analyzed and reported gross margin information publicly. Other companies may calculate gross margin in a different manner.

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

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Results of Operations for the Three Months ended March 31, 2017

Overview and Highlights

Our net income for the quarter ended March 31, 2017 was $19.1 million, or $1.17 per share. This represents a decrease of $1.3 million, or $0.16 per share, compared to net income of $20.4 million, or $1.33 per share, reported for the same quarter in 2016. Operating income decreased $1.7 million for the three months ended March 31, 2017. Gross margin increased by $6.8 million, although other operating expenses increased by $8.5 million.

	Three Months Ended March 31,		Increase
	2017	2016	(decrease)
(in thousands except per share)			
Business Segment:			
Regulated Energy segment	$23,017	$24,319	$(1,302)
Unregulated Energy segment	11,530	11,936	(406)
Other businesses and eliminations	129	125	4
Operating Income	$34,676	$36,380	$(1,704)
Other expense, net	(277)	(34)	(243)
Interest charges	2,739	2,650	89
Pre-tax Income	31,660	33,696	(2,036)
Income taxes	12,516	13,329	(813)
Net Income	$19,144	$20,367	$(1,223)
Earnings Per Share of Common Stock			
Basic	$1.17	$1.33	$(0.16)
Diluted	$1.17	$1.33	$(0.16)

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Key variances, between the first quarter of 2016 and the first quarter of 2017, included:

(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
First Quarter of 2016 Reported Results	$33,696	$20,367	$ 1.33
Adjusting for unusual items:			
Weather impact	(1,074)	(650)	(0.04)
Impact of winding down of Xeron operations	(514)	(311)	(0.02)
	(1,588)	(961)	(0.06)
Increased (Decreased) Gross Margins:			
Eight Flags' CHP*	2,295	1,388	0.09
Natural gas marketing	2,154	1,302	0.08
Natural gas growth (excluding service expansions)	831	503	0.03
Service expansions*	759	459	0.03
GRIP*	680	411	0.03
Lower retail propane margins	(581)	(351)	(0.02)
Implementation of Delaware Division new rates*	546	330	0.02
Aspire Energy rates and management fees	526	318	0.02
Customer consumption - other	133	81	0.01
	7,343	4,441	0.29
Increased Other Operating Expenses:			
Higher staffing and associated costs	(3,220)	(1,947)	(0.13)
Higher outside services costs and facility maintenance	(1,719)	(1,040)	(0.07)
Higher depreciation, asset removal and property tax costs due to new capital investments	(1,359)	(822)	(0.05)
Eight Flags' operating expenses	(1,268)	(767)	(0.05)
	(7,566)	(4,576)	(0.30)
Interest charges	(88)	(53)	—
Change in other expense	(243)	(147)	(0.01)
Net other changes	106	73	(0.01)
	(225)	(127)	(0.02)
EPS impact of increase in outstanding shares due to September 2016 offering	—	—	(0.07)
First Quarter of 2017 Reported Results	$31,660	$19,144	$ 1.17

*See the Major Projects and Initiatives table.

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Summary of Key Factors

Major Projects and Initiatives

The following table summarizes gross margin for our major projects and initiatives recently completed 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			Year Ended			
	March 31,			December 31,	Estimate for		
	2017	2016	Variance	2016	2017	2018	2019
Existing Major Projects and Initiatives							
Capital Investment Projects	$9,319	$5,585	$ 3,734	$ 29,819	$34,969	$32,125	$33,035
Regulatory Proceedings	546		546	1,487	2,250	2,250	2,250
Total Existing Major Projects and Initiatives	9,865	5,585	4,280	31,306	37,219	34,375	35,285
Future Major Projects and Initiatives							
Capital Investment Projects [1]	—	—	—	—	386	15,551	20,899
Regulatory Proceedings [2]	—	—	—	—	1,875	4,500	4,500
Total Future Major Projects and Initiatives	—	—	—	—	2,261	20,051	25,399
Total	$9,865	$5,585	$ 4,280	$ 31,306	$39,480	$54,426	$60,684

(1) This represents gross margin for the 2017 Expansion Project and the Northwest Florida Expansion Project.

(2) In January 2017, Eastern Shore filed a rate case with the FERC. The outcome of the rate case is not known at this time. See Note 3, Rates and Other Regulatory Activities, for additional information. This table assumes recovery in the rate case of the costs of the System Reliability Project.

