CHESAPEAKE UTILITIES CORP
Form 10-Q
November 07, 2013
Table of Contents

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

FORM 10-Q

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

For the quarterly period ended: September 30, 2013

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 — 9,632,595 shares outstanding as of October 31, 2013.

Table of Contents

Table of Contents

Table of Contents

GLOSSARY OF KEY TERMS AND DEFINITIONS

KEY TERMS

Bulk delivery: Propane delivery to customers based on the level of propane remaining in the tank located at the customer's premises. We invoice and record revenues for the bulk delivery service at the time of delivery, rather than upon a customer's actual usage.

Cost of sales: Includes the purchased cost of natural gas, electricity and propane commodities, pipeline capacity costs needed to transport and store natural gas, transmission costs for electricity, transportation costs to transport propane purchases to our storage facilities and the direct cost of labor spent on revenue-producing activities.

Delmarva natural gas distribution operation: Chesapeake's Delaware and Maryland divisions.

Delmarva Peninsula: A peninsula on the east coast of the United States of America occupied by Delaware and portions of Maryland and Virginia. Chesapeake provides natural gas distribution, transmission and marketing services and propane distribution service to customers on the Delmarva Peninsula.

Electric distribution: Regulated electric distribution utility service. Florida Public Utilities Company provides this service to customers in northeast and northwest Florida. This service is regulated by the Florida Public Service Commission.

Florida natural gas distribution operation: Chesapeake's Florida division and the natural gas operation of Florida Public Utilities Company, including its Indiantown division.

Gross margin: A non-GAAP measure, which Chesapeake uses to evaluate the performance of its business segments. Gross margin is calculated by deducting the cost of sales from operating revenues. A more detailed description of gross margin, including how we calculate it, is provided in the Management's Discussion and Analysis of Financial Condition and Results of Operations section of this Quarterly Report on Form 10-Q.

Interruptible service: Large commercial customers whose regulated utility service can be temporarily interrupted in order for the utility to meet the needs of firm service customers. The interruptible service customers pay lower delivery rates than firm service customers, and they must be able to readily substitute an alternate fuel for natural gas.

Margin per gallon: A measure of profitability for propane distribution sales, calculated for each gallon of propane sold by deducting the cost of propane sold from the propane revenue.

Mark-to-market: The process of adjusting the carrying value of a position held in our forward contracts and derivative instruments to reflect their current fair value.

Natural gas distribution: Regulated natural gas distribution utility service. Both Chesapeake Utilities Corporation, through its Delaware, Maryland and Florida divisions, and Florida Public Utilities Company provide this service, which is regulated by the Public Service Commission of each respective state.

Natural gas marketing: Unregulated natural gas supply and supply management service for the sale of the natural gas commodity directly to residential, commercial and industrial customers through competitively-priced contracts. Peninsula Energy Services Company, Inc. provides this service.

Natural gas transmission: Regulated natural gas transportation service provided by Eastern Shore Natural Gas Company and Peninsula Pipeline Company, Inc. The interstate transportation service provided by Eastern Shore Natural Gas Company is regulated by the Federal Energy Regulatory Commission. The intrastate transportation service provided by Peninsula Pipeline Company, Inc. in Florida is regulated by the Florida Public Service Commission.

Normal Weather: The most recent 10–year average of heating and/or cooling degree-days in a particular geographic area.

Propane distribution: Unregulated propane distribution service to residential, commercial, industrial and wholesale customers. This service can be provided through delivery to a propane tank located on the customer's premises or through an underground pipeline system.

Propane wholesale marketing: Unregulated service offering where propane is marketed to major independent oil and petrochemical companies, wholesale resellers and retail propane companies located primarily in the southeastern United States of America. This service typically utilizes forward or other option contracts that are financially settled. Xeron, Inc. provides this service.

Table of Contents

Regulated energy: The largest operating segment of Chesapeake Utilities Corporation. All operations in this segment are regulated as to their rates and service, by the Public Service Commission having jurisdiction in each state in which the Company operates or by the Federal Energy Regulatory Commission.

DEFINITIONS

ASC: Accounting Standards Codification

ASU: Accounting Standards Update

Austin Cox: Austin Cox Home Services, Inc.

BravePoint: BravePoint®, Inc., Chesapeake's advanced information services subsidiary, headquartered in Norcross, Georgia

Calpine: Calpine Energy Services, L.P.

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

CP: Certificate of Public Convenience and Necessity

DSCP: Directors Stock Compensation Plan

Dts/d: Dekatherms per day

DPA: The Division of the Public Advocate

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

ESG: Eastern Shore Gas Company and its affiliates

EPA: United States Environmental Protection Agency

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 as of October 28, 2009, the date we acquired FPU

FRP: Fuel Retention Percentage

Franchise Agreement: The agreement between the City of Marianna, Florida and Florida Public Utilities Company, which granted a franchise to Florida Public Utilities Company for the operation and distribution and/or sale of electric energy

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

Glades: Glades Gas Co., Inc.

GSR: Gas Service Rates

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
IGC: Indiantown Gas Company
MGP: Manufactured gas plant, which is a site where coal was previously used to manufacture gaseous fuel for industrial, commercial and residential use
MDE: Maryland Department of Environment
Marianna Commission: The City Commission of Marianna, Florida
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
NRG: NRG Energy Center Dover LLC
OTC: Over-the-counter
PBF Energy: PBF Energy Inc.
PESCO: Peninsula Energy Services Company, Inc., a wholly-owned natural gas marketing subsidiary of Chesapeake
Peninsula Pipeline: Peninsula Pipeline Company, Inc., a wholly-owned Florida intrastate pipeline subsidiary of Chesapeake
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: Florida Public Utilities Company 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 to be issued on December 16, 2013 pursuant to the Note Agreement
Series B Notes: Series B of the unsecured Senior Notes to be issued on May 15, 2014 pursuant to the Note Agreement
SERP: Supplemental Executive Retirement Plan
Sharp: Sharpgas, Inc.
TETLP: Texas Eastern Transmission, LP
TOU: Time-of-use
Xeron: Xeron, Inc., a wholly-owned propane wholesale marketing subsidiary of Chesapeake, based in Houston, Texas

Table of Contents

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

	Three Months		Nine Months	
For the Periods Ended September 30,	2013	2012	2013	2012
(in thousands, except shares and per share data)				
Operating Revenues				
Regulated energy	$55,680	$52,196	$192,463	$180,045
Unregulated energy	28,262	23,259	119,278	93,323
Other	2,603	2,720	9,678	9,619
Total Operating Revenues	86,545	78,175	321,419	282,987
Operating Expenses				
Regulated energy cost of sales	22,591	22,102	86,321	81,207
Unregulated energy and other cost of sales	21,795	17,602	90,656	72,056
Operations	21,300	20,804	65,878	60,831
Maintenance	2,146	1,801	5,688	5,635
Depreciation and amortization	6,274	5,767	18,071	17,413
Other taxes	3,719	2,535	10,383	7,753
Total Operating Expenses	77,825	70,611	276,997	244,895
Operating Income	8,720	7,564	44,422	38,092
Other income (loss), net of other expenses	101	(136)	413	212
Interest charges	2,026	2,126	6,114	6,657
Income Before Income Taxes	6,795	5,302	38,721	31,647
Income taxes	2,916	2,083	15,617	12,641
Net Income	$3,879	$3,219	$23,104	$19,006
Weighted Average Common Shares Outstanding:				
Basic	9,625,435	9,592,417	9,616,269	9,583,316
Diluted	9,702,334	9,676,658	9,692,311	9,673,681
Earnings Per Share of Common Stock:				
Basic	$0.40	$0.34	$2.40	$1.98
Diluted	$0.40	$0.33	$2.39	$1.97
Cash Dividends Declared Per Share of Common Stock	$0.385	$0.365	$1.135	$1.080

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

Table of Contents

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

	Three Months		Nine Months	
For the Periods Ended September 30,	2013	2012	2013	2012
(in thousands)				
Net Income	$3,879	$3,219	$23,104	$19,006
Other Comprehensive Income (Loss), net of tax:				
Employee Benefits, net of tax:				
Amortization of prior service cost, net of tax of ($6), ($6), ($18) and ($19), respectively	(9)	(9)	(27)	(28)
Net gain, net of tax of $43, $51, $124 and $152, respectively	64	76	186	228
Total other comprehensive income	55	67	159	200
Comprehensive Income	$3,934	$3,286	$23,263	$19,206

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

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

Assets	September 30, 2013	December 31, 2012
(in thousands, except shares and per share data)		
Property, Plant and Equipment		
Regulated energy	$635,859	$585,429
Unregulated energy	73,816	70,218
Other	21,048	20,067
Total property, plant and equipment	730,723	675,714
Less: Accumulated depreciation and amortization	(171,060)	(155,378)
Plus: Construction work in progress	50,256	21,445
Net property, plant and equipment	609,919	541,781
Current Assets		
Cash and cash equivalents	1,792	3,361
Accounts receivable (less allowance for uncollectible accounts of $1,215 and $826, respectively)	60,578	53,787
Accrued revenue	7,948	11,688
Propane inventory, at average cost	7,383	7,612
Other inventory, at average cost	3,452	5,841
Regulatory assets	2,063	2,736
Storage gas prepayments	5,309	3,716
Income taxes receivable	724	4,703
Deferred income taxes	837	791
Prepaid expenses	7,357	6,020
Mark-to-market energy assets	379	210
Other current assets	160	132
Total current assets	97,982	100,597
Deferred Charges and Other Assets		
Goodwill	4,716	4,090
Other intangible assets, net	3,075	2,798
Investments, at fair value	2,788	4,168
Regulatory assets	76,179	77,408
Receivables and other deferred charges	2,898	2,904
Total deferred charges and other assets	89,656	91,368
Total Assets	$797,557	$733,746

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

Table of Contents

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

Capitalization and Liabilities	September 30, 2013	December 31, 2012
(in thousands, except shares and per share data)		
Capitalization		
Stockholders' equity		
Common stock, par value $0.4867 per share (authorized 25,000,000 shares)	$4,685	$4,671
Additional paid-in capital	151,676	150,750
Retained earnings	118,330	106,239
Accumulated other comprehensive loss	(4,903)	(5,062)
Deferred compensation obligation	1,110	982
Treasury stock	(1,110)	(982)
Total stockholders' equity	269,788	256,598
Long-term debt, net of current maturities	107,344	101,907
Total capitalization	377,132	358,505
Current Liabilities		
Current portion of long-term debt	8,234	8,196
Short-term borrowing	91,297	61,199
Accounts payable	41,013	41,992
Customer deposits and refunds	26,943	29,271
Accrued interest	2,581	1,437
Dividends payable	3,706	3,502
Accrued compensation	6,467	7,435
Regulatory liabilities	4,397	1,577
Mark-to-market energy liabilities	124	331
Other accrued liabilities	10,252	7,226
Total current liabilities	195,014	162,166
Deferred Credits and Other Liabilities		
Deferred income taxes	135,305	125,205
Deferred investment tax credits	84	113
Regulatory liabilities	6,808	5,454
Environmental liabilities	8,838	9,114
Other pension and benefit costs	33,118	33,535
Accrued asset removal cost—Regulatory liability	39,156	38,096
Other liabilities	2,102	1,558
Total deferred credits and other liabilities	225,411	213,075
Other commitments and contingencies (Note 5 and 6)		
Total Capitalization and Liabilities	$797,557	$733,746

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

Table of Contents

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

For the Nine Months Ended September 30,	2013	2012
(in thousands)		
Operating Activities		
Net Income	$23,104	$19,006
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	18,071	17,413
Depreciation and accretion included in other costs	4,504	4,079
Deferred income taxes, net	9,947	12,102
(Gain) loss on sale of assets	(142)	18
Unrealized (gain) loss on commodity contracts	(277)	147
Unrealized (gain) loss on investments	217	(401)
Realized gain on sales of investments, net	(702)	(20)
Employee benefits	708	2,268
Share-based compensation	1,246	1,111
Other, net	(84)	(21)
Changes in assets and liabilities:		
Purchase of investments	(436)	(292)
Accounts receivable and accrued revenue	(567)	36,523
Propane inventory, storage gas and other inventory	(933)	3,722
Regulatory assets	(1,158)	(456)
Prepaid expenses and other current assets	(1,361)	(856)
Accounts payable and other accrued liabilities	8,174	(20,138)
Income taxes receivable	3,980	(1,010)
Accrued interest	1,144	1,509
Customer deposits and refunds	(2,559)	(1,086)
Accrued compensation	(1,060)	(554)
Regulatory liabilities	4,688	(4,097)
Other assets and liabilities, net	(77)	(4,502)
Net cash provided by operating activities	66,427	64,465
Investing Activities		
Property, plant and equipment expenditures	(68,579)	(51,351)
Proceeds from sales of assets	154	2,281
Proceeds from sale of investments	2,300	—
Acquisitions	(19,367)	(124)
Environmental expenditures	(276)	(345)
Net cash used in investing activities	(85,768)	(49,539)
Financing Activities		
Common stock dividends	(9,716)	(9,160)
Purchase of stock for Dividend Reinvestment Plan	(1,001)	(946)
Change in cash overdrafts due to outstanding checks	(2,692)	(1,559)
Net borrowing (repayment) under line of credit agreements	32,790	(2,393)
Proceeds from issuance of long-term debt	7,000	—
Repayment of long-term debt	(8,609)	(1,459)
Net cash provided by (used in) financing activities	17,772	(15,517)
Net Decrease in Cash and Cash Equivalents	(1,569)	(591)
Cash and Cash Equivalents—Beginning of Period	3,361	2,637

Cash and Cash Equivalents—End of Period	$1,792	$2,046

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

Table of Contents

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

(in thousands, except shares and per share data)	Common Stock Number of Shares[1]	Common Stock Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total
Balances at December 31, 2011	9,567,307	$4,656	$149,403	$91,248	$ (4,527)	$ 817	$(817)	$240,780
Net Income	—	—	—	28,863	—	—	—	28,863
Other comprehensive loss	—	—	—	—	(535)	—	—	(535)
Dividend Reinvestment Plan	—	—	(7)	—	—	—	—	(7)
Conversion of debentures	10,975	5	181	—	—	—	—	186
Share-based compensation [2] [3]	19,217	10	1,001	—	—	—	—	1,011
Tax benefit on share-based compensation	—	—	172	—	—	—	—	172
Deferred Compensation Plan	—	—	—	—	—	165	(165)	—
Purchase of treasury stock	(1,019)	—	—	—	—	—	(45)	(45)
Sale and distribution of treasury stock	1,019	—	—	—	—	—	45	45
Dividends on share-based compensation	—	—	—	(64)	—	—	—	(64)
Cash dividends [4]	—	—	—	(13,808)	—	—	—	(13,808)
Balances at December 31, 2012	9,597,499	4,671	150,750	106,239	(5,062)	982	(982)	256,598
Net Income	—	—	—	23,104	—	—	—	23,104
Other comprehensive income	—	—	—	—	159	—	—	159
Dividend Reinvestment Plan	—	—	(5)	—	—	—	—	(5)
Conversion of debentures	5,166	3	85	—	—	—	—	88
Share-based compensation [2] [3]	23,348	11	846	—	—	—	—	857
Deferred Compensation Plan	—	—	—	—	—	128	(128)	—
Purchase of treasury stock	(763)	—	—	—	—	—	(38)	(38)
Sale and distribution of treasury stock	763	—	—	—	—	—	38	38

Dividends on share-based compensation	—	—	—	(92)	—	—	—	(92)
Cash dividends [4]	—	—	—	(10,921)	—	—	—	(10,921)
Balances at September 30, 2013	9,626,013	$4,685	$151,676	$118,330	$ (4,903)	$ 1,110	$(1,110)	$269,788

(1) Includes 34,224 and 33,461 shares at September 30, 2013 and December 31, 2012, respectively, held in a Rabbi Trust related to the Company's Deferred Compensation Plan.

