CHESAPEAKE UTILITIES CORP
Form 10-Q
August 07, 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: June 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 — 9,714,994 shares outstanding as of July 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., our advanced information services subsidiary, headquartered in Norcross, Georgia
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
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
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
FPU Pension Plan: A separate defined benefit pension plan for FPU sponsored by Chesapeake
FRP: Fuel Retention Percentage

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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 or will be entered into with the Note Holders
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
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
TETLP: Texas Eastern Transmission, LP
Xeron: Xeron, Inc., our propane wholesale marketing subsidiary, based in Houston, Texas

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
(in thousands, except shares and per share data)				
Operating Revenues				
Regulated energy	$61,646	$55,216	$163,812	$136,783
Unregulated energy	34,321	36,025	114,294	91,016
Other	4,530	2,905	8,728	7,075
Total Operating Revenues	100,497	94,146	286,834	234,874
Operating Expenses				
Regulated energy cost of sales	24,672	22,115	78,979	63,730
Unregulated energy and other cost of sales	28,442	28,773	89,766	68,861
Operations	24,615	22,822	51,242	44,577
Maintenance	2,457	1,820	4,606	3,542
Depreciation and amortization	6,736	5,977	13,371	11,797
Other taxes	3,118	3,487	6,791	6,665
Total Operating Expenses	90,040	84,994	244,755	199,172
Operating Income	10,457	9,152	42,079	35,702
Other income, net of other expenses	405	24	413	312
Interest charges	2,303	2,016	4,459	4,088
Income Before Income Taxes	8,559	7,160	38,033	31,926
Income taxes	3,425	2,804	15,218	12,701
Net Income	$5,134	$4,356	$22,815	$19,225
Weighted Average Common Shares Outstanding:				
Basic	9,704,161	9,621,580	9,681,422	9,611,610
Diluted	9,737,852	9,695,470	9,715,762	9,687,253
Earnings Per Share of Common Stock:				
Basic	$0.53	$0.45	$2.36	$2.00
Diluted	$0.53	$0.45	$2.35	$1.99
Cash Dividends Declared Per Share of Common Stock	$0.405	$0.385	$0.790	$0.750

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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
(in thousands)				
Net Income	$5,134	$4,356	$22,815	$19,225
Other Comprehensive Income, net of tax:				
Employee Benefits, net of tax:				
Amortization of prior service cost, net of tax of ($6), ($6), ($12), and ($12) respectively	(9)	(9)	(18)	(18)
Net gain, net of tax of $27, $43, $53 and $81, respectively	40	64	79	122
Cash Flow Hedges, net of tax:				
Unrealized loss on commodity contract cash flow hedges, net of tax of ($1), $0, ($1) and $0, respectively.	(1)	—	(1)	—
Total other comprehensive income	30	55	60	104
Comprehensive Income	$5,164	$4,411	$22,875	$19,329

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	June 30, 2014	December 31, 2013
(in thousands, except shares)		
Property, Plant and Equipment		
Regulated energy	$710,444	$691,522
Unregulated energy	78,616	76,267
Other	21,677	21,002
Total property, plant and equipment	810,737	788,791
Less: Accumulated depreciation and amortization	(186,663)	(174,148)
Plus: Construction work in progress	36,615	16,603
Net property, plant and equipment	660,689	631,246
Current Assets		
Cash and cash equivalents	2,529	3,356
Accounts receivable (less allowance for uncollectible accounts of $1,819 and $1,635, respectively)	44,858	75,293
Accrued revenue	7,631	13,910
Propane inventory, at average cost	6,836	10,456
Other inventory, at average cost	3,382	4,880
Storage gas prepayments	3,131	4,318
Prepaid expenses	4,229	6,910
Income taxes receivable	—	2,609
Mark-to-market energy assets	136	385
Regulatory assets	5,822	2,436
Deferred income taxes	1,657	1,696
Other current assets	203	160
Total current assets	80,414	126,409
Deferred Charges and Other Assets		
Investments, at fair value	3,542	3,098
Regulatory assets	66,300	66,584
Goodwill	4,625	4,354
Other intangible assets, net	2,775	2,975
Receivables and other deferred charges	2,740	2,856
Total deferred charges and other assets	79,982	79,867
Total Assets	$821,085	$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	June 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)	$4,727	$4,691
Additional paid-in capital	154,619	152,341
Retained earnings	139,350	124,274
Accumulated other comprehensive loss	(2,473)	(2,533)
Deferred compensation obligation	1,202	1,124
Treasury stock	(1,202)	(1,124)
Total stockholders' equity	296,223	278,773
Long-term debt, net of current maturities	165,370	117,592
Total capitalization	461,593	396,365
Current Liabilities		
Current portion of long-term debt	11,117	11,353
Short-term borrowing	47,870	105,666
Accounts payable	30,184	53,482
Accrued compensation	5,495	8,394
Accrued interest	1,352	1,235
Dividends payable	3,933	3,710
Income taxes payable	695	—
Mark-to-market energy liabilities	32	127
Regulatory liabilities	5,875	4,157
Customer deposits and refunds	23,482	26,140
Other accrued liabilities	9,978	7,678
Total current liabilities	140,013	221,942
Deferred Credits and Other Liabilities		
Deferred income taxes	142,766	142,597
Deferred investment tax credits	57	74
Regulatory liabilities	3,975	4,402
Accrued asset removal cost—Regulatory liability	39,991	39,510
Environmental liabilities	9,076	9,155
Other pension and benefit costs	20,123	21,000
Other liabilities	3,491	2,477
Total deferred credits and other liabilities	219,479	219,215
Other commitments and contingencies (Note 6)		
Total Capitalization and Liabilities	$821,085	$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)

	Six Months Ended June 30, 2014	2013
(in thousands)		
Operating Activities		
Net income	$22,815	$19,225
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	13,371	11,797
Depreciation and accretion included in other costs	3,447	3,030
Deferred income taxes, net	166	5,796
Gain on sale of assets	(420)	(39)
Unrealized (gain) loss on commodity contracts	62	(153)
Unrealized gain on investments	(152)	(42)
Realized gain on sales of investments, net	—	(310)
Employee benefits	319	458
Share-based compensation	1,065	861
Other, net	(1)	(22)
Changes in assets and liabilities:		
Purchase of investments	(293)	(398)
Accounts receivable and accrued revenue	36,713	(6,268)
Propane inventory, storage gas and other inventory	6,074	2,180
Regulatory assets	(5,250)	1,721
Prepaid expenses and other current assets	3,183	2,312
Accounts payable and other accrued liabilities	(22,491)	8,074
Income taxes receivable and payable	3,305	6,599
Accrued interest	118	(316)
Customer deposits and refunds	(2,658)	(3,958)
Accrued compensation	(2,975)	(2,060)
Regulatory liabilities	1,761	5,588
Other assets and liabilities, net	63	(12)
Net cash provided by operating activities	58,222	54,063
Investing Activities		
Property, plant and equipment expenditures	(42,753)	(41,220)
Proceeds from sales of assets	459	45
Acquisitions	—	(19,541)
Environmental expenditures	(79)	(209)
Net cash used in investing activities	(42,373)	(60,925)
Financing Activities		
Common stock dividends	(6,754)	(6,356)
Purchase of stock for Dividend Reinvestment Plan	(392)	(655)
Change in cash overdrafts due to outstanding checks	(806)	(1,240)
Net borrowing (repayment) under line of credit agreements	(56,990)	15,532
Proceeds from issuance of long-term debt	50,000	7,000
Repayment of long-term debt and capital lease obligation	(1,734)	(8,570)
Net cash provided by (used in) financing activities	(16,676)	5,711
Net Decrease in Cash and Cash Equivalents	(827)	(1,151)
Cash and Cash Equivalents—Beginning of Period	3,356	3,361

