CHESAPEAKE UTILITIES CORP
Form 10-Q
November 06, 2014
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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: September 30, 2014

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	¨	Accelerated filer	x
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 — 14,583,221 shares outstanding as of October 31, 2014.

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GLOSSARY OF DEFINITIONS

ASC: Accounting Standards Codification
ASU: Accounting Standards Update
Austin Cox: Austin Cox Home Services, Inc.
BravePoint: BravePoint, Inc., which was our advanced information services subsidiary, headquartered in Norcross, Georgia, prior to the sale on October 1, 2014
CDD: Cooling degree-days, which is the measure of the variation in weather based on the extent to which the daily average temperature (from 10:00 am to 10:00 am) is above 65 degrees Fahrenheit
Chesapeake: Chesapeake Utilities Corporation, its divisions and its subsidiaries, as appropriate in the context of the disclosure
Chesapeake Pension Plan: A defined benefit pension plan sponsored by Chesapeake
Chesapeake Postretirement Plan: An unfunded postretirement health care and life insurance plan sponsored by Chesapeake
Chesapeake SERP: An unfunded supplemental executive retirement pension plan sponsored by Chesapeake
CHP: A combined heat and power plant being constructed by Eight Flags in Nassau County, Florida
Company: Chesapeake Utilities Corporation, its divisions and its subsidiaries, as appropriate in the context of the disclosure
CP: Certificate of Public Convenience and Necessity
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 and fees
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
DSCP: Directors Stock Compensation Plan
Dts/d: Dekatherms per day
Eastern Shore: Eastern Shore Natural Gas Company, a wholly-owned natural gas transmission subsidiary of Chesapeake
EGWIC: Eastern Gas & Water Investment Company, LLC, an affiliate of Eastern Shore Gas Company
Eight Flags: Eight Flags Energy, LLC, a subsidiary of Chesapeake
EPA: United States Environmental Protection Agency
ESG: Eastern Shore Gas Company and its affiliates
FASB: Financial Accounting Standards Board
FERC: Federal Energy Regulatory Commission, an independent agency of the Federal government that regulates the interstate transmission of electricity, natural gas, and oil
FDEP: Florida Department of Environmental Protection
FDOT: Florida Department of Transportation
FGT: Florida Gas Transmission Company
FPU: Florida Public Utilities Company, a wholly-owned subsidiary of Chesapeake
FPU Medical Plan: A separate unfunded postretirement medical plan for FPU sponsored by Chesapeake

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FPU Pension Plan: A separate defined benefit pension plan for FPU sponsored by Chesapeake
FRP: Fuel Retention Percentage
GAAP: Accounting principles generally accepted in the United States of America
Glades: Glades Gas Co., Inc.
GRIP: Gas Reliability Infrastructure Program, which is a surcharge to natural gas customers designed to recover capital and other program-related costs, inclusive of an appropriate return on investment, associated with accelerating the replacement of qualifying distribution mains and services in Florida
Gulf Power: Gulf Power Company
Gulfstream: Gulfstream Natural Gas System, LLC
HDD: Heating degree-days, 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
MDE: Maryland Department of Environment
MGP: Manufactured gas plant, which is a site where coal was previously used to manufacture gaseous fuel for industrial, commercial and residential use
NAM: Natural Attenuation Monitoring
Note Agreement: Note Purchase Agreement entered into by Chesapeake with Note Holders on September 5, 2013
Note Holders: PAR U Hartford Life & Annuity Comfort Trust, The Prudential Insurance Company of America, The Gibraltar Life Insurance Co., Ltd., The Penn Mutual Life Insurance Company, Thrivent Financial for Lutherans, United of Omaha Life Insurance Company, and Companion Life Insurance Company, which are collectively the lenders that entered into the Note Agreement with Chesapeake on September 5, 2013
Notes: Series A and B unsecured Senior Notes that have been entered into with the Note Holders
OPT ≤ 90 Service: Off Peak ≤ 90 Firm Transportation Service, a new tariff associated with Eastern Shore's firm transportation service that will allow Eastern Shore the right not to schedule 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., our wholly-owned Florida intrastate pipeline subsidiary
PESCO: Peninsula Energy Services Company, Inc., our wholly-owned natural gas marketing subsidiary
PIP: Performance Incentive Plan
PPA: Power Purchase Agreement
PSC: Public Service Commission, which is the state agency that regulates the rates and services provided by Chesapeake’s natural gas and electric distribution operations in Delaware, Maryland and Florida and Peninsula Pipeline in Florida
Sandpiper: Sandpiper Energy, Inc.
Sanford Group: FPU and other responsible parties involved with the Sanford environmental site
SEC: Securities and Exchange Commission
Series A Notes: Series A of the unsecured Senior Notes issued on December 16, 2013 pursuant to the Note Agreement
Series B Notes: Series B of the unsecured Senior Notes issued on May 15, 2014 pursuant to the Note Agreement
Sharp: Sharp Energy, Inc., our wholly-owned propane distribution subsidiary
SICP: 2013 Stock and Incentive Compensation Plan, which replaced DSCP and PIP effective May 2, 2013

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TETLP: Texas Eastern Transmission, LP
Xeron: Xeron, Inc., our propane wholesale marketing subsidiary, based in Houston, Texas

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PART I—FINANCIAL INFORMATION
Item 1. Financial Statements
Chesapeake Utilities Corporation and Subsidiaries
Condensed Consolidated Statements of Income (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
(in thousands, except shares and per share data)				
Operating Revenues				
Regulated energy	$59,356	$55,680	$223,168	$192,463
Unregulated energy	27,071	28,262	141,365	119,278
Other	5,192	2,603	13,921	9,678
Total Operating Revenues	91,619	86,545	378,454	321,419
Operating Expenses				
Regulated energy cost of sales	23,040	22,591	102,020	86,321
Unregulated energy and other cost of sales	22,935	21,795	112,702	90,656
Operations	25,365	21,300	76,604	65,878
Maintenance	2,562	2,146	7,168	5,688
Depreciation and amortization	6,774	6,274	20,146	18,071
Other taxes	3,151	3,719	9,942	10,383
Total Operating Expenses	83,827	77,825	328,582	276,997
Operating Income	7,792	8,720	49,872	44,422
Other income (loss), net of other expenses	(32)	101	380	413
Interest charges	2,495	2,026	6,954	6,114
Income Before Income Taxes	5,265	6,795	43,298	38,721
Income taxes	2,085	2,916	17,303	15,617
Net Income	$3,180	$3,879	$25,995	$23,104
Weighted Average Common Shares Outstanding:				
Basic	14,574,678	14,438,152	14,539,841	14,424,404
Diluted	14,616,665	14,553,501	14,588,130	14,538,467
Earnings Per Share of Common Stock:				
Basic	$0.22	$0.27	$1.79	$1.60
Diluted	$0.22	$0.27	$1.78	$1.59
Cash Dividends Declared Per Share of Common Stock	$0.270	$0.257	$0.797	$0.757

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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
(in thousands)				
Net Income	$3,180	$3,879	$25,995	$23,104
Other Comprehensive Income, net of tax:				
Employee Benefits, net of tax:				
Amortization of prior service cost, net of tax of ($6), ($6), ($18), and ($18) respectively	(9)	(9)	(26)	(27)
Net gain, net of tax of $27, $43, $80 and $124, respectively	39	64	118	186
Cash Flow Hedges, net of tax:				
Unrealized loss on commodity contract cash flow hedges, net of tax of ($18), $0, ($19) and $0, respectively.	(27)	—	(28)	—
Total Other Comprehensive Income	3	55	64	159
Comprehensive Income	$3,183	$3,934	$26,059	$23,263

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	September 30, 2014	December 31, 2013
(in thousands, except shares)		
Property, Plant and Equipment		
Regulated energy	$730,879	$691,522
Unregulated energy	80,500	76,267
Other	21,974	21,002
Total property, plant and equipment	833,353	788,791
Less: Accumulated depreciation and amortization	(192,515)	(174,148)
Plus: Construction work in progress	38,611	16,603
Net property, plant and equipment	679,449	631,246
Current Assets		
Cash and cash equivalents	2,285	3,356
Accounts receivable (less allowance for uncollectible accounts of $1,282 and $1,635, respectively)	43,270	75,293
Accrued revenue	7,629	13,910
Propane inventory, at average cost	7,303	10,456
Other inventory, at average cost	2,991	4,880
Storage gas prepayments	4,990	4,318
Prepaid expenses	7,887	6,910
Income taxes receivable	2,100	2,609
Mark-to-market energy assets	187	385
Regulatory assets	7,790	2,436
Deferred income taxes	1,700	1,696
Other current assets	201	160
Total current assets	88,333	126,409
Deferred Charges and Other Assets		
Investments, at fair value	3,481	3,098
Regulatory assets	66,241	66,584
Goodwill	4,625	4,354
Other intangible assets, net	2,675	2,975
Receivables and other deferred charges	2,746	2,856
Total deferred charges and other assets	79,768	79,867
Total Assets	$847,550	$837,522

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	September 30, 2014	December 31, 2013
(in thousands, except shares and per share data)		
Capitalization		
Stockholders' equity		
Common stock, par value $0.4867 per share (authorized 25,000,000 shares)	$7,095	$4,691
Additional paid-in capital	155,407	152,341
Retained earnings	136,188	124,274
Accumulated other comprehensive loss	(2,469)	(2,533)
Deferred compensation obligation	1,217	1,124
Treasury stock	(1,217)	(1,124)
Total stockholders' equity	296,221	278,773
Long-term debt, net of current maturities	165,044	117,592
Total capitalization	461,265	396,365
Current Liabilities		
Current portion of long-term debt	11,113	11,353
Short-term borrowing	71,169	105,666
Accounts payable	33,371	53,482
Accrued compensation	7,269	8,394
Accrued interest	3,347	1,235
Dividends payable	3,936	3,710
Mark-to-market energy liabilities	141	127
Regulatory liabilities	2,797	4,157
Customer deposits and refunds	24,970	26,140
Other accrued liabilities	10,950	7,678
Total current liabilities	169,063	221,942
Deferred Credits and Other Liabilities		
Deferred income taxes	142,507	142,597
Deferred investment tax credits	49	74
Regulatory liabilities	3,772	4,402
Accrued asset removal cost—Regulatory liability	39,851	39,510
Environmental liabilities	9,022	9,155
Other pension and benefit costs	18,246	21,000
Other liabilities	3,775	2,477
Total deferred credits and other liabilities	217,222	219,215
Other commitments and contingencies (Note 6)		
Total Capitalization and Liabilities	$847,550	$837,522

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)

	Nine Months Ended September 30,	
	2014	2013
(in thousands)		
Operating Activities		
Net income	$25,995	$23,104
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	20,146	18,071
Depreciation and accretion included in other costs	5,152	4,504
Deferred income taxes, net	(156)	9,947
Gain on sale of assets	(436)	(142)
Unrealized (gain) loss on commodity contracts	67	(277)
Unrealized (gain) loss on investments	(111)	217
Realized gain on sales of investments, net	—	(702)
Employee benefits	476	708
Share-based compensation	1,519	1,246
Other, net	2	(84)
Changes in assets and liabilities:		
Purchase of investments	(272)	(436)
Accounts receivable and accrued revenue	38,304	(567)
Propane inventory, storage gas and other inventory	4,137	(933)
Regulatory assets	(8,237)	(1,158)
Prepaid expenses and other current assets	(804)	(1,361)
Accounts payable and other accrued liabilities	(18,704)	8,174
Income taxes receivable	510	3,980
Accrued interest	2,112	1,144
Customer deposits and refunds	(1,169)	(2,559)
Accrued compensation	(1,242)	(1,060)
Regulatory liabilities	(1,286)	4,688
Other assets and liabilities, net	(1,643)	(77)
Net cash provided by operating activities	64,360	66,427
Investing Activities		
Property, plant and equipment expenditures	(68,981)	(68,579)
Proceeds from sales of assets	505	154
Proceeds from sale of investments	—	2,300
Acquisitions	—	(19,367)
Environmental expenditures	(134)	(276)
Net cash used in investing activities	(68,610)	(85,768)
Financing Activities		
Common stock dividends	(10,319)	(9,716)
Purchase of stock for Dividend Reinvestment Plan	(260)	(1,001)
Change in cash overdrafts due to outstanding checks	(503)	(2,692)
Net borrowing (repayment) under line of credit agreements	(33,994)	32,790
Proceeds from issuance of long-term debt	49,975	6,985
Repayment of long-term debt and capital lease obligation	(1,720)	(8,594)
Net cash provided by financing activities	3,179	17,772
Net Decrease in Cash and Cash Equivalents	(1,071)	(1,569)

Cash and Cash Equivalents—Beginning of Period	3,356	3,361
Cash and Cash Equivalents—End of Period	$2,285	$1,792

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							
(in thousands, except shares and per share data)	Number of Shares[1]	Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total
Balance at December 31, 2012	14,396,248	$4,671	$150,750	$106,239	$ (5,062)	$ 982	$(982)	$256,598
Net income	—	—	—	32,787	—	—	—	32,787
Other comprehensive income	—	—	—	—	2,529	—	—	2,529
Dividend declared ($1.013 per share)	—	—	(6)	(14,752)	—	—	—	(14,758)
Conversion of debentures	26,075	8	287	—	—	—	—	295
Share-based compensation and tax benefit [2] [3]	35,022	12	1,310	—	—	—	—	1,322
Treasury stock activities	—	—	—	—	—	142	(142)	—
Balance at December 31, 2013	14,457,345	4,691	152,341	124,274	(2,533)	1,124	(1,124)	278,773
Net income	—	—	—	25,995	—	—	—	25,995
Other comprehensive income	—	—	—	—	64	—	—	64
Dividend declared ($0.797 per share)	18,078	6	790	(11,716)	—	—	—	(10,920)
Retirement savings plan	14,751	5	597	—	—	—	—	602
Conversion of debentures	47,313	15	520	—	—	—	—	535
Share-based compensation and tax benefit [2] [3]	40,158	13	1,159	—	—	—	—	1,172
Stock split in the form of stock dividend	—	2,365	—	(2,365)	—	—	—	—
Treasury stock activities	—	—	—	—	—	93	(93)	—
Balance at September 30, 2014	14,577,645	$7,095	$155,407	$136,188	$ (2,469)	$ 1,217	$(1,217)	$296,221

(1) Includes 52,760 and 51,743 shares at September 30, 2014 and December 31, 2013, respectively, held in a Rabbi Trust related to our Non-Qualified Deferred Compensation Plan.