Major Projects and Initiatives Recently Completed

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

	Gross Margin for the Period [1]						
	Three Months Ended			Year Ended			
	March 31,			December 31,	Estimate for		
	2017	2016	Variance	2016	2017	2018	2019
Capital Investment Projects:							
Service Expansions:							
Short-term contracts (Delaware)	$2,663	$2,543	$ 120	$ 11,454	$5,265	$1,407	$1,407
Long-term contracts (Delaware)	1,094	455	639	1,815	7,611	7,605	7,583
Total Service Expansions	3,757	2,998	759	13,269	12,876	9,012	8,990
Florida GRIP	3,267	2,587	680	11,552	13,727	14,407	15,085
Eight Flags' CHP Plant	2,295	—	2,295	4,998	8,366	8,706	8,960
Total Capital Investment Projects	9,319	5,585	3,734	29,819	34,969	32,125	33,035
Regulatory Proceedings:							
Delaware Division Rate Case	546	—	546	1,487	2,250	2,250	2,250
Total Existing Regulatory Proceedings	546	—	546	1,487	2,250	2,250	2,250
Total Existing Major Projects and Initiatives	$9,865	$5,585	$ 4,280	$ 31,306	$37,219	$34,375	$35,285

(1) Does not include gross margin of $4.6 million and $13.9 million for the quarter ended March 31, 2016 and year ended December 31, 2016, respectively, which consists primarily of gross margin attributable to Aspire Energy for those periods. The acquisition of Aspire Energy was previously disclosed as a major project; however, the gross margin attributable to Aspire Energy is now being excluded from this table.

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Service Expansions

In August 2014, Eastern Shore entered into a precedent agreement with an electric power generator in Kent County, Delaware, to provide, upon the satisfaction of certain conditions, a 20-year natural gas transmission service for 45,000 Dts/d deliverable to the lateral serving the customer's facility. In July 2016, the FERC authorized Eastern Shore to construct and operate the proposed project, which consists of 5.4 miles of 16-inch pipeline looping and new compression capability in Delaware. Eastern Shore provided interim services to this customer pending construction of facilities. Construction of the project is complete, and long-term service commenced on March 1, 2017, pursuant to a 20-year OPT 90 ≤ service agreement we entered into with this customer. This service generated an additional gross margin of $106,000 during the three months ended March 31, 2017 compared to the same period in 2016. This service is expected to generate gross margin of $7.0 million for 2017 and between $5.8 million and $7.8 million annually through the remaining term of the agreement.

In October 2015, Eastern Shore submitted an application to the FERC to make certain meter tube and control valve replacements 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 44 percent of the increased capacity has been subscribed on a short-term firm service basis. This service generated an additional gross margin of $678,000 for the three months ended March 31, 2017 compared to the same period in 2016. The remaining capacity is available for firm or interruptible service.

GRIP

GRIP is a natural gas pipe replacement program approved by the Florida PSC, designed to expedite the replacement of qualifying distribution mains and services (any material other than coated steel or plastic) to enhance the 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 $105.7 million to replace 230 miles of qualifying distribution mains, including $2.8 million during the first three months of 2017. The increased investment in GRIP generated additional gross margin of $680,000 for the three months ended March 31, 2017 compared to the same period in 2016.

Eight Flags' CHP plant

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 MWH of base load power and includes a heat recovery steam generator capable of providing approximately 75,000 pounds per hour of residual steam. In June 2016, Eight Flags began selling power generated from the CHP plant to FPU, pursuant to a 20-year power purchase agreement for distribution to its retail electric customers. In July 2016, it also started selling steam to the industrial customer that owns the property on which Eight Flags' CHP plant is located, pursuant to a separate 20-year contract.

The CHP plant is powered by natural gas transported by FPU through its distribution system and by Peninsula Pipeline through its intrastate pipeline. For the three months ended March 31, 2017, Eight Flags and other affiliates of Chesapeake Utilities generated $2.3 million in additional gross margin as a result of these services that began in June 2016. This amount includes gross margin of $491,000 for the three months ended March 31, 2017, attributable to natural gas distribution and transportation services provided to the CHP plant by our affiliates.

Major Projects and Initiatives Underway

Northwest Florida Expansion Project: Peninsula Pipeline and Chesapeake Utilities' Florida natural gas division are constructing a pipeline in Escambia County, Florida that will interconnect with FGT's pipeline. The project consists of 33 miles of 12-inch transmission line from the FGT interconnect that will be operated by Peninsula Pipeline and 8 miles of 8-inch lateral distribution lines that will be operated by Chesapeake Utilities' Florida natural gas division. We have signed agreements to serve two industrial customers. The estimated annual gross margin associated with this project, once in service, is approximately $5.1 million.

System Reliability Project: In July 2016, the FERC authorized Eastern Shore to construct and operate its proposed System Reliability Project, which will consist of 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. A 2.5 mile looping segment was completed and placed into service in December 2016. The remaining looping and the new compressor are anticipated to be completed by the end of May 2017. This project was included in Eastern Shore's January 2017 base rate case filing with the FERC. The estimated annual gross margin associated with this project, assuming full recovery in the 2017 rate case, is approximately $4.5 million. We have assumed recovery of this project's costs beginning in August 2017, coinciding with the proposed effectiveness of new rates, subject to refund pending final resolution of the base rate case.