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

(3) The shares issued under the Performance Incentive Plan ("PIP") are net of shares withheld for employee taxes. For the nine months ended September 30, 2013 and for the year ended December 31, 2012, the Company withheld 10,411 and 5,670 shares, respectively, for taxes.

(4) Cash dividends per share for the periods ended September 30, 2013 and December 31, 2012 were $1.135 and $1.440, respectively.

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

Table of Contents

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 Securities and Exchange Commission (“SEC”) and accounting principles generally accepted in the United States of America (“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, 2012. 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.

During the third quarter of 2013, we recorded an accrual of $698,000 (424,000, net of tax) due to a contingency for taxes other than income, $248,000, $222,000 and $60,000 of which relate to the years ended December 31, 2012, 2011 and 2010, respectively. This reduced our earnings in the third quarter of 2013 and was reflected in other taxes in the accompanying condensed consolidated statements of income for the three and nine months ended September 30, 2013. All of the amounts are related to our unregulated energy segment.

We have assessed and reported on subsequent events through the date of issuance of these condensed consolidated financial statements.

Reclassifications

We reclassified certain amounts in the condensed consolidated cash flows statement for the nine months ended September 30, 2012 to conform to the current year’s presentation. These reclassifications are considered immaterial to the overall presentation of our condensed consolidated financial statements.

Financial Accounting Standards Board (“FASB”) Statements and Other Authoritative Pronouncements

Recent Accounting Standards Yet to be Adopted

Income Taxes (Accounting Standards Codification ("ASC") 740) - In July 2013, the FASB issued Accounting Standards Update (“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. This ASU is effective prospectively beginning on January 1, 2014 for all unrecognized tax benefits existing at the adoption of this new standard. Retrospective implementation and early adoption of this standard are permitted. We expect the adoption of ASU 2013-11 to have no material impact on our financial position and results of operations.

Recently Adopted Accounting Standards

Comprehensive Income (ASC 220) - Effective January 1, 2013, we adopted ASU 2013-02, “Reporting of Amounts Reclassified Out Of Accumulated Other Comprehensive Income,” which requires enhanced disclosures of amounts reclassified out of accumulated other comprehensive income by component. The adoption of ASU 2013-02 had no impact on our financial position and results of operations. See Note 8, "Accumulated Other Comprehensive Income (Loss)," for additional disclosures required under this new standard.

Balance Sheet (ASC 210) - Effective January 1, 2013, we adopted ASU 2011-11, “Disclosures About Offsetting Assets and Liabilities,” and ASU 2013-01, “Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities.” These new standards require disclosures about offsetting and related arrangements in order to help financial statement users better understand the effect of those arrangements on our financial position. The adoption of ASU 2011-11 and ASU

2013-01 had no material impact on our financial position and results of operations. See Note 12, "Derivative Instruments," for additional disclosures about our offsetting of certain assets and liabilities.

Table of Contents

2. Calculation of Earnings Per Share

	Three Months		Nine Months	
For the Periods Ended September 30,	2013	2012	2013	2012
(in thousands, except shares and per share data)				
Calculation of Basic Earnings Per Share:				
Net Income	$3,879	$3,219	$23,104	$19,006
Weighted average shares outstanding	9,625,435	9,592,417	9,616,269	9,583,316
Basic Earnings Per Share	$0.40	$0.34	$2.40	$1.98
Calculation of Diluted Earnings Per Share:				
Reconciliation of Numerator:				
Net Income	$3,879	$3,219	$23,104	$19,006
Effect of 8.25% Convertible debentures	11	13	33	41
Adjusted numerator—Diluted	$3,890	$3,232	$23,137	$19,047
Reconciliation of Denominator:				
Weighted shares outstanding—Basic	9,625,435	9,592,417	9,616,269	9,583,316
Effect of dilutive securities:				
Share-based Compensation	26,123	23,770	23,888	22,684
8.25% Convertible debentures	50,776	60,471	52,154	67,681
Adjusted denominator—Diluted	9,702,334	9,676,658	9,692,311	9,673,681
Diluted Earnings Per Share	$0.40	$0.33	$2.39	$1.97

Table of Contents

3. Acquisitions

Eastern Shore Gas Company

On May 31, 2013, upon obtaining the necessary approval from the Maryland Public Service Commission (“PSC”), which is further discussed in Note 4, “Rates and Other Regulatory Activities,” we completed the purchase of the operating assets of Eastern Shore Gas Company and its affiliates (collectively “ESG”). ESG was not related to, or affiliated with, our interstate natural gas transmission subsidiary, Eastern Shore Natural Gas Company ("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 Energy, Inc. (“Sandpiper”) and our propane distribution subsidiary, Sharpgas, Inc. ("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, where such conversion is both economical and feasible.

In connection with this acquisition, we recorded $12.6 million in property, plant and equipment, $344,000 in propane inventory, $2.5 million in accounts receivable and accrued revenue and $227,000 in other current liabilities, which included the effect of the purchase price adjustment in the third quarter of 2013. 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 preliminary, and we will complete the final purchase price allocation as soon as practicable but no later than one year from the purchase of the assets.

Sales tax of approximately $726,000 included in the purchase price was expensed as a transaction cost and was reflected in other taxes in the accompanying condensed consolidated statements of income for the nine months ended September 30, 2013. Excluding this $726,000 of sales tax expense, the revenue and net income from this acquisition that were included in our condensed consolidated statements of income for the three months and nine months ended September 30, 2013 were not material.

At closing, we entered into a capacity, supply and operating agreement with Eastern Gas & Water Investment Company, LLC ("EGWIC"), an affiliate of the seller. Pursuant to this agreement, Sandpiper has access to 13 propane storage tanks in Worcester County, Maryland, with total storage capacity of 570,000 gallons for a six-year period. For this access, Sandpiper has agreed to pay a monthly fee of $42,000 for the first annual period and a monthly fee of $125,000 for the remaining term of the agreement. Sandpiper will also purchase propane supply (initially estimated at approximately 7.4 million gallons of annual contract volume) from EGWIC over the same six-year period. Sandpiper has the option to pay a fixed per-gallon price for some or all of the propane purchases under this agreement or a market-based price using one of two local propane pricing indices. As further discussed in Note 4, “Rates and Other Regulatory Activities,” the cost of the capacity, supply and operating agreement will be recovered as a fuel cost in Sandpiper's new annual Gas Service Rate (“GSR”) filing.

Due to the specific property involved and the fixed monthly payments for the use of the storage capacity, the capacity portion of the capacity, supply and operating agreement must be accounted for as a capital lease. As a result, we recorded a capital lease asset and capital lease obligation of $7.1 million at the inception of the agreement. During the three and nine months ended September 30, 2013, we recorded approximately $62,000 and $83,000, respectively, for the interest on the capital lease obligation. During the three and nine months ended September 30, 2013, we recorded approximately $63,000 and $84,000, respectively, for the amortization of the capital lease asset. Since the entire amount of the capacity payments is expected to be recovered through the GSR mechanism, the timing and amount of the expense recognition, as well as the presentation of the expenses, will also follow the regulatory accounting.

Other Acquisitions

On June 7, 2013, we acquired the operating assets of Austin Cox Home Services, Inc. ("Austin Cox") for approximately $600,000. The purchased assets are used to provide heating, ventilation and air conditioning, plumbing and electrical services to residential, commercial and industrial customers throughout the lower Delmarva Peninsula. In connection with this acquisition, we recorded $105,000 in property, plant and equipment, $94,000 in inventory, $250,000 as an intangible asset related to a non-compete agreement to be amortized over five years beginning in July 2013 and $173,000 in goodwill. Valuation of certain property, plant and equipment and the intangible asset 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.

Table of Contents

On February 5, 2013, Flo-Gas Corporation, our Florida propane distribution subsidiary, purchased the propane operating assets of Glades Gas Co., Inc. (“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, $502,000 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 $453,000 in goodwill. Valuation of certain property, plant and equipment and the intangible asset 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.

4. Rates and Other Regulatory Activities

Our natural gas distribution operations in Delaware and Maryland, including Sandpiper, are subject to regulation by their respective PSC; Chesapeake’s Florida natural gas distribution division and the natural gas and electric operations of Florida Public Utilities Company (“FPU”) continue to be subject to regulation by the Florida PSC as separate entities. Eastern Shore, our natural gas transmission subsidiary, is subject to regulation by the Federal Energy Regulatory Commission (“FERC”); and Peninsula Pipeline Company, Inc. (“Peninsula Pipeline”), our intrastate pipeline subsidiary, is subject to regulation by the Florida PSC.

Delaware

Natural Gas Expansion Service Offerings: On June 25, 2012, our Delaware division filed with the Delaware PSC an application for proposed natural gas expansion service offerings in order to increase the availability of natural gas within its Delaware service areas. In this filing, the Delaware division is seeking approval from the Delaware PSC of the following:

(i) a monthly fixed charge to customers in portions of eastern Sussex County, Delaware, which will enable the Delaware division to extend its distribution system to provide natural gas service to these customers economically without upfront contributions from these customers;

(ii) optional service offerings to customers to facilitate conversions to natural gas, including a conversion finance service to help customers manage their cost of conversion equipment; and

(iii) a slight rate increase for all Delaware customers in order to support the additional costs associated with the administration of the proposed service offerings.

On July 3, 2012, the Delaware PSC opened the docket and set a period for formal interventions to be filed. On January 4, 2013, the Division of the Public Advocate (“DPA”) filed a motion to close the docket on the grounds that the proposed expansion service offerings should only be considered in the context of a full base rate case. On February 6, 2013, the Hearing Examiner assigned to the case issued a report recommending that the Delaware PSC deny the DPA’s motion. Subsequently, the DPA, Delaware PSC staff and our Delaware division reached an agreement in principle, which included the key provisions described above, with the exception of the proposed rate increase for Delaware customers residing outside of the expansion area. In July 2013, we filed the terms of this agreement in principle in supplemental testimony. A public comment hearing was held on September 12, 2013. On September 30, 2013, the parties involved in the agreement in principle submitted a signed settlement agreement, and on November 5, 2013, the Delaware PSC approved the settlement agreement.

Maryland

ESG Acquisition: On September 7, 2012, we filed an application with the Maryland PSC for approval of the acquisition of the ESG operating assets and the transfer of the ESG franchises to Chesapeake (see Note 3, “Acquisitions,” for additional information on the ESG acquisition). In this application, we also requested the Maryland PSC to approve the overall regulatory framework we proposed for our operation in Worcester County. The proposed regulatory framework includes: (i) a request for approval of a new gas service tariff and rates applicable to natural gas and propane distribution customers in Worcester County, including the customers currently being served by ESG; (ii) a request for approval of the capacity, supply and operating agreement with ESG for the supply and storage of propane, which will be utilized to serve the ESG system customers; and (iii) a request for approval of the accounting treatment for certain purchased assets.

On April 8, 2013, the parties finalized a settlement agreement, which was approved by the Maryland PSC, effective May 29, 2013. Under the order, the Maryland PSC granted approval of: (i) the ESG acquisition; (ii) the overall regulatory framework requested; and (iii) recovery of the cost of the capacity, supply and operating agreement with ESG. In addition, the Maryland PSC's order requires us to file a depreciation study within the first year after the

Table of Contents

acquisition, at which point, the proper amount of the accumulated depreciation associated with the purchased assets in the rate base and the depreciation rates on those assets will be determined and then applied prospectively. The order also requires us to file a base rate case within two and a half years of Sandpiper's new service in Worcester County. The acquisition of the ESG operating assets was completed on May 31, 2013.

On July 31, 2013, Sandpiper filed an application with the Maryland PSC to revise its tariff to allow, on a temporary basis until the next base rate case, negotiated contract rates for a discrete subset of commercial customers receiving propane service who: (i) experienced rate increases on June 1, 2013, when Sandpiper’s tariff took effect in Worcester County and (ii) do not meet the minimum usage requirement for eligibility for negotiated contract rates under the current tariff. On August 14, 2013, the Maryland PSC considered the application and accepted the proposed tariff revisions, effective August 14, 2013.

Florida

Marianna Franchise: On July 7, 2009, the City Commission of Marianna, Florida (the “Marianna Commission”) adopted an ordinance granting a franchise to FPU, effective February 1, 2010, for a period not to exceed ten years for the operation and distribution and/or sale of electric energy (the “Franchise Agreement”). The Franchise Agreement required FPU to develop and implement new time-of-use (“TOU”) and interruptible electric power rates, or other similar rates, mutually agreeable to FPU and the City of Marianna, effective no later than February 17, 2011, and available to all customers within FPU’s northwest division, which includes the City of Marianna. If the rates were not in effect by February 17, 2011, the City of Marianna would have the right to give notice to FPU within 180 days thereafter of its intent to exercise an option in the Franchise Agreement to purchase FPU’s property (consisting of the electric distribution assets) within the City of Marianna. Any such purchase would be subject to approval by the Marianna Commission, which would also need to approve the presentation of a referendum to voters in the City of Marianna for the approval of the purchase and the operation by the City of Marianna of an electric distribution facility. If the purchase were approved by the Marianna Commission and by the referendum, the closing of the purchase would have had to occur within 12 months after the referendum was approved. If the City of Marianna had elected to purchase the Marianna property, the Franchise Agreement would require the City of Marianna to pay FPU the fair market value for such property as determined by three qualified appraisers.

In accordance with the terms of the Franchise Agreement, FPU developed TOU and interruptible rates, and on December 14, 2010, FPU filed a petition with the Florida PSC for authority to implement such proposed TOU and interruptible rates on or before February 17, 2011. On January 26, 2011, FPU filed a petition with the Florida PSC for approval of an amendment to FPU’s Generation Services Agreement between FPU and Gulf Power Company (“Gulf Power”). The amendment provides for a reduction in the capacity demand quantity, which generates the savings necessary to support the TOU and interruptible rates approved by the Florida PSC. The amendment also extended the current agreement by two years, with a new expiration date of December 31, 2019.

On February 11, 2011, the Florida PSC issued an order approving FPU’s petition for authority to implement the proposed TOU and interruptible rates, which became effective on February 8, 2011. The City of Marianna objected to the proposed rates and filed a petition protesting the entry of the Florida PSC’s order. On June 21, 2011, the Florida PSC issued an order approving the amendment to FPU's Generation Services Agreement. On July 12, 2011, the City of Marianna filed a protest of this decision and requested a hearing on the amendment. On January 24, 2012, the Florida PSC dismissed with prejudice the protests by the City of Marianna regarding both the TOU and interruptible rates and the amendment to the Generation Services Agreement.

The City of Marianna filed an appeal with the Florida Supreme Court on March 7, 2012 and with the Florida PSC on March 19, 2012, seeking an appellate review of both of the decisions by the Florida PSC with respect to the protests by the City of Marianna.

As more fully disclosed in Note 6, “Other Commitments and Contingencies,” on March 2, 2011, the City of Marianna filed a complaint against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida, alleging breaches of the Franchise Agreement by FPU and seeking a declaratory judgment that the City of Marianna has the right to exercise its option to purchase FPU’s property in the City of Marianna in accordance with the terms of the Franchise Agreement. Prior to the scheduled trial date, FPU and the City of Marianna reached an agreement in principle to resolve their dispute, which resulted in the City of Marianna dismissing its legal action with prejudice on February 11, 2013. Subsequently, FPU and the City of Marianna entered into a settlement agreement, which contemplated, among other items, the City of Marianna proceeding with a referendum on the purchase of FPU’s facilities. On April 9, 2013, the referendum took place, and the citizens of the City of Marianna voted, by a wide margin, to reject the purchase of FPU's facilities by the City of Marianna. As a result of the outcome of the referendum

Table of Contents

and pursuant to the terms of the settlement agreement, FPU’s franchise with the City of Marianna was extended by ten years. Also pursuant to the settlement agreement, the City of Marianna withdrew its appeals before the Florida Supreme Court of the Florida PSC’s orders regarding the implementation of TOU and interruptible rates and the amendment to the Generation Services Agreement between FPU and Gulf Power.