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

(3) The shares issued under the SICP are net of shares withheld for employee taxes. For the nine months ended September 30, 2014 and for the year ended December 31, 2013, we withheld 12,687 and 15,617 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,” “we,” “us” and “our” are intended to mean Chesapeake Utilitie 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, 2013. 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.

Reclassifications

We reclassified certain amounts in the condensed consolidated cash flows statement for the nine months ended September 30, 2013 to conform to the current year's presentation. These reclassifications are considered immaterial to the overall presentation of our condensed consolidated financial statements.

Stock Dividend

On July 2, 2014, our Board of Directors approved a three-for-two stock split of our outstanding common stock to be effected in the form of a stock dividend. Each stockholder as of the close of business on the record date of August 13, 2014 received one additional share of common stock for every two shares of common stock owned. The additional shares were distributed on September 8, 2014. All share and per share data in this Form 10-Q are presented on a post-split basis. As a result of the stock split, we reclassified approximately $2.4 million from retained earnings to common stock. The $2.4 million represents $0.4867 par value per share of the shares issued in the stock split.

Assets and Liabilities Held for Sale

As of September 30, 2014, the following amounts included in the accompanying condensed consolidated balance sheet were held for sale:

- Assets and liabilities of BravePoint sold in October 2014 (see Note 3, Acquisitions and Disposition, for further details), which included $1.8 million of net property, plant and equipment, $4.8 million of current assets, $16,000 of other deferred charges, $2.6 million of current liabilities and $313,000 of deferred income taxes; and
- An office building and land located in Winter Haven, Florida, with $497,000 of net property, plant and equipment, which are subject to an agreement for them to be sold to an unaffiliated purchaser.

The amounts for these assets and liabilities held for sale at September 30, 2014 were not material, and therefore, they are not presented separately in the accompanying condensed consolidated balance sheet.

FASB Statements and Other Authoritative Pronouncements

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. ASU 2014-09 is effective for reporting periods (interim and annual) beginning after December 15, 2016. We are currently assessing the impact this standard will have on our financial position and results of operations.

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Recently Adopted Accounting Standards

Presentation of Financial Statements (ASC 205) and Property Plant and Equipment (ASC 360) - In April 2014, the FASB issued ASU 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. The new standard limits discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have or will have a major effect on an entity's operations and financial results, and requires additional disclosures related to discontinued operations. Upon adoption of the new standard, fewer disposals are expected to be presented as discontinued operations. We early adopted the provisions of this standard in the third quarter of 2014 and applied them to the sale of BravePoint (see Note 3, Acquisitions and Disposition for additional details on the sale). As a result, BravePoint is not presented as a discontinued operation in the accompanying condensed consolidated statements of income.

Income Taxes (ASC 740) - In July 2013, the FASB issued ASU 2013-11, Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists, which requires the netting of certain unrecognized tax benefits against a deferred tax asset for a loss or other similar tax carryforward that would apply upon settlement of an uncertain tax position. ASU 2013-11 became effective for us on January 1, 2014. The adoption of ASU 2013-11 had no material impact on our financial position and results of operations.

2. Calculation of Earnings Per Share

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
(in thousands, except shares and per share data)				
Calculation of Basic Earnings Per Share:				
Net Income	$3,180	$3,879	$25,995	$23,104
Weighted average shares outstanding	14,574,678	14,438,152	14,539,841	14,424,404
Basic Earnings Per Share	$0.22	$0.27	$1.79	$1.60
Calculation of Diluted Earnings Per Share:				
Reconciliation of Numerator:				
Net Income	$3,180	$3,879	$25,995	$23,104
Effect of 8.25% Convertible debentures (1)	—	11	—	33
Adjusted numerator—Diluted	$3,180	$3,890	$25,995	$23,137
Reconciliation of Denominator:				
Weighted shares outstanding—Basic	14,574,678	14,438,152	14,539,841	14,424,404
Effect of dilutive securities:				
Share-based Compensation	41,987	39,185	48,289	35,832
8.25% Convertible debentures (1)	—	76,164	—	78,231
Adjusted denominator—Diluted	14,616,665	14,553,501	14,588,130	14,538,467
Diluted Earnings Per Share	$0.22	$0.27	$1.78	$1.59

(1) As of March 1, 2014, we no longer have any outstanding convertible debentures. See Note 14, Long-term debt for additional information.

As discussed in Note 1, Summary of Accounting Policies, previously reported share and per share amounts have been restated in the accompanying condensed consolidated financial statements and related notes to reflect the stock split effected in the form of a stock dividend.

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3. Acquisitions and Disposition

Eastern Shore Gas Company

On May 31, 2013, the Maryland PSC approved the acquisition of ESG. Upon receiving this approval, we completed the purchase of certain operating assets of ESG, which was not related to, or affiliated with, our interstate natural gas transmission subsidiary, Eastern Shore. We paid approximately $16.5 million at the closing of the transaction, which was subject to certain adjustments specified in the asset purchase agreement. During the third quarter of 2013, the purchase price was reduced by $543,000 due to adjustments to property, plant and equipment, propane inventory, accounts receivable and other accrued liabilities. The purchase price included approximately $726,000 of sales tax related to the transaction. We financed the acquisition using unsecured short-term debt.

Approximately 11,000 residential and commercial underground propane distribution system customers and 500 bulk propane delivery customers acquired in the transaction are being served by our new subsidiary, Sandpiper, and our propane distribution subsidiary, Sharp, respectively. Sandpiper's operations, which cover all of Worcester County, Maryland, are subject to rate and service regulation by the Maryland PSC. We are evaluating the potential conversion of some of the underground propane distribution systems to natural gas distribution and have begun to convert some of the acquired customers. Although most of these customers are currently being served with propane, we classify Sandpiper's operations as natural gas distribution in the Regulated Energy segment.

In connection with this acquisition, we recorded $12.6 million in property, plant and equipment, $384,000 in propane inventory, $2.5 million in accounts receivable and accrued revenue and $227,000 in other current liabilities, which included the effect of purchase price adjustments in the third quarter of 2013 and the second quarter of 2014. All but insignificant amounts of assets and liabilities are recorded in the Regulated Energy segment. No goodwill or intangible asset was recorded from this acquisition, and the allocation of the purchase price and valuation of assets are final.

The revenue from this acquisition included in our condensed consolidated statement of income for the three and nine months ended September 30, 2014 was $4.4 million and $18.8 million, respectively. The net income from this acquisition included in our condensed consolidated statement of income for the three and nine months ended September 30, 2014 was $266,000 and $2.1 million, respectively.

The revenue from this acquisition included in our condensed consolidated statement of income for the three and nine months ended September 30, 2013 was $3.6 million and $4.6 million, respectively. The net income/loss from this acquisition included in our condensed consolidated statement of income for the three and nine months ended September 30, 2013 was $203,000 of net income and $204,000 of net loss, respectively.

Other Acquisitions

On December 2, 2013, we acquired certain operating assets of the City of Fort Meade, Florida, for approximately $792,000. The purchased assets are used to provide natural gas distribution service in the City of Fort Meade, Florida. In connection with this acquisition, we recorded $670,000 in property, plant and equipment; $14,000 in inventory; $150,000 in goodwill; and $42,000 in other current liabilities. Valuation of certain property, plant and equipment is preliminary and may be adjusted in the future based upon the final valuation, but no later than one year from the date of acquisition. All of the goodwill is expected to be deductible for income tax purposes. The revenue and net income from this acquisition that were included in our condensed consolidated statement of income for the three and nine months ended September 30, 2014 were not material.

On February 5, 2013, we purchased the propane operating assets of Glades for approximately $2.9 million. The purchased assets are used to provide propane distribution service to approximately 3,000 residential and commercial customers in Okeechobee, Glades and Hendry Counties, Florida. In connection with this acquisition, we recorded $1.6 million in property, plant and equipment; $231,000 in propane and other inventory; $300,000 in an intangible asset related to Glades’ customer list, to be amortized over 12 years beginning in February 2013; and $724,000 in goodwill. All of the goodwill is expected to be deductible for income tax purposes. These amounts reflect an adjustment to the allocation of the purchase price during the first quarter of 2014 based on our final valuation, which decreased the value of propane inventory by $271,000 and increased goodwill by the same amount. The revenue and net income from this acquisition that were included in our condensed consolidated statement of income for the three and nine months ended September 30, 2014 were not material.

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Disposition of BravePoint

Subsequent to the end of third quarter of 2014, we completed the sale of BravePoint for approximately $12.0 million in cash. As of September 30, 2014, our investment in BravePoint was approximately $3.6 million. After deducting various expenses and transaction costs associated with the sale, we expect to record a pre-tax gain of approximately $6.5 million to $7.0 million (approximately $4.0 million after-tax) from this sale in the fourth quarter of 2014. Our condensed consolidated statements of income for the three and nine months ended September 30, 2014 included $5.5 million and $15.1 million of revenue, respectively, and $268,000 of net income and $232,000 of net loss, respectively, from BravePoint.

4. Rates and Other Regulatory Activities

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

There were no significant rates and other regulatory activities in Delaware during the first nine months of 2014.

Maryland

Sandpiper depreciation study: On March 24, 2014, Sandpiper filed a depreciation study with the Maryland PSC regarding the assets purchased in the ESG acquisition. This depreciation study was filed in accordance with the order dated May 29, 2013, which allowed Sandpiper to recommend the proper depreciation rates and accumulated depreciation associated with the acquired assets. After a series of testimonies and discussions, Sandpiper, the Maryland Office of People's Counsel and the technical staff of the Maryland PSC reached a settlement agreement, which, among other things, establishes new depreciation rates and accumulated depreciation for the acquired assets. Under the terms of the settlement agreement, Sandpiper would adopt new depreciation rates, which are lower than the rates currently in place, and decreases accumulated depreciation included in its rate base by approximately $3.0 million for future rate making purposes. Sandpiper also agrees to file a new depreciation study within five years. The settlement agreement does not change Sandpiper's rates charged to its customers. On September 29, 2014, the Public Utility Law Judge approved the settlement and issued a proposed order, which became a final order of the Maryland PSC on October 30, 2014. The decrease in accumulated depreciation of the acquired assets is for regulatory rate-making purposes and does not change the value of those assets reflected on our condensed consolidated balance sheets, which, pursuant to U.S. GAAP, were originally recorded based on the fair value of those assets on the date of the ESG acquisition.

Florida

Electric rate case: On April 28, 2014, FPU filed a base rate case for its electric distribution operation. FPU requested interim rate relief of approximately $2.4 million and final rate relief of approximately $5.9 million. The interim rate relief requested was based on the twelve-month period ended September 30, 2013. At the July 10, 2014 Agenda Conference, the Florida PSC approved interim rate relief of approximately $2.2 million. The interim rates were effective for meter readings on or after August 10, 2014. On August 29, 2014, FPU and the Florida Office of Public Counsel reached a settlement agreement, which provides, among other things, an increase in annual base rates of approximately $3.8 million and a rate of common equity return of 10.25 percent. On September 15, 2014, the Florida PSC approved the settlement agreement. New final rates will be effective for all meter reads on or after November 1, 2014.

PPA with Eight Flags: On September 26, 2014, FPU filed a PPA with the Florida PSC pursuant to which FPU proposes to purchase up to 20 megawatts of electricity from its affiliate, Eight Flags, to service its customers in the Northeast division. Eight Flags is pursuing the development and construction of a CHP plant in Nassau County, Florida. FPU expects the PPA to provide significant savings in fuel costs over its 20-year term, which FPU will pass on to its customers. FPU requested in its filing, approval of the Florida PSC before the end of 2014 in order to avoid any delay in construction of the CHP plant.

Other matters: We also had developments in the following regulatory matters in Florida:

On November 15, 2013, Chesapeake's Florida natural gas distribution division petitioned the Florida PSC for an extension to its surcharge to recover an additional $381,000 in estimated remaining environmental cleanup costs that have not yet been recovered. The Florida PSC approved the extension of the surcharge and the additional

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amount for recovery at the Agenda Conference on January 7, 2014. This extension is effective for two years, beginning January 1, 2014.

On January 13, 2014, FPU's natural gas distribution divisions and Chesapeake's Florida natural gas distribution division filed a consolidated natural gas depreciation study with the Florida PSC. We also filed for approval to establish a regulatory asset and related amortization to address the costs associated with the development of this study. Depending on the results of this proceeding, we may be required to change the depreciation expense for our Florida natural gas distribution operations. The PSC agenda date for the depreciation study is scheduled for November 25, 2014.

On September 30, 2014, FPU filed for approval with the Florida PSC two contracts with its Peninsula Pipeline affiliate for additional natural gas transportation services in Nassau and Palm Beach Counties, Florida. The PSC agenda date for these cases is scheduled for December 18, 2014.

Eastern Shore

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

OPT ≤ 90 Service: On August 7, 2014, Eastern Shore submitted for filing and acceptance tariff records to establish a new OPT ≤ 90 Service. The OPT ≤ 90 Service is designed to allow a customer to contract to receive unrestricted firm service subject to Eastern Shore’s right to not schedule service for up to 90 days during the peak months of November through April of each year. In addition, during these peak months, the OPT ≤ 90 Service would have a scheduling priority below that of Firm Transportation Service but above the priority given to all secondary firm and interruptible services. On September 5, 2014, the FERC issued an order accepting Eastern Shore’s tariff changes to be made effective September 7, 2014. On October 1, 2014, the FERC accepted and approved Eastern Shore’s compliance filing, and no further action is required.