Cash and Cash Equivalents—End of Period	$2,529	$2,210

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	9,597,499	$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 ($1.520 per share)	—	—	(6)	(14,752)	—	—	—	(14,758)
Conversion of debentures	17,383	8	287	—	—	—	—	295
Share-based compensation and tax benefit [2] [3]	23,348	12	1,310	—	—	—	—	1,322
Treasury stock activities	—	—	—	—	—	142	(142)	—
Balance at December 31, 2013	9,638,230	4,691	152,341	124,274	(2,533)	1,124	(1,124)	278,773
Net Income	—	—	—	22,815	—	—	—	22,815
Other comprehensive income	—	—	—	—	60	—	—	60
Dividend declared ($0.790 per share)	5,193	3	318	(7,739)	—	—	—	(7,418)
Retirement Savings Plan	9,834	5	597	—	—	—	—	602
Conversion of debentures	31,542	15	520	—	—	—	—	535
Share-based compensation and tax benefit [2] [3]	26,772	13	843	—	—	—	—	856
Treasury stock activities	—	—	—	—	—	78	(78)	—
Balance at June 30, 2014	9,711,571	$4,727	$154,619	$139,350	$ (2,473)	$ 1,202	$(1,202)	$296,223

(1) Includes 34,960 and 34,495 shares at June 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 quarter ended June 30, 2014 and for the year ended December 31, 2013, we withheld 8,458 and 10,411 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.

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 will receive one additional share of common stock for every two shares of common stock owned. The stock dividend will be issued on September 8, 2014.

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.

Recently Adopted Accounting Standards

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.

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2. Calculation of Earnings Per Share

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
(in thousands, except shares and per share data)				
Calculation of Basic Earnings Per Share:				
Net Income	$5,134	$4,356	$22,815	$19,225
Weighted average shares outstanding	9,704,161	9,621,580	9,681,422	9,611,610
Basic Earnings Per Share	$0.53	$0.45	$2.36	$2.00
Calculation of Diluted Earnings Per Share:				
Reconciliation of Numerator:				
Net Income	$5,134	$4,356	$22,815	$19,225
Effect of 8.25% Convertible debentures [1]	—	11	—	22
Adjusted numerator—Diluted	$5,134	$4,367	$22,815	$19,247
Reconciliation of Denominator:				
Weighted shares outstanding—Basic	9,704,161	9,621,580	9,681,422	9,611,610
Effect of dilutive securities:				
Share-based Compensation	33,691	22,454	34,340	22,789
8.25% Convertible debentures [1]	—	51,436	—	52,854
Adjusted denominator—Diluted	9,737,852	9,695,470	9,715,762	9,687,253
Diluted Earnings Per Share	$0.53	$0.45	$2.35	$1.99

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

3. Acquisitions

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 now 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. The allocation of the purchase price and valuation of assets are final, as the final purchase price allocation was completed.

The revenue from this acquisition for the three and six months ended June 30, 2014, included in our condensed consolidated statement of income, were $4.2 million and $14.4 million, respectively. The net income from this acquisition for the three and six months ended June 30, 2014, included in our condensed consolidated statement of income, were $123,000 and $1.8 million, respectively.

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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 six months ended June 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 six months ended June 30, 2014 were not material.

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 rates and other regulatory activities in Delaware during the first six months of 2014.

Maryland

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. Sandpiper recommended slightly lower depreciation rates to be applied prospectively and a reduction of $4.5 million in accumulated depreciation. On June 20, 2014, the Maryland PSC staff recommended lower depreciation rates than those recommended by Sandpiper and a reduction of $5.5 million in accumulated depreciation. The Office of People's Counsel also recommended lower depreciation rates and no adjustment to accumulated depreciation. The parties are currently discussing a potential settlement in advance of an evidentiary hearing in August 2014.

Florida

On April 28, 2014, FPU filed a base rate proceeding 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 is 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, as recommended by the Florida PSC staff. The interim rates are effective for meter readings on or after August 10, 2014. Any increase to our rates as a result of this interim rate relief may be subject to refund, depending on the outcome of the final rate relief request. The base rate proceeding hearing is currently scheduled for September 15-18, 2014. The revenue requirement will be determined at the Agenda Conference, currently scheduled for November 25, 2014, and final rates will be determined at the Agenda Conference, currently scheduled for December 16, 2014. Final rates are expected to be effective in January 2015.

On January 13, 2014, FPU's natural gas 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 depreciation expense for our Florida natural gas distribution operations. The PSC agenda date for the depreciation study has not yet been set.

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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. This extension would be effective for two years, beginning January 1, 2014. The Florida PSC approved the extension of the surcharge and the additional amount for recovery at the Agenda Conference on January 7, 2014.

Eastern Shore

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

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 will allow 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, but this requested improvement will 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 project consists 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 is designed to provide 55,200 Dts/d of delivery lateral firm transportation service to an industrial customer facility currently under construction. The total cost of the project is estimated to be approximately $11.5 million.

On August 9, 2013, the FERC issued a notice of intent to prepare an environmental assessment for the project. The comment period concluded on September 9, 2013, with no comments being filed in the docket. The environmental assessment was issued on October 4, 2013, and FERC staff recommended a finding of no significant impact. Eastern Shore filed the implementation plan and acceptance of conditions, stating that it will comply with all environmental conditions as set forth in the order. On November 27, 2013, the FERC issued a CP for this project. On January 17, 2014, the FERC issued its notice to allow construction to proceed, and Eastern Shore began construction activities for this project on January 22, 2014, for a planned in-service date of January 1, 2015.

Other matters: Eastern Shore also had developments in the following FERC 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, 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 June 30, 2014, we had approximately $10.2 million in environmental liabilities related to all of FPU’s MGP sites in Florida, which include the Key West, Pensacola, Sanford and West Palm Beach sites, representing our estimate of the future costs associated with those sites. FPU has approval to recover up to $14.0 million of its environmental costs related to all of its MGP sites from insurance and from customers through rates, approximately $9.4 million of which has been recovered as of June 30, 2014. We had approximately $4.6 million in regulatory assets for future recovery of environmental costs from FPU’s customers.

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In addition to the FPU MGP sites, we had $454,000 in environmental liabilities at June 30, 2014, related to Chesapeake's MGP sites in Maryland and Florida, representing our estimate of future costs associated with these sites. As of June 30, 2014, we had approximately $503,000 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 ultimately will 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. In January 2007, FPU and the Sanford Group signed a Third Participation Agreement, which provides for the funding of the final remedy approved by the EPA for the site. FPU's share of remediation costs under the Third Participation Agreement is set at five percent of a maximum of $13.0 million, or $650,000. As of June 30, 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 June 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 June 30, 2014.

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 via e-mail on

October 9, 2012 that, based on the data, NAM appears to be an appropriate remedy for the site.
The FDEP issued a Remedial Action Plan approval order, dated October 12, 2012, which specified that a limited semi-annual monitoring program is to be conducted. The most recent groundwater-monitoring event was conducted on March

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13, 2014. The results were reported in a letter to FDEP dated April 26, 2014. Natural Attenuation Default Criteria were met at all locations sampled. The next semi-annual sampling event is scheduled for September of 2014. 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 FDEP would approve a conditional No Further Action determination for the site, which must include a requirement for institutional and engineering controls. On December 13, 2011, Gulf Power, the City of Pensacola, FDOT and FPU submitted to FDEP a draft covenant for institutional and engineering controls for the site. Upon FDEP's approval and the subsequent recording of the institutional and engineering controls, no further work is expected to be required of the parties. Assuming FDEP approves the draft institutional and engineering controls, 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. Recent groundwater sampling results show a continuing reduction in contaminant concentrations from the treatment system, which has been in operation since 2002. Currently, we predict that remedial action objectives could be met in approximately two to three years for the area being treated by the remediation system. On August 7, 2012, FDEP issued a letter discussing the need to evaluate further remedial options, which could incorporate risk-management options, including natural attenuation and the use of institutional and engineering controls. Modifications to the existing consent order and the remedial action plan modification could be required to incorporate risk-management options into the remedy for the site. A response letter was submitted to FDEP on May 7, 2013. FDEP issued an additional comment letter, dated September 16, 2013, containing various requests and questions, which we responded to on October 10, 2013.