FPU has incurred approximately $1.9 million of expenses associated with the City of Marianna litigation. In order to seek regulatory recovery of these extraordinary expenses, FPU filed a petition with the Florida PSC on August 27, 2012, for approval to: (i) defer, as a regulatory asset, the expenses associated with the litigation initiated by the City of Marianna; and (ii) amortize over five years, beginning in January 2013, previously expensed as well as future litigation expenses. Although this petition did not request recovery of these expenses, FPU sought deferral treatment of the expenses for regulatory purposes, which could allow future recovery of those expenses. On December 3, 2012, the Florida PSC issued an order approving FPU's request. Since this order does not provide specific recovery of these costs, we did not defer these costs as a regulatory asset at that point until further assurance of recovery can be obtained. Subsequent discussions with the Office of Public Counsel resulted in a settlement agreement on October 11, 2013. Under this settlement agreement, FPU will recover approximately $1.8 million of the total expenses associated with the City of Marianna litigation by retaining the $1.8 million refund received from Gulf Power. This refund represented the higher fuel cost paid by FPU during the City of Marianna franchise dispute as a result of the delay in implementing the amendment to the Generation Service Agreement. Upon reinstatement of the amendment, Gulf Power refunded this amount to FPU pursuant to the terms of the amendment. The remaining litigation expenses would be amortized over the five-year period beginning in January 2013, as previously approved by the Florida PSC. The Florida PSC approved the settlement agreement on October 24, 2013.

Upon reaching the settlement agreement and obtaining a recommendation from the Florida PSC Staff supporting the approval of this settlement agreement, we established a regulatory asset of approximately$1.9 million at September 30, 2013 by reversing approximately $1.5 million of expenses recognized in 2011 and 2012 and $376,000 of expenses recognized during 2013. The refund of $1.8 million received from Gulf Power was reflected as a regulatory liability at September 30, 2013.

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

On September 28, 2012, FPU provided a letter to the Florida PSC stating its intent to request approval of a $745,800 acquisition adjustment associated with FPU’s purchase of the operating assets of Indiantown Gas Company (“IGC”) in 2010. In this letter, FPU also acknowledged the jurisdiction of the Florida PSC to calculate and dispose of prospective overearnings, if any, occurring after October 1, 2012, as the Florida PSC may determine at the conclusion of the acquisition adjustment proceeding. On December 11, 2012, FPU filed a petition to request approval of this acquisition adjustment associated with FPU’s purchase of IGC’s assets. The Florida PSC has scheduled an agenda on December 3, 2013 for a decision on this matter.

On December 14, 2012, Peninsula Pipeline filed a petition with the Florida PSC, asking for approval of a transportation service agreement with FPU. The agreement provides for an upstream interconnection of Peninsula Pipeline’s facilities with the Florida Gas Transmission Company (“FGT”) system and a downstream interconnection with FPU’s facilities. At the agenda conference on July 30, 2013, the Florida PSC approved this agreement.

On July 2, 2013, FPU filed a petition with the Florida PSC for recognition of a regulatory liability for a one-time curtailment gain associated with a change in the FPU Medical Plan. The change in the FPU Medical Plan was implemented effective January 1, 2012 in an effort to conform the benefits offered to FPU's employees to those offered by Chesapeake. The change in the FPU Medical Plan resulted in a total curtailment gain of $892,000, $722,000 of which was allocated to FPU's regulated operations. Since this gain resulted from the merger integration effort, FPU believes that the treatment most consistent with prior regulatory treatment would be to record the gain allocated to the regulated operations as a regulatory liability and amortize that amount over a specified period. This treatment is similar to how merger-related costs and a one-time tax contingency gain were treated. FPU is requesting approval to record regulatory liabilities of $464,000 and $258,000, respectively, in its natural gas and electric operations. FPU also seeks permission to amortize the proposed regulatory liabilities over a 34-month period, beginning January 1, 2012, and ending October 30, 2014. The Florida PSC approved this petition on October 24, 2013. We will record the amortization of this regulatory liability, including immediate recognition in current period earnings of the amortization related to the period prior to the Florida PSC's approval, beginning in the fourth quarter of 2013. This will reduce depreciation and amortization expense.

Table of Contents

Eastern Shore

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

Mainline Expansion Project: On May 14, 2012, Eastern Shore submitted to the FERC an application for a Certificate of Public Convenience and Necessity ("CP") for approval to construct the facilities necessary to deliver additional firm service of 15,040 dekatherms per day (“Dts/d”) to an existing electric power generation customer and to Chesapeake’s Delaware and Maryland divisions. The estimated capital cost of the project is approximately $16.3 million. The filing was publicly noticed on May 25, 2012. Two of Eastern Shore’s existing customers and Chesapeake’s Delaware and Maryland divisions filed motions to intervene in support of the project. One existing customer filed a motion to intervene and protest. On June 28, 2012, Eastern Shore submitted a response to the protest, and on August 31, 2012, the protesting customer filed a reply to Eastern Shore’s response. On October 3, 2012, the US Department of the Interior submitted comments on the FERC’s environmental assessment regarding Eastern Shore’s re-vegetation plan. On October 9, 2012, a non-profit organization also submitted comments on the FERC’s environmental assessment, asserting that the environmental assessment was deficient and requesting the FERC to extend the comment period by 60 days. In February 2013, the FERC approved Eastern Shore’s application and issued a CP. On March 11, 2013, Eastern Shore accepted this CP and filed its environmental compliance plan. On March 21, 2013, the FERC issued a notice to proceed with construction. On November 1, 2013, Eastern Shore commenced service upon completion of construction and receipt of necessary approval by the FERC.

Daleville Compressor Station Upgrade Filing: On October 12, 2012, Eastern Shore submitted to the FERC an application for a CP, seeking authorization to construct a new gas-fired compressor unit at its existing Daleville Compressor Station located in Chester County, Pennsylvania. The new unit will provide 17,500 Dts/d of additional firm transportation service to two of Eastern Shore’s existing customers. In this application, Eastern Shore also included a description of a second new gas fired compressor unit to be installed at the Daleville Compressor Station, which will replace the three existing compressors that serve as back-up units to existing primary compressor units. Eastern Shore also plans to replace the engine exhaust devices of the existing primary compressor units with air emissions control equipment to comply with new environmental regulations. The replacement compressor unit and new engine exhaust devices will result in improved air emissions, reliability and flexibility on Eastern Shore’s system. Eastern Shore does not need specific FERC approval to construct the replacement compressor unit or emission controls; however, Eastern Shore wants the FERC to be fully advised of these improvement efforts. The estimated capital costs of the project are approximately $12.1 million. On March 4, 2013, the FERC approved this application. On April 19, 2013, the FERC issued a notice to proceed with construction. On November 1, 2013, Eastern Shore commenced service upon completion of construction and receipt of necessary approval by the FERC.

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 Calpine Energy Services, L.P. ("Calpine") for its proposed 309 megawatt combined-cycle power plant under development. The total cost of the project is estimated to be approximately $11.2 million. Eastern Shore requested that the FERC issue an order granting the CP by December 14, 2013.

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 the federal authorization decision deadline is January 2, 2014. Eastern Shore anticipates beginning construction in early 2014 for an in-service date of January 1, 2015.

Other matters: Eastern Shore also had developments in the following FERC matters:

On May 31, 2013, Eastern Shore submitted to the FERC a combined filing of its Fuel Retention Percentage (“FRP”) and Cash-Out Refund for a twelve-month period beginning April 2012 and ending March 2013. In this filing, Eastern Shore proposed an FRP rate of 0.24 percent and continuation of its existing zero percent rate for the Cash-Out Surcharge. During the period, Eastern Shore experienced an under-recovery of $285,000 in its Deferred Gas Required for Operations costs and an over-recovery of $146,000 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. On June 27, 2013, the FERC issued an order accepting Eastern Shore's submittal of a combined filing to update both its FRP and Cash-Out Refund mechanisms, effective July 1, 2013.

Table of Contents

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 remedy 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, assessment or remediation, and have exposures at six former manufactured gas plant ("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 Maryland Department of Environment ("MDE") regarding a seventh former MGP site located in Cambridge, Maryland.

As of September 30, 2013, we had approximately $10.3 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 $9.1 million of which has been recovered as of September 30, 2013. We had approximately $4.9 million in regulatory assets for future recovery of environmental costs from FPU's customers.

In addition to the FPU MGP sites, we had $100,000 in environmental liabilities at September 30, 2013, related to Chesapeake's MGP sites in Maryland and Florida, representing our estimate of future costs associated with these sites. As of September 30, 2013, we had approximately $339,000 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 Florida Department of Environmental Protection ("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 other responsible parties at the Sanford site (collectively with FPU the "Sanford Group") signed a Third Participation Agreement, which provides for the funding of the final remedy approved by the United States Environmental Protection Agency ("EPA") for the site. FPU's share of remediation costs under the Third Participation Agreement is set at five percent of a maximum of $13.0 million, or $650,000. As of September 30, 2013, FPU has paid $650,000 to the Sanford Group escrow account for its entire share of the funding requirements.

The total cost of the final remedy is now estimated to be over $20.0 million, which includes long-term monitoring and the settlement of claims asserted by two adjacent property owners to resolve damages that the property owners allege they have incurred and will incur as a result of the implementation of the EPA-approved remediation. In settlement of these claims, members of the Sanford Group, which in this instance does not include FPU, have agreed to pay specified sums of money to the parties. FPU has refused to participate in the funding of the third-party settlement agreements based on its contention that it did not contribute to the release of hazardous substances at the site giving rise to the third-party claims. FPU has advised the other members of the Sanford Group that it is unwilling at this time to agree to pay any sum in excess of the $650,000 committed by FPU in the Third Participation Agreement.

As of September 30, 2013, 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 as provided in the Third Participation Agreement to implement the final remedy for this site or will pursue a claim against FPU for a sum in excess of the $650,000 that FPU has paid under the Third Participation Agreement. No such claims have been made as of September 30, 2013.

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, Natural Attenuation Monitoring ("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 annual cost to conduct the limited NAM program is not expected to exceed $8,000. 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.

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 Florida Department of Transportation ("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. The 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, and the most recent groundwater monitoring report was submitted on June 17, 2013. FDEP issued an additional comment letter, dated September 16, 2013, containing various requests and questions, which we responded to on October 10, 2013. If modifications to the existing consent order and remedial action plan are required, we estimate that future remediation costs could be as much as $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 our approved rates.

The current treatment system at the Winter Haven site does not address impacted soils in the southwest corner of the site. In 2010, we obtained conditional approval from FDEP for a soil excavation plan; however, because the costs associated with shoreline stabilization and dewatering are likely to be substantial, alternatives to this excavation plan are being evaluated.

FDEP has indicated that we may be required to remediate sediments along the shoreline of Lake Shipp, immediately west of the site. Based on studies performed to date, we object to FDEP's suggestion that the sediments have been adversely impacted by the former operations of the MGP. Our early estimates indicate that some of the corrective measures discussed by FDEP could cost as much as $1.0 million. We believe that corrective measures for the

Table of Contents

sediments are not warranted and intend to oppose any requirement that we undertake corrective measures in the offshore sediments. We have not recorded a liability for sediment remediation, as the final resolution of this matter cannot be predicted at this time.

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.

We have investigated a potential environmental matter involving a property we recently purchased in Fernandina Beach, Florida. We determined that there was no contamination at this site; therefore, we have not recorded an environmental liability for this site.

Table of Contents

6. Other Commitments and Contingencies

Litigation

On March 2, 2011, the City of Marianna filed a complaint against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida. In the complaint, the City of Marianna alleged three breaches of the Franchise Agreement by FPU: (i) FPU failed to develop and implement TOU and interruptible rates that were mutually agreed to by the City of Marianna and FPU; (ii) mutually agreed upon TOU and interruptible rates by FPU were not effective or in effect by February 17, 2011; and (iii) FPU did not have such rates available to all of FPU's customers located within and without the corporate limits of the City of Marianna. The City of Marianna sought a declaratory judgment allowing it to exercise its option under the Franchise Agreement to purchase FPU's property (consisting of the electric distribution assets) within the City of Marianna. Any such purchase would be subject to approval by the Marianna Commission, which would also need to approve the presentation of a referendum to voters in the City of Marianna related to the purchase and the operation by the City of Marianna of an electric distribution facility. If the purchase were approved by the Marianna Commission and the referendum were approved by the voters, the closing of the purchase had to occur within 12 months after the referendum was approved. On March 28, 2011, FPU filed its answer to the declaratory action by the City of Marianna, in which it denied the material allegations by the City of Marianna and asserted several affirmative defenses. On August 3, 2011, the City of Marianna notified FPU that it was formally exercising its option to purchase FPU's property. On August 31, 2011, FPU advised the City of Marianna that it had no right to exercise the purchase option under the Franchise Agreement and that FPU would continue to oppose the effort by the City of Marianna to purchase FPU's property. In December 2011, the City of Marianna filed a motion for summary judgment. On April 3, 2012, the court conducted a hearing on the City of Marianna's motion for summary judgment. The court subsequently denied in part and granted in part the City of Marianna's motion after concluding that issues of fact remained for trial with respect to each of the three alleged breaches of the Franchise Agreement.

Prior to the February 2013 trial date, FPU and the City of Marianna reached an agreement in principle to resolve their dispute, which resulted in the City of Marianna dismissing its legal action with prejudice on February 11, 2013. Subsequently, FPU and the City of Marianna entered into a settlement agreement, which contemplated, among other items, the City of Marianna proceeding with a referendum on the purchase of FPU's facilities within the City of Marianna. On April 9, 2013, the referendum took place, and the citizens of the City of Marianna voted, by a wide margin, to reject the purchase of FPU's facilities by the City of Marianna. As a result of the dismissal with prejudice of the legal action by the City of Marianna and the outcome of the referendum on the purchase of FPU's facilities, we no longer have any contingencies related to claims by the City of Marianna.

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.

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. Our Delaware and Maryland natural gas distribution divisions had a contract with an unaffiliated energy marketing and risk management company to manage a portion of their natural gas transportation and storage capacity, which expired on March 31, 2013. On April 1, 2013, our Delaware and Maryland divisions entered into a new contract with a different company to perform similar asset management functions. The new contract expires on March 31, 2015.

As discussed in Note 3, "Acquisitions," in May 2013, Sandpiper entered into a capacity, supply and operating agreement with EGWIC to purchase propane over a six-year term. Sandpiper's initial annual commitment is estimated at approximately 7.4 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 Natural Gas System, LLC ("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 Peninsula Energy

Services Company, Inc. (“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 2013, PESCO renewed contracts to purchase natural gas from various suppliers. These contracts expire in May 2014.

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 (formerly known as Jacksonville Electric Authority) requires FPU to comply with the following ratios based on the results of the prior 12 months: (a) total liabilities to tangible net worth less than 3.75 times, and (b) a fixed charge coverage ratio greater than 1.5 times. If either ratio is not met by FPU, it has 30 days to cure the default or provide an irrevocable letter of credit if the default is not cured. FPU’s electric fuel supply agreement with Gulf Power requires FPU to meet the following ratios based on the average of the prior six quarters: (a) funds from operations interest coverage ratio (minimum of 2 times), and (b) total debt to total capital (maximum of 65 percent). If FPU fails to meet the requirements, it has to provide the supplier a written explanation of actions taken or proposed to be taken to become compliant. Failure to comply with the ratios specified in the Gulf Power agreement could result in FPU having to provide an irrevocable letter of credit. As of September 30, 2013, FPU was in compliance with all of the requirements of its fuel supply contracts.