TETLP Expansion Project: On January 31, 2014, Eastern Shore submitted to the FERC a request for prior notice authorization regarding a project that included certain improvements at Eastern Shore’s existing interconnection with TETLP near Honey Brook, Pennsylvania. This project allows Eastern Shore to increase its capacity to receive natural gas from TETLP by 57,000 Dts/d to a total capacity of 107,000 Dts/d; however, this project does not result in an increase in Eastern Shore’s overall system capacity. On April 8, 2014, the FERC approved Eastern Shore’s prior notice application, and Eastern Shore made this additional receipt point capacity available to an existing industrial customer.

White Oak Lateral Project Filing: On June 13, 2013, Eastern Shore submitted to the FERC an application for a CP, seeking authorization to construct the White Oak lateral project located in Kent County, Delaware. The FERC issued a CP for this project and a notice to allow construction to proceed. Eastern Shore completed construction activities for this project. On September 30, 2014, the FERC authorized Eastern Shore to place the project in service, and the service to an industrial customer commenced on October 1, 2014. The project consisted of installing approximately 5.5 miles of 16-inch diameter pipeline, metering facilities and miscellaneous appurtenances, extending from Eastern Shore's mainline system near its North Dover City Gate Station to the Garrison Oak Technical Park, all located in Dover, Delaware. This project was designed to provide 55,200 Dts/d of delivery lateral firm transportation service to an industrial customer facility that was under construction. The total cost of the project was approximately $11.5 million.

Other matters: On May 30, 2014, Eastern Shore submitted to the FERC a combined filing of its FRP and Cash-Out Refund for a twelve-month period from April 2013 to March 2014. In this filing, Eastern Shore proposed an FRP rate of 0.62 percent. During the period, Eastern Shore experienced an under-recovery of $494,000 in its Deferred Gas Required for Operations costs and an over-recovery of $160,000 in its Deferred Cash-Out costs. Eastern Shore proposed to incorporate the Cash-Out Refund into its FRP to mitigate the effect of the increase in the FRP to its customers.

5. Environmental Commitments and Contingencies

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

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

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Maryland. We were notified in December of 2013 by the DNREC that it would be conducting a facility evaluation of an eighth former MGP site located in Seaford, Delaware.

As of September 30, 2014, we had approximately $10.2 million in environmental liabilities, representing our estimate of the future costs associated with all of FPU's MGP sites in Florida, which include the Key West, Pensacola, Sanford and West Palm Beach sites. FPU has approval to recover, from insurance and from customers through rates, up to $14.0 million of its environmental costs related to all of its MGP sites, approximately $9.5 million of which has been recovered as of September 30, 2014, leaving approximately $4.5 million in regulatory assets for future recovery of environmental costs from FPU's customers.

In addition to the FPU MGP sites, we had $434,000 in environmental liabilities at September 30, 2014, related to Chesapeake's MGP sites in Maryland and Florida, representing our estimate of future costs associated with these sites. As of September 30, 2014, we had approximately $408,000 in regulatory and other assets for future recovery through Chesapeake's rates. Environmental liabilities for all of our MGP sites are recorded on an undiscounted basis based on the estimate of future costs provided by independent consultants.

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

The following discussion provides details on MGP sites:

West Palm Beach, Florida

Remedial options are being evaluated to respond to environmental impacts to soil and groundwater at, and in the immediate vicinity of, a parcel of property owned by FPU in West Palm Beach, Florida, where FPU previously operated a MGP. FPU is currently implementing a remedial plan approved by the FDEP for the east parcel of the West Palm Beach site, which includes installation of monitoring test wells, sparging of air into the groundwater system and extraction of vapors from the subsurface. It is anticipated 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 September 30, 2014, FPU has paid $650,000 to the Sanford Group escrow account for its entire share of the funding requirements.

The total cost of the final remedy is now 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 by FPU in the Third Participation Agreement.

As of September 30, 2014, 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 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 under the Third Participation Agreement. No such claims have been made as of September 30, 2014.

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Key West, Florida

FPU formerly owned and operated a MGP in Key West, Florida. Field investigations performed in the 1990s identified limited environmental impacts at the site, which is currently owned by an unrelated third party. In 2010, after 17 years of regulatory inactivity, FDEP observed that some soil and groundwater standards were exceeded and requested implementation of additional soil and groundwater fieldwork. The scope of work is limited to the installation of two additional monitoring wells and periodic monitoring of the new and existing wells. The two new monitoring wells were installed in November 2011, and groundwater monitoring began in December 2011. The first semi-annual report from the monitoring program was issued in May 2012. The data from the June 2012 and September 2012 monitoring events were submitted to the FDEP on October 4, 2012. FDEP responded on October 9, 2012 that, based on the data, NAM appears to be an appropriate remedy for the site.

In October 2012, FDEP issued a Remedial Action Plan approval order which specified that a limited semi-annual monitoring program be conducted. The most recent groundwater-monitoring event was conducted on September 15, 2014. Natural Attenuation Default Criteria were met at all locations sampled. The next semi-annual sampling event is scheduled for March of 2015.

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

Pensacola, Florida

FPU formerly owned and operated a MGP in Pensacola, Florida, which was subsequently owned by Gulf Power. Portions of the site are now owned by the City of Pensacola and the FDOT. In October 2009, FDEP informed Gulf Power that it would approve a conditional No Further Action determination for the site with the requirement for institutional and engineering controls. On September 11, 2014, FDEP issued a draft memorandum of understanding between FDOT and FDEP to implement site closure with approved institutional and engineering controls for the site. It is anticipated that FPU’s share of remaining legal and cleanup costs will not exceed $5,000.

Winter Haven, Florida

The Winter Haven site is located on the eastern shoreline of Lake Shipp, in Winter Haven, Florida. Pursuant to a consent order entered into with FDEP, we are obligated to assess and remediate environmental impacts at this former MGP site. Groundwater monitoring results have shown a continuing reduction in contaminant concentrations from the sparging system, which has been in operation since 2002. On September 12, 2014, FDEP issued a letter approving shut-down 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. We have 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. Although specific remedial actions have not yet been identified, we estimate that future remediation costs for the subsurface soils and groundwater at the site should not exceed $443,000, which includes an estimate of $100,000 to implement additional actions, such as institutional controls, at the site. We continue to believe that the entire amount will be recoverable from customers through rates.

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

Salisbury, Maryland

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

Other

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

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In a letter dated December 5, 2013, the DNREC notified us that it will be conducting a facility evaluation of a former MGP site in Seaford, Delaware. The facility evaluation has not been conducted, and the outcome of this evaluation cannot be determined at this time; therefore, we have not recorded an environmental liability for this location.

6. Other Commitments and Contingencies

Natural Gas, Electric and Propane Supply

Our natural gas, electric and propane distribution operations have entered into contractual commitments to purchase natural gas, electricity and propane from various suppliers. The contracts have various expiration dates. For our Delaware and Maryland natural gas distribution divisions, we have a contract, which expires on March 31, 2015, with an unaffiliated energy marketing and risk management company to manage a portion of the divisions' natural gas transportation and storage capacity.

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

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

Chesapeake’s 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 natural gas marketers and other third parties, including PESCO. Under the terms of these capacity release agreements, Chesapeake is contingently liable to FGT and Gulfstream, should any party that acquired the capacity through release fail to pay for the service.

In May 2014, PESCO renewed contracts to purchase natural gas from various suppliers. These contracts expire in May 2015.

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 result in FPU having to provide an irrevocable letter of credit. As of September 30, 2014, FPU was in compliance with all of the requirements of its fuel supply contracts.

Corporate Guarantees

The Board of Directors has authorized us to issue corporate guarantees securing obligations of our subsidiaries and to obtain letters of credit securing our obligations, including the obligations of our subsidiaries. The maximum authorized liability under such guarantees and letters of credit is $45.0 million.

We have issued corporate guarantees to certain vendors of our subsidiaries, the largest portion of which is for Xeron and PESCO. These corporate guarantees provide for the payment of propane and natural gas purchases, respectively, in the event that Xeron or PESCO defaults. Neither subsidiary has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded when incurred. The aggregate amount guaranteed at September 30, 2014 was $31.6 million, with the guarantees expiring on various dates through September 2015.

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

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In addition to the corporate guarantees, we have issued a letter of credit for $1.0 million, which expires on September 12, 2015, related to the electric transmission services for FPU's northwest electric division. We have also issued a letter of credit to our current primary insurance company for $1.1 million, which expires on December 2, 2014, as security to satisfy the deductibles under our various insurance policies. As a result of a change in our primary insurance company in 2010, we renewed and decreased the letter of credit for $304,000 to our former primary insurance company, which will expire on June 1, 2015. There have been no draws on these letters of credit as of September 30, 2014. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future.

We provided a letter of credit for $2.3 million to TETLP related to the precedent agreement and firm transportation service agreement between our Delaware and Maryland divisions.

On July 25, 2014, we provided a letter to the Florida PSC guaranteeing potential refunds from interim rates to be charged by our Florida electric operation (see Note 4, Rates and Other Regulatory Activities, for further details on the Florida electric rate case). This guarantee expired in October 2014 upon approval of the permanent rate increase by the Florida PSC and determination that no refunds from interim rates were required.

Tax-related Contingencies

We are subject to various audits and reviews by the federal, state, local and other governmental authorities regarding income taxes and taxes other than income. As of September 30, 2014, we maintained a liability of $300,000 related to unrecognized income tax benefits and $848,000 related to contingencies for taxes other than income. As of December 31, 2013, we maintained a liability of $300,000 related to unrecognized income tax benefits and $1.0 million related to contingencies for taxes other than income.

Other

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

7. Segment Information

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

- Regulated Energy. The Regulated Energy segment includes natural gas distribution, natural gas transmission and electric distribution operations. All operations in this segment are regulated, as to their rates and services, by the PSC having jurisdiction in each operating territory or by the FERC in the case of Eastern Shore.
- Unregulated Energy. The Unregulated Energy segment includes propane distribution and wholesale marketing operations, and natural gas marketing operations, which are unregulated as to their rates and services. Also included in this segment are other unregulated energy services, such as energy-related merchandise sales and heating, ventilation and air conditioning, plumbing and electrical services.
- Other. At September 30, 2014, our "Other" segment consisted primarily of BravePoint, our advanced information services subsidiary. Also included in this segment are our unregulated subsidiaries that own real estate leased to Chesapeake and certain corporate costs not allocated to other operations. On October 1, 2014, we sold BravePoint (see Note 3, Acquisitions and Disposition, for further details).

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The following table presents financial information about our reportable segments:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
(in thousands)				
Operating Revenues, Unaffiliated Customers				
Regulated Energy	$59,086	$55,387	$222,308	$191,666
Unregulated Energy	27,041	26,103	141,215	115,367
Other	5,492	5,055	14,931	14,386
Total operating revenues, unaffiliated customers	$91,619	$86,545	$378,454	$321,419
Intersegment Revenues [1]				
Regulated Energy	$270	$293	$860	$797
Unregulated Energy	30	2,159	150	3,911
Other	258	274	760	743
Total intersegment revenues	$558	$2,726	$1,770	$5,451
Operating Income				
Regulated Energy	$9,202	$10,243	$41,004	$36,169
Unregulated Energy	(1,972)	(1,803)	8,843	8,013
Other and eliminations	562	280	25	240
Total operating income	7,792	8,720	49,872	44,422
Other income (loss), net of other expenses	(32)	101	380	413
Interest	2,495	2,026	6,954	6,114
Income before Income Taxes	5,265	6,795	43,298	38,721
Income taxes	2,085	2,916	17,303	15,617
Net Income	$3,180	$3,879	$25,995	$23,104

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

(in thousands)	September 30, 2014	December 31, 2013
Identifiable Assets		
Regulated energy	$744,142	$708,950
Unregulated energy	75,973	100,585
Other	27,435	27,987
Total identifiable assets	$847,550	$837,522

Our operations are almost entirely domestic. BravePoint had infrequent transactions in foreign countries, which were denominated and paid primarily in U.S. dollars. These transactions were immaterial to the consolidated revenues.

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8. Accumulated Other Comprehensive Income (Loss)

Defined benefit pension and postretirement plan items and unrealized gains (losses) of our propane swap agreements, 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 income (loss), net of related tax effects, for each component of other comprehensive income for the nine months ended September 30, 2014 and 2013.

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
As of December 31, 2013	$(2,533)	$—	$(2,533)
Other comprehensive loss before reclassifications	—	(28)	(28)
Amounts reclassified from accumulated other comprehensive loss	92	—	92
Net current-period other comprehensive income (loss)	92	(28)	64
As of September 30, 2014	$(2,441)	$(28)	$(2,469)

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
As of December 31, 2012	$(5,062)	$—	$(5,062)
Other comprehensive loss before reclassifications	(6)	—	(6)
Amounts reclassified from accumulated other comprehensive loss	165	—	165
Net current-period other comprehensive income	159	—	159
As of September 30, 2013	$(4,903)	$—	$(4,903)

The following table presents amounts reclassified out of accumulated other comprehensive loss for the three and nine months ended September 30, 2014 and 2013. The only such amounts for those periods were defined benefit pension and postretirement plan items, which had not occurred in those periods. Deferred gains or losses for our commodity contracts cash flow hedges are recognized in earnings upon settlement.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2014	2013	2014	2013
Amortization of defined benefit pension and postretirement plan items:				
Prior service cost [(1)]	$15	$15	$44	$45
Net loss [(1)]	(66)	(107)	(198)	(320)
Total before income taxes	(51)	(92)	(154)	(275)
Income tax benefit	21	37	62	110
Net of tax	$(30)	$(55)	$(92)	$(165)

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

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Amortization of defined benefit pension and postretirement plan items is included in operations expense in the accompanying condensed consolidated statements of income. The income tax benefit is included in income tax expense in the accompanying condensed consolidated statements of income.