An exploratory drilling program was conducted in November of 2013. The most recent groundwater monitoring event was conducted on April 11, 2014, and results were reported in a letter to FDEP dated June 6, 2014. A meeting was held with FDEP on June 12, 2014 to discuss the results of the drilling program, the groundwater conditions, and potential future remedial actions. FDEP indicated that it may be possible to close out the site with institutional controls without modifying the existing consent order. FDEP is currently evaluating its administrative options.

Even if modifications to the existing consent order and remedial action plan are required, 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. If we are required to incur this cost, 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.

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.

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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 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.

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 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 June 30, 2014, FPU was in compliance with all of the requirements of its fuel supply contracts.

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.

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 in the event of the respective subsidiary’s default. Neither subsidiary has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded when incurred. The aggregate amount guaranteed at June 30, 2014 was $31.6 million, with the guarantees expiring on various dates through June 2015.

Chesapeake 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).

In addition to the corporate guarantees, we have issued a letter of credit for $1.0 million, which expires on September 12, 2014, 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

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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 June 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. The interim rates, which provide a rate relief of approximately $2.2 million of revenue on an annual basis, were approved by the Florida PSC in July 2014 in connection with the base rate proceeding currently in progress. This guarantee will expire upon the release by the Florida PSC at the conclusion of the base rate proceeding. See Note 4, Rates and Other Regulatory Activities, for further details on the base rate proceeding involving the Florida electric operation.

Tax-related Contingencies

We are subject to various audits and reviews by the federal, state, local and other regulatory authorities regarding income taxes and taxes other than income. As of June 30, 2014, we maintained a liability of $300,000 related to unrecognized income tax benefits and $905,000 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 operations 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. The “Other” segment consists primarily of our advanced information services subsidiary, as well as our unregulated subsidiaries that own real estate leased to Chesapeake and certain corporate costs not allocated to other operations.

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The following table presents financial information about our reportable segments:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
(in thousands)				
Operating Revenues, Unaffiliated Customers				
Regulated Energy	$61,348	$54,975	$163,222	$136,279
Unregulated Energy	34,299	34,273	114,173	89,264
Other	4,850	4,898	9,439	9,331
Total operating revenues, unaffiliated customers	$100,497	$94,146	$286,834	$234,874
Intersegment Revenues [1]				
Regulated Energy	$298	$241	$590	$504
Unregulated Energy	22	1,752	121	1,752
Other	248	227	502	470
Total intersegment revenues	$568	$2,220	$1,213	$2,726
Operating Income				
Regulated Energy	$10,711	$8,619	$31,802	$25,925
Unregulated Energy	(43)	447	10,815	9,816
Other and eliminations	(211)	86	(538)	(39)
Total operating income	10,457	9,152	42,079	35,702
Other income, net of other expenses	405	24	413	312
Interest	2,303	2,016	4,459	4,088
Income before Income Taxes	8,559	7,160	38,033	31,926
Income taxes	3,425	2,804	15,218	12,701
Net Income	$5,134	$4,356	$22,815	$19,225

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

(in thousands)	June 30, 2014	December 31, 2013
Identifiable Assets		
Regulated energy	$716,126	$708,950
Unregulated energy	77,800	100,585
Other	27,159	27,987
Total identifiable assets	$821,085	$837,522

Our operations are almost entirely domestic. BravePoint has infrequent transactions in foreign countries, which are denominated and paid primarily in U.S. dollars. These transactions are 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 six months ended June 30, 2014 and 2013.

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
December 31, 2013	$(2,533)	$—	$(2,533)
Other comprehensive loss before reclassifications	—	(1)	(1)
Amounts reclassified from accumulated other comprehensive loss	61	—	61
Net current-period other comprehensive income (loss)	61	(1)	60
June 30, 2014	$(2,472)	$(1)	$(2,473)

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
December 31, 2012	$(5,062)	$—	$(5,062)
Other comprehensive loss before reclassifications	(6)	—	(6)
Amounts reclassified from accumulated other comprehensive loss	110	—	110
Net current-period other comprehensive income	104	—	104
June 30, 2013	$(4,958)	$—	$(4,958)

The following table presents amounts reclassified out of accumulated other comprehensive loss for the three and six months ended June 30, 2014 and 2013. The only such amounts for those periods were defined benefit pension and postretirement plan items. Deferred gains or losses for our commodity contracts cash flow hedges are recognized in earnings upon settlement.

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2014	2013	2014	2013
Amortization of defined benefit pension and postretirement plan items:				
Prior service cost [(1)]	$15	$15	$30	$30
Net loss [(1)]	(67)	(107)	(132)	(213)
Total before income taxes	(52)	(92)	(102)	(183)
Income tax benefit	21	37	41	73
Net of tax	$(31)	$(55)	$(61)	$(110)

[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 six months ended June 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 June 30,	2014	2013	2014	2013	2014	2013	2014	2013	2014	2013
(in thousands)										
Interest cost	$106	$103	$647	$594	$23	$20	$13	$12	$16	$16
Expected return on plan assets	(132)	(126)	(772)	(718)	—	—	—	—	—	—
Amortization of prior service cost	—	—	—	—	5	5	(20)	(20)	—	—
Amortization of net loss	38	57	—	81	12	16	17	19	—	—
Net periodic cost (benefit)	12	34	(125)	(43)	40	41	10	11	16	16
Amortization of pre-merger regulatory asset	—	—	191	191	—	—	—	—	2	2
Total periodic cost	$12	$34	$66	$148	$40	$41	$10	$11	$18	$18

	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP		Chesapeake Postretirement Plan		FPU Medical Plan	
For the Six Months Ended June 30,	2014	2013	2014	2013	2014	2013	2014	2013	2014	2013
(in thousands)										
Interest cost	$213	$205	$1,294	$1,188	$46	$41	$26	$24	$33	$32
Expected return on plan assets	(265)	(252)	(1,545)	(1,437)	—	—	—	—	—	—
Amortization of prior service cost	—	(1)	—	—	9	10	(39)	(39)	—	—
Amortization of net loss	75	114	—	162	24	32	33	36	—	—
Net periodic cost (benefit)	23	66	(251)	(87)	79	83	20	21	33	32
Amortization of pre-merger regulatory asset	—	—	381	381	—	—	—	—	4	4
Total periodic cost	$23	$66	$130	$294	$79	$83	$20	$21	$37	$36

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 $4.0 million and $4.4 million at June 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.

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 pursuant to a Florida PSC order. 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 six months ended June 30, 2014 and 2013:

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For the Three Months Ended June 30, 2014	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service cost (credit)	$ —	$—	$ 5	$ (20)	$—	(15)
Net loss	38	—	12	17	—	67
Total recognized in net periodic benefit cost	$ 38	$—	$ 17	$ (3)	$—	$52
Recognized from accumulated other comprehensive loss (1)	$ 38	$—	$ 17	$ (3)	$—	$52
Recognized from regulatory asset	—	—	—	—	—	—
Total	$ 38	$—	$ 17	$ (3)	$—	$52

For the Six Months Ended June 30, 2014	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service cost (credit)	$ —	$—	$ 9	$ (39)	$—	(30)
Net loss	75	—	24	33	—	132
Total recognized in net periodic benefit cost	$ 75	$—	$ 33	$ (6)	$—	$102
Recognized from accumulated other comprehensive loss (1)	$ 75	$—	$ 33	$ (6)	$—	$102
Recognized from regulatory asset	—	—	—	—	—	—
Total	$ 75	$—	$ 33	$ (6)	$—	$102