Sharp, our propane distribution subsidiary, 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 initial annual commitment is estimated at approximately 7.4 million gallons. The agreement between Sharp and EGWIC is separate from the agreement between Sandpiper and EGWIC, and neither agreement permits the parties to set off the rights and obligations specified in one agreement against those specified in the other agreement.

Corporate Guarantees

The Board of Directors has authorized the Company 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, primarily our propane wholesale marketing subsidiary and our natural gas marketing subsidiary. These corporate guarantees provide for the payment of propane and natural gas purchases in the event of the 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 September 30, 2013 was $31.1 million, with the guarantees expiring on various dates through September 2014.

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 renewed a letter of credit for $1.0 million, which now 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 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, 2014. There have been no draws on these letters of credit as of September 30, 2013. 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 Texas Eastern Transmission, LP (“TETLP”) related to firm transportation service agreements between our Delaware and Maryland divisions and TETLP.

Tax-related Contingencies

We are subject to various audits and reviews by the federal, state and local and other regulatory authorities regarding income taxes and taxes other than income. As of September 30, 2013, we maintained a liability of $300,000 related to unrecognized income tax benefits and $780,000 related to contingencies for taxes other than income. As of December 31, 2012, we maintained a liability of $300,000 related to unrecognized income tax benefits and $82,000 related to contingencies for taxes other than income. We recorded an additional accrual in the third quarter of 2013 related to taxes other than income based on our assessment of this contingency.

- 18

Table of Contents

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 are comprised of three operating segments:

- Regulated Energy. The regulated energy segment includes natural gas distribution, electric distribution and natural gas transmission 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 natural gas marketing, propane distribution and propane wholesale marketing operations, which are unregulated as to their rates and charges for their services.
- Other. The "other" segment consists primarily of the advanced information services operation, unregulated subsidiaries that own real estate leased to Chesapeake and certain corporate costs not allocated to other operations.

The following table presents financial information about our reportable segments.

	Three Months		Nine Months	
For the Periods Ended September 30,	2013	2012	2013	2012
(in thousands)				
Operating Revenues, Unaffiliated Customers				
Regulated Energy	$55,387	$51,868	$191,666	$179,139
Unregulated Energy	26,103	21,861	115,367	91,001
Other	5,055	4,446	14,386	12,846
Total operating revenues, unaffiliated customers	$86,545	$78,175	$321,419	$282,986
Intersegment Revenues (1)				
Regulated Energy	$293	$328	$797	$906
Unregulated Energy	2,159	1,398	3,911	2,322
Other	274	220	743	675
Total intersegment revenues	$2,726	$1,946	$5,451	$3,903
Operating Income				
Regulated Energy	$10,243	$7,848	$36,169	$33,151
Unregulated Energy	(1,803)	(709)	8,013	4,044
Other and eliminations	280	425	240	897
Total operating income	8,720	7,564	44,422	38,092
Other income, net of other expenses	101	(136)	413	212
Interest	2,026	2,126	6,114	6,657
Income before Income Taxes	6,795	5,302	38,721	31,647
Income taxes	2,916	2,083	15,617	12,641
Net Income	$3,879	$3,219	$23,104	$19,006

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

Table of Contents

(in thousands)	September 30, 2013	December 31, 2012
Identifiable Assets		
Regulated energy	$683,258	$615,438
Unregulated energy	88,032	79,287
Other	26,267	39,021
Total identifiable assets	$797,557	$733,746

Our operations are almost entirely domestic. Our advanced information services subsidiary, 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.

8. Accumulated Other Comprehensive Income (Loss)

The following table presents the changes in the balance of accumulated other comprehensive income (loss) for the three and nine months ended September 30, 2013. Defined benefit pension and postretirement plan items are the only component of our accumulated comprehensive income (loss). All amounts in the following table are presented net of tax.

For the Periods Ended September 30, 2013	Three Months		Nine Months	
(in thousands)				
Beginning balance	$(4,958	)	$(5,062	)
Other comprehensive loss before reclassifications	—		(6	)
Amounts reclassified from accumulated other comprehensive loss	55		165	
Net current-period other comprehensive income	55		159	
Ending balance	$(4,903	)	$(4,903	)

The following table presents amounts reclassified out of accumulated other comprehensive loss for the three and nine months ended September 30, 2013.

For the Periods Ended September 30, 2013	Three Months		Nine Months	
(in thousands)				
Amortization of defined benefit pension and postretirement plan items:				
Prior service cost [1]	$15		$45	
Net loss [1]	$(107	)	$(320	)
Total before tax	(92	)	(275	)
Tax benefit	37		110	
Net of tax	$(55	)	$(165	)

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

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

Table of Contents

9. Employee Benefit Plans

Net periodic benefit costs for our pension and post-retirement benefits plans for the three and nine months ended September 30, 2013 and 2012 are set forth in the following tables:

	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake Pension SERP		Chesapeake Postretirement Plan		FPU Medical Plan	
For the Three Months Ended September 30,	2013	2012	2013	2012	2013	2012	2013	2012	2013	2012
(in thousands)										
Service cost	$—	$—	$—	$—	$—	$—	$—	$—	$—	$40
Interest cost	102	125	594	638	21	23	12	15	16	45
Expected return on plan assets	(126)	(108)	(719)	(658)	—	—	—	—	—	—
Amortization of prior service cost	—	(1)	—	—	5	5	(19)	(20)	—	—
Amortization of net loss	57	85	81	43	16	11	18	18	—	23
Net periodic cost (benefit)	33	101	(44)	23	42	39	11	13	16	108
Amortization of pre-merger regulatory asset	—	—	191	190	—	—	—	—	2	2
Total periodic cost	$33	$101	$147	$213	$42	$39	$11	$13	$18	$110

	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake Pension SERP		Chesapeake Postretirement Plan		FPU Medical Plan	
For the Nine Months Ended September 30,	2013	2012	2013	2012	2013	2012	2013	2012	2013	2012
(in thousands)										
Service cost	$—	$—	$—	$—	$—	$—	$—	$—	$—	$120
Interest cost	307	375	1,782	1,916	62	68	36	45	47	135
Expected return on plan assets	(378)	(326)	(2,156)	(1,973)	—	—	—	—	—	—
Amortization of prior service cost	(1)	(4)	—	—	14	15	(58)	(60)	—	—
Amortization of net loss	171	255	243	131	48	34	55	53	—	68
Net periodic cost (benefit)	99	300	(131)	74	124	117	33	38	47	323
Amortization of pre-merger regulatory asset	—	—	571	571	—	—	—	—	6	6
Total periodic cost	$99	$300	$440	$645	$124	$117	$33	$38	$53	$329

We expect to record pension and postretirement benefit costs of approximately $999,000 for 2013. 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 of 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 $4.6 million and $5.2 million at September 30, 2013 and December 31, 2012, respectively.

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 nine months ended September 30, 2013:

- 21

Table of Contents

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

For the Nine Months Ended September 30, 2013	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake Pension SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service cost (credit)	$ (1)	$—	$ 14	$ (58)	$—	(45)
Net loss	171	243	48	55	—	517
Total recognized in net periodic benefit cost	$ 170	$243	$ 62	$ (3)	$—	$472
Recognized from accumulated other comprehensive loss (1)	$ 170	$46	$ 62	$ (3)	$—	$275
Recognized from regulatory asset	—	197	—	—	—	197
Total	$ 170	$243	$ 62	$ (3)	$—	$472

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

During the three and nine months ended September 30, 2013, we contributed $142,000 and $233,000, respectively, to the Chesapeake pension plan. We also contributed $211,000 and $421,000, respectively, to the FPU pension plan during the three and nine months ended September 30, 2013. We expect to contribute a total of $364,000 and $842,000 to the Chesapeake and FPU pension plans, respectively, during 2013, representing minimum contribution payments required in 2013.

The Chesapeake Pension Supplemental Executive Retirement Plan (“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 Pension SERP for the three and nine months ended September 30, 2013, were $22,000 and $67,000, respectively. We expect to pay total cash benefits of approximately $88,000 under the Chesapeake Pension SERP in 2013. Cash benefits paid for the Chesapeake Postretirement Plan, primarily for medical claims for the three and nine months ended September 30, 2013, were $16,000 and $53,000, respectively. We have estimated that approximately $97,000 will be paid for such benefits under the Chesapeake Postretirement Plan in 2013. Cash benefits paid for the FPU Medical Plan, primarily for medical claims for the three and nine months ended September 30, 2013, were $50,000 and $91,000, respectively. We estimate that approximately $258,000 will be paid for such benefits under the FPU Medical Plan in 2013.

Table of Contents

10. Investments

The investment balances at September 30, 2013 and December 31, 2012, consist of the following:

(in thousands)	September 30, 2013	December 31, 2012
Rabbi trust (associated with Supplemental Executive Retirement Savings Plan)	$2,691	$2,116
Rabbi trust (associated with certain directors' compensation)	97	39
Investments in equity securities	—	2,013
Total	$2,788	$4,168

We classify these investments as trading securities and report them at their fair value. For the three months ended September 30, 2013 and 2012, we recorded a net unrealized loss of $259,000 and a net unrealized gain of $102,000, respectively, in other income in the condensed consolidated statements of income related to these investments. For the nine months ended September 30, 2013 and 2012, we recorded a net unrealized gain of $217,000 and a net unrealized loss of $502,000, 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 and 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 2013 stock and incentive compensation plan. Prior to May 2, 2013, our non-employee directors and key employees were awarded share-based awards through our Directors Stock Compensation Plan (“DSCP”) and our Performance Incentive Plan (“PIP”), respectively. 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 each award on the date it was granted.

The table below presents the amounts included in net income related to share-based compensation expense for the awards granted under the DSCP and the PIP for the three and nine months ended September 30, 2013 and 2012:

	Three Months		Nine Months	
For the Periods Ended September 30,	2013	2012	2013	2012
(in thousands)				
Directors Stock Compensation Plan	$124	$111	$354	$332
Performance Incentive Plan	261	304	892	779
Total compensation expense	385	415	1,246	1,111
Less: tax benefit	(155)	(166)	(502)	(446)
Share-Based Compensation amounts included in net income	$230	$249	$744	$665

Directors Stock Compensation Plan

Shares granted under the DSCP 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 2013, each of our non-employee directors received an annual retainer of 857 shares of common stock under the DSCP. A summary of the stock activity under the DSCP during the nine months ended September 30, 2013 is presented below.

Table of Contents

	Number of Shares	Weighted Average Grant date Fair Value
Outstanding - December 31, 2012	—	—
Granted	9,427	$52.49
Vested	9,427	$52.49
Forfeited	—	—
Outstanding - September 30, 2013	—	—

At September 30, 2013, there was $288,000 of unrecognized compensation expense related to the DSCP awards. This expense will be recognized over the directors' remaining service periods ending April 30, 2014.

Performance Incentive Plan

The table below presents the summary of the stock activity for the PIP for the nine months ended September 30, 2013:

	Number of Shares	Weighted Average Fair Value
Outstanding—December 31, 2012	84,645	$37.86
Granted	23,491	$44.85
Vested	24,332	$33.26
Expired	3,043	$39.12
Outstanding—September 30, 2013	80,761	$42.30

In January 2013, the Board of Directors granted awards of 23,491 shares under the PIP, which are multi-year awards that will vest at the end of the three-year service period, or December 31, 2015. These awards are earned based upon the successful achievement of long-term goals, growth and financial results, which are comprised of both market-based and performance-based conditions or targets. The fair value of each performance-based condition or target is equal to the market price of our common stock on the date each award is granted. For the market-based conditions, we used the Black-Scholes pricing model to estimate the fair value of each market-based award granted. At September 30, 2013, the aggregate intrinsic value of the PIP awards was $4.2 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 September 30, 2013, our natural gas and electric distribution operations did not have any outstanding derivative contracts.

In June 2013, our propane distribution operation entered into put options to protect against the decline 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. The put options are exercised if propane prices fall 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 will receive the difference between the market price and the strike prices during those months. We paid $120,000 to purchase the put options, and we accounted for them as fair value hedges. As of September 30, 2013, the put options had a fair value of $63,000. The change in the fair value of the put options reduced our propane inventory balance.

In May 2013, our propane distribution operation 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 retail price that we can charge to those customers during the upcoming heating season, is capped at a pre-determined level. The call option is exercised if the propane prices rise above the strike price of $0.975

Table of Contents

per gallon in January through March of 2014. We will receive the difference between the market price and the strike price during those months. We paid $72,000 to purchase the call option, and we accounted for it as a derivative instrument on a mark-to-market basis with any change in its fair value being reflected in current period earnings. As of September 30, 2013, the call option had a fair value of $102,000.

In May 2012, our propane distribution operation entered into call options to protect against an increase in propane prices associated with 1.3 gallons purchased for the propane price cap program for December 2012 through March 2013. The call options would have been exercised if the propane prices had risen above the strike prices, which ranged from $0.905 per gallon to $0.990 per gallon during that four-month period. We paid $139,000 to purchase the call options, which expired without exercise as the market prices were below the strike prices. We accounted for these call options as a fair value hedge. There was no ineffective portion of this fair value hedge.

Xeron, Inc. (“Xeron”), our propane wholesale marketing subsidiary, engages in trading activities using forward and futures contracts. These contracts are considered derivatives and have been accounted for using the mark-to-market method of accounting. Under this method, the trading contracts are recorded at fair value, and the changes in fair value of those contracts are recognized as unrealized gains or losses in the statement of income for the period of change. As of September 30, 2013, we had the following outstanding trading contracts which we accounted for as derivatives:

At September 30, 2013	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts			
Sale	1,682,000	$0.9625 - $1.1338	$ 1.0370
Purchase	1,682,000	$0.9038 - $1.3176	$ 0.9861

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

Xeron has entered into master netting agreements with two counterparties to mitigate exposure to counterparty credit risk. The master netting agreements enable Xeron to net these two counterparties' outstanding accounts receivable and payable, which are presented on a gross basis in the accompanying condensed consolidated balance sheets. At September 30, 2013, Xeron had a right to offset $2.3 million and $1.1 million of accounts receivable and accounts payable, respectively, with these two counterparties. At December 31, 2012, Xeron had a right to offset $1.2 million and $511,000 of accounts receivable and accounts payable, respectively, with these two counterparties.

The following tables present information about the fair value and related gains and losses of our derivative contracts. We did not have any derivative contracts with a credit-risk-related contingency.

Fair values of the derivative contracts recorded in the condensed consolidated balance sheet as of September 30, 2013 and December 31, 2012, are as follows:

Table of Contents

	Asset Derivatives		
		Fair Value	
(in thousands)	Balance Sheet Location	September 30, 2013	December 31, 2012
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy assets	$214	$182
Call Option	Mark-to-market energy assets	102	$—
Derivatives designated as fair value hedges			
Call options (1)	Mark-to-market energy assets	—	28
Put Options(2)	Mark-to-market energy assets	63	—
Total asset derivatives		$379	$210

	Liability Derivatives		
		Fair Value	
(in thousands)	Balance Sheet Location	September 30, 2013	December 31, 2012
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy liabilities	$124	$331
Total liability derivatives		$124	$331

(1) We purchased call options for the propane price cap program in May 2012. The call options expired in March 2013.