9. Employee Benefit Plans

Net periodic benefit costs for our pension and post-retirement benefits plans for the three and nine months ended September 30, 2014 and 2013 are set forth in the following tables:

	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP		Chesapeake Postretirement Plan		FPU Medical Plan	
For the Three Months Ended September 30,	2014	2013	2014	2013	2014	2013	2014	2013	2014	2013
(in thousands)										
Interest cost	$107	$102	$647	$594	$23	$21	$13	$12	$17	$16
Expected return on plan assets	(133)	(126)	(773)	(719)	—	—	—	—	—	—
Amortization of prior service cost	—	—	—	—	5	5	(19)	(19)	—	—
Amortization of net loss	37	57	—	81	12	16	16	18	—	—
Net periodic cost (benefit)	11	33	(126)	(44)	40	42	10	11	17	16
Amortization of pre-merger regulatory asset	—	—	191	191	—	—	—	—	2	2
Total periodic cost	$11	$33	$65	$147	$40	$42	$10	$11	$19	$18

	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP		Chesapeake Postretirement Plan		FPU Medical Plan	
For the Nine Months Ended September 30,	2014	2013	2014	2013	2014	2013	2014	2013	2014	2013
(in thousands)										
Interest cost	$320	$307	$1,941	$1,782	$69	$62	$39	$36	$50	$47
Expected return on plan assets	(398)	(378)	(2,318)	(2,156)	—	—	—	—	—	—
Amortization of prior service cost	—	(1)	—	—	14	14	(58)	(58)	—	—
Amortization of net loss	112	171	—	243	36	48	50	55	—	—
Net periodic cost (benefit)	34	99	(377)	(131)	119	124	31	33	50	47
Amortization of pre-merger regulatory asset	—	—	571	571	—	—	—	—	6	6
Total periodic cost	$34	$99	$194	$440	$119	$124	$31	$33	$56	$53

We expect to record pension and postretirement benefit costs of approximately $578,000 for 2014. Included in these costs is $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 merger. 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 $3.8 million and $4.4 million at September 30, 2014 and December 31, 2013, respectively. The amortization included in pension expense is being offset by a net periodic benefit of $191,000, which will reduce our total expected benefit costs to $578,000.

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 merger. The portion of the unrecognized pension and postretirement benefit costs related to FPU's unregulated operations and Chesapeake's operations is recorded to accumulated other comprehensive income (loss). The following table presents the amounts included in the regulatory asset and accumulated other comprehensive income (loss) that were recognized as components of net periodic benefit cost during the three and nine months ended September 30, 2014 and 2013:

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For the Three Months Ended September 30, 2014	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service cost (credit)	$ —	$—	$ 5	$ (19)	$—	(14)
Net loss	37	—	12	16	—	65
Total recognized in net periodic benefit cost	$ 37	$—	$ 17	$ (3)	$—	$51
Recognized from accumulated other comprehensive loss (1)	$ 37	$—	$ 17	$ (3)	$—	$51
Recognized from regulatory asset	—	—	—	—	—	—
Total	$ 37	$—	$ 17	$ (3)	$—	$51

For the Nine Months Ended September 30, 2014	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service cost (credit)	$ —	$—	$ 14	$ (58)	$—	(44)
Net loss	112	—	36	50	—	198
Total recognized in net periodic benefit cost	$ 112	$—	$ 50	$ (8)	$—	$154
Recognized from accumulated other comprehensive loss (1)	$ 112	$—	$ 50	$ (8)	$—	$154
Recognized from regulatory asset	—	—	—	—	—	—
Total	$ 112	$—	$ 50	$ (8)	$—	$154

For the Three Months Ended September 30, 2013	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service cost (credit)	$ —	$—	$ 5	$ (19)	$—	(14)
Net loss	57	81	16	18	—	172
Total recognized in net periodic benefit cost	$ 57	$81	$ 21	$ (1)	$—	$158
Recognized from accumulated other comprehensive loss (1)	$ 57	$15	$ 21	$ (1)	$—	$92
Recognized from regulatory asset	—	66	—	—	—	66
Total	$ 57	$81	$ 21	$ (1)	$—	$158

For the Nine Months Ended September 30, 2013	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service cost (credit)	$ (1)	$—	$ 14	$ (58)	$—	(45)
Net loss	171	243	48	55	—	517
Total recognized in net periodic benefit cost	$ 170	$243	$ 62	$ (3)	$—	$472
	$ 170	$46	$ 62	$ (3)	$—	$275

Recognized from accumulated other comprehensive loss [1]						
Recognized from regulatory asset	—	197	—	—	—	197
Total	$ 170	$ 243	$ 62	$ (3)	$ —	$ 472

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

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During the three and nine months ended September 30, 2014, we contributed $308,000 and $529,000, respectively, to the Chesapeake Pension Plan and $1.4 million and $2.0 million, respectively, to the FPU Pension Plan. We expect to contribute a total of $709,000 and $2.6 million to the Chesapeake Pension Plan and FPU Pension Plan, respectively, during 2014, which represent the minimum contribution payments required during the year.

The Chesapeake SERP, the Chesapeake Postretirement Plan and the FPU Medical Plan are unfunded and are expected to be paid out of our general funds. Cash benefits paid under the Chesapeake SERP for the three and nine months ended September 30, 2014, were $22,000 and $67,000, respectively. We expect to pay total cash benefits of approximately $88,000 under the Chesapeake Pension SERP in 2014. Cash benefits paid for the Chesapeake Postretirement Plan, primarily for medical claims for the three and nine months ended September 30, 2014, were $12,000 and $57,000, respectively. We have estimated that approximately $95,000 will be paid for such benefits under the Chesapeake Postretirement Plan in 2014. Cash benefits paid for the FPU Medical Plan, primarily for medical claims for the three and nine months ended September 30, 2014, were $43,000 and $187,000, respectively. We estimate that approximately $245,000 will be paid for such benefits under the FPU Medical Plan in 2014.

10. Investments

The investment balances at September 30, 2014 and December 31, 2013, consist of the Rabbi Trust(s) associated with deferred compensation plan(s). We classify these investments as trading securities and report them at their fair value. For the three months ended September 30, 2014 and 2013, we recorded a net unrealized loss of $41,000 and $259,000, respectively, in other income in the condensed consolidated statements of income related to these investments. For the nine months ended September 30, 2014 and 2013, we recorded a net unrealized gain of $111,000 and a net unrealized loss of $217,000, respectively, in other income in the condensed consolidated statements of income related to these investments. We also have recorded an associated liability, which is included in other pension and benefit costs in the condensed consolidated balance sheets. This liability is adjusted each month for the gains and losses incurred by the Rabbi Trusts.

11. Share-Based Compensation

Since May 2, 2013, our non-employee directors and key employees have been granted share-based awards through our SICP. We record these share-based awards as compensation costs over the respective service period for which services are received in exchange for an award of equity or equity-based compensation. The compensation cost is based primarily on the fair value of the shares awarded, using the estimated fair value of each share on the date it was granted and the number of shares to be issued at the end of the service period.

The table below presents the amounts included in net income related to share-based compensation expense for the three and nine months ended September 30, 2014 and 2013:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
(in thousands)				
Awards to non-employee directors	$137	$124	$394	$354
Awards to key employees	317	261	1,125	892
Total compensation expense	454	385	1,519	1,246
Less: tax benefit	183	155	612	502
Share-Based Compensation amounts included in net income	$271	$230	$907	$744

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 date of the grant. 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 2014, each of our non-employee directors received an annual retainer of 1,209 shares of common stock under the SICP. A summary of the stock activity for our non-employee directors during the nine months ended September 30, 2014 is presented below.

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	Number of Shares	Weighted Average Grant date Fair Value
Outstanding - December 31, 2013	—	$—
Granted	13,299	$41.33
Vested	13,299	$41.33
Outstanding - September 30, 2014	—	$—

At September 30, 2014, there was $321,000 of unrecognized compensation expense related to these awards. This expense will be recognized over the period ending April 30, 2015, which approximates the expected remaining service period of those directors.

Key Employees

The table below presents the summary of the stock activity for awards to key employees for the nine months ended September 30, 2014:

	Number of Shares	Weighted Average Fair Value
Outstanding—December 31, 2013	121,142	$28.20
Granted	41,442	$39.99
Vested	39,546	$26.87
Outstanding—September 30, 2014	123,038	$32.60

In January and March 2014, the Board of Directors granted awards of 41,442 shares to key employees under the SICP. The awards of 34,800 shares granted in January 2014 are multi-year awards that will vest at the end of the three-year service period ending December 31, 2016. Another award of 6,642 shares granted in March 2014 to one key employee is a multi-year award that will vest at the end of the service period ending December 31, 2015. 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 date each award is granted. For the market-based conditions, we used the Black-Scholes pricing model to estimate the fair value of each market-based award granted.

At September 30, 2014, the aggregate intrinsic value of the SICP awards granted to key employees was $5.1 million.

12. Derivative Instruments

We use derivative and non-derivative contracts to engage in trading activities and manage risks related to obtaining adequate supplies and the price fluctuations of natural gas, electricity and propane. Our natural gas, electric and propane distribution operations have entered into agreements with suppliers to purchase natural gas, electricity and propane for resale to their customers. Purchases under these contracts typically either do not meet the definition of derivatives or are considered “normal purchases and sales” and are accounted for on an accrual basis. Our propane distribution operation may also enter into fair value hedges of its inventory or cash flow hedges of its future purchase commitments in order to mitigate the impact of wholesale price fluctuations. As of September 30, 2014, our natural gas and electric distribution operations did not have any outstanding derivative contracts.

In August 2014, Sharp entered into a call option to protect against an increase in propane prices associated with 630,000 gallons we expect to purchase at market-based prices to supply the demands of our propane price cap program customers. The retail price that we can charge to those customers during the upcoming heating season is capped at a pre-determined level. The call option is exercised if the propane prices rise above the strike price of $1.0875 per gallon in December 2014 through February of 2015. We will receive the difference between the market price and the strike price during those months. We paid $52,000 to purchase the call option, and we accounted for it as a cash flow hedge. As of September 30, 2014, the call option had a fair value of $35,000. The change in fair value of the call option is recorded as unrealized gain/loss in other comprehensive income (loss).

In May 2014, Sharp entered into swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with 630,000 gallons expected to be purchased for the upcoming heating season. Under these swap agreements,

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Sharp receives the difference between the index prices (Mont Belvieu prices in December 2014 through February 2015) and the swap prices of $1.1350, $1.0975 and $1.0475 per gallon for each swap agreement, to the extent the index prices exceed the swap prices. If the index prices are lower than the swap prices, Sharp will pay the difference. These swap agreements essentially fix the price of those 630,000 gallons purchased for the upcoming heating season. We accounted for them as cash flow hedges, and there is no ineffective portion of these hedges. As of September 30, 2014, two swap agreements had a fair value of $60,000 of liability and one swap agreement had a fair value of $13,000 of asset. The change in fair value of the swap agreements is recorded as unrealized gain/loss in other comprehensive income (loss).

In May 2014, Sharp also entered into put options to protect against declines in propane prices and related potential inventory losses associated with 630,000 gallons purchased for the propane price cap program in the upcoming heating season. The put options are exercised if propane prices fall below the strike prices of $0.9475, $0.9975 and $1.0350 per gallon, for each option agreement in December 2014 through February 2015, respectively. We will receive the difference between the market price and the strike prices during those months. We paid $128,000 to purchase the put options. We accounted for them as fair value hedges and there is no ineffective portion of these hedges. As of September 30, 2014, the put options had a fair value of $56,000. The change in fair value of the put options effectively reduced our propane inventory balance.

In June 2013, Sharp entered into put options to protect against declines in propane prices and related potential inventory losses associated with 1.3 million gallons purchased for the propane price cap program in the upcoming heating season. If exercised, we would have received the difference between the market price and the strike price if propane prices had fallen below the strike prices of $0.830 per gallon in December 2013 through February of 2014, and $0.860 per gallon in January through March 2014. We accounted for those options as fair value hedges, and there was no ineffective portion of those hedges. We paid $120,000 to purchase the put options, which expired without exercise as the market prices exceeded the strike prices.

In May 2013, Sharp entered into a call option to protect against an increase in propane prices associated with 630,000 gallons we expected to purchase at market-based prices to supply the demands of our propane price cap program customers. The program capped the retail price that we could charge to those customers during the upcoming heating season at a pre-determined level. The call option was exercised because propane prices rose above the strike price of $0.975 per gallon in January through March of 2014. We accounted for this call option as a derivative instrument on a mark-to-market basis with any change in its fair value being reflected in current period earnings. We paid $72,000 to purchase the call option. In January through March of 2014, we received $209,000, representing the difference between the market price and the strike price during those months.

Xeron engages in trading activities using forward and futures contracts. These contracts are considered derivatives and have been accounted for using the mark-to-market method of accounting. Under this method, the trading contracts are recorded at fair value, and the changes in fair value of those contracts are recognized as unrealized gains or losses in the statement of income for the period of change. As of September 30, 2014, we had the following outstanding trading contracts, which we accounted for as derivatives:

At September 30, 2014	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts			
Sale	1,260,000	$1.0838 - $1.1400	$1.1118
Purchase	1,261,000	$1.0913 - $1.3176	$1.1107

Estimated market prices and weighted average contract prices are in dollars per gallon. All contracts expire by the end of the fourth quarter of 2014.

Xeron has entered into master netting agreements with two counterparties to mitigate exposure to counterparty credit risk. The master netting agreements enable Xeron to net these two counterparties' outstanding accounts receivable and payable, which are presented on a gross basis in the accompanying condensed consolidated balance sheets. At September 30, 2014, Xeron had a right to offset $2.2 million and $1.6 million of accounts receivable and accounts payable, respectively, with these two counterparties. At December 31, 2013, Xeron had a right to offset $2.8 million and $3.2 million of accounts receivable and accounts payable, respectively, with these two counterparties.