2017 Expansion Project: In May 2016, Eastern Shore submitted a request to the FERC to initiate the FERC's pre-filing process for its proposed 2017 Expansion Project. This project, which will expand Eastern Shore's firm service capacity by 26 percent, will

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provide 61,162 Dts/d of additional firm natural gas transportation service on Eastern Shore's pipeline system with an additional 52,500 Dts/d of firm transportation service at certain Eastern Shore receipt facilities pursuant to precedent agreements Eastern Shore entered into with four existing customers as well as affiliates of Chesapeake Utilities. Facilities required to provide this new service will consist of: (i) approximately 23 miles of pipeline looping in Pennsylvania, Maryland and Delaware; (ii) upgrades to existing metering facilities in Lancaster County, Pennsylvania; (iii) installation of an additional 3,550-horsepower compressor unit at Eastern Shore’s existing Daleville compressor station in Chester County, Pennsylvania; and (iv) approximately 17 miles of new mainline extension and two pressure control stations in Sussex County, Delaware. The project will generate approximately $15.8 million of gross margin in the first full year after the new transportation services go into effect. The estimated cost of this expansion project is $98.6 million.

In April 2017, Eastern Shore entered into an agreement with an industrial customer to provide 11,000 Dts/d of interim firm transportation service from May 1, 2017 to October 31, 2017 or until the 2017 Expansion project is completed and in-service. Eastern Shore is expected to generate approximately $386,000 of additional gross margin from this interim service in 2017.

Other major factors influencing gross margin

Weather and Consumption

Warmer weather during the three months ended March 31, 2017, compared to temperatures in the same period in 2016, reduced our earnings. Lower customer consumption, directly attributable to warmer than normal temperatures, reduced gross margin by $1.1 million. The first quarter of 2017 was recorded as the third warmest first quarter on the Delmarva Peninsula during the last fifty years. The following table summarizes the HDD and CDD information for the three months ended March 31, 2017 and 2016 resulting from weather fluctuations in those periods.

HDD and CDD Information

	Three Months Ended March 31,		
	2017	2016	Variance
Delmarva			
Actual HDD	1,958	2,094	(136)
10-Year Average HDD ("Delmarva Normal")	2,403	2,400	3
Variance from Delmarva Normal	(445)	(306)	
Florida			
Actual HDD	285	505	(220)
10-Year Average HDD ("Florida Normal")	583	534	49
Variance from Florida Normal	(298)	(29)	
Ohio			
Actual HDD	2,484	2,791	(307)
10-Year Average HDD ("Ohio Normal")	3,137	3,131	6
Variance from Ohio Normal	(653)	(340)	
Florida			
Actual CDD	145	127	18
10-Year Average CDD ("Florida CDD Normal")	82	77	5
Variance from Florida CDD Normal	63	50	

Propane prices

Lower retail propane margins per gallon for our Delmarva and Florida propane distribution operations decreased gross margin by $581,000 for the three months ended March 31, 2017, of which $495,000 is associated with the larger Delmarva Peninsula propane distribution operation. Margins per retail gallon continued to return to more normal levels, driven principally by higher propane prices and local market conditions. These market conditions, including 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. We continue to assume more normal levels of margins in our long-term financial plans and forecasts.

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PESCO

PESCO provides natural gas supply and supply management services to residential, commercial, industrial and wholesale customers. PESCO operates primarily in Florida, on the Delmarva Peninsula, and in Ohio. PESCO competes with regulated utilities and other unregulated third-party marketers to sell natural gas supplies directly to residential, commercial and industrial customers through competitively-priced contracts. PESCO does not currently own or operate any natural gas transmission or distribution assets but sells gas that is delivered to retail or wholesale customers through affiliated and non-affiliated local distribution company systems and transmission pipelines.

In 2017, our Delaware and Maryland natural gas distribution operations entered into asset management agreements with PESCO to manage a portion of their natural gas transportation and storage capacity. The asset management agreements are effective April 1, 2017, and each has a three-year term, expiring on March 31, 2020. As a result of these agreements, PESCO will manage capacity on regional pipelines as well as third-party storage contracts for our Delaware and Maryland natural divisions in an expansion of PESCO's asset management services.

Operating revenues for PESCO were $45.0 million for the three months ended in March 2017 compared to $20.0 million in the same period in 2016. This revenue growth was attributable primarily to growth in customers served and volumes sold in Florida, Ohio and on the Delmarva Peninsula.

PESCO generated additional gross margin of $2.2 million in the first quarter of 2017, compared to the same period in 2016, as a result of revenues associated with providing natural gas under a supplier agreement to service approximately 40,000 end users on behalf of another utility as well as increased customer contracts in Florida. Under the supplier agreement, PESCO delivered the highest volumes during the first quarter of 2017, while fixed storage and pipeline fees were paid over the entire twelve-month period from April 1, 2016 to March 31, 2017. This supplier agreement ended March 31, 2017 and was not renewed.