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

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

		Amount of Gain (Loss) on Derivatives:			
	Location of Gain	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(in thousands)	(Loss) on Derivatives	2013	2012	2013	2012
Derivatives not designated as hedging instruments:					
Unrealized gain (loss) on forward contracts	Revenue	$86	86	239	(147)
Call Option	Cost of sales	38	—	29	—
Derivatives designated as fair value hedges:					
Put/Call Option	Cost of sales	—	—	(28)	27
Put/Call Options	Inventory	(43)	(2)	(57)	(17)
Total		$81	$84	$183	$(137)

- 26

Table of Contents

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 September 30, 2013	2012	For the Nine Months Ended September 30, 2013	2012
Realized gain on forward contracts and options	Revenue	$321	$911	$506	$2,233
Unrealized gain (loss) on forward contracts	Revenue	86	86	239	(147)
Total		$407	$997	$745	$2,086

13. Fair Value of Financial Instruments

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

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

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

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

The following table summarizes our financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements, by level, within the fair value hierarchy used at September 30, 2013 and December 31, 2012:

September 30, 2013	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	$512	$—	$—	$512
Investments—other	$2,276	$2,276	$—	$—
Mark-to-market energy assets, including put/call options	$379	$—	$379	$—
Liabilities:				
Mark-to-market energy liabilities	$124	$—	$124	$—

December 31, 2012 (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—equity securities	$2,007	$2,007	$—	$—
Investments—other	$2,161	$2,161	$—	$—
Mark-to-market energy assets, including call options	$210	$—	$210	$—

Liabilities:				
Mark-to-market energy liabilities	$331	$—	$331	$—

- 27

Table of Contents

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

At September 30,	2013
(in thousands)	
Beginning Balance	$—
Transfers in due to change in trustee	425
Purchases and adjustments	98
Transfers	(16)
Investment Income	5
Ending Balance	$512

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

The following valuation techniques were used to measure fair value assets in the table above on a recurring basis as of September 30, 2013 and December 31, 2012:
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 over the counter (“OTC”) markets.
Propane put/call options—The fair value of the propane put/call options are determined using market transactions for similar assets and liabilities in either the listed or OTC markets.
Level 3 Fair Value Measurements:
Investments- guaranteed income fund—The fair values of these investments are recorded at the contract value, which approximates their fair value.

At September 30, 2013, there were no non-financial assets or liabilities required to be reported at fair value. We review our non-financial assets for impairment at least on an annual basis, as required.
Other Financial Assets and Liabilities
Financial assets with carrying values approximating fair value include cash and cash equivalents and accounts receivable. Financial liabilities with carrying values approximating fair value include accounts payable and other accrued liabilities and short-term debt. The fair value of cash and cash equivalents is measured using the comparable value in the active market and approximates its carrying value (Level 1 measurement). The fair value of short-term debt approximates the carrying value due to its short maturities and because interest rates approximate current market rates (Level 3 measurement).
At September 30, 2013, long-term debt, including current maturities but excluding a capital lease obligation, had a carrying value of $108.5 million. This compares to a fair value of $127.2 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, 2012, long-term debt, including the current maturities, had a carrying value of $110.1 million, compared to the estimated fair value of $133.2 million. The valuation technique used to estimate the fair value of long-term debt would be considered a Level 3 measurement.

- 28

Table of Contents

14. Long-Term Debt

Our outstanding long-term debt is shown below:

(in thousands)	September 30, 2013	December 31, 2012
FPU secured first mortgage bonds [(A)] :		
9.57% bond, due May 1, 2018	$—	$5,444
10.03% bond, due May 1, 2018	—	2,994
9.08% bond, due June 1, 2022	7,966	7,962
Uncollateralized senior notes:		
7.83% note, due January 1, 2015	4,000	4,000
6.64% note, due October 31, 2017	13,636	13,636
5.50% note, due October 12, 2020	16,000	16,000
5.93% note, due October 31, 2023	30,000	30,000
5.68% note, due June 30, 2026	29,000	29,000
6.43% note, due May 2, 2028	7,000	—
Convertible debentures:		
8.25% due March 1, 2014	854	942
Promissory note	80	125
Capital lease obligation	7,042	—
Total long-term debt	115,578	110,103
Less: current maturities	(8,234)	(8,196)
Total long-term debt, net of current maturities	$107,344	$101,907

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

In June 2010, we entered into an agreement with Metropolitan Life Insurance Company and New England Life Insurance Company to issue up to $36.0 million of Chesapeake's unsecured senior notes. In June 2011, we issued $29.0 million of 5.68 percent unsecured senior notes to permanently finance the redemption of two series of FPU first mortgage bonds in 2010. On May 2, 2013, we issued an additional $7.0 million of 6.43 percent unsecured senior notes under the same agreement. These notes have similar covenants and default provisions as the senior notes issued in June 2011. We used these proceeds to redeem the 9.57 percent and 10.03 percent series of FPU's first mortgage bonds in May 2013, prior to their respective maturities. The difference between the carrying value of those bonds and the amount paid at redemption totaling $93,000 was deferred as a regulatory asset. We are amortizing this difference over the remaining terms of these bonds as adjustments to interest expense, as allowed by the Florida PSC.

On September 5, 2013, we entered into a Note Purchase Agreement (the "Note Agreement") with 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 (collectively, the "Note Holders"). Under the terms of the Note Agreement, we will issue $70.0 million in aggregate of unsecured Senior Notes to the Note Holders. Series A of the unsecured Senior Notes ("Series A Notes"), with an aggregate principal amount of $20.0 million, will be issued on December 16, 2013 at a rate of 3.73 percent. Series B of the unsecured Senior Notes ("Series B Notes" and collectively with Series A Notes, the "Notes"), with an aggregate principal amount of $50.0 million, will be issued on May 15, 2014, at a rate of 3.88 percent. The proceeds received from the issuances of the Notes will be used to reduce our short-term borrowings under our lines of credit and to fund capital expenditures.

Series A Notes require annual principal payments of $2.0 million commencing on December 16, 2019. The entire outstanding principal balance of the Series A Notes is due and payable on December 16, 2028. Semiannual payments for Series A Notes are due on June 16 and December 16 of each year, commencing on June 16, 2014. All accrued but unpaid interest due under the Series A Notes is payable on December 16, 2028. Series B Notes require annual principal payments of $5.0 million commencing on May 15, 2020. The entire outstanding principal balance of the Series B Notes is due and payable on May 15, 2029. Semiannual payments for Series B Notes are due on May 15 and November 15 of each year, commencing on November 15, 2014. All accrued but unpaid interest due under the Series B Notes is payable on May 15, 2029.

Table of Contents

The Notes may be accelerated if the aggregate net book value of our regulated business assets is less than 50 percent of our consolidated total assets. The Notes may also be accelerated upon the occurrence of a default as provided in the Note Agreement. The Note Agreement sets forth certain business and financial covenants to which the Company is subject, including covenants that limit or restrict the Company and its subsidiaries to incur indebtedness and to incur certain liens and encumbrances on any of its property.

15. Short-Term Debt

On June 28, 2013, we entered into a $55.0 million committed unsecured, short-term credit facility with Bank of America, N.A., which increases the total short-term loan capacity available from Bank of America, N.A. from $50.0 million to $75.0 million. This facility replaces a $30.0 million committed unsecured, short-term credit facility, which expired on June 28, 2013. This new committed unsecured, short-term facility matures on June 27, 2014. Borrowings under this new credit facility will bear interest at a rate equal to LIBOR plus 125 basis points or Bank of America's Base Rate (as defined in the term note agreement) plus 125 basis points, with the form of interest rate selected at our discretion. Other terms and conditions of this facility are substantially the same as the former facility available from Bank of America, N.A. We intend to utilize this credit facility for working capital needs, to temporarily fund capital expenditures and general corporate purposes. In addition to the $55.0 million, committed unsecured short-term credit facility, we have a $20.0 million uncommitted unsecured, short-term credit facility with Bank of America, N.A., which was also renewed on June 28, 2013. In addition to the Bank of America, N.A. facilities, Chesapeake has other short-term credit facilities with PNC Bank, N.A. totaling $90.0 million, $70.0 million of which is committed and $20.0 million of which is uncommitted.

Table of Contents

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, 2012, 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 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 (including deregulation);
- 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 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;
- declines in the value of the pension plan assets and resultant cash funding requirements for our defined benefit pension plans;
- the creditworthiness of counterparties with which we are engaged in transactions;
- the extent of success in connecting natural gas and electric supplies to transmission systems and in expanding natural gas and electric markets;
- the effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- conditions of the capital markets and equity markets during the periods covered by the forward-looking statements;
- the ability to successfully execute, manage and integrate merger, acquisition or divestiture plans, regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, and the success of the business following a merger, acquisition or divestiture;
- the ability to establish and maintain new key supply sources;
- the effect of spot, forward and future market prices on our distribution, wholesale marketing and energy trading businesses;
- the effect of competition on our businesses;
- the ability to construct facilities at or below estimated costs; and

- changes in technology affecting our advanced information services business.

Table of Contents

Introduction

We are a diversified utility company engaged, directly or through 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;
- providing additional services in our current and new service territories, including conversion opportunities;
- 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 executing new unregulated energy opportunities 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;
- empowering and energizing our employees at all levels to work in unison to achieve our strategy;
- engaging our local communities and government 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 are determined in accordance with GAAP. We believe that gross margin, although a non-GAAP measure, is useful and meaningful to investors as a basis for making investment decisions. It provides investors with information that demonstrates the profitability achieved by the Company under its allowed rates for regulated energy operations and under its competitive pricing structure for unregulated natural gas marketing and propane distribution operations. 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.

Results of Operations for the For the Three and Nine Months Ended September 30, 2013

Overview and Highlights

Our net income for the quarter ended September 30, 2013 was $3.9 million, or $0.40 per share (diluted). This represents an increase of $660,000, or $0.07 per share (diluted), compared to net income of $3.2 million, or $0.33 per share (diluted), as reported for the same quarter in 2012.

For the Three Months Ended September 30,	2013	2012	Increase (decrease)
(in thousands except per share)			
Business Segment:			
Regulated Energy	$10,243	$7,848	$2,395
Unregulated Energy	(1,803)	(709)	(1,094)
Other	280	425	(145)
Operating Income	8,720	7,564	1,156
Other Income	101	(136)	237
Interest Charges	2,026	2,126	(100)
Income Taxes	2,916	2,083	833
Net Income	$3,879	$3,219	$660
Earnings Per Share of Common Stock			
Basic	$0.40	$0.34	$0.06
Diluted	$0.40	$0.33	$0.07

Key variances included:

(in thousands, except per share)	Pre-tax Income	Net Income	Earnings Per Share
Third Quarter of 2012 Reported Results	$5,302	$3,219	$0.33
Adjusting for unusual items:			
Regulatory recovery of litigation-related costs	1,870	1,135	0.11
Accrual for additional taxes other than income	(698)	(424)	(0.04)
	1,172	711	0.07
Increased (Decreased) Gross Margins:			
Contribution from new acquisitions	2,416	1,467	0.15
Natural gas growth	1,213	738	0.07
Propane wholesale marketing	(517)	(314)	(0.04)
	3,112	1,891	0.18
Increased Other Operating Expenses:			
Operating the acquisitions	(2,057)	(1,249)	(0.12)
Additional investments in corporate resources to capitalize on future growth opportunities	(389)	(236)	(0.02)
Increased administrative costs (accounting, information technology and insurance)	(156)	(95)	(0.01)
	(2,602)	(1,580)	(0.15)
Net Other Changes	(189)	(362)	(0.03)
Third Quarter of 2013 Reported Results	$6,795	$3,879	$0.40

- 33

Table of Contents

Our results in the third quarter of 2013 reflected (a) a reduction in operating expense of $1.9 million due to establishing a regulatory asset, resulting from approval by the Florida PSC of the recovery of previously expensed City of Marianna franchise litigation costs, and (b) an accrual of $698,000 due to a contingency for taxes other than income. These two items resulted in a quarter-over-quarter increase in pre-tax income of $1.2 million ($711,000 in net income, or $0.07 per share).

Our results also reflected additional gross margin generated by:

(a) serving new customers acquired in 2013 through acquisitions;

(b) new and additional transmission services, which commenced in May 2013, to the NRG Energy Center Dover LLC ("NRG") electric generation plant in Dover, Delaware and the PBF Energy Inc. ("PBF Energy") refinery in Delaware City, Delaware; and

(c) growth in residential, commercial and industrial natural gas distribution customer growth on the Delmarva Peninsula and in Florida.

These increases were partially offset by lower gross margin generated by Xeron as lower volatility in wholesale propane prices resulted in lower margins in executed trades and increased other operating expenses as a result of:

(a) additional costs incurred to serve new customers acquired in 2013;

(b) additional investments in corporate resources to further develop our capability to capitalize on future growth opportunities; and

(c) increased costs associated with administrative functions, such as accounting, information technology and insurance.

Our net income for the nine months ended September 30, 2013 was $23.1 million or $2.39 per share (diluted). This represents an increase of $4.1 million, or $0.42 per share (diluted), compared to a net income of $19.0 million, or $1.97 per share (diluted), as reported for the same period in 2012.

For the Nine Months Ended September 30,	2013	2012	Increase (decrease)
(in thousands except per share)			
Business Segment:			
Regulated Energy	$36,169	$33,151	$3,018
Unregulated Energy	8,013	4,044	3,969
Other	240	897	(657)
Operating Income	44,422	38,092	6,330
Other Income	413	212	201
Interest Charges	6,114	6,657	(543)
Income Taxes	15,617	12,641	2,976
Net Income	$23,104	$19,006	$4,098
Earnings Per Share of Common Stock			
Basic	$2.40	$1.98	$0.42
Diluted	$2.39	$1.97	$0.42

- 34

Table of Contents

Key variances included:

(in thousands, except per share)	Pre-tax Income	Net Income	Earnings Per Share
Nine months ended September 30, 2012 Reported Results	$31,647	$19,006	$1.97
Adjusting for unusual items:			
Weather impact (due primarily to significantly warmer-than-normal weather in 2012)	3,891	2,337	0.24
Regulatory recovery of litigation-related costs	1,494	897	0.09
One-time sales tax expensed by Sandpiper associated with the acquisition	(726)	(436)	(0.05)
Accrual for additional taxes other than income	(698)	(419)	(0.04)
	3,961	2,379	0.24
Increased (Decreased) Gross Margins:			
Natural gas growth	3,942	2,369	0.25
Contribution from new acquisitions	3,753	2,254	0.23
Higher propane retail margins per gallon	3,265	1,961	0.20
Propane wholesale marketing	(1,453)	(873)	(0.09)
	9,507	5,711	0.59
Increased Other Operating Expenses:			
Operating the acquisitions	(3,186)	(1,913)	(0.19)
Larger accrual for incentive bonuses	(1,374)	(825)	(0.09)
Additional investments in corporate resources to capitalize on future growth opportunities	(969)	(582)	(0.06)
Increased administrative costs (accounting, information technology and insurance)	(668)	(401)	(0.04)
	(6,197)	(3,721)	(0.38)
Net Other Changes	(197)	(271)	(0.03)
Nine months ended September 30, 2013 Reported Results	$38,721	$23,104	$2.39

Our results in the first nine months of 2013 reflected additional gross margin generated by:
(a) new services and customer growth in the natural gas transmission and distribution operations as a result of major expansion initiatives completed in 2012 and 2013;
(b) new and additional transmission services, which commenced in May 2013, to the NRG electric generation plant in Dover, Delaware and the PBF Energy refinery in Delaware City, Delaware;
(c) temperatures on the Delmarva Peninsula returning to more normal levels during the first nine months of 2013 (primarily during the heating season), compared to the same period in 2012;
(d) serving new customers acquired in 2013 through acquisitions; and
(e) strong retail propane margins per gallon through the first nine months of 2013 due to the significant decrease in the average wholesale market price of propane, which lowered our cost of propane sales.
A reduction in operating expense due to establishing a regulatory asset for the recovery of previously expensed City of Marianna franchise litigation costs also contributed to the increased financial results. These increases were partially offset by decreased gross margins for Xeron as lower price volatility during the current period resulted in lower-than-usual profit on trading activity and increased other operating expenses as a result of:
(a) additional costs incurred to serve new customers acquired in 2013;
(b) increased accruals for incentive bonuses due to the timing of bonus recognition, increased participation in the bonus program and our financial performance on a year-to-date basis;
(c) additional investments in corporate resources to further develop our capability to capitalize on future growth opportunities;
(d) one-time sales tax expensed by Sandpiper related to the acquisition;

Table of Contents

(e) an accrual due to a contingency for taxes other than income; and
(f) increased costs associated with administrative functions, such as accounting, information technology and insurance.