For the Three Months Ended June 30, 2013	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service cost (credit)	$ —	$—	$ 5	$ (20)	$—	(15)
Net loss	57	81	16	19	—	173
Total recognized in net periodic benefit cost	$ 57	$81	$ 21	$ (1)	$—	$158
Recognized from accumulated other comprehensive loss	$ 57	$15	$ 21	$ (1)	$—	$92
Recognized from regulatory asset	—	66	—	—	—	66
Total	$ 57	$81	$ 21	$ (1)	$—	$158

For the Six Months Ended June 30, 2013	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service cost (credit)	$ (1)	$—	$ 10	$ (39)	$—	(30)
Net loss	114	162	32	36	—	344
Total recognized in net periodic benefit cost	$ 113	$162	$ 42	$ (3)	$—	$314
Recognized from accumulated other comprehensive loss	$ 113	$31	$ 42	$ (3)	$—	$183
Recognized from regulatory asset	—	131	—	—	—	131

Total	$ 113	$ 162	$ 42	$ (3)	$ —	$ 314

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

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During the three and six months ended June 30, 2014, we contributed $130,000 and $221,000, respectively, to the Chesapeake Pension Plan and $419,000 and $630,000, respectively, to the FPU Pension Plan. We expect to contribute a total of $520,000 and $1.7 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 six months ended June 30, 2014, were $22,000 and $45,000, 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 six months ended June 30, 2014, were $22,000 and $45,000, 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 six months ended June 30, 2014, were $89,000 and $144,000, 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 June 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 June 30, 2014 and 2013, we recorded a net unrealized gain of $114,000 and a net unrealized loss of $241,000, respectively, in other income in the condensed consolidated statements of income related to these investments. For the six months ended June 30, 2014 and 2013, we recorded a net unrealized gain of $152,000 and $42,000, 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

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
(in thousands)				
Awards to non-employee directors	$132	$120	$256	$231
Awards to key employees	295	341	809	630
Total compensation expense	427	461	1,065	861
Less: tax benefit	172	186	429	347
Share-Based Compensation amounts included in net income	$255	$275	$636	$514

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 806 shares of common stock under the SICP. A summary of the stock activity for our non-employee directors during the six months ended June 30, 2014 is presented below.

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	Number of Shares	Weighted Average Grant date Fair Value
Outstanding - December 31, 2013	—	$—
Granted	8,866	$62.00
Vested	8,866	$62.00
Outstanding - June 30, 2014	—	$—

At June 30, 2014, there was $458,000 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 the awards to key employees for the six months ended June 30, 2014:

	Number of Shares	Weighted Average Fair Value
Outstanding—December 31, 2013	80,761	$42.30
Granted	27,628	$59.98
Vested	26,364	$40.30
Outstanding—June 30, 2014	82,025	$48.90

In January and March 2014, the Board of Directors granted awards of 27,628 shares to key employees under the SICP. The awards of 23,200 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 4,428 shares granted in March 2014 to one key employee is a multi-year award that will vest at the end of the three-year 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 June 30, 2014, the aggregate intrinsic value of the SICP awards awarded to key employees was $5.9 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 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 in order to mitigate the impact of wholesale price fluctuations. As of June 30, 2014, our natural gas and electric distribution operations did not have any outstanding derivative contracts.

In May 2014, Sharp entered into swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with 630,000 gallons purchased for the upcoming heating season. Under these swap agreements, 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 June 30, 2014, the swap agreements had a fair value of $(2,000). 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 June 30, 2014, the put options had a fair value of $99,000. 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 these options as fair value hedges, and there is no ineffective portion of these 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 expected to be purchased at market-based prices to supply the demands of our propane price cap program customers. The program caps the retail price that we can 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 June 30, 2014, we had the following outstanding trading contracts, which we accounted for as derivatives:

At June 30, 2014	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts			
Sale	630,000	$1.1400	$1.1400
Purchase	631,000	$1.1300 - $1.3176	$1.1302

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 June 30, 2014, Xeron had a right to offset $1.7 million and $425,000 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 June 30, 2014 and December 31, 2013, are as follows:

	Asset Derivatives		
		Fair Value As Of	
(in thousands)	Balance Sheet Location	June 30, 2014	December 31, 2013
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy assets	$37	$196
Call Option [1]	Mark-to-market energy assets	—	169
Derivatives designated as fair value hedges			
Put Options	Mark-to-market energy assets	99	20
Total asset derivatives		$136	$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 June 30, 2014.

	Liability Derivatives		
		Fair Value As Of	
(in thousands)	Balance Sheet Location	June 30, 2014	December 31, 2013
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy liabilities	$30	$127
Derivatives designated as cash flow hedges			
Propane swap agreements	Mark-to-market energy liabilities	2	—
Total liability derivatives		$32	$127

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

		Amount of Gain (Loss) on Derivatives:			
	Location of Gain	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
(in thousands)	(Loss) on Derivatives	2014	2013	2014	2013
Derivatives not designated as hedging instruments					
Unrealized gain (loss) on forward contracts	Revenue	$6	$(60)	(62)	$153
Call Option	Cost of sales	—	(8)	137	(8)
Derivatives designated as fair value hedges					
Put/Call Options	Cost of sales	(29)	—	(49)	(28)
Put/Call Options	Inventory		(14)		(14)
Derivatives designated as cash flow hedges					
Propane swap agreements	Other Comprehensive loss	(2)	—	(2)	—
Total		$(25)	$(82)	$24	$103

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

(in thousands)	Location in the Statements of Income	For the Three Months Ended June 30, 2014	2013	For the Six Months Ended June 30, 2014	2013
Realized gain on forward contracts	Revenue	$84	$110	$1,330	$185
Unrealized gain (loss) on forward contracts	Revenue	6	(60)	(62)	153
Total		$90	$50	$1,268	$338

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 June 30, 2014 and December 31, 2013:

June 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	$410	$—	$—	$410
Investments—other	$3,132	$3,132	$—	$—
Mark-to-market energy assets, incl. put/call options	$136	$—	$136	$—
Liabilities:				
Mark-to-market energy liabilities incl. swap agreements	$32	$—	$32	$—

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	$—

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

	Six Months Ended June 30,	
	2014	2013
(in thousands)		
Beginning Balance	$458	$—
Transfers in due to change in trustee	—	425
Purchases and adjustments	(26)	96
Transfers	(25)	(16)
Investment income	3	4
Ending Balance	$410	$509

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 June 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.
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 June 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 June 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 $188.0 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)	June 30, 2014	December 31, 2013
FPU secured first mortgage bonds [A] :		
9.08% bond, due June 1, 2022	$7,968	$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	344	445
Capital lease obligation	6,766	6,978
Total long-term debt	176,487	128,945
Less: current maturities	(11,117)	(11,353)
Total long-term debt, net of current maturities	$165,370	$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, Convertible Debentures totaling $537,000 were converted to stock and $109,000 were redeemed for cash. As of March 1, 2014, we no longer have any outstanding Convertible Debentures.

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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;
- risks related to cyber-attack or failure of information technology systems; and

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- changes in technology affecting our advanced information services business.

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, including advanced information services.

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.

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Results of Operations for the Three and Six Months ended June 30, 2014

Overview and Highlights

Our net income for the quarter ended June 30, 2014 was $5.1 million, or $0.53 per share (diluted). This represents an increase of $778,000, or $0.08 per share (diluted), compared to net income of $4.4 million, or $0.45 per share (diluted), as reported for the same quarter in 2013.