Operating income for PESCO was $2.5 million for the three months ended March 31, 2017, compared to $803,000 for the same period in 2016. PESCO incurred higher operating expenses of $479,000 in the first quarter of 2017 to support the growth of the business.

Xeron

After a thorough review of Xeron’s performance and careful evaluation of alternative strategies, our management determined that there was no viable strategy to restore Xeron to profitability in the near term and accordingly, decided to wind down Xeron's operations. We recorded $606,000 in pre-tax losses from Xeron in the first quarter of 2017, driven primarily by the costs associated with non-recurring employee severance costs and quarter-to-date Xeron operating losses. We may record additional losses in the future associated with the termination of the leased office space in Houston, Texas, if we incur lease termination costs or are unable to sublease the office space at a rental rate sufficient to offset our rental and expense obligation under the lease.

Other Natural Gas Growth - Distribution Operations

In addition to service expansions, the natural gas distribution operations on the Delmarva Peninsula generated $520,000 in additional gross margin for the three months ended March 31, 2017, compared to the same period in 2016, due to an increase in residential, commercial and industrial customers served. The average number of residential customers on the Delmarva Peninsula increased by four percent during the three months ended March 31, 2017 compared to the same period in 2016. The natural gas distribution operations in Florida generated $440,000 in additional gross margin for the three months ended March 31, 2017, compared to the same period in 2016, due primarily to an increase in commercial and industrial customers in Florida.

Regulatory Proceedings

Delaware Division rate case

In December 2016, the Delaware PSC approved a settlement agreement as recommended by the Hearing Examiner's report. The settlement agreement, among other things, provided for an increase in our Delaware division revenue requirement of $2.25 million and a rate of return on common equity of 9.75 percent. The new authorized rates went into effect on January 1, 2017. Any amounts collected through 2016 interim rates in excess of the respective portion of the $2.25 million were refunded to the ratepayers in March 2017.

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Eastern Shore Rate Case
In January 2017, Eastern Shore filed a base rate proceeding with the FERC, as required by the terms of its 2012 rate case settlement agreement. Eastern Shore's proposed rates are based on a cost of service of approximately $60 million, resulting in an overall requested revenue increase of approximately $18.9 million and a requested rate of return on common equity of 13.75 percent. The FERC issued a notice of the filing in January 2017, and the comment period ended in February 2017. Fourteen parties intervened in the proceeding, with six of those parties filing protests of some aspect of the rate filing. The FERC issued an order suspending the effectiveness of the proposed tariff rates for the usual five-month period. Accordingly, the new rates are to become effective, subject to refund, on August 1, 2017.

Investing for Future Growth
To support and continue our growth, we have expanded, and will continue to expand, our resources and capabilities. Eastern Shore has expanded, and has announced significant additional expansions to its transmission system, and is therefore increasing its staffing. We requested recovery of most of Eastern Shore's increased staffing costs in its 2017 rate case. Growth in non-regulated businesses, including Aspire Energy, PESCO and Eight Flags, requires additional staff as well as corporate resources to support the increased scope of their activities. Finally, to allow us to continue to identify and move growth initiatives forward and to assist in developing additional strategic initiatives for sustained future growth, resources have been added in our corporate shared services departments. In the first quarter of 2017, our staffing and associated costs increased by $3.2 million, or 18 percent, compared to the same period in 2016. We expect to make additional investments in human resources and systems, as needed, to further develop our capability to capitalize on future growth opportunities.

We also pursued several strategic transaction opportunities during the quarter, which ultimately did not materialize. In connection with such efforts, we recorded costs of approximately $600,000 for the quarter. We intend to continue to seek new opportunities in the future, and we will incur costs in pursuing them, whether opportunities come to fruition or not.

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Regulated Energy Segment

For the quarter ended March 31, 2017 compared to the quarter ended March 31, 2016

	Three Months Ended March 31,		Increase
	2017	2016	(decrease)
(in thousands)			
Revenue	$97,654	$89,216	$8,438
Cost of sales	40,244	34,905	5,339
Gross margin	57,410	54,311	3,099
Operations & maintenance	23,958	20,460	3,498
Depreciation & amortization	6,885	6,296	589
Other taxes	3,550	3,236	314
Other operating expenses	34,393	29,992	4,401
Operating income	$23,017	$24,319	$(1,302)

Operating income for the Regulated Energy segment for the quarter ended March 31, 2017 was $23.0 million, a decrease of $1.3 million compared to the same quarter in 2016. The decreased operating income was due to an increase in operating expenses of$4.4 million offset by a $3.1 million increase in gross margin. Of the total increase in operating expenses of $4.4 million, $2.3 million is associated with Eastern Shore's recent growth and planned future growth.