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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.
Fair values of the derivative contracts recorded in the condensed consolidated balance sheets as of September 30, 2014 and December 31, 2013, are as follows:

	Asset Derivatives		
		Fair Value As Of	
(in thousands)	Balance Sheet Location	September 30, 2014	December 31, 2013
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy assets	$83	$196
Call Option [1]	Mark-to-market energy assets	—	169
Derivatives designated as fair value hedges			
Put Options	Mark-to-market energy assets	56	20
Derivatives designated as cash flow hedges			
Propane swap agreements	Mark-to-market energy assets	13	—
Call Option	Mark-to-market energy assets	35	—
Total asset derivatives		$187	$385

(1) We purchased a call option for the propane price cap program in May 2013. The call option was fully exercised during 2014. There was no outstanding call option at September 30, 2014.

	Liability Derivatives		
		Fair Value As Of	
(in thousands)	Balance Sheet Location	September 30, 2014	December 31, 2013
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy liabilities	$81	$127
Derivatives designated as cash flow hedges			
Propane swap agreements	Mark-to-market energy liabilities	60	—
Total liability derivatives		$141	$127

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

		Amount of Gain (Loss) on Derivatives:			
	Location of Gain	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(in thousands)	(Loss) on Derivatives	2014	2013	2014	2013
Derivatives not designated as hedging instruments					
Unrealized gain (loss) on forward contracts	Revenue	$(5)	$86	$(67)	$239
Call Option	Cost of sales	—	38	137	29
Derivatives designated as fair value hedges					
Put/Call Options	Cost of sales	(43)	—	(92)	(28)
Put/Call Options [1]	Propane Inventory	—	(43)	—	(57)
Derivatives designated as cash flow hedges					
Propane swap agreements	Other Comprehensive loss	(45)	—	(46)	—
Total		$(93)	$81	$(68)	$183

(1) 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 call option effectively changed the value of propane inventory.

The effects of trading activities on the condensed consolidated statements of income are the following:

	Location in the	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(in thousands)	Statements of Income	2014	2013	2014	2013
Realized gain on forward contracts	Revenue	$54	$321	$1,384	$506
Unrealized gain (loss) on forward contracts	Revenue	(5)	86	(67)	239
Total		$49	$407	$1,317	$745

13. Fair Value of Financial Instruments

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

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

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

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

The following table summarizes our financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements, by level, within the fair value hierarchy used at September 30, 2014 and December 31, 2013:

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September 30, 2014	Fair Value	Fair Value Measurements Using: Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(in thousands)				
Assets:				
Investments—guaranteed income fund	$315	$—	$—	$315
Investments—other	$3,166	$3,166	$—	$—
Mark-to-market energy assets, incl. put/call options	$187	$—	$187	$—
Liabilities:				
Mark-to-market energy liabilities incl. swap agreements	$141	$—	$141	$—

December 31, 2013 (in thousands)	Fair Value	Fair Value Measurements Using: Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets:				
Investments—guaranteed income fund	$458	$—	$—	$458
Investments—other	$2,640	$2,640	$—	$—
Mark-to-market energy assets, incl. put/call options	$385	$—	$385	$—
Liabilities:				
Mark-to-market energy liabilities	$127	$—	$127	$—

The following table sets forth the summary of the changes in the fair value of Level 3 investments for the nine months ended September 30, 2014 and 2013:

	Nine Months Ended September 30, 2014	2013
(in thousands)		
Beginning Balance	$458	$—
Transfers in due to change in trustee	—	425
Purchases and adjustments	(89)	98
Transfers	(58)	(16)
Investment income	4	5
Ending Balance	$315	$512

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

The following valuation techniques were used to measure fair value assets in the table above on a recurring basis as of September 30, 2014 and December 31, 2013:

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- 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.

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Level 2 Fair Value Measurements:
Mark-to-market energy assets and liabilities—These forward contracts are valued using market transactions in either the listed or OTC markets.
Propane put/call options and swap agreements—The fair value of the propane put/call options and swap agreements are determined 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.

At September 30, 2014, there were no non-financial assets or liabilities required to be reported at fair value. We review our non-financial assets for impairment at least on an annual basis, as required.
Other Financial Assets and Liabilities
Financial assets with carrying values approximating fair value include cash and cash equivalents and accounts receivable. Financial liabilities with carrying values approximating fair value include accounts payable and other accrued liabilities and short-term debt. The fair value of cash and cash equivalents is measured using the comparable value in the active market and approximates its carrying value (Level 1 measurement). The fair value of short-term debt approximates the carrying value due to its short maturities and because interest rates approximate current market rates (Level 3 measurement).
At September 30, 2014, long-term debt, including current maturities but excluding a capital lease obligation, had a carrying value of $169.7 million. This compares to a fair value of $186.6 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, 2013, long-term debt, including the current maturities but excluding a capital lease obligation, had a carrying value of $122.0 million, compared to the estimated fair value of $136.8 million. The valuation technique used to estimate the fair value of long-term debt would be considered a Level 3 measurement.

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14. Long-Term Debt

Our outstanding long-term debt is shown below:

(in thousands)	September 30, 2014	December 31, 2013
FPU secured first mortgage bonds [A] :		
9.08% bond, due June 1, 2022	$7,969	$7,967
Uncollateralized senior notes:		
7.83% note, due January 1, 2015	2,000	2,000
6.64% note, due October 31, 2017	10,909	10,909
5.50% note, due October 12, 2020	14,000	14,000
5.93% note, due October 31, 2023	28,500	30,000
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	—
Convertible debentures:		
8.25% due March 1, 2014	—	646
Promissory notes	329	445
Capital lease obligation	6,450	6,978
Total long-term debt	176,157	128,945
Less: current maturities	(11,113)	(11,353)
Total long-term debt, net of current maturities	$165,044	$117,592

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

Uncollateralized Senior Notes

In September 2013, we entered into the Note Agreement to issue $70.0 million in aggregate of Notes to the Note Holders. In December 2013, we issued the Series A Notes, with an aggregate principal amount of $20.0 million, at a rate of 3.73 percent. On May 15, 2014, we issued the Series B Notes, with an aggregate principal amount of $50.0 million, at a rate of 3.88 percent. The proceeds received from the issuances of the Notes were used to reduce our short-term borrowings under our lines of credit and to fund capital expenditures.

Convertible Debentures

During the first two months of 2014, $537,000 of Convertible Debentures were converted to stock and $109,000 were redeemed for cash, leaving no outstanding Convertible Debentures as of March 1, 2014.

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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, 2013, 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 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 recovered in rates;
- the loss of customers due to a government-mandated sale of our utility distribution facilities;
- industrial, commercial and residential growth or contraction in our markets or service territories;
- the weather and other natural phenomena, including the economic, operational and other effects of hurricanes, ice storms and other damaging weather events;
- the timing and extent of changes in commodity prices and interest rates;
- general economic conditions, including any potential effects arising from terrorist attacks and any consequential hostilities or other hostilities or other external factors over which we have no control;
- changes in environmental and other laws and regulations to which we are subject and changes in environmental conditions of property that we now or may in the future own or operate;
- the results of financing efforts, including our ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general economic conditions;
- the impact to the asset values and resulting higher costs and funding obligations of the Company's pension and other postretirement benefit plans as a result of potential downturns in the financial markets, lower discount rates or impacts associated with the Patient Protection and Affordable Care Act;
- the creditworthiness of counterparties with which we are engaged in transactions;
- the extent of success in connecting natural gas and electric supplies to transmission systems and in expanding natural gas and electric markets;
- the effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- conditions of the capital markets and equity markets during the periods covered by the forward-looking statements;
- the ability to successfully execute, manage and integrate merger, acquisition or divestiture plans, regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, and the success of the business following a merger, acquisition or divestiture;
- the ability to establish and maintain new key supply sources;
- the effect of spot, forward and future market prices on our distribution, wholesale marketing and energy trading businesses;
- the effect of competition on our businesses;

- the ability to construct facilities at or below estimated costs; and
- risks related to cyber-attack or failure of information technology systems.

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Introduction

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

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

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

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

The following discussions and those elsewhere in the document on operating income and segment results include the use of the term “gross margin.” Gross margin is determined by deducting the cost of sales from operating revenue. Cost of sales includes the purchased cost of natural gas, electricity and propane and the cost of labor spent on direct revenue-producing activities. Gross margin should not be considered an alternative to operating income or net income, which is 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 energy operations and under our competitive pricing structure for non-regulated segments. Our management uses gross margin in measuring our business units’ performance and has historically analyzed and reported gross margin information publicly. Other companies may calculate gross margin in a different manner.

Share and per-share amounts for all periods presented reflect the three-for-two stock split declared on July 2, 2014, effected in the form of a stock dividend, and distributed on September 8, 2014.

Results of Operations for the Three and Nine Months ended September 30, 2014

Overview and Highlights

Our net income for the quarter ended September 30, 2014 was $3.2 million, or $0.22 per share (diluted). This represents a decrease of $699,000, or $0.05 per share (diluted), compared to net income of $3.9 million, or $0.27 per share (diluted), as reported for the same quarter in 2013.

	Three Months Ended September 30, 2014	2013	Increase (decrease)
(in thousands except per share)			
Business Segment:			
Regulated Energy	$9,202	$10,243	$(1,041)
Unregulated Energy	(1,972)	(1,803)	(169)
Other	562	280	282
Operating Income	7,792	8,720	(928)
Other Income (loss), net of other expenses	(32)	101	(133)
Interest Charges	2,495	2,026	469
Pre-tax Income	5,265	6,795	(1,530)
Income Taxes	2,085	2,916	(831)
Net Income	3,180	3,879	(699)
Earnings Per Share of Common Stock			
Basic	$0.22	$0.27	$(0.05)
Diluted	$0.22	$0.27	$(0.05)

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Key variances included:

(in thousands, except per share)	Pre-tax Income	Net Income	Earnings Per Share
Third Quarter of 2013 Reported Results	$6,795	$3,879	$0.27
Adjusting for Unusual Items:			
Regulatory recovery of litigation-related costs in 2013	(1,870)	(1,112)	(0.08)
Accrual for additional taxes other than income in 2013	698	415	0.03
	(1,172)	(697)	(0.05)
Increased (Decreased) Gross Margins:			
Major Projects (See Major Projects Highlights table)			
Service expansions	1,213	721	0.05
Contribution from Sandpiper	141	84	0.01
Other natural gas growth	690	410	0.03
GRIP	671	399	0.03
Higher consulting and product revenues from BravePoint	581	346	0.02
Propane wholesale marketing	(357)	(212)	(0.01)
FPU electric interim rates	348	207	0.01
	3,287	1,955	0.14
Increased Other Operating Expenses:			
Higher payroll costs	(1,184)	(704)	(0.05)
Higher depreciation, amortization, asset removal and property tax costs due to new capital investments	(719)	(428)	(0.03)
Higher facility maintenance costs	(380)	(226)	(0.02)
Higher safety and related customer communications activities	(308)	(183)	(0.01)
Higher accrual for incentive bonuses	(301)	(179)	(0.01)
	(2,892)	(1,720)	(0.12)
Interest Charges	(469)	(279)	(0.02)
Net Other Changes	(284)	42	—
Third Quarter of 2014 Reported Results	$5,265	$3,180	$0.22

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Our net income for the nine months ended September 30, 2014 was $26.0 million, or $1.78 per share (diluted). This represents an increase of $2.9 million, or $0.19 per share (diluted), compared to net income of $23.1 million, or $1.59 per share (diluted), as reported for the same period in 2013.

	Nine Months Ended September 30,		Increase
	2014	2013	(decrease)
(in thousands except per share)			
Business Segment:			
Regulated Energy	$41,004	$36,169	$4,835
Unregulated Energy	8,843	8,013	830
Other	25	240	(215)
Operating Income	49,872	44,422	5,450
Other Income, net of other expenses	380	413	(33)
Interest Charges	6,954	6,114	840
Pre-tax Income	43,298	38,721	4,577
Income Taxes	17,303	15,617	1,686
Net Income	$25,995	$23,104	$2,891
Earnings Per Share of Common Stock			
Basic	$1.79	$1.60	$0.19
Diluted	$1.78	$1.59	$0.19

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Key variances included:

(in thousands, except per share)	Pre-tax Income	Net Income	Earnings Per Share
Nine Months Ended September 30, 2013 Reported Results	$38,721	$23,104	$1.59
Adjusting for unusual items:			
Weather impact (due primarily to colder temperatures in 2014)	2,346	1,400	0.10
Regulatory recovery of litigation-related costs in 2013	(1,494)	(891)	(0.06)
One-time sales tax expensed by Sandpiper associated with the acquisition of ESG in 2013	726	433	0.03
Accrual for additional taxes other than income in 2013	698	416	0.03
	2,276	1,358	0.10
Increased Gross Margins:			
Major Projects (See Major Projects Highlights table)			
Contribution from Sandpiper	5,396	3,220	0.22
Service expansions	4,182	2,495	0.17
GRIP	1,981	1,182	0.08
Other natural gas growth	1,806	1,078	0.07
Increased wholesale propane sales	1,357	810	0.06
Higher consulting and product revenues from BravePoint	821	490	0.03
	15,543	9,275	0.63
Increased Other Operating Expenses:			
Higher payroll costs	(3,849)	(2,297)	(0.16)
Expenses from acquisitions	(3,068)	(1,831)	(0.13)
Higher depreciation, amortization, asset removal costs and property tax costs due to new capital investments	(2,381)	(1,421)	(0.10)
Higher benefits costs	(1,768)	(1,055)	(0.07)
Higher facility maintenance	(1,079)	(644)	(0.04)
Larger accrual for incentive bonuses	(971)	(579)	(0.04)
	(13,116)	(7,827)	(0.54)
Interest Charges	(839)	(501)	(0.03)
Net Other Changes	713	586	0.03
Nine Months Ended September 30, 2014 Reported Results	$43,298	$25,995	$1.78

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Summary of Key Factors

The following information highlights certain key factors contributing to our results for the current and future periods.