	Three Months Ended June 30, 2014	2013	Increase (decrease)
(in thousands except per share)			
Business Segment:			
Regulated Energy	$10,711	$8,619	$2,092
Unregulated Energy	(43)	447	(490)
Other	(211)	86	(297)
Operating Income	10,457	9,152	1,305
Other Income	405	24	381
Interest Charges	2,303	2,016	287
Income Taxes	3,425	2,804	621
Net Income	$5,134	$4,356	$778
Earnings Per Share of Common Stock			
Basic	$0.53	$0.45	$0.08
Diluted	$0.53	$0.45	$0.08

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Key variances included:

(in thousands, except per share)	Pre-tax Income	Net Income	Earnings Per Share
Second Quarter of 2013 Reported Results	$7,160	$4,356	$0.45
Adjusting for unusual items:			
One-time sales tax expensed by Sandpiper associated with the acquisition	759	462	0.05
	759	462	0.05
Increased Gross Margins:			
Major Projects (See Major Projects Highlights table)			
Service expansions	1,545	939	0.10
Contribution from Sandpiper	966	588	0.06
GRIP	643	391	0.04
Other natural gas growth	572	348	0.04
Contribution from other acquisitions	53	32	—
	3,779	2,298	0.24
(Increased) Decreased Other Operating Expenses:			
Higher payroll costs	(1,509)	(918)	(0.09)
Expenses from acquisitions	(1,098)	(668)	(0.07)
Higher depreciation, asset removal and property tax costs due to new capital investments	(852)	(519)	(0.05)
Higher benefits costs	(661)	(402)	(0.04)
Lower accrual for incentive bonuses	316	193	0.02
	(3,804)	(2,314)	(0.23)
Net Other Changes	665	332	0.02
Second Quarter of 2014 Reported Results	$8,559	$5,134	$0.53

Our net income for the six months ended June 30, 2014 was $22.8 million, or $2.35 per share (diluted). This represents an increase of $3.6 million, or $0.36 per share (diluted), compared to net income of $19.2 million, or $1.99 per share (diluted), as reported for the same period in 2013.

	Six Months Ended June 30,		Increase
	2014	2013	(decrease)
(in thousands except per share)			
Business Segment:			
Regulated Energy	$31,802	$25,925	$5,877
Unregulated Energy	10,815	9,816	999
Other	(538)	(39)	(499)
Operating Income	42,079	35,702	6,377
Other Income	413	312	101
Interest Charges	4,459	4,088	371
Income Taxes	15,218	12,701	2,517
Net Income	$22,815	$19,225	$3,590
Earnings Per Share of Common Stock			
Basic	$2.36	$2.00	$0.36
Diluted	$2.35	$1.99	$0.36

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Key variances included:

(in thousands, except per share)	Pre-tax Income	Net Income	Earnings Per Share
Six months ended June 30, 2013 Reported Results	$31,926	$19,225	$1.99
Adjusting for unusual items:			
Weather impact (due primarily to colder temperatures in 2014)	2,266	1,365	0.14
One-time sales tax expensed by Sandpiper associated with the acquisition	759	457	0.05
	3,025	1,822	0.19
Increased Gross Margins:			
Major Projects (See Major Projects Highlights table)			
Contribution from Sandpiper	5,255	3,165	0.33
Service expansions	2,970	1,789	0.18
GRIP	1,310	789	0.08
Increased wholesale propane sales	1,286	774	0.08
Other natural gas growth	1,159	698	0.07
Propane wholesale marketing	930	560	0.06
Contributions from other acquisitions	555	334	0.03
	13,465	8,109	0.83
Increased Other Operating Expenses:			
Expenses from acquisitions	(3,214)	(1,935)	(0.20)
Higher payroll costs	(2,664)	(1,605)	(0.17)
Higher benefits costs	(1,709)	(1,030)	(0.11)
Higher depreciation, asset removal costs and property tax costs due to new capital investments	(1,631)	(982)	(0.10)
Larger accrual for incentive bonuses	(742)	(447)	(0.05)
	(9,960)	(5,999)	(0.63)
Net Other Changes	(423)	(342)	(0.03)
Six months ended June 30, 2014 Reported Results	$38,033	$22,815	$2.35

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 are evaluating the potential conversion of some of the underground propane distribution systems to natural gas distribution and have begun to convert some of these customers. This acquisition was accretive to earnings per share in the first full year of operations, generating $0.22 in additional earnings per share. We generated $966,000 and $5.3 million, in additional gross margin from Sandpiper for the three and six months ended June 30, 2014, respectively, and incurred $782,000 and $2.2 million in additional other operating expenses for the three and six months ended June 30, 2014, respectively. Additionally, in the second quarter of 2013, we recorded $759,000 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

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margin of $740,000 and $2.0 million in the three and six months ended June 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 $599,000 in the second quarter of 2014, and is expected to generate $1.9 million and $767,000 of gross margin in 2014 and 2015, respectively.

Eastern Shore is constructing a pipeline lateral to an industrial customer facility under construction in Kent County, Delaware. Upon completion of this lateral, which is currently expected in October 2014, this new service is expected to generate annual gross margin between $1.2 million to $1.8 million. During 2014, we expect to generate $463,000 in additional gross margin from this new service. The new facilities include approximately 5.5 miles of pipeline lateral and metering facilities, which will extend from Eastern Shore's mainline to the new industrial customer facility.

In August 2013, Peninsula Pipeline, our intrastate natural gas transmission subsidiary, commenced a new firm transportation service in Florida with an unaffiliated utility. This new service generated $210,000 and $420,000 in gross margin for the three and six months ended June 30, 2014.

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

	Q2 2014	YTD 2014	2014 (1)
Acquisition:			
ESG acquisition being served by Sandpiper in Worcester County, Maryland (2)	$1,504	$5,794	$9,817
Service Expansions			
Natural Gas Distribution:			
Long-term			
Sussex County, Delaware (3)	$155	$359	$694
Natural Gas Transmission:			
Short-term			
New Castle County, Delaware (4) (5)	$599	$599	$1,862
Kent County, Delaware (5)	—	—	—
Total Short-term	$599	$599	$1,862
Long-term			
Sussex County, Delaware (6)	$431	$863	$1,725
New Castle County, Delaware (6) (7)	741	1,482	2,964
Nassau County, Florida (6)	328	655	1,300
Worcester County, Maryland (6)	137	274	547
Cecil County, Maryland (6)	287	574	1,147
Indian River County, Florida	210	420	840
Kent County, Delaware	665	1,330	3,123
Total Long-term	$2,799	$5,598	$11,646
Total Service Expansions	$3,553	$6,556	$14,202
Total Major Projects	$5,057	$12,350	$24,019
Less: 2013 Margin	$2,545	$4,124	$13,176
Incremental Margin in 2014 over 2013	$2,512	$8,226	$10,843

(1) The figures provided represent the estimated annual gross margin.
(2) During the three months and six months ended June 30, 2014, we incurred $782,000 and $2.2 million, respectively, in other operating expenses related to Sandpiper's operation. We expect to incur a total of $6.3 million in other operating expenses during 2014.

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(3) These services generated $153,000 and $355,000 in gross margin for the three and six months ended June 30, 2013, respectively.
(4) 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.
(5) We provided short-term service for New Castle County and generated $128,000 and $168,000 in gross margin for the three and six months ended June 30, 2013, respectively. We also provided short-term service for Kent County and generated $386,000 in gross margin for the three and six months ended June 30, 2013. These short-term services were displaced by the new long-term services in November 2013.
(6) Gross margin generated by these services for the three months ended June 30, 2013 was $345,000 for Sussex County, Delaware; $343,000 for New Castle County, Delaware; $334,000 for Nassau County, Florida; $98,000 for Worcester County, Maryland; and $220,000 for Cecil County, Maryland. Gross margin generated by these services for the six months ended June 30, 2013 was $690,000 for Sussex County, Delaware; $686,000 for New Castle County, Delaware; $665,000 for Nassau County, Florida; $195,000 for Worcester County, Maryland; and $441,000 for Cecil County, Maryland.
(7) 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.

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 $29.3 million. During the first half of 2014, we invested $9.5 million and expect to invest an additional $12.4 million during the second half of 2014. These investments generated additional gross margin of $643,000 and $1.3 million for the three and six months ended June 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. Eastern Shore also increased its staffing. Finally, resources have been added in our corporate shared services departments to increase our overall capabilities to support sustained future growth. The additional staffing has increased payroll expenses for our Regulated Energy segment by $439,000 and $864,000, respectively, for the three and six months ended June 30, 2014, compared to the same periods in 2013. We expect to make additional investments in human resources, as needed, to further develop our capability to capitalize on future growth opportunities.