Summary of Key Factors

The following is a summary of key factors affecting our businesses and their impacts on our results during the current and future periods.

Growth

New natural gas transmission services and growth in natural gas distribution customers generated $1.2 million and $3.9 million, respectively, in additional gross margin during the three and nine months ended September 30, 2013. These growth initiatives are further explained in the following section.

We continue to see growth in our natural gas businesses as a result of strategic initiatives over the past several years to expand delivery of natural gas to customers on the Delmarva Peninsula and in Florida. In 2012 and 2013, we expanded natural gas transmission and distribution services in Sussex County, Delaware; Worcester County, Maryland; and Nassau County, Florida, where natural gas was not previously available. We also initiated natural gas transmission service in Cecil County, Maryland. We continue to pursue several opportunities on the Delmarva Peninsula to expand our transmission facilities to meet increased demand for natural gas by industrial customers, as further discussed below.

Major Service Expansions and Customer Growth Reflected in Results

Expansion of natural gas transmission and distribution services in Sussex County, Delaware, Cecil and Worcester Counties, Maryland, and Nassau County, Florida, which commenced during the period from March 2012 to January 2013, generated additional gross margin of $119,000 and $1.1 million in the three and nine months ended September 30, 2013, respectively, compared to the same periods in 2012.

In May 2013, Eastern Shore commenced a new transmission service to the NRG electric generation plant in Dover, Delaware, which generated $579,000 and $965,000 in additional gross margin in the three and nine months ended September 30, 2013, respectively. This new service is part of Eastern Shore's current system expansion to provide 13,440 Dts/d of firm transportation service to this plant. Eastern Shore received approval from the FERC in February 2013 to construct the new facilities required for this service. In advance of completion of the construction, which is anticipated in November 2013, Eastern Shore began providing the service in May 2013 using existing system capacity under a short-term contract. Once the facilities are constructed for the NRG plant, a long-term service contract will replace the short-term contract and generate $2.4 million to $2.8 million of annual gross margin.

Also in May 2013, Eastern Shore commenced additional services to the PBF Energy refinery located in Delaware City, Delaware. These new services, which generated $133,000 and $221,000 in gross margin in the three and nine months ended September 30, 2013, respectively, are part of Eastern Shore's current system expansion to provide 15,000 Dts/d of firm transportation service to this existing customer and will replace the 10,000 Dts/d contract that expired in November 2012. Eastern Shore received necessary approval from the FERC in March 2013 to construct the new facilities required for this service. Once the additional facilities to serve the PBF Energy Delaware City refinery are constructed, the incremental service is expected to generate annual gross margin of $1.6 million. Eastern Shore provided additional interruptible service for the three and nine months ended September 30, 2013, which generated $43,000 and $487,000, respectively, of additional gross margin. This interruptible service was partially replaced by a short-term firm service contract for 5,000 Dts/d for the period from May to October 2013, which will generate $265,000 of gross margin, and ultimately by a new long-term firm service contract for 15,000 Dts/d, commencing in December 2013.

In August 2013, Peninsula Pipeline commenced a new firm transportation service in Florida with an unaffiliated utility. This new service generated $140,000 in gross margin in the three and nine months ended September 30, 2013.

The following table summarizes our major service expansions initiated in 2012 and 2013 (dollars in thousands):

Table of Contents

Project	Date of New Service	Q3 2013 Margin	YTD 2013 Margin	Estimated 2013 Margin	Estimated Annualized Margin
Sussex County, DE expansion					
Transmission (for southeastern part) 1,550 Dts/d(1)	Mar-12 to May-12	$111	$334	$446	$446
Distribution—Two facilities of an existing customer in the southeastern part of Sussex County (2)	Mar-12 to Aug-12	49	149	151	154
		$160	$483	$597	$600
Cecil County, MD expansion					
Transmission - 4,070 Dts/d(3)	Nov-12	$220	$661	$882	$882
Worcester County, MD expansion					
Transmission - 1,450 Dts/d(4)	Jun-12 to Jan-13	$98	$293	$391	$391
Nassau County, FL expansion					
Transmission - A new fixed annual rate service(5)	Apr-12	$328	$993	$1,300	$1,300
Unaffiliated FL utility, FL expansion					
Service to unaffiliated utility	Aug-13	$140	$140	$350	$840
Service to NRG's Dover, DE electric generation plant					
Short-term contract - 13,440 Dts/d(6)	May-13 to Oct-13	$579	$965	$1,158	$—
Transmission - 13,440 Dts/d (7)	Starting in Nov-13	$—	$—	$400 to $467	$2,400 to $2,800
PBF Energy's Delaware City, DE refinery expansion					
Short-term contract - 5,000 Dts/d(6)	May-13 to Oct-13	$133	$221	$265	$—
Transmission - 15,000 Dts/d (6) (7) (8)	Starting in Nov-13	$—	$—	$265	1,600
		$1,658	$3,756	$5,608 to $5,675	$8,013 to $8,413
2012 margin		$687	$1,356	$2,198	
Incremental margin in 2013 over 2012		$971	$2,400	$3,410 to $3,477	
Total by Geographic Location of the Project:					
Delmarva Natural Gas Distribution		$49	$149	$151	$154
Delmarva Natural Gas Transmission		1,141	2,474	3,807 to 3,874	5,719 to 6,119
Florida Natural Gas Transmission		468	1,133	1,650	2,140
		$1,658	$3,756	$5,608 to $5,675	$8,013 to $8,413

(1) These services generated $111,000 and $223,000 in gross margin for the three and nine months ended September 30, 2012, respectively. These services also generated $334,000 in gross margin for the year ended December 31, 2012.
(2) These services generated $19,000 and $39,000 in gross margin for the three and nine months ended September 30, 2012, respectively. These services also generated $89,000 in gross margin for the year ended December 31, 2012.
(3) These services generated $147,000 in gross margin for the year ended December 31, 2012.

(4) These services generated $29,000 and $39,000 in gross margin for the three and nine months ended September 30, 2012, respectively. These services also generated $90,000 in gross margin for the year ended December 31, 2012.
(5) These services generated $527,000 and $1.1 million in gross margin for the three and nine months ended September 30, 2012, respectively. These services also generated $1.5 million in gross margin for the year ended December 31, 2012.
(6) Prior to commencing the new service using new facilities, Eastern Shore agreed to provide a short-term service utilizing the existing system capacity from May 2013 to October 2013. During the three and nine months ended September 30, 2013, Eastern Shore provided interruptible service to the Delaware City Refinery that generated $43,000 and $487,000, respectively, in additional gross margin.
(7) A precedent agreement has been entered into by the parties for these services. The figures provided represent the estimated gross margin pursuant to the respective precedent agreement. A firm transportation service agreement, which will specify the final terms and conditions, will be entered into by the parties upon satisfying certain conditions.
(8) This contract is expected to replace the 10,000 Dts/d contract with its associated annualized gross margin of $1.1 million, which expired in November 2012.

In addition to these service expansions, our natural gas distribution operations on the Delmarva Peninsula and in Florida have generated $329,000 and $1.5 million in additional gross margin in the three and nine months ended September 30, 2013, respectively, compared to the same periods in 2012, due to increases in the number of residential, commercial and industrial

Table of Contents

customers served. These increases are due primarily to a two percent increase in residential customers on the Delmarva Peninsula, excluding the impact of the acquisition, and increases in commercial and industrial customers in Florida.

Future Major Expansion Initiatives and Opportunities

In June 2013, Eastern Shore filed an application with the FERC seeking approval to construct a pipeline lateral to the Calpine electric power plant under construction in Dover, Delaware. Upon obtaining approval from the FERC and completing construction of the required facilities, this new service is expected to generate annual gross margin of approximately \$1.2 million to \$1.8 million. The new facilities include approximately 5.5 miles of lateral pipeline and metering facilities and extend from Eastern Shore's mainline to the new Calpine plant. The construction of this lateral will not increase the overall capacity of our mainline system. Service is projected to commence in January 2015, although this is dependent upon the timing of the receipt of the necessary regulatory approval.

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

Project	Estimated Date of New Service	Estimated 2013 Margin	Estimated Annualized Margin
Service to Calpine's Dover, DE proposed electric generation plant			
Transmission - 55,200 Dts/d (1)	Starting in Jan-15	$—	$1,200 to $1,800
		$—	$1,200 to $1,800

(1) The estimated gross margin is based upon the precedent agreement entered into by the parties for these services. A firm transportation service agreement, which will specify the final terms and conditions, will be entered into by the parties upon satisfying certain conditions. The construction of this lateral will not increase the overall capacity of our mainline system.

As we expand our natural gas service to new areas, initially through transmission and distribution service to large industrial customers, our natural gas distribution operations continue to pursue additional opportunities to provide service to residential and other commercial and industrial customers in those areas. In an effort to increase the availability of natural gas within Delaware, we filed an application with the Delaware PSC in June 2012 to add several natural gas expansion service offerings. These offerings include a monthly fixed charge in lieu of upfront contributions from customers to extend the distribution system and optional service offerings to assist customers in the process of converting to natural gas. The goal of these new offerings is to meet the energy needs of residents, communities and businesses throughout our service territory, including areas of southeastern Sussex County. On November 5, 2013, the Delaware PSC approved our application.

Acquisition

In late 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 these systems to natural gas and will pursue such conversion where it is both feasible and economical. This acquisition is expected to be accretive to earnings per share in the first full year of operations. We generated \$1.7 million in additional gross margin and incurred \$1.3 million in other operating expenses for the three months ended September 30, 2013. For the nine months ended September 30, 2013, the Company generated \$2.2 million in additional gross margin and incurred \$1.8 million in other operating expenses.

Investing in Growth

We continue to expand our resources and capabilities to support growth. Our Delmarva natural gas distribution operation is in the early stages of natural gas distribution expansions in Sussex County, Delaware, and Worcester and Cecil Counties, Maryland. These expansions will require not only the construction or conversion of distribution facilities, but also the conversion of residential customers’ appliances or equipment. We have begun the process of reorganizing our Delmarva natural gas distribution operation and expect to increase our staffing to support these expansions. Eastern Shore is currently constructing new facilities to provide additional services to the NRG electric generation plant and the PBF Energy Delaware City refinery as well as developing other opportunities to further expand its transmission system. As Eastern Shore continues to expand its facilities and service, we also expect Eastern Shore to increase its staffing. Finally, to increase our overall

Table of Contents

capabilities to move growth initiatives forward and to assist in developing additional strategic initiatives for sustained future growth, resources have been, and will continue to be, added in several key functional areas, including, but not limited to, Human Resources, Communications and Strategic Business Development. We expect to make additional investments in corporate resources to further develop our capability to capitalize on future growth opportunities.

Weather and Consumption

Weather affects customer energy consumption, especially the consumption by residential and commercial customers during the peak heating and cooling seasons. Natural gas, electricity and propane are all used for heating in our service territories, and we use heating degree-days ("HDD") to analyze the weather impact. Only electricity is used for cooling and we use cooling degree-days ("CDD") to analyze the weather impact. A degree-day is the measure of the variation in the weather based on the extent to which the average daily temperature (from 10:00 am to 10:00 am) falls above or below 65 degrees Fahrenheit. Each degree of temperature above or below 65 degrees Fahrenheit is counted as one CDD or one HDD. We use 10-year historical averages to define "normal" weather for this analysis.

Although weather was not a significant factor in the second and third quarters, temperatures on the Delmarva Peninsula and in Florida returned to more normal levels during the first three months of 2013 and had a significant impact on our earnings. We generated $3.9 million of additional gross margin due to higher energy consumption as temperatures on the Delmarva Peninsula and in Florida in the first nine months of 2013 were 27 percent (651 HDD) and 40 percent (140 HDD), respectively, colder than the same period in 2012.

Propane Prices

Propane prices affect both retail and wholesale marketing margins. Our propane distribution operation usually benefits from rising propane prices by selling propane to its customers based upon higher wholesale prices, while its average cost of inventory trails behind. Retail prices generally take into account replacement cost, along with other factors, such as competition and market conditions. When wholesale prices (replacement costs) increase, retail prices generally increase, and our margins expand until the current wholesale price is fully reflected in the average cost of inventory. The opposite occurs when wholesale propane prices decline.

Although retail propane margins returned to more normal levels in the third quarter, retail margins remained strong through the heating season in early 2013, as a 25-percent decline in our propane costs from lower propane wholesale prices in late 2012 and early 2013 outpaced a slight decline in retail prices. Our propane distribution operation generated additional gross margin of $3.3 million in the nine months ended September 30, 2013, compared to the same period in 2012, due to higher retail margins per gallon. 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, and may fluctuate based on changes in demand, supply and other energy commodity prices.

Xeron, our propane wholesale marketing subsidiary, benefits from price volatility in the propane wholesale market by entering into trading transactions. Xeron experienced a decrease in gross margin of $517,000 and $1.5 million for the three and nine months ended September 30, 2013, respectively, compared to the same periods in 2012. Lower propane wholesale price volatility during the current periods resulted in lower-than-usual profit on trading activity.

Table of Contents

Regulated Energy
For the quarter ended September 30, 2013 compared to 2012

For the Three Months Ended September 30,	2013	2012	Increase (decrease)
(in thousands, except degree-day and customer information)			
Revenue	$55,680	$52,196	$3,484
Cost of sales	22,591	22,102	489
Gross margin	33,089	30,094	2,995
Operations & maintenance	15,213	15,421	(208)
Depreciation & amortization	5,216	4,798	418
Other taxes	2,417	2,027	390
Other operating expenses	22,846	22,246	600
Operating Income	$10,243	$7,848	$2,395
Weather and Customer Analysis			
Delmarva Peninsula			
HDD:			
Actual	129	79	50
10-year average	46	47	(1)
Estimated gross margin per HDD	$1,712	$2,064	$(352)
Per residential customer added:			
Estimated gross margin	$375	$375	$—
Estimated other operating expenses	$116	$113	$3
Florida			
HDD:			
Actual	—	—	—
10-year average	—	—	—
Cooling degree-days:			
Actual	1,475	1,475	—
10-year average	1,504	1,505	(1)
Residential Customer Information			
Average number of customers:			
Delmarva natural gas distribution	59,886	48,927	10,959
Florida natural gas distribution	63,280	62,215	1,065
Florida electric distribution	23,771	23,703	68
Total	146,937	134,845	12,092

Operating income for the regulated energy segment for the three months ended September 30, 2013 was $10.2 million, an increase of $2.4 million, or 31 percent, compared to the same quarter in 2012. An increase in gross margin of $3.0 million was partially offset by an increase in other operating expenses of $600,000.

Table of Contents

Gross Margin

Gross margin for our regulated energy segment increased by $3.0 million, or ten percent, in the third quarter of 2013, compared to the same quarter in 2012. Items contributing to the quarter-over-quarter increase in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended September 30, 2012	$30,094
Factors contributing to the gross margin increase for the three months ended September 30, 2013:	
Contribution from Sandpiper	1,659
Customer growth	1,213
Other	267
Decreased customer consumption - weather and other	(144)
Gross margin for the three months ended September 30, 2013	$33,089

Contribution from Sandpiper

In late May 2013, upon completion of the purchase of the ESG operating assets, Sandpiper, our new subsidiary, began providing services to approximately 11,000 propane underground distribution system customers in Worcester County, Maryland under the new tariff approved by the Maryland PSC. Sandpiper generated $1.7 million of gross margin in the third quarter of 2013.