Major Projects

Acquisition

In May 2013, we completed the purchase of the operating assets of ESG. Approximately 11,000 residential and commercial underground propane distribution system customers acquired in this transaction are now being served by Sandpiper under the tariff approved by the Maryland PSC. We have begun to convert some of the former ESG customers to natural gas distribution service and are evaluating the potential conversion of others. This acquisition was accretive to earnings per share in the first full year of operations, generating $0.15 in additional earnings per share. We generated $141,000 and $5.4 million, in additional gross margin from Sandpiper for the three and nine months ended September 30, 2014, respectively, and incurred $22,000 and $2.2 million in additional other operating expenses for the same periods, respectively. Additionally, in the second quarter of 2013, we recorded $726,000 in a one-time sales tax expense associated with the acquisition of ESG.

Service Expansions

During 2013, Eastern Shore, our interstate natural gas transmission subsidiary, commenced new natural gas transmission services to local distribution utilities and industrial customers in Delaware and Maryland. These new services generated additional gross margin of $504,000 and $2.5 million in the three and nine months ended September 30, 2014, respectively, compared to the same periods in 2013.

Eastern Shore also executed a one-year contract with another industrial customer to provide 50,000 Dts/d of additional transmission service from April 2014 to April 2015. This short-term contract generated $657,000 and $1.3 million for the three and nine months ended September 30, 2014, and is expected to generate $1.9 million and $767,000 of gross margin in 2014 and 2015, respectively.

In August 2013, Peninsula Pipeline, our intrastate natural gas transmission subsidiary, commenced a new firm transportation service in Florida for an unaffiliated utility. This new service generated $70,000 and $490,000 in gross margin for the three and nine months ended September 30, 2014.

On October 1, 2014, Eastern Shore commenced a new service to an industrial customer facility in Kent County, Delaware. This new service is expected to generate annual gross margin between $1.2 million to $1.8 million. During the fourth quarter of 2014, we expect to generate $463,000 in additional gross margin from this new service, which required construction of new facilities, including approximately 5.5 miles of pipeline lateral and metering facilities, extending from Eastern Shore's mainline to the new industrial customer facility.

Future New Service

Eight Flags, one of our unregulated energy subsidiaries, is engaged in the development and construction of a CHP plant in Nassau County, Florida. This CHP plant, which will consist of a natural-gas-fired turbine and associated electric generator, is designed to generate approximately 20 megawatts of base load power and will include a heat recovery system generator capable of providing approximately 75,000 pounds per hour of unfired steam. Eight Flags will sell the power generated from the CHP plant to FPU for distribution to its retail electric customers pursuant to a 20-year PPA. It will also sell the steam to an industrial customer pursuant to a separate 20-year contract. FPU and Peninsula Pipeline, our intrastate pipeline subsidiary, will transport natural gas through their distribution and transmission systems respectively, to Eight Flags’ CHP plant to produce power and steam. On a consolidated basis, this project is expected to generate approximately $7.3 million in annual gross margin, which could fluctuate based upon various factors, including, but not limited to, the quantity of steam delivered and the CHP plant’s hours of operations. Construction of the CHP plant and associated transactions are subject to various conditions, including obtaining necessary governmental approvals, environmental and regulatory permits and completion and execution of various agreements. If all conditions are satisfied, construction of the CHP plant is currently scheduled to commence in early 2015 with commercial operation expected to commence in July 2016.

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The following Major Project Highlights table summarizes 2014 gross margin from our major projects initiated since 2011 (dollars in thousands):

	Gross Margin for the Period				
	Three Months Ended September 30,		Nine Months Ended September 30,		Estimate for
	2014	2013	2014	2013	2014
Acquisition:					
ESG acquisition being served by Sandpiper in Worcester County, Maryland (1)	$1,800	$1,659	$7,594	$2,198	$9,817
Service Expansions					
Natural Gas Distribution:					
Long-term					
Sussex County, Delaware	$121	$136	$480	$491	$694
Natural Gas Transmission:					
Short-term					
New Castle County, Delaware (2)	$657	$173	$1,256	$341	$1,862
Kent County, Delaware	—	579	—	965	—
Total Short-term	$657	$752	$1,256	$1,306	$1,862
Long-term					
Sussex County, Delaware	$431	$345	$1,294	$1,035	$1,725
New Castle County, Delaware (3)	741	343	2,229	1,035	2,964
Nassau County, Florida	326	328	981	993	1,300
Worcester County, Maryland	137	98	411	293	547
Cecil County, Maryland	287	220	860	661	1,147
Indian River County, Florida	210	140	630	140	840
Kent County, Delaware	665	—	1,995	—	3,123
Total Long-term	$2,797	$1,474	$8,400	$4,157	$11,646
Total Service Expansions	$3,575	$2,362	$10,136	$5,954	$14,202
Total Major Projects	$5,375	$4,021	$17,730	$8,152	$24,019

(1) During the three months and nine months ended September 30, 2014, we incurred $22,000 and $2.2 million, respectively, in other operating expenses related to Sandpiper's operations. We expect to incur a total of $6.3 million in other operating expenses during 2014.
(2) Expected gross margin in 2014 includes $1.9 million from a new short-term contract for 50,000 Dts/d for one year, which began in April 2014.
(3) Gross margin generated from this service expansion replaces the 10,000 Dts/d contract, which expired in November 2012. This expired contract had annualized gross margin of $1.1 million.

The following table summarizes our future major expansion initiatives and opportunities with executed contracts (dollars in thousands):

Project	Estimated Date of New Service	Estimated Annualized Margin
Eight Flags CHP plant in Nassau County, Florida	Third quarter of 2016	$7.3 million

GRIP

In August 2012, the Florida PSC approved the GRIP, which is designed to recover capital and other program-related-costs, inclusive of a return on investment, to replace older pipes in our Florida service territories. We received approval to invest $75.0 million to replace qualifying distribution mains and services (any material other than coated steel or plastic). Since the program's inception on August 12, 2012, we have invested $35.9 million. During the first nine months of 2014, we invested $16.1 million and expect

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to invest an additional $5.4 million during the remainder of 2014. These investments generated additional gross margin of $671,000 and $2.0 million for the three and nine months ended September 30, 2014, respectively, compared to the same periods in 2013.

Investing in Growth

We have continued to expand our resources and capabilities to support growth. Our Delmarva natural gas distribution operation has initiated natural gas distribution expansions in Sussex County, Delaware, and Worcester and Cecil Counties, Maryland, which require the construction and conversion of distribution facilities, as well as the conversion of residential customers' appliances and equipment. To support this growth as well as future expansions, our Delmarva natural gas distribution operation increased staffing. Resources have also been added in our corporate shared services departments to increase our overall capabilities to support sustained future growth. The additional staffing to support growth has increased payroll expenses of our Regulated Energy segment by $484,000 and $1.3 million for the three and nine months ended September 30, 2014, respectively, compared to the same periods in 2013. We expect to make additional investments in personnel, as needed, to further develop our capability to capitalize on future growth opportunities.

Weather and Consumption

Weather was not a significant factor in the third quarter. Temperatures on the Delmarva Peninsula and in Florida during the first quarter of 2014 were significantly colder compared to the same period in 2013, which positively affected our 2014 year-to-date results. The following tables highlight the HDD and CDD information for the three and nine months ended September 30, 2014 and 2013 and the gross margin variance resulting from weather fluctuations in those periods.

HDD and CDD Information

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2014	2013	Variance	2014	2013	Variance
Delmarva						
Actual HDD	89	129	(40)	3,262	3,026	236
10-Year Average HDD ("Normal")	61	46	15	2,893	2,867	26
Variance from Normal	28	83		369	159	
Florida						
Actual HDD	—	—	—	574	487	87
10-Year Average HDD ("Normal")	—	—	—	555	570	(15)
Variance from Normal	—	—		19	(83)	
Florida						
Actual CDD	1,528	1,475	53	2,498	2,421	77
10-Year Average CDD ("Normal")	1,519	1,504	15	2,501	2,490	11
Variance from Normal	9	(29)		(3)	(69)	

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Gross Margin Variance attributed to Weather

(in thousands)	Q3 2014 vs. Q3 2013	Q3 2014 vs. Normal	YTD 2014 vs. YTD 2013	YTD 2014 vs. Normal
Delmarva				
Regulated Energy	$13	$167	$268	$803
Unregulated Energy	101	(13)	1,629	1,037
Florida				
Regulated Energy	132	38	401	(284)
Unregulated Energy	—	—	48	81
Total	$246	$192	$2,346	$1,637

Propane

During 2014, retail propane margins on the Delmarva Peninsula began to decline to more normal levels as a significant increase in wholesale prices in late 2013 and early 2014 increased our average propane inventory cost. This reduced our Delmarva gross margin by $292,000 and $1.2 million for the three and nine months ended September 30, 2014, respectively. In Florida, higher retail propane margins as a result of local market conditions increased gross margin by $514,000 and $1.2 million for the three and nine months ended September 30, 2014.

Wholesale propane sales increased, generating additional gross margin of $71,000 and $1.4 million for the three and nine months ended September 30, 2014, respectively, due primarily to sales to an affiliate of ESG.

Xeron, which benefits from wholesale price volatility by entering into trading transactions, experienced a quarter-over-quarter gross margin decrease of $357,000 for the three months ended September 30, 2014 due to lower wholesale price volatility. For the nine months ended September 30, 2014, Xeron generated an increase in gross margin of $572,000, compared to the same period in 2013. This increase was due to higher wholesale price volatility primarily during the winter heating season, which resulted in increased trading activities and higher profits on executed trades.

Florida Electric Rate Case

On September 15, 2014, the Florida PSC approved a settlement agreement between FPU and the Florida Office of Public Counsel in FPU's base rate case filing, which provides, among other things, an increase in FPU's annual revenue requirement of approximately $3.8 million and a rate of return on common equity of 10.25 percent for FPU’s electric distribution operation. The new rates will be effective for all meter reads on or after November 1, 2014. Previously, the Florida PSC approved interim rate relief, effective for meter readings on or after August 10, 2014, which generated $348,000 in additional gross margin for FPU’s electric operation for the quarter and nine months ended September 30, 2014.

Other Developments

Subsequent to the end of the third quarter of 2014, we completed the sale of BravePoint for approximately $12.0 million in cash. We expect to record a pre-tax gain of approximately $6.5 million to $7.0 million (approximately $4.0 million after-tax) from this sale in the fourth quarter of 2014. We plan to reinvest the proceeds from this sale in our regulated and unregulated energy businesses.

We have been working on implementation of a new customer billing system for our natural gas and electric distribution operations. As of September 30, 2014, approximately $6.4 million of the cost associated with this implementation project has been capitalized. We are currently reviewing the status of this project to determine its future strategy and implementation plan, which include the allocation of future capital and resources, evaluation of strategic alternatives and assessment of regulatory recovery with respect to this project.

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Regulated Energy

For the quarter ended September 30, 2014 compared to 2013

	Three Months Ended September 30,		Increase
	2014	2013	(decrease)
(in thousands)			
Revenue	$59,356	$55,680	$3,676
Cost of sales	23,040	22,591	449
Gross margin	36,316	33,089	3,227
Operations & maintenance	18,906	15,213	3,693
Depreciation & amortization	5,633	5,216	417
Other taxes	2,575	2,417	158
Other operating expenses	27,114	22,846	4,268
Operating Income	$9,202	$10,243	$(1,041)

Operating income for the Regulated Energy segment for the quarter ended September 30, 2014 was $9.2 million, a decrease of $1.0 million, or 10 percent, compared to the same quarter in 2013. An increase in gross margin of $3.2 million was more than offset by an increase in other operating expenses of $4.3 million. The increase in other operating expenses was partly due to the absence of a one-time credit of $1.9 million associated with the City of Marianna litigation cost recovery in the third quarter of 2013.

Gross Margin

Items contributing to the quarter-over-quarter increase of $3.2 million, or 10 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended September 30, 2013	$33,089
Factors contributing to the gross margin increase for the three months ended September 30, 2014:	
Service expansions	1,213
Other natural gas growth	690
Additional revenue from GRIP in Florida	671
Implementation of interim electric rates in Florida	347
Other	306
Gross margin for the three months ended September 30, 2014	$36,316

Service Expansions

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

- $657,000 from a short-term contract with an industrial customer to provide 50,000 Dts/d of additional natural gas transmission services from April 2014 to April 2015. This short-term contract is expected to generate $1.9 million and $767,000 of gross margin in 2014 and 2015, respectively.
- $312,000 from long-term natural gas transmission services, which commenced in November 2013, to industrial customers located in New Castle and Kent Counties, Delaware, which displaced short-term services to the same customers from May through October 2013. These long-term services are expected to generate $4.3 million of annual gross margin. They also displace annualized gross margin of $1.1 million from an older contract, which expired in November 2012.
- $244,000 from service expansions completed in 2013 that facilitated new natural gas transmission and distribution services in Sussex County, Delaware; Worcester and Cecil Counties, Maryland; and Indian River County, Florida.

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Other Natural Gas Growth

Increased gross margin from other natural gas growth was due primarily to the following:

- $548,000 from Florida natural gas customer growth due primarily to new services to commercial and industrial customers; and
- $127,000 from a three-percent increase in residential customers, as well as growth in commercial and industrial customers, in our Delmarva natural gas distribution operations.

Additional Revenue from GRIP in Florida

In August 2012, the Florida PSC approved the GRIP for FPU and Chesapeake's Florida division. This program provides additional revenue designed to recover capital and other program-related costs, inclusive of an appropriate rate of return on investment, associated with accelerating the replacement of qualifying natural gas distribution mains and services. During the third quarter of 2014, FPU and Chesapeake's Florida division recorded $671,000 in additional gross margin as a result of additional GRIP capital expenditures.

Implementation of Interim Electric Rates in Florida

Our FPU electric distribution operation generated an additional gross margin of $347,000 as a result of implementing interim rates as part of its base rate case filing.