Weather and Consumption

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

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HDD and CDD Information

	Three Months Ended June 30, 2014	2013	Variance	Six Months Ended June 30, 2014	2013	Variance
Delmarva						
Actual HDD	456	490	(34)	3,173	2,897	276
10-Year Average HDD ("Normal")	459	473	(14)	2,820	2,850	(30)
Variance from Normal	(3)	17		353	47	
Florida						
Actual HDD	17	19	(2)	574	487	87
10-Year Average HDD ("Normal")	26	28	(2)	555	569	(14)
Variance from Normal	(9)	(9)		19	(82)	
Florida						
Actual CDD	928	865	63	970	946	24
10-Year Average CDD ("Normal")	908	911	(3)	982	986	(4)
Variance from Normal	20	(46)		(12)	(40)	

Gross Margin Variance attributed to Weather

(in thousands)	Q2 2014 vs. Q2 2013	Q2 2014 vs. Normal	YTD 2014 vs. YTD 2013	YTD 2014 vs. Normal
Delmarva				
Regulated Energy	$(256)	$19	$255	$636
Unregulated Energy	(39)	(46)	1,694	1,096
Florida				
Regulated Energy	(56)	(116)	269	(322)
Unregulated Energy	—	—	48	81
Total	$(351)	$(143)	$2,266	$1,491

Propane

During 2014, retail propane margins on the Delmarva Peninsula reverted 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 $75,000 and $891,000 for the three and six months ended June 30, 2014, respectively. In Florida, higher retail propane margins as a result of local market conditions increased gross margin by $312,000 and $637,000 for the three and six months ended June 30, 2014.

Wholesale propane sales increased, generating additional gross margin of $254,000 and $1.3 million for the three and six months ended June 30, 2014, respectively, due primarily to sales to an affiliate of ESG.
Xeron, which benefits from wholesale price volatility by entering into trading transactions, did not have a significant impact on the quarter-over-quarter variance for the three months ended June 30, 2014 due to lower wholesale price volatility. For the six months ended June 30, 2014, Xeron generated an increase in gross margin of $930,000, 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.

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Regulated Energy

For the quarter ended June 30, 2014 compared to 2013

	Three Months Ended June 30, 2014	2013	Increase (decrease)
(in thousands)			
Revenue	$61,646	$55,216	$6,430
Cost of sales	24,672	22,115	2,557
Gross margin	36,974	33,101	3,873
Operations & maintenance	18,109	16,683	1,426
Depreciation & amortization	5,623	4,897	726
Other taxes	2,531	2,902	(371)
Other operating expenses	26,263	24,482	1,781
Operating Income	$10,711	$8,619	$2,092

Operating income for the Regulated Energy segment for the quarter ended June 30, 2014 was $10.7 million, an increase of $2.1 million, or 24 percent. An increase in gross margin of $3.9 million was partially offset by an increase in other operating expenses of $1.8 million.

Gross Margin

Items contributing to the quarter-over-quarter increase of $3.9 million, or 12 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended June 30, 2013	$33,101
Factors contributing to the gross margin increase for the three months ended June 30, 2014:	
Service expansions	1,545
Contributions from acquisitions	1,007
Additional revenue from GRIP in Florida	643
Other natural gas growth	572
Other	106
Gross margin for the three months ended June 30, 2014	$36,974

Service Expansions

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

- $599,000 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.
- $549,000 from long-term natural gas transmission services that commenced in November 2013 to several industrial customers, located in New Castle and Kent Counties, Delaware. These long-term transmission services displaced short-term services that Eastern Shore provided to these customers from May through October 2013 and 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.
- $398,000 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 Nassau and Indian River Counties, Florida.

Contributions from Acquisitions

In late May 2013, upon completion of the purchase of the ESG operating assets, Sandpiper began providing services to approximately 11,000 propane underground distribution system customers in Worcester County, Maryland, under a tariff approved by the Maryland PSC. Sandpiper generated $966,000 of additional gross margin in the second quarter of 2014. Also, the acquisition

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of certain operating assets of the City of Fort Meade, Florida, in December 2013, generated $41,000 of additional gross margin during the second quarter of 2014.

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 second quarter of 2014, FPU and Chesapeake's Florida division recorded $643,000 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:

- $473,000 from Florida natural gas customer growth due primarily to new services to commercial and industrial customers; and
- $165,000 from three percent residential customer growth, as well as growth in commercial and industrial customers, in our Delmarva natural gas distribution operation.

Other Operating Expenses

The increase in other operating expenses was due primarily to: (a) $832,000 in higher depreciation, amortization, asset removal and property tax costs associated with capital investments to support growth and maintain system integrity; (b) $782,000 in other operating expenses associated with Sandpiper's operations; (c) $439,000 in higher payroll costs incurred primarily to support recent growth and expand our capability to cultivate future growth; (d) $399,000 in higher benefits costs; and (e) $419,000 in higher payroll costs in Florida due primarily to a vacation policy change in 2013, which reduced the accrual for that year. These increases in other operating expenses were partially offset by the absence of a one-time sales tax expense of $759,000 in the second quarter of 2013 related to the ESG acquisition.

For the six months ended June 30, 2014 compared to 2013

	Six Months Ended June 30, 2014	2013	Increase (decrease)
(in thousands)			
Revenue	$163,812	$136,783	$27,029
Cost of sales	78,980	63,731	15,249
Gross margin	84,832	73,052	11,780
Operations & maintenance	36,510	32,150	4,360
Depreciation & amortization	11,150	9,706	1,444
Other taxes	5,370	5,271	99
Other operating expenses	53,030	47,127	5,903
Operating Income	$31,802	$25,925	$5,877

Operating income for the Regulated Energy segment for the six months ended June 30, 2014 was $31.8 million, an increase of $5.9 million, or 23 percent. An increase in gross margin of $11.8 million was partially offset by an increase in other operating expenses of $5.9 million.

Gross Margin

Items contributing to the period-over-period increase of $11.8 million, or 16 percent, in gross margin are listed in the following table:

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(in thousands)	
Gross margin for the six months ended June 30, 2013	$73,052
Factors contributing to the gross margin increase for the six months ended June 30, 2014:	
Contributions from acquisitions	5,358
Service expansions	2,970
Additional revenue from GRIP in Florida	1,310
Other natural gas growth	1,159
Increased customer consumption - weather and other	540
Other	443
Gross margin for the six months ended June 30, 2014	$84,832

Contributions from Acquisitions

Sandpiper generated $5.3 million of additional gross margin in the first six months of 2014. Also, the acquisition of certain operating assets of the City of Fort Meade, Florida, in December 2013, generated $102,000 of additional gross margin during the first six months of 2014.

Service Expansions

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

- $1.6 million from long-term natural gas transmission services, which commenced in November 2013, for services provided by Eastern Shore to industrial customers located in New Castle and Kent Counties, Delaware. These long-term transmission services, which displaced short-term services provided by Eastern Shore to these customers from May through October 2013, 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.
- $799,000 from expansions completed in 2013 that facilitated new natural gas transmission and distribution services in Sussex County, Delaware; Worcester and Cecil Counties, Maryland; and Nassau and Indian River Counties, Florida.
- $599,000 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.

Additional Revenue from GRIP in Florida

During the first half of 2014, FPU and Chesapeake's Florida division recorded $1.3 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:

- $997,000 from Florida natural gas customer growth due primarily to new services to commercial and industrial customers.
- $445,000 from a three-percent residential customer growth rate, as well as growth in commercial and industrial customers, in our Delmarva natural gas distribution operation.
- These increases were partially offset by a decrease in Eastern Shore's interruptible service to an existing industrial customer, which lowered lower gross margin by $454,000.

Increased Customer Consumption—Weather and Other

Higher customer consumption due to colder temperatures on the Delmarva Peninsula and in Florida during the first six months of 2014 generated increased gross margin of approximately $255,000 and $269,000, respectively.