Gross Margin

Items contributing to the quarter-over-quarter increase of $3.1 million, or 5.7 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended March 31, 2016	$54,311
Factors contributing to the gross margin increase for the three months ended March 31, 2017:	
Natural Gas Growth (Excluding Service Expansions)	831
Service Expansions	759
Additional Revenue from GRIP in Florida	680
Delaware Division Base Rate Increase	546
Decreased Customer Consumption - Weather and Other	(527)
Service to Eight Flags	491
Other	319
Gross margin for the three months ended March 31, 2017	$57,410

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

Natural Gas Growth (excluding service expansions)

Increased gross margin of $831,000 from other growth in natural gas (excluding service expansions) was generated primarily from the following:

- $520,000 from a four percent increase in the average number of residential customers in the Delmarva natural gas distribution operations, as well as growth in the number of commercial and industrial customers, and
- $440,000 from Florida natural gas customer growth due primarily to new services to commercial and industrial customers.

Service Expansions

Increased gross margin of $759,000 from natural gas service expansions was generated primarily from the following:

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$678,000 from short-term firm service that commenced in March 2017, following certain measurement and related improvements to Eastern Shore's interconnect with TETLP that increased Eastern Shore's natural gas receipt capacity

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from TETLP by 53,000 Dts/d, for a total capacity of 160,000 Dts/d. The remaining capacity is available for firm or interruptible service.

Additional Revenue from GRIP in Florida
Increased investment in GRIP generated additional gross margin of $680,000 for the three months ended March 31, 2017, compared to the same period in 2016.
Implementation of Delaware Division Rates
Our Delaware Division generated additional gross margin of $546,000 from the implementation of new rates as a result of its rate case filing. See Note 3, Rates and Other Regulatory Activities, to the condensed consolidated financial statements for additional details.

Decreased Customer Consumption - Weather and Other
Gross margin decreased by $527,000 from lower customer consumption of electricity and natural gas due primarily to warmer temperatures in Florida and on the Delmarva Peninsula. Because Sandpiper Energy includes in its rates a weather normalization adjustment for residential heating and smaller commercial heating customers, it experienced less of an impact from the warmer weather during the quarter.
Service to Eight Flags
We generated additional gross margin of $491,000 in the first quarter of 2017, compared to the same period in 2016, from new natural gas transmission and distribution services provided by our affiliates to Eight Flags' CHP plant.
Other Operating Expenses
Other operating expenses increased by $4.4 million. The significant components of the increase in other operating expenses included:
- $2.1 million in higher staffing and associated costs for additional personnel to support growth;
- $1.2 million in higher outside services and facility maintenance costs to support growth; and
- $901,000 in higher depreciation, asset removal and property tax costs associated with recent capital investments to support growth and system integrity.

Unregulated Energy Segment

For the quarter ended March 31, 2017 compared to the quarter ended March 31, 2016

	Three Months Ended March 31,		Increase
	2017	2016	(decrease)
(in thousands)			
Revenue	$92,725	$57,516	$35,209
Cost of sales	65,906	34,415	31,491
Gross margin	26,819	23,101	3,718
Operations & maintenance	12,425	9,389	3,036
Depreciation & amortization	1,903	1,183	720
Other taxes	961	593	368
Other operating expenses	15,289	11,165	4,124
Operating Income	$11,530	$11,936	$(406)

Operating income for the Unregulated Energy segment for the three months ended March 31, 2017 was $11.5 million, a decrease of $406,000 compared to the same period in 2016. The decreased operating income was due to an increase in operating expenses of $4.1 million offset by a $3.7 million increase in gross margin.

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Gross Margin

Items contributing to the quarter-over-quarter increase of $3.7 million in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended March 31, 2016	$23,101
Factors contributing to the gross margin increase for the three months ended March 31, 2017:	
Natural Gas Marketing	2,154
Eight Flags' CHP Plant	1,805
Decreased retail propane margins	(581)
Aspire Energy's Rates and Management Fees	526
Decreased Customer Consumption - Weather and Other	(414)
Other	228
Gross margin for the three months ended March 31, 2017	$26,819

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

Natural Gas Marketing

PESCO generated additional gross margin of $2.2 million in the first quarter of 2017 compared to the same period in 2016. Favorable results in 2017 were the result of revenues associated with providing natural gas under an agreement to supply approximately 40,000 end users within one customer pool as well as commercial and industrial customers served in Florida. Under the supplier agreement, PESCO delivered the highest volumes of natural gas during the first quarter of 2017 while paying fixed storage and pipeline fees over the entire twelve-month contract period from April 1, 2016 to March 31, 2017.

Eight Flags

Eight Flags' CHP plant, which commenced operations in June 2016, generated $1.8 million in additional gross margin.