Other Operating Expenses

The increase in other operating expenses was due primarily to: (a) the absence of a one-time credit of $1.9 million associated with the City of Marianna litigation cost recovery in the third quarter of 2013 ($376,000 of $1.9 million was incurred during 2013); (b) $634,000 in higher depreciation, amortization, asset removal and property tax costs associated with capital investments to support growth and maintain system integrity; (c) $558,000 in higher payroll costs incurred primarily to support recent growth and expand our capabilities to cultivate future growth; (d) $362,000 in higher safety and related customer communications activities; (e) $257,000 in increased accruals for incentive bonuses as a result of strong year-to-date financial performance; and (f) $246,000 in higher costs associated with facility maintenance.

For the nine months ended September 30, 2014 compared to 2013

	Nine Months Ended September 30,		Increase
	2014	2013	(decrease)
(in thousands)			
Revenue	$223,168	$192,463	$30,705
Cost of sales	102,020	86,321	15,699
Gross margin	121,148	106,142	15,006
Operations & maintenance	55,416	47,363	8,053
Depreciation & amortization	16,783	14,922	1,861
Other taxes	7,945	7,688	257
Other operating expenses	80,144	69,973	10,171
Operating Income	$41,004	$36,169	$4,835

Operating income for the Regulated Energy segment for the nine months ended September 30, 2014 was $41.0 million, an increase of $4.8 million, or 13 percent, compared to the same period in 2013. An increase in gross margin of $15.0 million was partially offset by an increase in other operating expenses of $10.2 million.

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Gross Margin

Items contributing to the period-over-period increase of $15.0 million, or 14 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the nine months ended September 30, 2013	$106,142
Factors contributing to the gross margin increase for the nine months ended September 30, 2014:	
Contributions from acquisitions	5,532
Service expansions	4,182
Additional revenue from GRIP in Florida	1,981
Other natural gas growth	1,806
Increased customer consumption - weather and other	710
Implementation of interim electric rates in Florida	348
Other	447
Gross margin for the nine months ended September 30, 2014	$121,148

Contributions from Acquisitions

Sandpiper generated $5.4 million of additional gross margin in the first nine months of 2014. Also, the acquisition of certain operating assets of the City of Fort Meade, Florida, in December 2013, generated $136,000 of additional gross margin during the first nine months of 2014.

Service Expansions

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

- $1.9 million from long-term natural gas transmission services commenced in November 2013 to industrial customers located in New Castle and Kent Counties, Delaware, which displaced short-term services provided to the same customers from May through October 2013. These long-term services are expected to generate $4.3 million of annual gross margin. They also displace annualized gross margin of $1.1 million from an older contract, which expired in November 2012.
- $1.3 million from a short-term contract with an existing industrial customer to provide an additional 50,000 Dts/d of natural gas transmission services from April 2014 to April 2015. This short-term contract is expected to generate $1.9 million and $767,000 of gross margin in 2014 and 2015, respectively.
- $1.0 million from expansions completed in 2013 that facilitated new natural gas transmission and distribution services in Sussex County, Delaware; Worcester and Cecil Counties, Maryland; and Indian River County, Florida.

Additional Revenue from GRIP in Florida

During the first nine months of 2014, FPU and Chesapeake's Florida division recorded $2.0 million in additional gross margin as a result of additional GRIP capital expenditures.

Other Natural Gas Growth

Increased gross margin from other natural gas growth was due primarily to the following:

- $1.5 million from Florida natural gas customer growth due primarily to new services to commercial and industrial customers.
- $572,000 from a three-percent increase in residential customers, as well as growth in commercial and industrial customers, in our Delmarva natural gas distribution operations.

Increased Customer Consumption—Weather and Other

Higher customer consumption due to colder temperatures on the Delmarva Peninsula and in Florida during the first nine months of 2014 generated increased gross margin of approximately $268,000 and $401,000, respectively.

Implementation of Interim Electric Rates in Florida

Our FPU electric distribution operation generated an additional gross margin of $347,000 as a result of implementing interim rates as part of its base rate case filing.

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Other Operating Expenses

The increase in other operating expenses was due primarily to: (a) $2.2 million in higher depreciation, amortization, asset removal and property tax costs associated with capital investments to support growth and maintain system integrity; (b) $2.2 million in other operating expenses associated with Sandpiper's operations; (c) $2.0 million in higher payroll costs to support recent and future growth and from a change in vacation policy in 2013; (d) the absence of a one-time credit of $1.5 million associated with the City of Marianna litigation cost recovery in 2013; (e) $1.1 million in higher benefits costs as a result of healthcare costs and other employee-related expenses; (f) $748,000 in higher costs associated with facilities maintenance; and (g) $727,000 in increased accruals for incentive bonuses as a result of strong year-to-date financial performance. These increases in other operating expenses were partially offset by the non-recurrence of a sales tax expense of $726,000 in 2013 directly related to the ESG acquisition.

Unregulated Energy

For the quarter ended September 30, 2014 compared to 2013

	Three Months Ended September 30,		Increase
	2014	2013	(decrease)
(in thousands)			
Revenue	$27,071	$28,262	$(1,191)
Cost of sales	20,623	21,484	(861)
Gross margin	6,448	6,778	(330)
Operations & maintenance	7,063	6,557	506
Depreciation & amortization	1,014	944	70
Other taxes	343	1,080	(737)
Other operating expenses	8,420	8,581	(161)
Operating Income (Loss)	$(1,972)	$(1,803)	$(169)

The Unregulated Energy segment reported an operating loss of $2.0 million in the third quarter of 2014, compared to $1.8 million in the same quarter of 2013. Due to the seasonal nature of propane distribution operations, this segment typically reports an operating loss in the third quarter. A decrease in gross margin of $330,000 was partially offset by a decrease in other operating expenses of $161,000.

Gross Margin

Items contributing to the quarter-over-quarter decrease of $330,000 in gross margin are as follows:

(in thousands)	
Gross margin for the three months ended September 30, 2013	$6,778
Factors contributing to the gross margin decrease for the three months ended September 30, 2014:	
Decrease in margins from propane wholesale marketing	(357)
Increase in retail propane margins	223
Other	(196)
Gross margin for the three months ended September 30, 2014	$6,448

Decrease in Margins from Propane Wholesale Marketing

Xeron's gross margin decreased by $357,000 during the third quarter of 2014, compared to the same quarter in 2013. Lower margins from executed trades and lower trading volume due primarily to lower price volatility in the wholesale propane market contributed to this decrease.

Increase in Retail Propane Margins

Higher retail propane margins for our Florida propane distribution operation increased gross margin by $514,000, which was partially offset by $292,000 in lower retail propane margins on the Delmarva Peninsula.

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Other Operating Expenses
Other operating expenses decreased by $161,000, due to the non-recurrence of an accrual of $698,000 recorded in 2013 related to a contingency for taxes other than income; this decrease was partially offset by $375,000 of higher payroll costs principally attributable to resources added to support growth.

For the nine months ended September 30, 2014 compared to 2013

	Nine Months Ended September 30, 2014	2013	Increase (decrease)
(in thousands)			
Revenue	$141,365	$119,278	$22,087
Cost of sales	105,802	87,224	18,578
Gross margin	35,563	32,054	3,509
Operations & maintenance	22,508	19,265	3,243
Depreciation & amortization	2,981	2,811	170
Other taxes	1,231	1,965	(734)
Other operating expenses	26,720	24,041	2,679
Operating Income	$8,843	$8,013	$830

Operating income for the Unregulated Energy segment for the nine months ended September 30, 2014 was $8.8 million, an increase of $830,000, or 10 percent, compared to the same period in 2013. An increase in gross margin of $3.5 million was partially offset by an increase in other operating expenses of $2.7 million.
Gross Margin
Items contributing to the period-over-period increase of $3.5 million, or 11 percent, in gross margin are as follows:

(in thousands)	
Gross margin for the nine months ended September 30, 2013	$32,054
Factors contributing to the gross margin increase for the nine months ended September 30, 2014:	
Increased customer consumption—weather and other	1,587
Increased wholesale propane sales	1,357
Increased margins from propane wholesale marketing	572
Other	(7)
Gross margin for the nine months ended September 30, 2014	$35,563

Increased Customer Consumption—Weather and Other
Higher customer consumption, due primarily to colder temperatures on the Delmarva Peninsula during 2014 generated an additional gross margin of $1.6 million.
Increased Wholesale Propane Sales
An increase in wholesale propane sales generated additional gross margin of $1.4 million due primarily to the supply agreement entered into in May 2013 with an affiliate of ESG.

Increased Margins from Propane Wholesale Marketing
Xeron generated additional gross margin of $572,000 during the first nine months of 2014 as it executed trades with higher profits principally during the first quarter of 2014. Higher price volatility in the wholesale propane market during that period resulted in profitable trading opportunities.

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Other

Lower retail propane margins for our Delmarva propane distribution operation decreased gross margin by $1.2 million. This decrease was partially offset by $1.2 million in higher retail propane margins in Florida as a result of sustained pricing in response to local market conditions. Retail propane margins have begun to decline to more normal levels on the Delmarva Peninsula during the first nine months of 2014, as a significant increase in wholesale prices in late 2013 and early 2014 increased our average propane inventory costs. In contrast, retail propane margins on the Delmarva Peninsula were unusually strong in the first nine months of 2013, due to a 27 percent decline in propane costs from lower propane wholesale prices in late 2012 and early 2013, which significantly outpaced a slight decline in retail prices. The propane retail price per gallon is subject to various market conditions, including competition with other propane suppliers and the availability and price of alternative energy sources. The propane retail price per gallon may fluctuate based on changes in demand, supply and other energy commodity prices.

Other Operating Expenses

The increase in other operating expenses was due primarily to: (a) $1.2 million in higher payroll expense due to increased seasonal overtime and additional resources to support growth; (b) $728,000 in additional expenses incurred by the entities acquired in 2013; and (c) the non-recurrence of an accrual of $698,000 recorded in 2013 related to a contingency for taxes other than income.

Other

For the quarter ended September 30, 2014 compared to 2013

	Three Months Ended September 30,		Increase
	2014	2013	(decrease)
(in thousands)			
Revenue	$5,192	$2,603	$2,589
Cost of sales	2,312	311	2,001
Gross margin	2,880	2,292	588
Operations & maintenance	1,958	1,676	282
Depreciation & amortization	127	114	13
Other taxes	233	222	11
Other operating expenses	2,318	2,012	306
Operating Income	$562	$280	$282

The “Other” segment, which consisted primarily of BravePoint, reported operating income of $562,000 for the quarter ended September 30, 2014, compared to $280,000 in the same quarter in 2013. A gross margin increase of $588,000 due to higher consulting and product sale revenue was partially offset by a $306,000 increase in other operating expenses due primarily to the addition of sales resources.

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For the nine months ended September 30, 2014 compared to 2013

(in thousands)	Nine Months Ended September 30, 2014	2013	Increase (decrease)
Revenue	$13,921	$9,678	$4,243
Cost of sales	6,900	3,432	3,468
Gross margin	7,021	6,246	775
Operations & maintenance	5,848	4,938	910
Depreciation & amortization	382	338	44
Other taxes	766	730	36
Other operating expenses	6,996	6,006	990
Operating Income	$25	$240	$(215)

The “Other” segment reported operating income of $25,000 and $240,000 for the nine months ended September 30, 2014 and 2013, respectively. BravePoint’s gross margin increased by $821,000 as a result of higher consulting revenues, while its other operating expenses increased by $1.0 million as a result of higher payroll due primarily to the addition of sales resources and benefits expenses.

Interest Charges

For the quarter ended September 30, 2014 compared to 2013
Interest charges for the three months ended September 30, 2014 increased by approximately $469,000, or 23 percent, compared to the same quarter in 2013. The increase in interest charges is attributable to an increase of $520,000 in long-term interest charges as a result of the Notes issued in December 2013 and May 2014.
For the nine months ended September 30, 2014 compared to 2013
Interest charges for the nine months ended September 30, 2014 increased by approximately $840,000, or 14 percent, compared to the same period in 2013. The increase in interest charges is attributable to higher debt balances during 2014 as a result of funding capital expenditures and the issuance of the Notes in December 2013 and May 2014.

Income Taxes

For the quarter ended September 30, 2014 compared to 2013
Income tax expense was $2.1 million in the third quarter of 2014, compared to $2.9 million in the same quarter in 2013. The decrease in income tax expense was due primarily to lower taxable income. Our effective income tax rate was 39.6 percent and 42.9 percent for the third quarters of 2014 and 2013, respectively. The effective income tax rate for the third quarter of 2013 was unusually high due to additional income tax expense recorded in that quarter associated with an adjustment for state income tax expense.

For the nine months ended September 30, 2014 compared to 2013
Income tax expense was $17.3 million for the nine months ended September 30, 2014, compared to $15.6 million in the same period in 2013. The increase in income tax expense was due to higher taxable income. Our effective income tax rate was 40.0 percent and 40.3 percent for the first nine months of 2014 and 2013, 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 finance capital expenditures.

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

Capital expenditures, which are our investments in new or acquired plant and equipment, are our largest capital requirements. We originally budgeted $110.9 million for capital expenditures during 2014. Our current projection of capital expenditures during 2014 is $112.3 million. The following table shows the projected 2014 capital expenditures by segment:

(dollars in thousands)	
Regulated Energy:	
Natural gas distribution	$59,558
Natural gas transmission	25,199
Electric distribution	8,694
Total Regulated Energy	93,451
Unregulated Energy:	
Propane distribution	8,827
Other unregulated energy	1,246
Total Unregulated Energy	10,073
Other	
Advanced information services	102
Other	8,647
Total Other	8,749
Total 2014 projected capital expenditures	$112,273

We expect to fund the 2014 capital expenditures from short-term borrowings, cash provided by operating activities, and other sources. In addition, as further discussed in the Capital Structure section below, we issued $50.0 million of our Series B Notes in May 2014.

The capital expenditures 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 projected amounts.