Other Operating Expenses

The increase in other operating expenses for the Regulated Energy segment was due primarily to: (a) $2.2 million in other operating expenses associated with Sandpiper's operations; (b) $1.6 million in higher depreciation, amortization, asset removal and property tax costs associated with capital investments to support growth and maintain system integrity; (c) $1.1 million in higher benefits costs; (d) $864,000 in higher payroll costs to support recent and future growth; and (e) $610,000 in higher payroll costs in Florida principally resulting from a change in vacation policy in 2013, which reduced the accrual for that year. These increases in other

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operating expenses were partially offset by the absence a one-time sales tax expense of $759,000 in 2013 related to the ESG acquisition.

Unregulated Energy

For the quarter ended June 30, 2014 compared to 2013

	Three Months Ended June 30,		Increase
	2014	2013	(decrease)
(in thousands)			
Revenue	$34,321	$36,025	$(1,704)
Cost of sales	26,020	27,934	(1,914)
Gross margin	8,301	8,091	210
Operations & maintenance	7,022	6,319	703
Depreciation & amortization	986	967	19
Other taxes	336	358	(22)
Other operating expenses	8,344	7,644	700
Operating Income (Loss)	$(43)	$447	$(490)

The Unregulated Energy segment reported an operating loss of $43,000 in the second quarter of 2014, compared to operating income of $447,000 in the same quarter of 2013. Gross margin increased by $210,000 while other operating expense increased by $700,000.

Gross Margin

Items contributing to the quarter-over-quarter increase of $210,000 in gross margin are as follows:

(in thousands)	
Gross margin for the three months ended June 30, 2013	$8,091
Factors contributing to the gross margin increase for the three months ended June 30, 2014:	
Increased wholesale propane sales	254
Increase in retail propane margins	237
Decreased customer consumption—weather and other	(195)
Contributions from acquisitions	12
Other	(98)
Gross margin for the three months ended June 30, 2014	$8,301

Increased Wholesale Propane Sales

An increase in wholesale propane sales generated additional gross margin of $254,000 as a result of a supply agreement entered into in May 2013 with an affiliate of ESG.

Increase in Retail Propane Margins

Higher retail propane margins for our Florida propane distribution operation increased gross margin by $312,000. The higher margins in Florida were partially offset by $75,000 in lower retail propane margins on the Delmarva Peninsula.

Decreased Customer Consumption—Weather and Other

Lower customer consumption decreased gross margin by $195,000. This lower consumption was due primarily to a decrease in non-weather related consumption by Florida customers, partially offset by an increase in non-weather related consumption on the Delmarva Peninsula.

Contributions from Acquisitions

The acquisition of the operating assets of Austin Cox in June 2013 generated $12,000 of additional gross margin during the second quarter of 2014.

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Other Operating Expenses

Other operating expenses for the Unregulated Energy segment increased by $700,000 of which $466,000 is attributable to higher payroll and benefits costs principally attributed to resources added to support growth.

For the six months ended June 30, 2014 compared to 2013

	Six Months Ended June 30, 2014	2013	Increase (decrease)
(in thousands)			
Revenue	$114,294	$91,016	$23,278
Cost of sales	85,179	65,741	19,438
Gross margin	29,115	25,275	3,840
Operations & maintenance	15,447	12,706	2,741
Depreciation & amortization	1,966	1,867	99
Other taxes	887	886	1
Other operating expenses	18,300	15,459	2,841
Operating Income	$10,815	$9,816	$999

Operating income for the Unregulated Energy segment for the six months ended June 30, 2014 was $10.8 million, an increase of $999,000, or 10 percent. An increase in gross margin of $3.8 million was partially offset by an increase in other operating expenses of $2.8 million.

Gross Margin

Items contributing to the period-over-period increase of $3.8 million, or 15 percent, in gross margin are as follows:

(in thousands)	
Gross margin for the six months ended June 30, 2013	$25,275
Factors contributing to the gross margin increase for the six months ended June 30, 2014:	
Increased customer consumption—weather and other	1,640
Increased wholesale propane sales	1,286
Increased margins from propane wholesale marketing	930
Contributions from acquisitions	452
Decrease in retail propane margins	(254)
Other	(214)
Gross margin for the six months ended June 30, 2014	$29,115

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Increased Customer Consumption—Weather and Other
Higher customer consumption increased gross margin by $1.6 million. This increase was due primarily to colder temperatures on the Delmarva Peninsula during the first six months of 2014.
Increased Wholesale Propane Sales
An increase in wholesale propane sales generated additional gross margin of $1.3 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 $930,000 during the first half of 2014 as a result of: (a) trades executed with higher margins because of higher price volatility in the wholesale propane market, primarily during the first three months of 2014, and (b) a 34-percent increase in trading activity.
Contributions from Acquisitions
The acquisitions of the operating assets of Glades in February 2013 and Austin Cox in June 2013 generated $146,000 and $306,000, respectively, of additional gross margin during the first six months of 2014.

Decrease in Retail Propane Margins
Lower retail propane margins for our Delmarva propane distribution operation decreased gross margin by $891,000. This decrease was partially offset by $637,000 in higher retail propane margins in Florida as a result of sustained pricing in response to local market conditions. Retail propane margins began to return to more normal levels on the Delmarva Peninsula during the first six 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 six 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) $905,000 in additional expenses incurred by the entities acquired in 2013; (b) $857,000 in higher payroll expense due to increased seasonal overtime and additional resources to support growth; and (c) $256,000 in increased accruals for incentive bonuses as a result of strong financial performance on a year-to-date basis.

Other

For the quarter ended June 30, 2014 compared to 2013

	Three Months Ended June 30, 2014	2013	Increase (decrease)
(in thousands)			
Revenue	$4,530	$2,905	$1,625
Cost of sales	2,422	839	1,583
Gross margin	2,108	2,066	42
Operations & maintenance	1,941	1,640	301
Depreciation & amortization	127	113	14
Other taxes	251	227	24
Other operating expenses	2,319	1,980	339
Operating Income (Loss)	$(211)	$86	$(297)

The “Other” segment, which consists primarily of BravePoint, reported an operating loss of $211,000 for the quarter ended June 30, 2014, compared to operating income of $86,000 in the same quarter in 2013. This increased loss resulted from a $339,000 increase

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in operating expenses partially offset by a $42,000 increase in gross margin. The increased operating expenses were due primarily to augmented sales resources for BravePoint.

For the six months ended June 30, 2014 compared to 2013

	Six Months Ended June 30,		Increase
	2014	2013	(decrease)
(in thousands)			
Revenue	$8,728	$7,075	$1,653
Cost of sales	4,587	3,120	1,467
Gross margin	4,141	3,955	186
Operations & maintenance	3,890	3,263	627
Depreciation & amortization	255	223	32
Other taxes	534	508	26
Other operating expenses	4,679	3,994	685
Operating Loss	$(538)	$(39)	$(499)

The “Other” segment reported an operating loss of $538,000 and $39,000 for the six months ended June 30, 2014 and 2013, respectively. BravePoint’s gross margin increased by $240,000 as a result of higher consulting revenues, while its other operating expenses increased by $725,000 as a result of higher payroll due primarily to the addition of sales resources and benefits expenses.

Interest Charges

For the quarter ended June 30, 2014 compared to 2013
Interest charges for the three months ended June 30, 2014 increased by approximately $287,000, or 14 percent, compared to the same quarter in 2013. The increase in interest charges is attributable primarily to an increase of $225,000 in long-term interest charges as a result of the Notes issued in 2013 and 2014, partially offset by a decrease in interest charges as a result of scheduled principal payments.

For the six months ended June 30, 2014 compared to 2013
Interest charges for the six months ended June 30, 2014 increased by approximately $371,000, or nine percent, compared to the same period in 2013. The increase in interest charges is attributable primarily to higher short-term and long-term debt balances during 2014 as a result of funding capital expenditures and the issuance of the Notes in 2013 and 2014.