Decreased Retail Propane Margins

Lower retail propane margins for our Delmarva and Florida propane distribution operations decreased gross margin by $581,000, of which $495,000 is associated with the Delmarva Peninsula propane distribution operation, as retail margins per gallon continued to return to more normal levels. The decline in margin was driven principally by higher propane prices and local market conditions. We continue to assume more normal levels of margins in our long-term financial plans and forecasts.

Aspire Energy Rates and Management Fees

An increase in gross margin of $526,000 was due to pricing amendments to long-term sales agreements and higher rates to customers, which generated $1.1 million in gross margin, offset by the absence of a one-time management fee of $560,000 paid by CGC in the first quarter of 2016.

Decreased Customer Consumption - Weather and Other

Gross margin decreased by $414,000 as a result of:

- Lower sales of propane due to warmer weather in 2017 compared to 2016; and
- Decreased deliveries of natural gas for Aspire Energy due to warmer temperatures in Ohio.

Other Operating Expenses

Other operating expenses increased by $4.1 million. The significant components of the increase in other operating expenses included:

- $1.3 million incurred by Eight Flags' CHP plant, which commenced operations in June 2016;
- $1.1 million in higher staffing and associated costs for additional personnel to support growth;
- $581,000 in higher outside services costs associated primarily with growth and ongoing compliance activities;
- $458,000 in higher depreciation expense due to increased capital investments for Aspire Energy; and

- $438,000 in higher operating expenses associated with the winding down of operations by Xeron.

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INTEREST EXPENSE

For the quarter ended March 31, 2017 compared to the quarter ended March 31, 2016

Interest charges for the three months ended March 31, 2017 increased by approximately $89,000, compared to the same period in 2016, attributable to an increase of $280,000 in interest from higher short-term borrowings, partially offset by a decrease of $117,000 in interest from long-term debt.

INCOME TAXES

For the quarter ended March 31, 2017 compared to the quarter ended March 31, 2016

Income tax expense was $12.5 million for the three months ended March 31, 2017, compared to $13.3 million in the same period in 2016. The decrease in income tax expense was due primarily to a decrease in our operating results. Our effective income tax rate was 39.5 percent and 39.6 percent, for the three months ended March 31, 2017 and 2016, 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 our target capital structure.

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

Capital expenditures for investments in new or acquired plant and equipment are our largest capital requirements. Our capital expenditures were $32.9 million for the three months ended March 31, 2017.

We originally budgeted $260.3 million for capital expenditures during 2017, which has been subsequently revised to an estimated $241.2 million for capital expenditures in 2017. The following table shows the current 2017 capital expenditure budget by segment and by business line:

	2017
(dollars in thousands)	
Regulated Energy:	
Natural gas distribution	$78,452
Natural gas transmission	121,760
Electric distribution	13,002
Total Regulated Energy	213,214
Unregulated Energy:	
Propane distribution	12,075
Other unregulated energy	6,603
Total Unregulated Energy	18,678
Other:	
Corporate and other businesses	9,266
Total Other	9,266
Total 2017 Capital Expenditures	$241,158

The capital expenditure projection is subject to continuous review and modification. Actual capital requirements may vary from the above estimates due to a number of factors, including changing economic conditions, customer growth in existing areas, regulation, new growth or acquisition opportunities and availability of capital. Historically, actual capital expenditures have typically lagged behind the budgeted amounts.

The timing of capital expenditures can vary based on delays in regulatory approvals, securing environmental approvals and other permits. The regulatory application and approval process has lengthened in the past few years, 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 energy 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 March 31, 2017 and December 31, 2016:

(in thousands)	March 31, 2017		December 31, 2016	
Long-term debt, net of current maturities	$136,537	23 %	$136,954	23 %
Stockholders’ equity	460,829	77 %	446,086	77 %
Total capitalization, excluding short-term debt	$597,366	100%	$583,040	100%

(in thousands)	March 31, 2017		December 31, 2016	
Short-term debt	$199,333	25 %	$209,871	26 %
Long-term debt, including current maturities	148,648	18 %	149,053	19 %
Stockholders’ equity	460,829	57 %	446,086	55 %
Total capitalization, including short-term debt	$808,810	100%	$805,010	100%

Included in the long-term debt balances at March 31, 2017 and December 31, 2016, was a capital lease obligation associated with Sandpiper's capacity, supply and operating agreement ($1.7 million excluding current maturities and $3.1 million including current maturities, and $2.1 million excluding current maturities and $3.5 million, including current maturities, respectively). At the closing of the ESG acquisition in May 2013, Sandpiper entered into this agreement, which has a six-year term. The capacity portion of this agreement is accounted for as a capital lease.

Our target ratio of equity to total capitalization, including short-term borrowings, is between 50 and 60 percent. We have maintained a ratio of equity to total capitalization, including short-term borrowings, between 50 percent and 57 percent during the past three years. In September 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 $57.4 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.