Customer Growth

Increased gross margin from customer growth is due primarily to the following:

- $712,000 from Eastern Shore's short-term services - Eastern Shore generated additional gross margins in the third quarter of 2013 of $579,000 and $133,000 from short-term services to NRG and PBF Energy, respectively, which commenced in May 2013. These interim services are utilizing existing system capacity and will be replaced with long-term firm transportation services when new expansion facilities are completed in the fourth quarter of 2013.
- $318,000 from major expansion initiatives - Major expansion initiatives completed in 2012 and 2013 in Sussex County, Delaware and Worcester and Cecil Counties, Maryland generated $318,000 in additional gross margin in the third quarter of 2013, compared to the same quarter in 2012.
- $271,000 from Florida customer growth - Our Florida natural gas distribution operation generated $271,000 of additional gross margin in the third quarter of 2013, compared to the same quarter in 2012, due primarily to growth in commercial and industrial customers.
- $57,000 from Delmarva customer growth - A two-percent growth in residential customer and other growth in commercial and industrial customers in our Delmarva natural gas distribution operation generated $57,000 of additional gross margin in the third quarter of 2013, compared to the same quarter in 2012.

Partially offsetting the above increases was a decrease of $199,000 in gross margin generated by Peninsula Pipeline due to additional transportation costs incurred to serve Nassau County, Florida. Peninsula Pipeline began its service to Nassau County in April 2012, using compressed natural gas while a new pipeline was being constructed. The new pipeline was completed and placed in service in December 2012. Upon completion of the new pipeline, Peninsula Pipeline began to incur approximately $800,000 in annual transportation costs, which reduced its gross margin.

Decreased Customer Consumption—Weather and Other

Lower customer consumption of natural gas and electricity due to weather and other factors decreased gross margin by $144,000.

Other Operating Expenses

Other operating expenses for the regulated energy segment increased by $600,000, or three percent, in the third quarter of 2013, compared to the same quarter in 2012. The increase in other operating expenses was due primarily to: (a) $1.3 million in other operating expenses associated with Sandpiper's operations, (b) $411,000 in higher depreciation expense, amortization, asset

Table of Contents

removal and property tax costs associated with capital investments to support growth and maintain system integrity, (c) $319,000 in increased administrative costs, such as accounting, information technology and insurance costs, and (d) $298,000 in additional investments in corporate resources to further develop our capability to capitalize on future growth opportunities. These increases were partially offset by a reduction of $1.9 million in operations expense to establish a regulatory asset for the recovery of previously expensed City of Marianna franchise litigation costs.

For the nine months ended September 30, 2013 compared to 2012

For the Nine Months Ended September 30,	2013	2012	Increase (decrease)
(in thousands, except degree-day and customer information)			
Revenue	$192,463	$180,045	$12,418
Cost of sales	86,321	81,207	5,114
Gross margin	106,142	98,838	7,304
Operations & maintenance	47,363	45,148	2,215
Depreciation & amortization	14,922	14,527	395
Other taxes	7,688	6,012	1,676
Other operating expenses	69,973	65,687	4,286
Operating Income	$36,169	$33,151	$3,018
Weather and Customer Analysis			
Delmarva Peninsula			
HDD:			
Actual	3,026	2,375	651
10-year average	2,867	2,899	(32)
Estimated gross margin per HDD	$1,712	$2,064	$(352)
Per residential customer added:			
Estimated gross margin	$375	$375	$—
Estimated other operating expenses	$116	$113	$3
Florida			
HDD:			
Actual	487	347	140
10-year average	570	587	(17)
Cooling degree-days:			
Actual	2,421	2,622	(201)
10-year average	2,490	2,486	4
Residential Customer Information			
Average number of customers:			
Delmarva natural gas distribution	60,519	49,516	11,003
Florida natural gas distribution	63,316	62,316	1,000
Florida electric distribution	23,757	23,663	94
Total	147,592	135,495	12,097

Operating income for the regulated energy segment for the nine months ended September 30, 2013 was $36.2 million, an increase of $3.0 million, or nine percent, compared to the same period in 2012. An increase in gross margin of $7.3 million was partially offset by an increase in other operating expenses of $4.3 million.

- 42

Table of Contents

Gross Margin

Gross margin for our regulated energy segment increased by $7.3 million, or seven percent, for the nine months ended September 30, 2013, compared to the same period in 2012. Items contributing to the period-over-period increase in gross margin are listed in the following table:

(in thousands)	
Gross margin for the nine months ended September 30, 2012	$98,838
Factors contributing to the gross margin increase for the nine months ended September 30, 2013:	
Customer growth	3,941
Contribution from Sandpiper	2,198
Increased customer consumption—weather and other	800
Other	493
Florida natural gas accrued revenue adjustment - recorded in 2012	(128)
Gross margin for the nine months ended September 30, 2013	$106,142

Customer Growth

Increased gross margin from customer growth is due primarily to the following:

- $1.1 million from major expansion initiatives - Major expansion initiatives completed in 2012 and 2013 in Sussex County, Delaware; Worcester and Cecil Counties, Maryland; and Nassau County, Florida generated $1.1 million in additional gross margin in the first nine months of 2013.
- $1.1 million from Florida customer growth - Our Florida natural gas distribution operation generated $1.1 million of additional gross margin in the first nine months of 2013, compared to the same period in 2012, due primarily to a three-percent growth in commercial and industrial customers.
- $1.2 million from Eastern Shore's short-term services - Eastern Shore generated additional margins of $965,000 and $221,000 from short-term services to NRG and PBF Energy, respectively, which commenced in May 2013. These interim services are utilizing existing system capacity and will be replaced with long-term firm transportation services when new expansion facilities are completed in the fourth quarter of 2013.
- $387,000 from Delmarva customer growth - A two-percent residential customer growth and other growth in commercial and industrial customers in our Delmarva natural gas distribution operation generated $387,000 of additional gross margin in the first nine months of 2013, compared to the same period in 2012.

Contribution from Sandpiper

In late May 2013 upon completion of the purchase of the ESG operating assets, Sandpiper, our new subsidiary, began providing services to approximately 11,000 propane underground distribution system customers in Worcester County, Maryland under the new tariff approved by the Maryland PSC. Sandpiper generated $2.2 million of gross margin in the period from the completion of the acquisition in May 2013 through September 2013.

Increased Customer Consumption—Weather and Other

Higher customer consumption, due to temperatures on the Delmarva Peninsula and in Florida returning to more normal levels during the first nine months of 2013, generated increased gross margin of approximately $1.1 million. HDD increased by 651, or 27 percent, on the Delmarva Peninsula and 140, or 40 percent, in Florida during the first nine months of 2013, compared to the same period in 2012.

Other Operating Expenses

Other operating expenses for the regulated energy segment increased by $4.3 million, or seven percent, in the first nine months of 2013, compared to the same period in 2012. The increase in other operating expenses was due primarily to (a) $1.8 million in other operating expenses associated with Sandpiper's operations, (b) an increase of $989,000 in the accrual for incentive bonuses as a result of increased participation in the bonus program and our financial performance on a year-to-date basis, (c) $942,000 in increased administrative costs, such as accounting, information technology and insurance costs, (d) $824,000 in additional investments in corporate resources to further develop our capability to capitalize on future growth opportunities, (e) a one-time sales tax of $726,000 expensed by

Sandpiper related to the acquisition in May 2013, and (f) $560,000 in higher

- 43

Table of Contents

depreciation, amortization, asset removal costs and property taxes associated with capital expenditures to support growth and maintain system integrity. These increases were partially offset by a reduction of $1.5 million for the recovery of previously expensed litigation costs.

Unregulated Energy
For the quarter ended September 30, 2013 compared to 2012

For the Three Months Ended September 30,	2013	2012	Increase (decrease)
(in thousands, except degree-day data)			
Revenue	$28,262	$23,259	$5,003
Cost of sales	21,484	17,033	4,451
Gross margin	6,778	6,226	552
Operations & maintenance	6,557	5,756	801
Depreciation & amortization	944	861	83
Other taxes	1,080	318	762
Other operating expenses	8,581	6,935	1,646
Operating Loss	$(1,803)	$(709)	$(1,094)
Weather Analysis—Delmarva Peninsula			
Actual HDD	129	79	50
10-year average HDD	46	47	(1)
Estimated gross margin per HDD	$2,882	$2,869	$13

Operating loss for the unregulated energy segment for the third quarter of 2013 was $1.8 million, compared to an operating loss of $709,000 in the same quarter in 2012. An increase in gross margin of $552,000 was partially offset by an increase in other operating expenses of $1.6 million.

Gross Margin

Gross margin for our unregulated energy segment increased by $552,000, or nine percent, in the third quarter of 2013, compared to the same quarter in 2012. Items contributing to the quarter-over-quarter increase in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended September 30, 2012	$6,226
Factors contributing to the gross margin increase for the three months ended September 30, 2013:	
Contribution from acquisitions	757
Decreased margins from propane wholesale marketing	(517)
Other	224
Increased customer consumption—weather and other	163
Decrease in retail margins per gallon	(75)
Gross margin for the three months ended September 30, 2013	$6,778

Contribution from Acquisitions

The acquisitions of the operating assets of Glades in February 2013 and Austin Cox in June 2013 generated $270,000 and $487,000 of additional gross margin during the third quarter of 2013.

- 44

Table of Contents

Decreased Margins from the Propane Wholesale Marketing Operation

Xeron, our propane wholesale marketing operation, experienced a decrease in gross margin of $517,000 in the third quarter of 2013, compared to the same quarter in 2012 as a result of lower margins in executed trades. Xeron executed trades with lower margins due primarily to lower price volatility in the wholesale propane market during the current quarter compared to the same quarter in 2012.

Increased Customer Consumption—Weather and Other

Increased gross margin from higher customer consumption is due primarily to the following:

- $89,000 from increased weather-related consumption - Temperatures on the Delmarva Peninsula returning to more normal levels during the third quarter of 2013 increased gross margin by $89,000.
- $45,000 from lower non-weather-related consumption - Gross margin decreased by $45,000 as a result of lower customer consumption due to the timing of deliveries to bulk-delivery customers on the Delmarva Peninsula, and a decline in non-weather-related consumption by Florida customers in the third quarter of 2013, compared to the same quarter in 2012.
- $119,000 from higher wholesale sales - An increase in wholesale propane sales generated $119,000 of additional gross margin in the third quarter of 2013, compared to the same quarter in 2012.

Decrease in Retail Margins per Gallon

Higher retail margins per gallon for our Delmarva propane distribution operation generated $234,000 of additional gross margin in the third quarter of 2013, compared to the same quarter in 2012, offset by lower margins per gallon of $310,000 for our Florida propane distribution operation.

Other Operating Expenses

Other operating expenses for the unregulated energy segment increased by $1.6 million, or 24 percent, in the third quarter of 2013, compared to the same quarter in 2012. The increase in other operating expenses was due primarily to $754,000 in additional expenses associated with serving newly acquired customers and an accrual of $698,000 due to a contingency for taxes other than income during the quarter.

For the nine months ended September 30, 2013 compared to 2012

For the Nine Months Ended September 30,	2013	2012	Increase (decrease)
(in thousands, except degree-day data)			
Revenue	$119,278	$93,323	$25,955
Cost of sales	87,224	68,646	18,578
Gross margin	32,054	24,677	7,377
Operations & maintenance	19,265	16,974	2,291
Depreciation & amortization	2,811	2,552	259
Other taxes	1,965	1,107	858
Other operating expenses	24,041	20,633	3,408
Operating Income	$8,013	$4,044	$3,969
Weather Analysis—Delmarva Peninsula			
Actual HDD	3,026	2,375	651
10-year average HDD	2,867	2,899	(32)
Estimated gross margin per HDD	$2,882	$2,869	$13

Operating income for the unregulated energy segment for the nine months ended September 30, 2013 was $8.0 million, an increase of $4.0 million, or 98 percent, compared to the same period in 2012. An increase in gross margin of $7.4 million was partially offset by an increase in other operating expenses of $3.4 million.

Table of Contents

Gross Margin

Gross margin for our unregulated energy segment increased by $7.4 million, or 30 percent, in the first nine months of 2013, compared to the same period in 2012. Items contributing to the period-over-period increase in gross margin are listed in the following table:

(in thousands)	
Gross margin for the nine months ended September 30, 2012	$24,677
Factors contributing to the gross margin increase for the nine months ended September 30, 2013:	
Increase in retail margin per gallon	3,265
Increased customer consumption—weather and other	3,227
Contributions from acquisitions	1,555
Decreased propane wholesale marketing margins	(1,453)
Other	783
Gross margin for the nine months ended September 30, 2013	$32,054

Increase in Retail Margins per Gallon

Higher retail margins per gallon in the Delmarva propane distribution operation generated $3.3 million of additional gross margin in the first nine months of 2013, compared to the same period in 2012. Retail margins per gallon in the Florida propane distribution operation declined slightly and resulted in lower gross margin of $56,000 for the same period. Retail margins remained strong through the heating season in early 2013, as a 25-percent decline in propane inventory costs from lower propane wholesale prices in late 2012 and early 2013 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, and may fluctuate based on changes in demand, supply and other energy commodity prices.

Increased Customer Consumption—Weather and Other

Increased gross margin from higher customer consumption is due primarily to the following:

- $2.8 million from increased weather-related consumption - Temperatures on the Delmarva Peninsula and in Florida returned to more normal levels during the first nine months of 2013, compared to the same period in 2012, and increased gross margin by $2.8 million.
- $389,000 from higher wholesale sales - An increase in wholesale propane sales generated $389,000 of additional gross margin in the first nine months of 2013, compared to the same period in 2012.

Contribution from Acquisitions

The acquisitions of the operating assets of Glades in February 2013 and Austin Cox in June 2013 generated $831,000 and $724,000 of additional gross margin in the first nine months of 2013.

Decreased Margins from the Propane Wholesale Marketing Operation

Xeron, our propane wholesale marketing operation, experienced a decrease in gross margin of $1.5 million in the first nine months of 2013 compared to the same period in 2012, as a result of lower margins on executed trades. Lower margins in executed trades as a result of low price volatility in the wholesale propane market, and a decrease in trading volume reduced Xeron's gross margin in the first nine months of 2013 compared to the same period in 2012.

Other

Increased gross margin from other factors is primarily attributable to $251,000 and $504,000 from merchandise sales and miscellaneous fees, respectively.

Other Operating Expenses

Other operating expenses for the unregulated energy segment increased by $3.4 million, or 17 percent, in the first nine months of 2013, compared to the same period in 2012. The increase in other operating expenses was due primarily to: (a) $1.4 million in additional expenses associated with serving newly acquired customers, (b) an accrual of $698,000 due to a contingency for

- 46

Table of Contents

taxes other than income, and (c) $371,000 in the increased accrual for incentive bonuses as a result of the strong 2013 year-to-date financial performance of the unregulated business segment.

Other

For the quarter ended September 30, 2013 compared to 2012

For the Three Months Ended September 30,	2013	2012	Increase (decrease)
(in thousands)			
Revenue	$2,603	$2,720	$(117)
Cost of sales	311	569	(258)
Gross margin	2,292	2,151	141
Operations & maintenance	1,676	1,428	248
Depreciation & amortization	114	108	6
Other taxes	222	190	32
Other operating expenses	2,012	1,726	286
Operating Income—Other	$280	$425	$(145)

Operating income for our “other” segment, which is comprised primarily of BravePoint®, Inc. (“BravePoint”), our advanced information services subsidiary, decreased by $145,000, or 34 percent, in the third quarter of 2013, compared to the same quarter in 2012, which was attributable to a gross margin increase of $141,000 and an operating expenses increase of $286,000 due to higher payroll and related costs.