Income Taxes

For the quarter ended June 30, 2014 compared to 2013
Income tax expense was $3.4 million in the second quarter of 2014, compared to $2.8 million in the same quarter in 2013. The increase in income tax expense was due to higher taxable income. Our effective income tax rate was 40.0 percent and 39.2 percent for the second quarters of 2014 and 2013, respectively.

For the six months ended June 30, 2014 compared to 2013
Income tax expense was $15.2 million for the six months ended June 30, 2014, compared to $12.7 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 39.8 percent for the first six 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 $145.9 million. The following table shows the projected 2014 capital expenditure by segment:

(dollars in thousands)	
Regulated Energy:	
Natural gas distribution	$63,985
Natural gas transmission	51,442
Electric distribution	7,867
Total Regulated Energy	123,294
Unregulated Energy:	
Propane distribution	8,774
Other unregulated energy	3,946
Total Unregulated Energy	12,720
Other	
Advanced information services	898
Other	9,034
Total Other	9,932
Total 2014 projected capital expenditures	$145,946

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 June 30, 2014 and December 31, 2013:

	June 30, 2014		December 31, 2013	
(in thousands)				
Long-term debt, net of current maturities	$165,370	36 %	$117,592	30 %
Stockholders' equity	296,223	64 %	278,773	70 %
Total capitalization, excluding short-term debt	$461,593	100 %	$396,365	100 %

	June 30, 2014		December 31, 2013	
(in thousands)				
Short-term debt	$47,870	9 %	$105,666	21 %
Long-term debt, including current maturities	176,487	34 %	128,945	25 %
Stockholders' equity	296,223	57 %	278,773	54 %
Total capitalization, including short - term debt	$520,580	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 June 30, 2014 and December 31, 2013, was a capital lease obligation associated with Sandpiper's capacity, supply and operating agreement ($5.5 million and $6.1 million, respectively, net of current maturities and $6.8 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 June 30, 2014 and December 31, 2013 were $47.9 million and $105.7 million, respectively, at weighted average interest rates of 1.18 percent and 1.25 percent, respectively.

As of June 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 six months ended June 30, 2014 and 2013:

	Six Months Ended June 30, 2014	2013
(in thousands)		
Net cash provided by (used in):		
Operating activities	$58,222	$54,063
Investing activities	(42,373)	(60,925)
Financing activities	(16,676)	5,711
Net decrease in cash and cash equivalents	(827)	(1,151)
Cash and cash equivalents—beginning of period	3,356	3,361

Cash and cash equivalents—end of period	$2,529	$2,210

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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 six months ended June 30, 2014 and 2013, net cash provided by operating activities was $58.2 million and $54.1 million, respectively, resulting in an increase in cash flows of $4.2 million. Significant operating activities generating the cash flow change were as follows:

- The changes in net accounts receivable and payable increased cash flows by $12.4 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 $10.8 million, due primarily to a change in fuel costs collected through fuel cost recovery;
- Net cash flows from changes in propane and natural gas inventories increased by approximately $3.9 million, compared to 2013, as a result of the higher levels of propane and natural gas usage, which decreases the levels of our inventory;
- Higher net income taxes paid decreased the cash flows by $3.3 million, due primarily to the absence of a bonus depreciation deduction in 2014, versus 2013.
- Lower refunds of customer deposits increased cash flows by $1.3 million.

Cash Flows Used in Investing Activities

Net cash used in investing activities totaled $42.4 million and $60.9 million during the six months ended June 30, 2014 and 2013, respectively, resulting in an increase in cash flows of $18.5 million. Significant investing activities generating the cash flow change were as follows:

- Net cash of $19.5 million was used to acquire Glades, Sandpiper, and Austin Cox during the first six months of 2013; there were no corresponding transactions during the same period in 2014;
- Cash paid for capital expenditures increased by $1.6 million to $42.8 million for the first six months of 2014, compared to $41.2 million for the same period in 2013.

Cash Flows Used by Financing Activities

Net cash used in financing activities totaled $16.7 million in the first six months of 2014, compared to net cash of $5.7 million provided by financing activities in the same period in 2013. This resulted in a decrease of $22.4 million in cash flows. Significant financing activities generating the cash flow change were as follows:

- During the six months ended June 30, 2014, we received $50.0 million in cash proceeds from a long-term issuance of Series B Notes and paid $1.7 million for scheduled principal payments. During the first six months ended June 30, 2013, we issued $7.0 million in long-term debt to refinance $8.5 million of existing secured long-term bonds. These long-term debt activities increased cash flows by $49.8 million.
- Net repayments of $57.0 million under our lines of credit during the six months ended June 30, 2014, compared to net borrowings of $15.5 million in the same period in 2013, decreased cash flows by $72.5 million. The proceeds from the long-term debt issuance during the first six months of 2014 were used to repay borrowings under our lines of credit.

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 of the respective subsidiary’s default. 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 June 30, 2014 was $31.6 million, with the guarantees expiring on various dates through June 2015.

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In addition to the corporate guarantees, we have issued a letter of credit for $1.0 million, which was renewed through September 12, 2014, 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 June 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. The interim rates, which provide a rate relief of approximately $2.2 million of revenue on an annual basis, were approved by the Florida PSC in July 2014 in connection with the base rate proceeding currently underway. This guarantee will expire upon the release by the Florida PSC at the conclusion of the base rate proceeding. See Note 4, Rates and Other Regulatory Activities, to the condensed consolidated financial statements for further details on the base rate proceeding involving the Florida electric operation.

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 commodity purchase obligations and forward contracts entered into in the ordinary course of our business. The following table summarizes the commodity and forward contract obligations at June 30, 2014.

	Payments Due by Period				
Purchase Obligations	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
(in thousands)					
Commodities [(1)]	$10,917	$621	$—	$ —	$11,538
Propane	27,958	18,639	3,610	—	50,207
Total Purchase Obligations	$38,875	$19,260	$3,610	$ —	$61,745

(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 June 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 proceeding 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 is 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, as recommended by the Florida PSC staff.

The interim rates are effective for meter readings on or after August 10, 2014. Any increase to our rates as a result of this interim rate relief may be subject to refund, depending on the outcome of the final rate relief request. The base rate proceeding hearing is currently scheduled for September 15-18, 2014. The revenue requirement will be determined at the Agenda Conference, currently scheduled for November 25, 2014, and final rates will be determined at the Agenda Conference, currently scheduled for December 16, 2014. Final rates are expected to be effective in January 2015.

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Recent Authoritative Pronouncements on Financial Reporting and Accounting

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Market risk represents the potential loss arising from adverse changes in market rates and prices. Long-term debt is subject to potential losses based on changes in interest rates. Our long-term debt consists of fixed-rate senior notes and secured debt. All of our long-term debt, excluding a capital lease obligation, is fixed-rate debt and was not entered into for trading purposes. The carrying value of our long-term debt, including current maturities, but excluding a capital lease obligation, was $169.7 million at June 30, 2014, as compared to a fair value of $188.0 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 June 30, 2014 is presented in the following table.

At June 30, 2014	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts			
Sale	630,000	$1.1400	$1.1400
Purchase	631,000	$1.1300 - $1.3176	$1.1302

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 June 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:

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(in thousands)	June 30, 2014	December 31, 2013
Mark-to-market energy assets, including call options	$136	$385
Mark-to-market energy liabilities, including swap agreements	$32	$127

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

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

Changes in Internal Control over Financial Reporting

During the quarter ended June 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	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (2)	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs (2)
April 1, 2014 through April 30, 2014(1)	229	$61.23	—	—
May 1, 2014 through May 31, 2014	—	$—	—	—
June 1, 2014 through June 30, 2014	—	$—	—	—
Total	229	$61.23	—	—

(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 June 30, 2014, 229 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.

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 August 7, 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 August 7, 2014.
32.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated August 7, 2014.
32.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated August 7, 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: August 7, 2014