As described below under “Short-term Borrowings,” we entered into the Credit Agreement and the Revolver with the Lenders in October 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.”

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

Shelf Agreement

In October 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.

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.

In May 2016, Prudential confirmed and accepted our request that Prudential purchase $70.0 million of 3.25 percent Shelf Notes under the Shelf Agreement. We issued the Shelf Notes on April 21, 2017 and used the proceeds to reduce short-term borrowings under the Revolver, which had increased as a result of funding capital expenditures on a temporary basis.

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Short-term Borrowings

Our outstanding short-term borrowings at March 31, 2017 and December 31, 2016 were $199.3 million and $209.9 million, respectively. The weighted average interest rates for our short-term borrowings were 1.75 percent and 1.36 percent, for the three months ended March 31, 2017 and 2016, 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 March 31, 2017, 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 $150.0 million Revolver has a five-year term and is subject to the terms and conditions set forth in the Credit Agreement. Borrowings under the Revolver will be used for general corporate purposes, including repayments of short-term borrowings, working capital requirements and capital expenditures. Borrowings under the Revolver will bear interest at: (i) the LIBOR Rate plus an applicable margin of 1.25 percent or less, with such margin based on total indebtedness as a percentage of total capitalization, both as defined by the Credit Agreement, or (ii) the base rate plus 0.25% or less. Interest is payable quarterly, and the Revolver is subject to a commitment fee on the unused portion of the facility. We 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.

None of the unsecured bank lines of credit requires compensating balances. We are currently authorized by our Board of Directors to incur up to $275.0 million of short-term borrowing.

Cash Flows

The following table provides a summary of our operating, investing and financing cash flows for the three months ended March 31, 2017 and 2016:

	Three Months Ended March 31,	
	2017	2016
(in thousands)		
Net cash provided by (used in):		
Operating activities	$59,954	$44,134
Investing activities	(42,193)	(37,831)
Financing activities	(16,239)	(5,843)
Net increase in cash and cash equivalents	1,522	460
Cash and cash equivalents—beginning of period	4,178	2,855
Cash and cash equivalents—end of period	$5,700	$3,315

Cash Flows Provided By Operating Activities

Changes in our cash flows from operating activities are attributable primarily to changes in net income, adjusted for non-cash items such changes in deferred income taxes, depreciation 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 three months ended March 31, 2017 and 2016, net cash provided by operating activities was $60.0 million and $44.1 million, respectively, resulting in an increase in cash flows of $15.9 million. Significant operating activities generating the cash flows change were as follows:

- Net income, adjusted for reconciling activities, increased cash flows by $4.9 million, due primarily to (i) an increase in deferred income taxes as a result of utilization of an investment tax credit related to our investments in Eight Flags' CHP plant as well as bonus depreciation in the first three months of 2017, which resulted in a higher book-to-tax timing difference, and (ii) higher non-cash adjustments for depreciation and amortization related to increased investing activities.

- Net cash flows from changes in propane and natural gas inventories increased by approximately $3.6 million, as a result of the higher use of propane and natural gas, which decreased the levels of our inventory.

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- Changes in net accounts receivable and accrued revenue and accounts payable and accrued liabilities increased cash flows by $2.8 million, due primarily to higher revenues and the timing of the receipt of customer payments as well as the timing of payments to vendors.
- Changes in net regulatory assets and liabilities increased cash flows by $2.2 million, due primarily to changes in fuel costs collected through the various fuel cost recovery mechanisms.

Cash Flows Used in Investing Activities

Net cash used in investing activities totaled $42.2 million and $37.8 million during the three months ended March 31, 2017 and 2016, respectively, resulting in a decrease in cash flows of $4.4 million. The decrease was due primarily to an increase in cash used for capital expenditures.

Cash Flows Used in Financing Activities

Net cash used in financing activities totaled $16.2 million and $5.8 million during the three months ended March 31, 2017 and 2016, respectively. The decrease is due primarily to repayment of $11.1 million under our line of credit arrangements, partially offset by a $2.1 million increase in cash overdrafts.

Off-Balance Sheet Arrangements

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily Xeron and PESCO. These corporate guarantees provide for the payment of propane and natural gas purchases in the event of the respective subsidiary's default. Neither of these subsidiaries has ever defaulted on their obligations to pay their suppliers. The liabilities for these purchases are recorded in our financial statements when incurred. The aggregate amount guaranteed at March 31, 2017 was $56.6 million, with the guarantees expiring on various dates through April 2018. We have notified all of Xeron's counterparties holding parental guarantees that Xeron began winding down operations during the first of quarter of 2017. Upon winding down of Xeron's business, the corporate guarantees were canceled in accordance with their respective terms and conditions.