For the nine months ended September 30, 2013 compared to 2012

For the Nine Months Ended September 30,	2013	2012	Increase (decrease)
(in thousands)			
Revenue	$9,678	$9,619	$59
Cost of sales	3,432	3,410	22
Gross margin	6,246	6,209	37
Operations & maintenance	4,938	4,345	593
Depreciation & amortization	338	333	5
Other taxes	730	634	96
Other operating expenses	6,006	5,312	694
Operating Income—Other	$240	$897	$(657)

The “other” segment reported operating income of $240,000 through the first nine months of 2013, compared to $897,000 through the same period in 2012. The decrease in operating income was attributable to an increase in other operating expenses for BravePoint due to higher payroll and related costs.

Interest Charges

For the quarter ended September 30, 2013 compared to 2012

Interest charges for the three months ended September 30, 2013 decreased by approximately $100,000, or five percent, compared to the same quarter in 2012. The decrease in interest charges is attributable primarily to decreases of $208,000 in other long-term interest expense due to scheduled repayments and $52,000 in interest on deposits from customers due to a lower interest rate on those deposits. These decreases were partially offset by an increase of $157,000 in short-term interest expense due to higher borrowings in 2013.

For the nine months ended September 30, 2013 compared to 2012

Table of Contents

Interest charges for the nine months ended September 30, 2013 decreased by approximately $543,000, or eight percent, compared to the same period in 2012. The decrease in interest charges is attributable primarily to decreases of $520,000 in other long-term interest expense due to scheduled repayments and $370,000 in interest on deposits from customers due to a lower interest rate on those deposits. These decreases were partially offset by an increase of $344,000 in short-term interest expense due to higher borrowings in 2013.

Income Taxes

For the quarter ended September 30, 2013 compared to 2012

Income tax expense was $2.9 million in the third quarter of 2013, compared to $2.1 million in the same quarter in 2012. The increase in income tax expense was due to higher taxable income. Our effective income tax rate was 42.9 percent and 39.3 percent for the third quarters of 2013 and 2012, respectively. A higher effective income tax rate in the third quarter of 2013 is due to additional income tax expense associated with the reconciliation of income tax returns filed during the quarter and an adjustment to state tax expense.

For the nine months ended September 30, 2013 compared to 2012

Income tax expense was $15.6 million through the first nine months of 2013, compared to $12.6 million for the same period in 2012. The increase in income tax expense was due to higher taxable income. Our effective income tax rate was 40.3 percent and 39.9 percent for the first nine months of 2013 and 2012, respectively.

Table of Contents

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 by our natural gas, electric, 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.

Capital expenditures, which are our investments in new or acquired plant and equipment, are our largest capital requirements. We originally budgeted $112.3 million for capital expenditures during 2013. As a result of continued growth, expansion opportunities and the timing of capital projects, we have increased our capital expenditure projection for 2013 to $126.8 million. Included in the 2013 capital expenditure projection is approximately $16.0 million for the ESG acquisition, which was completed in May 2013. The following table shows the 2013 capital expenditure projection by segment:

(dollars in thousands)	
Regulated Energy:	
Natural gas distribution	$68,763
Natural gas transmission	37,556
Electric distribution	6,399
Total Regulated Energy	112,718
Unregulated Energy:	
Propane distribution	5,528
Other unregulated energy	1,653
Total Unregulated Energy	7,181
Other	
Advanced information services	623
Other	6,241
Total Other	6,864
Total 2013 projected capital expenditures	$126,763

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

In June 2013, we increased our total short-term borrowing capacity under bank credit facilities from $140.0 million to $165.0 million. These bank credit facilities are available to provide funds for our short-term cash needs to meet seasonal working capital requirements and to temporarily fund portions of our capital expenditures. We are currently authorized by our Board of Directors to borrow up to $140.0 million of short-term debt, as required, under these bank credit facilities.

In September 2013, we entered into the Note Agreement with the Note Holders to issue $20.0 million and $50.0 million of unsecured senior notes on December 16, 2013 and May 15, 2014, respectively. These notes have a 15-year term with semiannual principal payments beginning six years after their respective issuance. These unsecured senior notes bear interest at 3.73 percent and 3.88 percent, respectively. We expect to use the proceeds from these unsecured senior notes to permanently fund our capital expenditures.

- 49

Table of Contents

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, will enable us to attract capital from outside sources at a reasonable cost. We believe that the achievement of these objectives will provide benefits to our customers, creditors and investors. The following presents our capitalization, excluding and including short-term borrowings, as of September 30, 2013 and December 31, 2012:

	September 30, 2013			December 31, 2012		
(in thousands)						
Long-term debt, net of current maturities	$107,344	28	%	$101,907	28	%
Stockholders’ equity	269,788	72	%	256,598	72	%
Total capitalization, excluding short-term debt	$377,132	100	%	$358,505	100	%

	September 30, 2013			December 31, 2012		
(in thousands)						
Short-term debt	$91,297	19	%	$61,199	14	%
Long-term debt, including current maturities	115,578	24	%	110,103	26	%
Stockholders’ equity	269,788	57	%	256,598	60	%
Total capitalization, including short - term debt	$476,663	100	%	$427,900	100	%

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

Short-term Borrowings

Our outstanding short-term borrowings at September 30, 2013 and December 31, 2012 were $91.3 million and $61.2 million, respectively, at weighted average interest rates of 1.26 percent and 1.48 percent, respectively.

As of September 30, 2013, we had five unsecured short-term credit facilities with two financial institutions for a total of $165.0 million. Two of these unsecured bank lines, totaling $85.0 million, are available under committed lines of credit. Advances offered under the uncommitted lines of credit, totaling $40.0 million, are subject to the discretion of the banks. None of these unsecured bank lines of credit requires compensating balances. The remaining $40.0 million of our short-term credit facilities is structured in the form of a revolving credit note.

Cash Flows

The following table provides a summary of our operating, investing and financing cash flows for the nine months ended September 30, 2013 and 2012:

For the Nine Months Ended September 30,	2013		2012	
(in thousands)				
Net cash provided by (used in):				
Operating activities	$66,427		$64,465	
Investing activities	(85,768	)	(49,539	)
Financing activities	17,772		(15,517	)
Net decrease in cash and cash equivalents	(1,569	)	(591	)
Cash and cash equivalents—beginning of period	3,361		2,637	
Cash and cash equivalents—end of period	$1,792		$2,046	

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 income taxes and working capital. Changes in working capital are determined by a variety of factors,

- 50

Table of Contents

including weather, the prices of natural gas, electricity and propane, the timing of customer collections, payments for purchases of natural gas, electricity and propane, and deferred fuel cost recoveries.

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

During the nine months ended September 30, 2013 and 2012, net cash provided by operating activities was $66.4 million and $64.5 million, respectively, resulting in an increase in cash flows of $2.0 million. Significant operating activities generating the cash flow change were as follows:

- Higher net accounts receivable and payable decreased the cash flows by $8.8 million, due primarily to the timing of the collections and payments associated with trading contracts entered into by our propane wholesale and marketing subsidiary.
- Lower net regulatory assets and liabilities increased the cash flows by $8.1 million, due primarily to an increase in fuel costs collected through fuel cost recovery. Also, the absence of a $1.2 million refund in January 2012 by Eastern Shore to customers as a result of its rate case settlement contributed to this increase.
- Lower net income taxes paid increased the cash flows by $2.8 million, due primarily to a tax refund of approximately $5.0 million received from the Internal Revenue Service during the first nine months of 2013. This was partially offset by an increase in estimated tax payments in 2013 due to higher operating results.

Cash Flows Used in Investing Activities

Net cash used in investing activities totaled $85.8 million and $49.5 million during the nine months ended September 30, 2013 and 2012, respectively, resulting in a decrease in cash flows of $36.2 million. Significant investing activities generating the cash flow change were as follows:

- Cash paid for capital expenditures increased by $17.2 million to $68.6 million for the first nine months of 2013, compared to $51.4 million for the same period in 2012.
- Cash paid for acquisitions was $19.4 million and cash received from the sale of equity securities was $2.3 million in the first nine months of 2013.
- In February 2012, we sold an office building in West Palm Beach, Florida for approximately $2.2 million in cash.

Cash Flows Used by Financing Activities

Net cash provided by financing activities totaled $17.8 million in the first nine months of 2013, compared to net cash used in financing activities of $15.5 million for the same period in 2012, resulting in an increase of $33.3 million in cash flows. Significant financing activities generating the cash flow change were as follows:

- During the first nine months of 2013, we had a net borrowing of $32.8 million under our line of credit agreements, compared to a net repayment of $2.4 million for the same period in 2012, resulting in a net cash increase of $35.2 million. Changes in cash overdrafts increased by $1.1 million, resulting in a period-over-period net cash increase.
- We paid $9.7 million and $9.2 million in cash dividends for the nine months ended September 30, 2013 and 2012, respectively.

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 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 September 30, 2013 was $31.1 million, with the guarantees expiring on various dates through September 2014.

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

Table of Contents

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, 2014. There have been no draws on these letters of credit as of September 30, 2013. 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.

Contractual Obligations

There has not been any material change in the contractual obligations presented in our 2012 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 September 30, 2013.

	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)]	$17,238	$558	$29	$ —	$17,825
Propane [(2)]	11,022	19,857	7,569	1,470	39,918
Total Purchase Obligations	$28,260	$20,415	$7,598	$ 1,470	$57,743

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

(2) We have also entered into forward sale contracts in the aggregate amount of $1.7 million. See Part I, Item 3, “Quantitative and Qualitative Disclosures about Market Risk,” below, for further information.

Environmental Matters

As more fully described in Note 5, “Environmental Commitments and Contingencies,” to the unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q, we continue to work with federal and state environmental agencies to assess the environmental impact and explore corrective action at seven environmental sites. We believe that future costs associated with these sites will be recoverable in rates or through sharing arrangements with, or contributions by, other responsible parties.

OTHER MATTERS

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 their respective PSC; Eastern Shore is subject to regulation by the FERC; and Peninsula Pipeline is subject to regulation by the Florida PSC. At September 30, 2013, 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.

Competition

Our natural gas and electric distribution operations and our natural gas transmission operations compete with other forms of energy, including natural gas, electricity, oil, propane and other alternative sources of energy. The principal competitive factors are price and, to a lesser extent, accessibility. Our natural gas distribution operations have several large-volume industrial customers that are able to use fuel oil as an alternative to natural gas. When oil prices decline, these interruptible customers may convert to oil to satisfy their fuel requirements, and our interruptible sales volumes may decline. Oil prices, as well as the prices of other fuels, fluctuate for a variety of reasons; therefore, future competitive conditions are not predictable. To address this uncertainty, we use flexible pricing arrangements on both the supply and sales sides of this business to compete with

Table of Contents

alternative fuel price fluctuations. As a result of the conversion of our natural gas transmission operations to open access and Chesapeake's Florida natural gas distribution division's restructuring of its services, these businesses have shifted from providing bundled transportation and sales service to providing only transmission and contract storage services. Our electric distribution operation currently does not face substantial competition because the electric utility industry in Florida has not been deregulated. In addition, natural gas is the only viable alternative fuel to electricity in our electric service territories and is available only in a small area.

Our natural gas distribution operations in Delaware, Maryland and Florida offer unbundled transportation services to certain commercial and industrial customers. In 2002, Chesapeake's Florida natural gas distribution division, Central Florida Gas, extended such service to residential customers. With such transportation service available on our distribution systems, we are competing with third-party suppliers to sell gas to all customers. With respect to unbundled transportation services, our competitors include interstate transmission companies, if the distribution customers are located close enough to a transmission company's pipeline to make connections economically feasible. The customers at risk are usually large volume commercial and industrial customers with the financial resources and capability to bypass our existing distribution operations in this manner. In certain situations, our distribution operations may adjust services and rates for these customers to retain their business. We expect to continue to expand the availability of unbundled transportation service to additional classes of distribution customers in the future. We have also established a natural gas marketing operation in Florida, Delaware and Maryland to provide such service to customers eligible for unbundled transportation services.

Our propane distribution operations compete with several other propane distributors in their respective geographic markets, primarily on the basis of service and price, emphasizing responsive and reliable service. Our competitors generally include local outlets of national distributors and local independent distributors, whose proximity to customers entails lower costs to provide service. Propane competes with electricity as an energy source, because it is typically less expensive than electricity, based on equivalent BTU value. Propane also competes with home heating oil as an energy source. Since natural gas has historically been less expensive than propane, propane is generally not distributed in geographic areas served by natural gas pipeline or distribution systems.

The propane wholesale marketing operation competes against various regional and national marketers, many of which have significantly greater resources and are able to obtain price or volumetric advantages.

Our advanced information services subsidiary faces significant competition from a number of larger competitors having substantially greater resources available to them than does our subsidiary. In addition, changes in the advanced information services business are occurring rapidly and could adversely affect the markets for the products and services offered by these businesses. This segment competes on the basis of technological expertise, reputation and price.

Inflation

Inflation affects the cost of supply, labor, products and services required for operations, maintenance and capital improvements. While the impact of inflation has remained low in recent years, natural gas and propane prices are subject to rapid fluctuations. In the regulated natural gas and electric distribution operations, fluctuations in natural gas and electricity prices are passed on to customers through the fuel cost recovery mechanism in our tariffs. To help cope with the effects of inflation on our capital investments and returns, we seek rate increases from regulatory commissions for our regulated operations and closely monitor the returns of our unregulated business operations. To compensate for fluctuations in propane gas prices, we adjust propane selling prices to the extent allowed by the market.

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, secured debt and convertible debentures. 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 these long-term debt, including current maturities, was $108.5 million at September 30, 2013, as compared to a fair value of $127.2 million, using a discounted cash flow methodology that incorporates a market interest rate that is 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.

Table of Contents

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 6.0 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 forward contracts, primarily propane contracts, with various third parties. These contracts 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 futures contracts at September 30, 2013 is presented in the following tables.

At September 30, 2013	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts			
Sale	1,682,000	$0.9625 - $1.1338	$ 1.0370
Purchase	1,682,000	$0.9038 - $1.3176	$ 0.9861

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

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

At September 30, 2013 and December 31, 2012, we marked these forward and other contracts to market, using market transactions in either the listed or OTC markets, which resulted in the following assets and liabilities:

(in thousands)	September 30, 2013	December 31, 2012
Mark-to-market energy assets, including call options	$379	$210
Mark-to-market energy liabilities	$124	$331

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer and Chief Financial Officer of the Company, with the participation of other Company officials, have evaluated our "disclosure controls and procedures" (as such term is defined under Rules 13a-15(e) and

15d-15(e), promulgated under the Securities Exchange Act of 1934, as amended) as of September 30, 2013. Based upon their evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2013.

Table of Contents

Changes in Internal Control over Financial Reporting

During the quarter ended September 30, 2013, 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.

Table of Contents

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, 2012, 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]
July 1, 2013 through July 31, 2013 [1]	259	$53.07	—	—
August 1, 2013 through August 31, 2013	—	$—	—	—
September 1, 2013 through September 30, 2013	—	$—	—	—
Total	259	$53.07	—	—

(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 15, Employee Benefit Plans" in our latest Annual Report on Form 10-K for the year ended December 31, 2012. During the quarter, 259 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 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Table of Contents

Item 6. Exhibits

4.1	Note Agreement entered into by Chesapeake on September 5, 2013 pursuant to which Chesapeake will issue Series A Notes and Series B Notes to the Noteholders is not being filed herewith pursuant to Item 601(b)(4)(v) of Regulation S-K under the Securities Act of 1933, as amended. We hereby agree to furnish a copy of the agreement to the SEC upon request.
31.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, dated November 7, 2013.
31.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, dated November 7, 2013.
32.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated November 7, 2013.
32.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated November 7, 2013.
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.

Table of Contents

SIGNATURES

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

CHESAPEAKE UTILITIES CORPORATION

/S/ BETH W. COOPER
Beth W. Cooper
Senior Vice President and Chief Financial Officer
Date: November 7, 2013