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Capital Structure

We are committed to maintaining a sound capital structure and strong credit ratings to provide the financial flexibility needed to access capital markets when required. This commitment, along with adequate and timely rate relief for our regulated operations, is intended to ensure our ability to attract capital from outside sources at a reasonable cost. We believe that the achievement of these objectives will provide benefits to our customers, creditors and investors. The following presents our capitalization, excluding and including short-term borrowings, as of September 30, 2014 and December 31, 2013:

	September 30, 2014		December 31, 2013	
(in thousands)				
Long-term debt, net of current maturities	$165,044	36 %	$117,592	30 %
Stockholders' equity	296,221	64 %	278,773	70 %
Total capitalization, excluding short-term debt	$461,265	100 %	$396,365	100 %

	September 30, 2014		December 31, 2013	
(in thousands)				
Short-term debt	$71,169	13 %	$105,666	21 %
Long-term debt, including current maturities	176,157	32 %	128,945	25 %
Stockholders' equity	296,221	55 %	278,773	54 %
Total capitalization, including short-term debt	$543,547	100 %	$513,384	100 %

In September 2013, we entered into the Note Agreement with the Note Holders to issue $70.0 million of Notes. We issued $20.0 million in Series A Notes in December 2013 and $50.0 million in Series B Notes in May 2014. The proceeds from these issuances were used to reduce our short-term borrowings and fund capital expenditures.

Included in the long-term debt balances at September 30, 2014 and December 31, 2013, was a capital lease obligation associated with Sandpiper's capacity, supply and operating agreement ($5.2 million and $6.1 million, respectively, net of current maturities and $6.4 million and $7.0 million, respectively, including current maturities). Sandpiper entered into this six-year agreement at the closing of the ESG acquisition in May 2013. The capacity portion of this agreement is accounted for as a capital lease.

Short-term Borrowings

Our outstanding short-term borrowings at September 30, 2014 and December 31, 2013 were $71.2 million and $105.7 million, respectively, at weighted average interest rates of 1.16 percent and 1.25 percent, respectively.

As of September 30, 2014, we had five unsecured short-term credit facilities with two financial institutions for a total of $165.0 million. Two of these unsecured bank lines, totaling $85.0 million, are available under committed lines of credit. Advances offered under the uncommitted lines of credit, totaling $40.0 million, are subject to the discretion of the banks. None of these unsecured bank lines of credit requires compensating balances. The remaining $40.0 million of our short-term credit facilities is structured in the form of a revolving credit note.

Cash Flows

The following table provides a summary of our operating, investing and financing cash flows for the nine months ended September 30, 2014 and 2013:

	Nine Months Ended September 30,	
	2014	2013
(in thousands)		
Net cash provided by (used in):		
Operating activities	$64,360	$66,427
Investing activities	(68,610)	(85,768)
Financing activities	3,179	17,772
Net decrease in cash and cash equivalents	(1,071)	(1,569)
Cash and cash equivalents—beginning of period	3,356	3,361

Cash and cash equivalents—end of period	$2,285	$1,792

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Cash Flows Provided By Operating Activities

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

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 and propane delivered by our natural gas and propane distribution operations 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.

During the nine months ended September 30, 2014 and 2013, net cash provided by operating activities was $64.4 million and $66.4 million, respectively, resulting in a decrease in cash flows of $2.0 million. Significant operating activities generating the cash flow change were as follows:

- The changes in net accounts receivable and payable increased cash flows by $12.0 million, due primarily to the timing of the collections and payments associated with trading contracts entered into by our propane wholesale marketing subsidiary;
- The changes in net regulatory assets and liabilities decreased cash flows by $13.1 million, due primarily to a change in fuel costs collected through fuel cost recovery;
- Net cash flows from changes in propane, natural gas and materials inventories increased by approximately $5.1 million, compared to 2013, as a result of the higher levels of propane, natural gas and materials usage, which decreases the levels of our inventory; and
- Net cash flows related to income taxes, which include deferred income taxes in non-cash adjustments to net income and the change in income taxes receivable, decreased by $13.6 million, due primarily to the absence of a bonus depreciation deduction in 2014, versus 2013.

Cash Flows Used in Investing Activities

Net cash used in investing activities totaled $68.6 million and $85.8 million during the nine months ended September 30, 2014 and 2013, respectively, resulting in an increase in cash flows of $17.2 million. Significant investing activities generating the cash flow change were as follows:

- We paid $19.4 million in net cash to acquire Glades, ESG, and Austin Cox during the first nine months of 2013; there were no corresponding transactions during the same period in 2014; and
- We received $2.3 million from the sale of equity securities during the first nine months of 2013; there were no corresponding transactions during the same period in 2014.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities totaled $3.2 million in the first nine months of 2014, compared to $17.8 million in the same period in 2013. This resulted in a decrease of $14.6 million in cash flows. Significant financing activities generating the cash flow change were as follows:

- Net proceeds from and repayments of long-term debt increased cash flows by $49.9 million due primarily to the $50.0 million issuance of Series B Notes in May 2014; and
- Net borrowing/repayment under line of credit agreements decreased cash flows by $66.8 million. The proceeds from the issuance of Series B Notes were used to repay borrowings under line of credit agreements.

Off-Balance Sheet Arrangements

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily our propane wholesale marketing subsidiary and natural gas marketing subsidiary. These corporate guarantees provide for the payment of propane and natural gas purchases in the event that the respective subsidiary defaults. None of these subsidiaries has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded in our financial statements when incurred. The aggregate amount guaranteed at September 30, 2014 was $31.6 million, with the guarantees expiring on various dates through September 2015.

In addition to the corporate guarantees, we have issued a letter of credit for $1.0 million, which was renewed through September 12, 2015, related to the electric transmission services for FPU's northwest electric division. We have also issued a letter of credit to our current primary insurance company for $1.1 million, which expires on December 2, 2014, as security to satisfy the deductibles

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under our various insurance policies. As a result of a change in our primary insurance company in 2010, we renewed and decreased the letter of credit for $304,000 to our former primary insurance company, which will expire on June 1, 2015. There have been no draws on these letters of credit as of September 30, 2014. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future.

We provided a letter of credit for $2.3 million to TETLP related to the firm transportation service agreement between our Delaware and Maryland divisions and TETLP.

On July 25, 2014, we provided a letter to the Florida PSC guaranteeing potential refunds from interim rates to be charged by our Florida electric operation (see Note 4, Rates and Other Regulatory Activities, to the condensed consolidated financial statements for further details on the Florida electric rate case). This guarantee expired in October 2014 upon approval of the permanent rate increase by the Florida PSC and determination that no refunds from interim rates were required.

Contractual Obligations

There has not been any material change in the contractual obligations presented in our 2013 Annual Report on Form 10-K, except for long-term debt, commodity purchase obligations and forward contracts entered into in the ordinary course of our business. The following table summarizes long-term debt, commodity and forward contract obligations at September 30, 2014.

	Payments Due by Period				
	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
(in thousands)					
Long-term debt	$9,818	$18,496	$34,924	$ 106,500	$169,738
Purchase obligations - Commodity [1]	13,078	879	—	—	13,957
Forward purchase contracts - Propane	37,366	18,577	2,408	—	58,351
Total	$60,262	$37,952	$37,332	$ 106,500	$242,046

(1) In addition to the obligations noted above, the natural gas, electric and propane distribution operations have agreements with commodity suppliers that have provisions with no minimum purchase requirements. There are no monetary penalties for reducing the amounts purchased; however, the propane contracts allow the suppliers to reduce the amounts available in the winter season if we do not purchase specified amounts during the summer season. Under these contracts, the commodity prices will fluctuate as market prices fluctuate.

Rates and Regulatory Matters

Our natural gas distribution operations in Delaware, Maryland and Florida and electric distribution operation in Florida are subject to regulation by the respective state PSC; Eastern Shore is subject to regulation by the FERC; and Peninsula Pipeline is subject to regulation by the Florida PSC. At September 30, 2014, we were involved in rate filings and/or regulatory matters in each of the jurisdictions in which we operate. Each of these rate filings and/or regulatory matters is fully described in Note 4, Rates and Other Regulatory Activities, to the unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q.

On April 28, 2014, FPU filed a base rate case for its electric distribution operation. FPU requested interim rate relief of approximately $2.4 million and final rate relief of approximately $5.9 million. The interim rate relief requested was based on the twelve-month period ended September 30, 2013. At the July 10, 2014 Agenda Conference, the Florida PSC approved interim rate relief of approximately $2.2 million. The interim rates were effective for meter readings on or after August 10, 2014. On August 29, 2014, FPU and the Florida Office of Public Counsel reached a settlement agreement, which provides, among other things, an increase in annual revenue requirement of approximately $3.8 million and a rate of return on common equity of 10.25 percent. On September 15, 2014, the Florida PSC approved the settlement agreement. New final rates will be effective for all meter reads on or after November 1, 2014.

Recent Authoritative Pronouncements on Financial Reporting and Accounting

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

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

Market risk represents the potential loss arising from adverse changes in market rates and prices. Long-term debt is subject to potential losses based on changes in interest rates. Our long-term debt consists of fixed-rate senior notes and secured debt. All of our long-term debt, excluding a capital lease obligation, is fixed-rate debt and was not entered into for trading purposes. The carrying value of our long-term debt, including current maturities, but excluding a capital lease obligation, was $169.7 million at September 30, 2014, as compared to a fair value of $186.6 million, using a discounted cash flow methodology that incorporates a market interest rate based on published corporate borrowing rates for debt instruments with similar terms and average maturities, with adjustments for duration, optionality, credit risk, and risk profile. We evaluate whether to refinance existing debt or permanently refinance existing short-term borrowing, based in part on the fluctuation in interest rates.

Our propane distribution business is exposed to market risk as a result of propane storage activities and entering into fixed price contracts for supply. We can store up to approximately 6.1 million gallons of propane (including leased storage and rail cars) during the winter season to meet our customers' peak requirements and to serve metered customers. Decreases in the wholesale price of propane may cause the value of stored propane to decline. To mitigate the impact of price fluctuations, we have adopted a Risk Management Policy that allows the propane distribution operation to enter into fair value hedges or other economic hedges of our inventory.

Our propane wholesale marketing operation is a party to natural gas liquids (primarily propane) forward contracts, with various third parties, which require that the propane wholesale marketing operation purchase or sell natural gas liquids at a fixed price at fixed future dates. At expiration, the contracts are typically settled financially without taking physical delivery of propane. The propane wholesale marketing operation also enters into futures contracts that are traded on the IntercontinentalExchange. In certain cases, the futures contracts are settled by the payment or receipt of a net amount equal to the difference between the current market price of the futures contract and the original contract price; however, they may also be settled by physical receipt or delivery of propane.

The forward and futures contracts are entered into for trading and wholesale marketing purposes. The propane wholesale marketing business is subject to commodity price risk on its open positions to the extent that market prices for natural gas liquids deviate from fixed contract settlement prices. Market risk associated with the trading of futures and forward contracts is monitored daily for compliance with our Risk Management Policy, which includes volumetric limits for open positions. To manage exposures to changing market prices, open positions are marked up or down to market prices and reviewed daily by our oversight officials. In addition, the Risk Management Committee reviews periodic reports on markets and the credit risk of counter-parties, approves any exceptions to the Risk Management Policy (within limits established by the Board of Directors) and authorizes the use of any new types of contracts. Quantitative information on forward and future contracts at September 30, 2014 is presented in the following table.

At September 30, 2014	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts			
Sale	1,260,000	$1.0838 - $1.1400	$1.1118
Purchase	1,261,000	$1.0913 - $1.3176	$1.1107

Estimated market prices and weighted average contract prices are in dollars per gallon. All contracts expire by the end of the fourth quarter of 2014

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

At September 30, 2014 and December 31, 2013, we marked these forward and other contracts to market, using market transactions in either the listed or OTC markets, which resulted in the following assets and liabilities:

(in thousands)	September 30, 2014	December 31, 2013
Mark-to-market energy assets, including call options	$187	$385
Mark-to-market energy liabilities, including swap agreements	$141	$127

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer and Chief Financial Officer of the Company, with the participation of other Company officials, have evaluated our “disclosure controls and procedures” (as such term is defined under Rules 13a-15(e) and 15d-15(e), promulgated under the Securities Exchange Act of 1934, as amended) as of September 30, 2014. Based upon their evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2014.

Changes in Internal Control over Financial Reporting

During the quarter ended September 30, 2014, there was no change in our internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II—OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

Our business, operations, and financial condition are subject to various risks and uncertainties. The risk factors described in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K, for the year ended December 31, 2013, should be carefully considered, together with the other information contained or incorporated by reference in this Quarterly Report on Form 10-Q and in our other filings with the SEC in connection with evaluating the Company, our business and the forward-looking statements contained in this Report. Additional risks and uncertainties not known to us at present, or that we currently deem immaterial also may affect the Company. The occurrence of any of these known or unknown risks could have a material adverse impact on our business, financial condition, and results of operations.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Period	Total Number of Shares Purchased [3]	Average Price Paid per Share [3]	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs [2]	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs [2]
July 1, 2014 through July 31, 2014[1]	320	$47.41	—	—
August 1, 2014 through August 31, 2014	—	$—	—	—
September 1, 2014 through September 30, 2014	—	$—	—	—
Total	320	$47.41	—	—

(1) Chesapeake purchased shares of stock on the open market for the purpose of reinvesting the dividend on deferred stock units held in the Rabbi Trust accounts for certain Directors and Senior Executives under the Deferred Compensation Plan. The Deferred Compensation Plan is discussed in detail in Item 8 under the heading "Notes to the Consolidated Financial Statements—Note 16, Employee Benefit Plans" in our latest Annual Report on Form 10-K for the year ended December 31, 2013. During the quarter ended September 30, 2014, 320 shares were purchased through the reinvestment of dividends on deferred stock units.

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

(3) Adjusted for the three-for-two stock split

Item 3. Defaults upon Senior Securities

None.

Item 5. Other Information

None.

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Item 6. Exhibits

31.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, dated November 6, 2014.
31.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, dated November 6, 2014.
32.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated November 6, 2014.
32.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated November 6, 2014.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

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SIGNATURES

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

CHESAPEAKE UTILITIES CORPORATION

/S/ BETH W. COOPER
Beth W. Cooper
Senior Vice President and Chief Financial Officer
Date: November 6, 2014