We have issued letters of credit totaling $7.0 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 December 2017. There have been no draws on these letters of credit as of March 31, 2017. 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 Note 5, 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 2016 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 March 31, 2017:

	Payments Due by Period				
	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
(in thousands)					
Purchase obligations - Commodity [1]	$16,720	$ 2,197	$ —	$ —	$18,917

(1) 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; 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.

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 March 31, 2017, we were involved in regulatory matters in each of the jurisdictions in which we operate. Our significant regulatory matters are fully described in Note 3, Rates and Other Regulatory Activities, to the 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 condensed consolidated financial statements in this Quarterly Report on Form 10-Q.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

INTEREST RATE RISK

Long-term debt is subject to potential losses based on changes in interest rates. Our long-term debt at March 31, 2017, consists of fixed-rate Senior Notes and $8.0 million of fixed-rate secured debt. We evaluate whether to refinance existing debt or permanently refinance existing short-term borrowings based in part on the fluctuation in interest rates. Additional information about our long-term debt is disclosed in Note 13, Long-term Debt, in the condensed consolidated financial statements.

COMMODITY PRICE RISK

Regulated Energy Segment

We have entered into agreements with various wholesale suppliers to purchase natural gas and electricity for resale to our customers. Our regulated energy distribution businesses that sell natural gas or electricity to end-use customers have fuel cost recovery mechanisms authorized by the PSCs that allow us to periodically adjust fuel rates to reflect changes in the wholesale cost of natural gas and electricity and to ensure that we recover all of the costs prudently incurred in purchasing natural gas and electricity for our customers. Therefore, our regulated energy distribution operations have limited commodity price risk exposure.

Unregulated Energy Segment

Sharp and Flo-gas are exposed to commodity price risk as a result of the competitive nature of retail pricing offered to our customers. In order to mitigate this risk, we utilize propane storage activities and forward contracts for supply. We can store up to approximately 6.2 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, particularly if we utilize fixed price forward contracts for supply. To mitigate the risk of propane commodity price fluctuations on the inventory valuation, we have adopted a Risk Management Policy that allows our propane distribution operation to enter into fair value hedges, cash flows hedges or other economic hedges of our inventory.

Aspire Energy is exposed to commodity price risk, primarily during the winter season, to the extent we are not successful in balancing our natural gas purchases and sales and have to secure natural gas from alternative sources at higher spot prices. In order to mitigate this risk, we procure firm capacity that meets our estimated volume requirements and we continue to seek out new producers with which to contract in order to fulfill our natural gas purchase requirements.

PESCO is a party to natural gas futures contracts. These contracts provide PESCO with the right to purchase natural gas at a fixed price at future dates. Upon expiration, the contracts can be settled financially without taking delivery of natural gas, or PESCO can procure natural gas for its customers.

PESCO is subject to commodity price risk on its open positions to the extent that market prices for natural gas liquids and natural gas deviate from fixed contract settlement prices. Market risk associated with the trading of futures and forward contracts is monitored daily for compliance with our Risk Management Policy, which includes volumetric limits for open positions. To manage exposures to changing market prices, open positions are marked up or down to market prices and reviewed daily by our oversight officials. In addition, the Risk Management Committee reviews periodic reports on markets, 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.

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WHOLESALE CREDIT RISK

The Risk Management Committee reviews credit risks associated with counterparties to commodity derivative contracts prior to such contracts being approved.

Additional information about our derivative instruments is disclosed in Note 11, Derivative Instruments, in the condensed consolidated financial statements.

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 March 31, 2017. Based upon their evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of March 31, 2017.

Changes in Internal Control over Financial Reporting

During the quarter ended March 31, 2017, there was no change in our internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

As disclosed in Note 5, Other Commitments and Contingencies, of the 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, 2016, 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 [2]	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs [2]
January 1, 2017 through January 31, 2017 [1]	355	$ 65.90	—	—
February 1, 2017 through February 28, 2017	—	$ —	—	—
March 1, 2017 through March 31, 2017	—	$ —	—	—
Total	355	$ 65.90	—	—

(1) Chesapeake Utilities purchased shares of stock on the open market for the purpose of reinvesting the dividend on deferred stock units held in the Rabbi Trust accounts for certain Directors and Senior Executives under the Deferred Compensation Plan. The Deferred Compensation Plan is discussed in detail in Item 8 under the heading "Notes to the Consolidated Financial Statements—Note 16, Employee Benefit Plans" in our latest Annual Report on Form 10-K for the year ended December 31, 2016. During the quarter ended March 31, 2017, 355 shares were purchased through the reinvestment of dividends on deferred stock units.

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

Item 3. Defaults upon Senior Securities

None.

Item 5. Other Information

None.

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Item 6. Exhibits

10.1	Form of Performance Share Agreement, effective January 10, 2017 for the period 2017 to 2019, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Elaine B. Bittner, Jeffry M. Householder and James F. Moriarty is filed herewith.
31.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
32.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350.
32.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

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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: May 3, 2017